1. Reference: Delivery Service Rate Overview

a) Have there been any significant changes to the chart of accounts that would impact comparability to prior test years. Please discuss.

As a result of organizational restructuring over the years there have been some changes to the chart of accounts over that time. However, none of these changes would materially affect comparability to prior test years.

b) Please confirm that "2015/16 Actual" in all schedules and tables in the application reflect actuals from April 1, 2015 to March 31, 2016. If not confirmed, please provide.

Confirmed, the "2015/16 Actual" column in all schedules and tables in the application reflect actuals from April 1, 2015 to March 31, 2016.

c) Please confirm that the "2016/17 Forecast" reflects 2016/17 audited actuals in all schedules and tables in the application. If not confirmed, please clarify.

The "2016/17 Forecast" column in all schedules and tables in the application reflects only 11 months of actual results from April 1, 2016 to February 28, 2017 plus the forecast results for March 31, 2017. These are not audited actual results for the year as those were not available when the rate application schedules were finalized. Final 2016/17 audited actual results were not materially different from the 2016-17 Forecast.

d) Please confirm that "2017/18 Forecast" and "2018/19 Forecast" in all schedules and tables in the application reflect the forecast from April 1 to March 31 of the following year.

Confirmed, the "2017/18 Forecast" in all schedules and tables in the application reflect the forecast from April 1, 2017 to March 31, 2018. The "2018/19 Forecast" in all schedules and tables in the application reflect the forecast from April 1, 2018 to March 31, 2019.

e) Page 2 of the application notes that capital spending on infrastructure since 2010 "produces no incremental revenue".

i. Please explain this statement in further detail and provide examples where capital spending would provide incremental revenue.

Capital spending related to integrity programming allows the corporation to continue to provide safe and reliable natural gas service to its customers. However, this capital investment does not generate an incremental revenue stream for the corporation from its delivery customers. By comparison, capital investment to connect new delivery customers does generate incremental revenue through increased basic monthly charge revenue and incremental delivery service revenue.

ii. Will the capital spending on infrastructure since 2010 reduce O&M expense going forward? Please discuss and quantify any expected

O&M savings from infrastructure renewal investments in the 2017/18 test year revenue requirement

Yes, an example would be the service upgrade program, and the leak survey program. A number of the services being upgraded are high risk and on a 3 to 6 week leak survey cycle. With the upgrade, the cycle will move to a 1 to 4 year cycle depending on location. Also the programs are risk based and therefore, number of leaks will decrease, thus saving operating dollars for response. A total value of savings has not been quantified at this time; however these are included in our annual efficiency reporting metrics.

f) Please confirm that the required rate increase is not driven by a change in customer usage characteristics or due to cost change for a specific customer class.

Confirmed.

g) For each revenue requirement item in Schedule 1.0:

i. Please provide a comparison of 2016/17 test year forecast from the 2016 Application to the year-to-date actuals [November 1, 2016 to June 1, 2017]. Please also update the 2016/17 test year forecast for the remaining months [July-October 2017].

The forecast for the months of July to October 2017 has not been finalized; however, no material changes are anticipated in the forecast for the remaining months of the test period. It is part of Q1 reporting to our Board and CIC and will not be available until after it has been reviewed by the SaskEnergy Executive, the SaskEnergy Board and CIC. The comparison of 2016/17 test year forecast from the 2016 Application to the year-to-date actuals [November 1, 2016 to June 30, 2017] has been provided below.

	2016-17 Test Year Nov 1-16 to June 2017 YTD Delivery Rate Application	2016-17 Test Year Nov 1-16 to June 2017 YTD Actuals	Variance
Component			
Operating and Maintenance	83,685	78,592	(5,093)
Transportation and Storage	34,022	33,367	(656)
Depreciation Expense	27,751	26,720	(1,031)
Tax Expense	3,335	3,161	(173)
Interest Expense	16,733	15,947	(786)
Net Earnings	43,615	44,435	821
Other Revenue	(16,104)	(14,971)	1,134
Net Delivery Revenue Requirement	193,037	187,252	(5,785)

ii. Please provide an explanation of any material differences between the 2016/17 test year forecast included in the Application and the updated 2016/17 test year [provided in (i)].

Please refer to 1g) i. response.

h) Please provide a version of Schedule 1.0 that shows the following:

i. The 2013 and 2014 test year revenue requirement from the 2013 Delivery Service Rate Application;

Schedule 1.0

Delivery Service Revenue Requirement Summary
($000's)

	2013/14* Test Year	2014/15** Test Year
Component		
Operating & Maintenance	105,855	108,149
Transportation & Storage	45,156	46,659
Depreciation Expense	39,003	41,598
Tax Expense	3,531	3,647
Interest Expense	17,323	18,415
Net Earnings	22,586	24,372
Total Delivery Revenue Requirement	233,454	242,840
Other Revenue and Adjustments		
Other Revenue	-23,153	-25,154
Net Delivery Revenue Requirement	210,301	217,686

***Information from the 2013 Delivery Rate Application**

* September 01, 2013 – August 31, 2014
** September 01, 2014 – August 31, 2015

ii. The 2015 and 2016 test year forecasts from the 2015 Delivery Service and Commodity Rate Application and calendar year forecast and actual results for 2015 and 2016 [calendar year];

Delivery Service Revenue Requirement Summary ($000's)	**2015/16* Test Year*** **	**2015* Calendar Year Forecast**	**2015* Calendar Year Actual**	**2016* Calendar Year Forecast**	**2016** Calendar Year Actual**
Component					
Operating & Maintenance	119,967	118,367	114,975	120,615	Not applicable
Transportation & Storage	50,324	48,350	48,547	50,718	Not applicable
Depreciation Expense	38,280	36,446	35,990	38,671	Not applicable
Tax Expense	4,999	4,803	4,569	5,166	Not applicable
Interest Expense	23,581	21,623	20,699	24,114	Not applicable
Net Earnings	18,009	15,155	9,574	16,558	Not applicable
Total Delivery Revenue Requirement	255,160	244,744	234,354	255,842	Not applicable
Other Revenue and Adjustments					
Other Revenue	(22,177)	(22,727)	(24,311)	(21,895)	Not applicable
Net Delivery Revenue Requirement	232,983	222,017	210,043	233,947	Not applicable

Information from the 2015 Delivery Rate Application
****SaskEnergy no longer reports calendar year results. Beginning in 2016-17, the fiscal year changed to April to March**
*****November 1, 2015 to October 31, 2016***

iii. The 2016/17 test year forecast, and the 2016 and 2017 calendar year forecasts from the 2016 Delivery Service and Commodity Rate Application and fiscal year actual results for 2015/16 and 2016/17.

Delivery Service Revenue Requirement Summary ($000's)	**2016/17* Test Year*** **	**2016* Calendar Year Forecast**	**2017* Calendar Year Forecast**	**2015/16 Fiscal** Actual**	**2016/17 Fiscal** Actual**
Component					
Operating & Maintenance	124,404	122,662	124,736	114,790	115,725
Transportation & Storage	51,964	50,269	52,303	49,085	50,176
Depreciation Expense	42,130	39,008	42,798	36,517	39,269
Tax Expense	5,578	5,064	5,635	4,713	4,938
Interest Expense	26,284	24,301	26,713	22,014	22,664
Net Earnings	28,302	20,282	28,948	1,743	28,888
Total Delivery Revenue Requirement	278,662	261,586	281,133	228,862	261,660
Other Revenue and Adjustments					
Other Revenue	(24,096)	(23,771)	(24,174)	(24,209)	(25,680)
Net Delivery Revenue Requirement	254,566	237,815	256,959	204,653	235,980

Information from the 2016 Delivery Rate Application
*****Fiscal indicates Apr to Mar consistent to SaskEnergy's reporting period***
******November 1, 2016 to October 31, 2017***

2. Reference: OM&A Costs

a) Please confirm that the correct "Subtotal Operations" expenses in Schedule 1.2 for 2017/18 Forecast is $121,163 [compared to $121,684 shown in the schedule] and for 2018/19 Forecast is $123,514 [compared to $123,737 shown in the schedule].

i. If confirmed, please file a corrected version of Schedule 1.2.

Confirmed. Please find the corrected schedule below.

SaskEnergy Incorporated Operating and Maintenance ($ 000's)									
	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2015/2016 Actual	2016/2017 Forecast	2017/18 Forecast	2018/19 Forecast	2017/18 Test Year*
Operations	in $ 000's	in $ 000's	in $ 000's	in $ 000's	in $ 000's	in $ 000's	in $ 000's	in $ 000's	in $ 000's
Costs Incurred	115,794	120,132	126,770	125,219	125,100	122,592	131,319	133,935	133,548
Capitalized & Recovered	(14,791)	(9,462)	(11,472)	(11,754)	(11,913)	(9,580)	(10,156)	(10,421)	(10,301)
Subtotal Operations	101,003	110,670	115,298	113,465	113,187	113,012	121,163	123,514	123,246
Engineering and Construction									
Costs Incurred	27,139	28,560	30,116	28,287	27,981	27,230	30,772	32,209	30,815
Capitalized & Recovered	(25,348)	(27,172)	(28,613)	(26,777)	(26,378)	(25,901)	(27,690)	(28,423)	(28,148)
Subtotal Engineering & Construction	1,791	1,388	1,503	1,510	1,603	1,329	3,082	3,786	2,667
Total Operating & Maintenance	102,794	112,058	116,801	114,975	114,790	114,341	124,245	127,300	125,913
*November 1, 2017 - October 31, 2018									

ii. Please confirm that there is no impact to the test year forecast from this correction.

There is no impact to the test year forecast from this correction.

b) Have there been any changes to SaskEnergy's OM&A budget process, including the review and approval process, since the last Delivery Service Rate Application? If so, please summarize the changes.

The process for developing SaskEnergy's OM&A budget has not changed since the last Delivery Service Rate Application. The timing for CIC Board review and approval of SaskEnergy's annual business plan has moved forward approximately one month from December to mid-January to more closely align with the provincial budget development process and Cabinet budget finalization.

c) With reference to Schedule 1.2, please describe the key factors driving the material increase [$10.063 million] in OM&A expense between 2016/17 Fiscal Year Forecast [$114,341,000] and 2017/18 Fiscal Year Forecast [$124,245,000].

The increase in OM&A costs between 2016/17 and 2017/18 relate primarily to increased employee obligation costs and contracts and consulting costs, including the third party hosting costs for systems such as the Distribution Work Management System, the Records and Information Management System and the Customer Information System. Computer costs are also increasing however the change relates primarily to how printer servicing and maintenance are performed. SaskEnergy has moved from a service and lease arrangement with a third party (Contracts and Consulting) to undertaking these tasks with internal resources in order to achieve higher quality service levels and operating savings. The other areas seeing moderate cost increases are in training, professional fees and dues, and advertising. These expenditures were drastically reduced in 2016-17 but are assumed to return to more sustainable levels for 2017-18.

d) Please discuss key drivers for any material differences between actual OM&A expense over the period from November 1, 2016 to October 31, 2017 and the 2016/17 test year forecast OM&A expense reviewed in the 2016 Commodity and Delivery Service Rate application.

The forecast for the months of July to October 2017 has not yet been developed. It is part of Q1 reporting to our Board and CIC and will not be available until after it has been reviewed by the SaskEnergy Executive, the SaskEnergy Board and CIC. Current trends indicate that OM&A costs will be on target in the forecast period as Employee obligations are trending slightly lower than planned with off sets related to lower capitalization than planned.

e) Please discuss if there have been any adverse impacts on operations from holding OM&A spending at 2015 actual levels [less than $115,000,000]. What measures are being taken to address any impacts in the 2017/18 test year, or going forward?

Despite restraint directives, SaskEnergy maintained its commitment to never compromise the safety of its system, its employees or the public. Aggressive OM&A cost management has been achieved through a reduction in non-emergency call out and over time as well as vacancy management (allowing vacant positions to remain un-filled for a period of time.) As a result, customer service levels have been negatively impacted, particularly as it relates to the phone queue where the number of dropped customer calls has increased. This level of savings in OM&A was achieved through temporary measures and the corporation always intended to return to a more "normal" approach to operations that would see customer service levels return to historic targets when the restraint directives had been met. Included as part of the return to "normal" operations, SaskEnergy has re-started its active involvement with industry committees and working groups in order to ensure its on-going alignment with industry best practices in all aspects of its operations.

f) With reference to Tab 9, how does the information for the 2016/17 forecast on page 1 of Tab 9 reconcile to the information for 2016/17 Actual and 2016/17 budget included in page 6?

The 2016/17 Forecast numbers provided on page 1 of Tab 9 contain 11 months of actual results for the period from April 2016 to February 2017 plus the forecast results for the month of March 2017. All the minimum filing requirements were prepared in March before actual results for the year were available. The 2016/17 Actual results provided on page 6 of Tab 9 reflect the actual results for the period from April 2016 to the end of March 2017 because this schedule is redone when actual results are available given that this schedule is a comparison of actual to budgeted results. The 2016/17 budget numbers provided on page 6 reflect the 2016/17 budget as approved by the SaskEnergy Board in October 2015.

g) With reference to Tab 9, page 5, please provide an explanation for the key changes in 2017/18 Fiscal Year compared to 2015/16 actuals and 2016/17 actuals for the following:

i. VP Customer Service, Gas Supply and Rates and VP Operations;

In the latter portion of the 2015/16 fiscal year and for all of 2016/17, fiscal restraint was a priority for SaskEnergy to address direction from the Province related to expense management. The SaskEnergy commitment was that safety would never be compromised, however costs associated with advertising, energy efficiency programming, planned overtime, sustenance and transportation and travel and training were significantly reduced in these time periods. Plans are to restore a portion of those expenses in the 2017-18 fiscal year as customer service remains a key focus for SaskEnergy. In addition, SaskEnergy began to provide a specialized peak day natural gas service in 2016/17 in two areas of the province (Aberdeen and St. Brieux) using LNG/CNG solutions which increases operating expenses. The associated costs are reflected in the increase in OM&A in the VP Operations area.

ii. VP Corporate Support;

As noted in part (i), the fiscal restraint directive was a priority for SaskEnergy to address in the latter part of 2015/16 and in 2016/17. In Corporate Support, one example of a cost saving initiative was that third party contractors were given two weeks of mandatory time off at the end of December 2016 in order to achieve cost savings. The 2017/18 forecast anticipates cost increases related to incremental hosting services and software lease and maintenance costs for the Distribution Work Management system, the Records Information Management system and the Customer Information System. Additional costs are also contemplated related to the development of a corporate database as well as workstation support forecasted in 2017-18.

iii. VP Human Resources & Corporate Affairs; and

In 2015/16 and 2016/17, fiscal restraint was a priority for SaskEnergy to address direction from the Province of Saskatchewan. Advertising and training costs were significantly reduced in these time periods and plans are to gradually increase costs beginning in 2017-18 as customer service, succession planning and employee development, and educational programs related to safety and community awareness are again made a priority and an area of strategic focus for SaskEnergy.

iv. President & CEO.

In 2015/16 and 2016/17, fiscal restraint was a priority for SaskEnergy to address the efficiency directives from the Province. The Internal Audit function reviews SaskEnergy's key business processes to access key corporate risks. Internal audit work has traditionally been accomplished at SaskEnergy using a combination of internal and external resourcing. The component of external resourcing is forecast to increase in Audit Services in 2017/18 given internal staff turnover. In addition, the 2017-18 year marks the expiration of the previous external quality assurance review period; an external consultant will be required to complete the review and issue the quality assurance verification.

Were any of the above changes related to the reorganization that occurred in 2016/17? Please discuss.

These changes discussed above are not related to the reorganization that occurred in 2016/17. The reorganization involved a restructuring of the business units involved in Customer Services and Operations and Maintenance to better align with the priorities of enhanced customer service and more efficient operations. The reorganization did not result in incremental costs to SaskEnergy.

h) Please explain FTE changes between executives/division [Tab 8, page 1] in 2015/16, 2016/17 and 2017/18. Please explain how these changes impact labour costs, if any, for the 2017/18 test year.

The year over year FTE changes have not been material however one more notable change in FTEs related to the executive team which showed a small increase in the FTE count on a temporary basis in 2016-17. This was attributable to an overlap of executive team members for succession planning purposes. In addition, the Senior Administration Coordinator moved to an existing position in another part of the company beginning in 2017-18. In early 2017, the executive team was then reduced by 2 with the retirement of the CEO and the elimination of another due to the restructure. The net result for the 2017/18 test year was a reduction in labour costs.

i) With reference to Tab 9, page 1, please explain the increase in Computer costs in the 2017/18 fiscal forecast compared to the 2016/17 fiscal forecast and the 2015/16 actuals.

Computer costs are increasing due to increased software lease and maintenance costs for Distribution Work Management (i.e.: Clicksoftware) and Request Management. ClickSoftware (Click) is the system selected as SaskEnergy's new distribution work management system. Clicksoftware is a market and technology leader in mobile workforce management. They provide tools for optimization, forecasting, planning, scheduling, mobile workforce management and customer communication.

j) Please update the table included in the response to Round 1 Information Request 3(f) in relation to the 2016 Delivery Service Rate Application by providing a breakout of OM&A expenses for Sustenance and Transportation for 2012-2015 (actual), 2015/16 and 2016/17 actual fiscal years, 2017/18 and 2018/19 fiscal year forecast, as well as the 2016/17 and 2017/18 test year revenue requirement.

Travel and Accomodation										
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Test Year**	**Test Year**
	2012	**2013**	**2014**	**2015**	**2015/16**	**2016-17**	**2017-18**	**2018-19**	**2016-2017**	**2017-2018**
Meals and Per Diems	1,525	1,567	1,566	1,388	1,369	1,308	1,550	1,551	1,704	1,551
Accomodations	1,165	1,090	1,107	1,010	982	864	1,188	1,188	1,183	1,188
Vehicle and Airline Travel	636	614	706	499	498	492	672	672	717	672
Vehicle Allowance and Rental	427	425	380	353	344	302	376	376	434	376
Total	3,753	3,696	3,760	3,251	3,194	2,966	3,787	3,788	4,037	3,787

3. Reference: Labour Costs

a) Please update the table included in the response to Round 1 Information Request 4 (a) in relation to the 2016 Delivery Service Rate Application. For each of the years 2012 through 2015, 2015/16 through 2018/19 actual and/or fiscal forecast and the 2017/18 test year, please provide a reconciliation itemizing the differences between the Labour costs included on page 1 of Tab 9 and the "Average Base Labour Costs" included on page 2 of Tab 8.

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015/2016	Forecast 2016/2017	Fiscal 2017/2018	Fiscal 2018/2019	Test Year 2017/2018
LDC Labour as per Section 9A including Overtime, Standby, and other labour costs	82,280	86,912	91,439	89,856	88,882	88,583	92,414	94,750	93,748
Less Allocations to all Non-Delivery Business (IE: other SaskEnergy Incorporated subsidiaries and other business operations within the LDC such as Contract Industrials and Commodity)	(4,871)	(5,588)	(5,592)	(5,923)	(5,570)	(5,522)	(6,809)	(7,086)	(6,965)
Average Total Labour Cost	77,409	81,324	85,847	83,933	83,312	83,061	85,604	87,664	86,783
Less the following:									
Overtime	(8,103)	(9,468)	(9,605)	(7,982)	(7,601)	(6,332)	(7,493)	(7,636)	(7,590)
Substitution	(311)	(404)	(350)	(284)	(268)	(270)	(315)	(321)	(318)
Holiday Extra Item Pay/Vacation Pay	(1,440)	(1,094)	(1,876)	(1,172)	(1,141)	(1,106)	(1,213)	(1,230)	(1,212)
Premiums	(97)	(117)	(107)	(91)	(79)	(83)	(87)	(89)	(88)
Standby	(1,870)	(1,983)	(2,062)	(2,055)	(2,059)	(2,060)	(2,069)	(2,108)	(2,092)
Inconvenience Pay, Shift Differential and Other	(421)	(538)	(554)	(532)	(611)	(499)	(573)	(595)	(586)
Base Labour Cost as per Tab 3 Page 8	65,168	67,720	71,293	71,815	71,553	72,711	73,855	75,686	74,896

b) Please update the table included in the response to Round 1 Information Request 4 (b) in relation to the 2016 Delivery Service Rate Application, and each of the years on page 2 of Tab 8 of the 2017 application, please itemize the costs included in the "Average Base Labour plus Overtime, Standby and other labour costs" compared to the "Average Base Labour Costs".

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015/2016	Forecast 2016/2017	Fiscal 2017/2018	Fiscal 2018/2019	Test Year 2017/2018
Average Total Labour Cost	77,409	81,324	85,847	83,933	83,312	83,061	85,604	87,664	86,783
Overtime	(8,103)	(9,468)	(9,605)	(7,982)	(7,601)	(6,332)	(7,493)	(7,636)	(7,590)
Substitution	(311)	(404)	(350)	(284)	(268)	(270)	(315)	(321)	(318)
Holiday Extra Item Pay/Vacation Pay	(1,440)	(1,094)	(1,876)	(1,172)	(1,141)	(1,106)	(1,213)	(1,230)	(1,212)
Premiums	(97)	(117)	(107)	(91)	(79)	(83)	(87)	(89)	(88)
Standby	(1,870)	(1,983)	(2,062)	(2,055)	(2,059)	(2,060)	(2,069)	(2,108)	(2,092)
Inconvenience Pay, Shift Differential and Other	(421)	(538)	(554)	(532)	(611)	(499)	(573)	(595)	(586)
Average Base Labour Cost	65,168	67,720	71,293	71,815	71,553	72,711	73,855	75,686	74,896

c) Please elaborate on the major types of projects or activities that are expected to contribute to any forecast overtime requirements in the 2016/17 and 2017/18 fiscal forecast years. Please discuss any impacts on the 2017/18 test year.

The major types of activities that are expected to contribute to forecasted overtime requirements in 2017/18 and 2018/19 fiscal years are efficiency, risk avoidance and emergency response initiatives focused on customer growth, customer safety and/or distribution system integrity.

SaskEnergy has an emergency response role that includes responding to issues related to our system but this role also extends to responding to inside the house issues such as inside odor and CO calls. This is the main overtime driver. Scheduled (non-emergency) overtime is used to complete critical or time sensitive tasks that may be related to compliance, risk avoidance or customer service activities.

d) Page 8 of the Application notes that the Collective Bargaining Agreement was in effect until January 31, 2017. Please provide a status update relative to this matter. How is this addressed in the test year forecasts?

Confidential Response

e) Please confirm whether the labour costs included in the revenue requirement are gross or net of the vacancy rate adjustment.

The labour costs included in the 2017-18 revenue requirement incorporated FTE reductions. A portion of the FTE reductions were planned vacancies during the test period and the balance relate to positions with salary dollars that were eliminated. Both approaches result in operating savings however, the vacancies may be temporary in nature and these positions could be filled in the future.

f) Please provide the actual vacancy rates for 2012 through 2015 (calendar), 2015/16 and 2016/17 (fiscal), and forecast vacancy rates for 2017/18 and 2018/19 (fiscal) and for the 2017/18 test year.

i. Please provide both percentage and number of vacancies (FTEs).

YEAR	VACANCY RATE	FTEs
2012	5.7%	53
2013	5.8%	54
2014	5.1%	49
2015	5.0%	48
2016/17	6.8%	64
2017/18 Forecast	5.5%	52
2018/19 Forecast	5.5%	52

ii. Please discuss the impact of vacancies on overtime costs.

SaskEnergy will continue to aggressively manage vacancies, while meeting our requirement to provide provincial 24/7 coverage. Overtime may increase slightly in areas that have field classifications subject to 24/7 coverage, however an overtime increase is less likely in office classifications.

g) With reference to Page 1 of Tab 9, please provide an explanation for the changes in "Misc Corporate Charges" from 2014 actual through 2018/19 forecast.

In 2014, there were significant gains ($0.7 million) realized from the sale of vehicles and equipment. These gains are reported in miscellaneous corporate charges and are an off-set to the costs. The magnitude of the gains realized in 2014 is not forecasted in 2016/17 through to 2018/19. In 2015, emergency response costs to the Northern Saskatchewan forest fires ($0.3 million), a contribution to STARS Air Ambulance ($0.4 million), and a pipe inventory write-off for spoiled pipe ($0.8 million) at the Saskatoon pipe yard were incurred under this cost category. These costs are not anticipated to continue in 2016/17 through to 2018/19.

h) With reference to Page 6 of Tab 9, please provide an explanation for the increase in Intercompany Allocations (2017/18 forecast compared to 2016/17 actual).

The Schedule on Page 6 of Tab 9 does not provide a comparison of the 2017/18 forecast with the 2016/17 Actual Intercompany Allocations. That comparison is found on Page 1 of Tab 9.

The budget for Intercompany Allocations in the 2017/18 fiscal year is approximately $662,000 higher than the forecast for 2016/17 and $952,000 higher than the actual 2016/17 result. The reason for the increase relates primarily to the increased costs planned for 2017-18 relative to the 2016/17 actual result. The allocation percentages remain relatively stable however the actual and budget amounts vary considerably. The lower actual result for 2016/17 relates to the austerity measures implemented during the year and the corporation's efforts to reduce discretionary expenditures. One area that was materially impacted was the Environment business unit where the budget for consulting was reduced significantly.

4. Reference: Charges to Capital

a) Please explain why "Charges to Capital" [Tab 9, page 1] is lower for 2016/17 compared to 2015/16 actual, and why 2017/18 and 2018/19 forecasts, including 2017/18 test year forecast remain at 2014, 2015 and 2015/16 actual level when SaskEnergy capital expenditures are forecast to grow materially as detailed in Tab 6 [2017/18 forecast charges to capital at $29.4 million with $132.9 million net capital spending, 2015/16 actuals charges to capital at $29.4 million with $99.8 million net capital spending].

Charges to capital is lower for 2016/17 compared to 2015/16 actual and lower for the forecast periods despite increasing total capital spending. The reason is due to the relative mix of capital spending. Given the forecast reduction in the number of new customers each year compared to the period from 2014 to 2015/16, charges to capital are also lower.

b) Please detail how Charges to Capital is calculated. Is this approach outlined in an internal policy or other document? If so please provide.

Charges to capital are calculated based on an analysis of the cost that was incurred to complete the capital work and an assessment of what work was done.

The usual driver would be hours and the cost allocation would be a cost per hour. An example would be construction crew costs. The construction crew incurs costs (wages & operating costs) when performing duties. Time is tracked by each crew based on projects they perform work on. If the work is for capital projects, the crew earns back a recovery of their expenses for charges to capital based on an hourly charge. No policy statement exists on this process. This is an established practice that occurs within the OneWorld general ledger system.

c) Please provide a breakdown of charges to capital [labour, non-labour, etc.].

Charges to Capital

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015/2016	Forecast 2016/2017	Fiscal 2017/2018	Fiscal 2018/2019	Test Year 2017/2018
LABOUR	(16,348)	(18,271)	(18,126)	(18,258)	(17,974)	(22,004)	(18,131)	(18,663)	(18,469)
NON-LABOUR	(10,465)	(9,434)	(11,569)	(11,821)	(11,433)	(7,270)	(11,313)	(11,611)	(11,492)
TOTAL	(26,813)	(27,705)	(29,695)	(30,079)	(29,407)	(29,274)	(29,444)	(30,274)	(29,961)

5. Reference: Communication, Public Relations, Fees, Dues and Community Contribution Costs

a) Please update the table provided in the response to Round 1 Information Request 5 (a) from the 2016 Application, and provide a breakdown of 2012-2015, 2015/16 and 2016/17 actuals and forecasts for 2017/18 and 2018/19 as well as 2017/18 test year for Communication, Public Relations and Fees, Dues and Community Contributions.

Communication, Public Relations, and Fees, Dues and Community Contributions
$000's

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Test Year 2017/18
General Advertising and Marketing	261	382	296	186	186	189	293	293	293
Safety and Awareness	718	587	462	373	350	491	761	761	761
Energy Efficiency Programs and Awareness	1,537	2,716	1,833	1,473	1,448	1,003	1,981	1,981	1,981
Professional Membership and Dues	764	711	717	674	723	666	708	708	708
Sponsorships and Donations	1,217	1,219	983	427	342	328	454	454	454
Scholarships	105	105	105	105	105	105	105	105	105
Training and Conferences	636	605	804	321	299	394	603	604	603
Damage Claims and Other	199	206	369	330	322	111	110	110	110
Business Telephones, Cellular and Network Services	2,164	2,224	2,509	2,189	2,149	2,450	2,447	2,516	2,487
Total	7,600	8,754	8,077	6,078	5,925	5,737	7,462	7,531	7,502

b) Please provide an estimate of the average sponsorship and donation per recipient in 2016/17 and the dollar value of the three largest individual sponsorships and donations in 2016/17.

i. Please provide the amount included in 2016/17 actual and 2017/18 test year.

The average sponsorship per recipient organization in 2016/17 was $899. The average sponsorship per recipient organization in 2016-17 was $899. Total sponsorship spending in the 2016-17 year was $287,580 and the number of groups receiving sponsorship was

320. For the test period the budget is approximately $400,000, with a planned average contribution of approximately $1,100 per recipient (assuming there are approximately 350 recipient organizations.)

*Sponsorship spending in 2016-17 was suspended for nearly 6 months due to extreme fiscal restraint measures, which accounts for the total spend difference compared to the upcoming test period.

The top three sponsorships in 2016-17 were:

- Children's Hospital Foundation of Saskatchewan – Saskatoon Radiothon - $25,000
- Saskatchewan Junior Hockey League (SJHL) – provincial Goals For KidSport Program - $25,000
- Saskatchewan Association of Science Fairs – Provincial Science Fair Association - $15,000

ii. Are the CIC Imagine Canada guidelines still used as a measure for sponsorship and donations? If so, please discuss how the actual and forecast expenses align with the CIC Imagine Canada guidelines. If not, please explain why not.

The CIC Imagine Canada guidelines are still used as a measure for the maximum level of community contributions through sponsorship/donations which is 1% of net profit. SaskEnergy has historically used a 5 year rolling average to plan future community contributions; however, restraint measures in the last two years have substantially reduced sponsorship/donation spending. In 2016-17 the level of giving was 0.35% of net profit which is well below the 1% maximum. Sponsorship/donation spending will be approximately $400,000 during the test period of 2017, which is expected to be about 0.52% of net profit, based on a projected 5 year rolling average of $77 million.

c) Please explain why the Public Relations cost is forecast to increase in 2017/18 by 80% over 2016/17 and by 52% over 2015/16 actuals.

The Public Relations costs for 2017/18 are forecast to increase substantially relative to 2015/16 and 2016/17 as the corporation returns to a more normal level of expenditure in this area following an election and the period of extreme fiscal restraint. These discretionary costs were curtailed in 2015/16 and 2016/17 in order to meet legislation with respect to the pre-election restriction period, and also to achieve cost savings in the short term. However, the corporation has identified a legitimate need to increase public relations expenditures, including advertising, in order to educate the general public about natural gas, energy efficiency and important safety issues.

6. Energy Efficiency

a) Are any energy efficiency program costs or savings included in the 2017/18 test year revenue requirement?

i. If so, please provide a breakdown of programs, costs and savings.

Yes. The energy efficiency program costs included in the 2017/18 test year revenue requirement are as follows:

Residential Programs	$525,000
Commercial Programs	$375,000
Commercial Heating, Ventilation, and Air Conditioning Program	$149,200
Gas Detection Rebate Program	$ 20,000
	$1,069,200

ii. If not, please explain why not.

Not applicable.

7. Reference: External Services

a) Please explain the growth in External Services [Tab 9, page 1 and 2] from 2016/17 fiscal to 2017/18 fiscal and 2018/19 fiscal. In particular, please explain and quantify key drivers for growth in Contract Services [from $23.9 million in 2016/17 to $29.6 million in 2017/18, and further to $31.6 million in 2018/19].

The use of external services has been a key part of the SaskEnergy resourcing strategy for several years as the corporate FTE level has remained relatively stable despite periods of significant growth. Resourcing to complete the necessary work requires a diverse skill set and includes employees, contractors (external service providers) and business partners. These groups work together to develop mutually beneficial solutions for customers as well as improve the efficiency and effectiveness of work processes. SaskEnergy's on-going commitment is to ensure we provide "the right resource at the right place at the right time".

SaskEnergy has worked with external service providers to manage escalating costs for external services as third party service contracts are renewed and as the range of services provided by third parties continues to grow. In particular, the third party hosting costs (included in Contract Services) for many of our information technology solutions such as Distribution Work Management (new in 2017-18), Customer Information

System and Records and Information Management are increasing, as negotiated, year over year.

b) At what point is it more cost effective and efficient for activities to be resourced internally rather than using external resources?

i. Please discuss in further detail how this cost/ benefit assessment is made?

SaskEnergy regularly evaluates the costs and benefits of its resourcing strategy given the dynamic environment in which we operate. There are many factors to consider, in addition to cost, when making an assessment of whether to undertake activities with internal or external resources. Management has actively managed this issue in two ways;

- the first is through the utilization of contracts for tasks that are very routine and do not require a unique/specialized skill set;
- the second is through the utilization of contractors with very specific skill sets that are only required from time to time.

By viewing the contracts in this manner, it has elevated the type of work that the SaskEnergy employees perform to a higher skill level that includes the need to exercise sound judgement. This has benefitted staff in the long run.

ii. Are there adverse impacts (cost or otherwise) that arise through increased use of external resources? Please discuss.

Cost increases may result however SaskEnergy works with external services providers to manage escalating costs for external services as third party service contracts are renewed and as the range of services provided by third parties continues to grow. These costs would be somewhat offset by the ability for SaskEnergy employees to perform higher skilled work, as noted above. As well, independent contractors may be let go with appropriate notice which allows SaskEnergy the opportunity to further manage costs.

c) Please explain how the External Recoveries and Internal Recoveries are estimated in relation to External Services. Specifically, please explain why External Recoveries for 2017/18 and 2018/19, as well as 2017/18 test year is forecast to be at 2016/17 level [about $3.6 million], while the External Services costs are forecast to increase by $6-$9 million over the 2016/17 level.

There is no direct correlation between External Services and External Recoveries. External Services is primarily contracts and consulting costs. SaskEnergy contracts with outside parties to complete the work that is required to be done. The types of services vary from contractor labour to data hosting services and increases relate to increased volumes of work as well as inflationary cost increases.

External recoverable work is a small slice of work we perform where we incur operating costs to complete the work but we are charging an external party to recover the costs that were incurred (i.e. line hits). These types of costs are fairly consistent year over year which is why they are budgeted as such.

Internal recoveries relate to work done by LDC staff for other subsidiaries.

d) Please update the information provided in the response to Round 1 Information Request 6 (b) from the 2016 Application, and provide further details regarding the proportion of Contract Services that SaskEnergy is using for customer connection related works. Please provide both the proportion of contract services for customer connections and the related expenses for 2012-2015, 2015/16 and 2016/17 actuals, 2017/18 and 2018/19 forecasts.

The following data is based on work performed to accommodate customer connect activity that includes Urban Mains and Services, Rural Mains and Services, Industrials, First Nations and Resort Communities:

Proportion of Contract Services For Customer Connections:

YEAR	% CONTRACT SERVICES
2012	73%
2013	71%
2014	71%
2015	71%
2015/16	70%
2016/17	71%

2017/18 Forecast	72%
2018/19 Forecast	71%

Contract Services Expenses Related to Customer Connections:

YEAR	CONTRACT SERVICES (Millions)
2012	$17.425
2013	$24.611
2014	$22.907
2015	$21.226
2015/16	$19.573
2016/17	$14.898
TOTAL	$120.640

2017/18 Forecast	$18.650
2018/19 Forecast	$16.743

e) With reference to page 2 of Tab 9, did the implementation of a new billing system in 2013 lead to any cost reductions in Billing Services? Please explain.

The new billing system was implemented to replace the previous legacy system which had become unsupported and posed a risk to the organization. The clear communication to all stakeholders at the time was that the implementation of a new customer billing system was overdue given the risks posed to the organization related to continuing to operate the old system and that the average cost per customer of just the new billing system was approximately $1 per customer per month. Any efficiencies that may be derived from the new system would be more than off-set by the increased costs associated with implementing and maintaining the new system.

f) Please quantify the forecast and actual meter reading efficiencies in 2016/17 through 2018/19. Please explain any variances between forecast and actuals.

Estimated meter reading efficiencies were developed based on the planned deployment of the AMI modules to customer meters and the ability of SaskEnergy to negotiate meter reading savings into the meter reading contract with SaskPower. The variances between actual and forecast meter reading savings are attributable to the timing of actual deployment. Please see below for the forecast and actual meter reading savings by fiscal year. Note that 2017-18 and 2018-19 actual meter reading savings are not yet available.

	Forecast	Actual
2016-17 Meter Reading Cost Savings	$500,000	$742,000
2017-18 Meter Reading Cost Savings	$0	N/A
2018-19 Meter Reading Cost Savings	$100,000	N/A

g) Please describe the activities included Routine Maintenance expense in 2016/17 through 2018/19. How long are these activities expected to continue at this level?

The increase in routine maintenance expenses in 2016/17 through to 2018/19 is due to our on-going commitment of safety and integrity for our distribution customers. More specifically, the focus on risk-based integrity programming has led to a greater reliance on initiatives such as cathodic protection, maintenance programs and corrosion control. It would be expected that Routine Maintenance will hit a plateau in the early 2020's for today's current maintenance activities. However it should be noted that maintenance standards are constantly changing in the industry as equipment is replaced and technology is enhanced.

h) Will capital expenditures on system integrity reduce or otherwise impact Routine Maintenance and other O&M costs in the short or longer term? Please discuss.

Please refer to 1 e) ii.

i) With reference to Tab 9, page 2, please explain the material increase in Office Services forecast in the 2018/19 fiscal forecast [$1,236 compared to $525 in the 2016/17 fiscal forecast] and in the 2017/18 test year [$939].

The increase in Office Services in the 2017-18 test year and the 2018/19 forecast relate to copier maintenance costs which are resident in

Information Systems. Copier maintenance has moved to a contract services arrangement and the increased costs are reflected in the External Services category. The 2017/18 test year cost reflects the partial year of this contract and the full contract cost is included in the 2018/19 forecast.

8. Reference: Intercompany Allocations

a) In Tab 10, page 1 SaskEnergy notes that the "manpower budget for the Distribution Division was 650 full time equivalents (FTEs) and the TransGas and Bayhurst Gas manpower budgets were 262 for a total FTE complement of 912. This results in a corporate allocation that apportions 71.31% of costs to the Distribution Division, 28.15% to TransGas and 0.54% to Bayhurst/Business Development." Please explain these differences and reconcile FTEs for Distribution Division with the FTEs provided in Tab 8 and explain steps for adjustments.

The difference in the Distribution FTEs referenced on page 1 of Tab 10 (650) and the FTE number provided in Tab 8 for "VP Customer Service, Gas Supply and Rates and the VP, Operations" (653) is due to timing. The Intercompany allocations provided in Tab 10 are prepared early in the budget development process and the calculation is based on preliminary FTE counts. As the budget process moved forward, decisions regarding FTEs were made however, the corporate allocation was not revisited and adjusted. The difference of the 3 FTEs would not result in a material understatement of costs for the purposes of intercompany allocations.

b) Please provide an updated version of Round 1 Information Request 20 (a) from the previous application that reconciles the intercompany allocation to Distribution Division provided in Tab 10 to the intercompany allocation provided in Tab 9.

$ in thousands	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015/2016	Forecast 2016/2017	Fiscal 2017/2018	Test Year 2017/2018
Intercompany Allocations as per Page 1 Tab 9	$(8,107)	$(8,278)	$(9,208)	$(8,928)	$ (9,208)	$ (9,765)	$ (10,427)	$ (10,785)
Remove Administration and Overhead of LDC Mgmt Charged to SaskFirst Call	68	63	59	59	59	60	62	63
Remove Administration and Overhead of LDC Mgmt Charged to SVGC	15	15						
Staff Realignment and Reorganization between Subsidiary Companies LDC and TGL	(191.8)	(8.0)	111.0	(46)		(56)	(107)	(118)
As Per Intercompany Allocation Schedule - Section 10	$(8,216)	$(8,208)	$(9,038)	$(8,915)	$ (9,149)	$ (9,761)	$ (10,472)	$ (10,840)

c) Please provide a list of allocation percentages for each year, from 2015/16 through 2018/19 in table format.

Information Request #8C - Inter-Company Cost Allocations

BU	BU Description	2017 Delivery Rate App 2015/16 Actual	2017 Delivery Rate App 2016/17 Forecast	2017 Delivery Rate App 2017/18 Forecast	2017 Delivery Rate App 2018/19 Forecast
Service Groups					
31	ABORIGINAL RELATIONS	50.0%	50.0%	50.0%	50.00%
32	MANAGEMENT	56.7%	56.4%	56.7%	56.70%
34	GAS SUPPLY	99.0%	99.0%	99.0%	99.00%
39	AUDIT SERVICES	42.2%	17.0%	17.0%	17.00%
40	BOARD OF DIRECTORS	65.0%	65.0%	70.0%	70.00%
41	LEGAL	60.4%	60.4%	60.4%	60.40%
42	LAND	35.0%	37.0%	37.0%	37.00%
44	CORPORATE AFFAIRS	83.0%	83.0%	83.0%	83.00%
48	HEALTH AND SAFETY	30.0%	30.0%	30.0%	30.00%
49	HUMAN RESOURCES	0.0%	0.0%	0.0%	0.00%
55	PRESIDENT`S OFFICE	0.0%	0.0%	0.0%	0.00%
Corporate Support					
201	ADMINISTRATION AND RECORDS MANAGEMENT	0%	0%	0%	0.00%
203	INFORMATION SYSTEMS	20.0%	20.0%	21.9%	21.90%
211	FLEET & CORPORATE SERVICES	80.0%	80.0%	80.0%	80.00%
213	STORES AND SALVAGE	0%	0%	0%	0.00%
214	BUILDINGS & SECURITY	0%	0%	0%	0.00%
216	PURCHASING	44.0%	52.0%	52.0%	52.00%
Finance					
220	VP, FINANCE AND CFO	0%	0%	0%	0.00%
222	PAYMENT SERVICES	0%	0%	100.0%	100.00%
223	BUSINESS MGR. BILLING & SUPPORT	100.0%	100.0%	100.0%	100.00%
224	TREASURY	78.3%	85.6%	84.9%	84.90%
225	DISTN ACCTG, BILLING SERVICES	100.0%	100.0%	100.0%	100.00%
226	DISTN ACCTG, C&C/PAY SERVS	100.0%	100.0%	100.0%	100.00%
227	DISTRIBUTION ACCOUNTING	35.8%	37.0%	37.0%	37.00%
230	PAYROLL	0.0%	0.0%	0.0%	0.00%
232	CORPORATE ACCOUNTING - A/P	0.0%	0.0%	0.0%	0.00%
233	FINANCIAL PLANNING	8.5%	8.5%	8.5%	8.50%
Distribution Utility					
1200	V.P. DISTRIBUTION UTILITY	100.0%	100.0%	100.0%	100.00%
2000	DIVISION ADMINISTRATION	100.0%	100.0%	100.0%	100.00%
2200	CUSTOMER SERVICE TRAINING/DEV	100.0%	100.0%	100.0%	100.00%
1100-1110	REGINA LDC	100.0%	100.0%	100.0%	100.00%
1700-1722	YORKTON	100.0%	100.0%	100.0%	100.00%
2500-2528	SWIFT CURRENT	100.0%	100.0%	100.0%	100.00%
3300-3310	SASKATOON LDC	100.0%	100.0%	100.0%	100.00%
4300-4319	NORTH BATTLEFORD & PRINCE ALBERT	100.0%	100.0%	100.0%	100.00%
4000	OPERATIONS PLANNING & MTCE	100.0%	100.0%	100.0%	100.00%
4500	CUSTOMER SOLUTIONS	100.0%	100.0%	100.0%	100.00%
4600	BUSINESS POLICY & ADMIN	100.0%	100.0%	100.0%	100.00%
5100	SASKATOON CONSTRUCTION	100.0%	100.0%	100.0%	100.00%
5200	DISTRIBUTION ENGINEERING	100.0%	100.0%	100.0%	100.00%
5300	REGINA CONSTRUCTION	100.0%	100.0%	100.0%	100.00%
5400	DISTRIBUTION INTEGRITY	100.0%	100.0%	100.0%	100.00%
5410	GEOGRAPHICAL INFORMATION SYSTEMS (GIS)	0.0%	100.0%	100.0%	100.00%
37	METER SHOP	92.2%	92.2%	92.2%	92.20%
BU39	Alloc Corp BU 39-Audit	0	36.10%	35.66%	35.66%
BU48	Alloc Corp BU 48-Health and Safety	14.40%	14.44%	14.26%	14.26%
BU49	Alloc Corp BU 49-Human Res.	72.00%	72.20%	71.31%	71.31%
BU55	Alloc Corp BU 55-President's Office	72.00%	72.20%	71.31%	71.31%
BU201	Alloc Corp BU 201-Infor.Sys	72.00%	72.20%	71.31%	71.31%
BU203	Alloc Corp BU 203	56.95%	57.11%	55.05%	55.05%
BU213	Alloc Corp BU 213	72.00%	72.00%	72.00%	72.00%
BU214	Alloc Corp BU 214	72.00%	72.00%	72.00%	72.00%
BU226&BU222	Alloc Corp BU 226&222	72.00%	72.00%	0.00%	0.00%
BU227	Alloc Corp BU 227	17.28%	16.68%	16.47%	16.47%
BU220	Alloc Corp BU 220 - VP Fin & Admin	72.00%	72.00%	72.00%	72.00%
BU230	Alloc Corp BU230 - Payroll	72.00%	72.00%	72.00%	72.00%
BU232	Alloc Corp BU232 - Accounts Payable	72.00%	72.00%	72.00%	72.00%
BU233	Alloc Corp BU233 - Financial Planning	59.69%	59.85%	59.12%	59.12%
BU40	Alloc Corp BU40 - Board of Directors	0.00%	0.00%	0.00%	0.00%
300	VP TRANSGAS LIMITED	7.0%	17.0%	17.0%	17.00%
330	ENVIRONMENT	36.0%	36.0%	36.0%	36.00%
140	TGL MARKET SERVICES AND SYSTEM MANAGEMENT	1.0%	1.0%	1.0%	1.00%
142	TRANSGAS CUSTOMER SERVICES	0.0%	0.0%	0.0%	0.00%
147	POLICIES, RATES & REGULATIONS	0.0%	0.0%	0.0%	0.00%
323	FACILITY PLANNING	0.0%	0.0%	0.0%	0.00%
320	PIPELINE CONTROL & PLANNING	20.0%	20.0%	20.0%	20.00%
325	SCADA	31.8%	32.0%	31.9%	31.90%
Engineering & Technology & System Integrity and Standards					
305	ENGINEERING & TECHNOLOGY	9.3%	10.4%	10.4%	10.40%
306	DIVISIONAL OVERHEAD	12.6%	10.4%	10.4%	10.40%
307	SYSTEM INTEGRITY PROGRAMS	15.8%	20.2%	20.2%	20.20%
308	PIPELINE ENGINEERING AND GEOGRAPHICAL INFORMATION S	25.0%	0.0%	0.0%	0.00%
315	ELECTRICAL, CONTROLS AND MEASUREMENT ENGINEERING	20.0%	20.0%	20.0%	20.00%
310	FACILITIES AND STORAGE ENGINEERING	0.0%	2.0%	9.0%	9.00%
312	SUPPORT SERVICES	4.0%	4.0%	14.0%	14.00%
313	COSTS CAPITALIZED	0.0%	0.0%	0.0%	0.00%
314	SYSTEM INTEGRITY & STANDARDS	36.6%	38.1%	38.1%	38.10%
Transmission Operations					
53110	MOBILE COMPRESSORS	0.0%	0.0%	0.0%	0.00%
56001	EXEC DIR TRANSMISSION OPERS	0.0%	0.0%	0.0%	0.00%
56100	PLANT MAINTENANCE	0.0%	0.0%	0.0%	0.00%
84001	OPERATIONS TRAINING	0.0%	0.0%	0.0%	0.00%
71001-71120	SOUTH DISTRICT	0.0%	0.0%	0.0%	0.00%
62001-62150	NORTH DISTRICT	0.0%	0.0%	0.0%	0.00%
	Alloc Corp BU56001-Dir Trans Ops	4.75%	1.08%	1.07%	1.07%
	Alloc Corp BU62001-North District	0.0%	0.72%	0.71%	0.71%
	Alloc Corp BU71001-South District	0.0%	0.72%	0.71%	0.71%

i. Please explain material differences year to year, particularly the large changes in TransGas VP, Engineering and Construction [7% from 2015/16 to 17% in 2016/17 onward], and TransGas Support Services [4% from 2015/16 to 14% in 2016/17 onward].

In general, the elevated regulatory burden is impacting the allocation of intercompany costs between the transmission and distribution utilities. Rather than adding incremental resources, the corporation has expanded roles in many cases to address both transmission and distribution work. For example, beginning in 2016-17, the Director of Emergency Management and Regulatory Affairs (who reports directly to the TransGas VP, Engineering, Integrity and Construction) saw the role expand to LDC issues including asset management, environment, and safety processes and documentation. The role has continued to evolve given the direct responsibility for the Unified Management System (UMS) which entails documentation of key programs including distribution system maintenance, distribution integrity management, distribution facility design, distribution project development review, drug and alcohol testing and employee and process safety. The increased level of effort by this position related to LDC specific issues has created the significant increase in the allocation.

The Support Services group provides drafting services, materials management, crossing management and geographical information and mapping services to the distribution utility. The increased allocation to 14% in 2016/17 from 4% in 2015/16 is primarily attributable to the foundational work to convert the Distribution assets into the GIS.

ii. How would the delivery service revenue requirement be impacted if 2015/16 allocation percentages were used?

The delivery service revenue requirement would decrease by $0.7 million if 2015/16 allocation percentages were used in the 2017-18 test year.

d) Please update the response to Round 1 Information Request 20 (b) from the 2016 Delivery Service Rate Application. Please provide a table that compares the dollar values of each of the cost areas allocated to the LDC for the 2017/18 test year on page 22 of Tab 10 to equivalent figures for the 2013/14 and 2014/15 test years from the 2013 Deliver Service Rate Application, 2015/16 test year from the 2015 Delivery Service and Commodity Rate Application and 2016/17 test year from the 2016 Delivery Service and Commodity Rate Application.

Tab 10 - Page 22 Inter-Company Cost Allocation Comparision

BU	BU Description	2013 Delivery Rate App 2013/2014 Test Year	2014 Delivery Rate App 2014/2015 Test Year	2015 Delivery Rate App 2015/16 Test Year	2016 Delivery Rate App 2016/2017 Test Year	2017 Delivery Rate App 2017/2018 Test Year
Service Groups						
31	ABORIGINAL RELATIONS	254,466	260,241	260,882	259,718	261,411
32	MANAGEMENT	1,473,353	1,540,013	1,652,164	1,650,219	1,884,961
34	GAS SUPPLY	1,752,366	1,820,996	1,693,372	1,660,400	1,564,273
39	AUDIT SERVICES	572,827	594,179	532,595	516,555	150,858
40	BOARD OF DIRECTORS	0	0	373,823	366,472	386,926
41	LEGAL	934,350	970,417	1,178,920	1,161,100	1,203,717
42	LAND	239,415	249,336	243,627	262,990	263,143
44	CORPORATE AFFAIRS	3,021,063	3,075,648	2,935,269	2,764,862	2,370,578
48	HEALTH AND SAFETY	318,218	329,008	349,445	291,410	304,311
49	HUMAN RESOURCES	0	0	0	0	0
55	PRESIDENT`S OFFICE	0	0	0	0	0
Corporate Support						
201	ADMINISTRATION AND RECORDS MANAGEMENT	0	0	0	0	0
203	INFORMATION SYSTEMS	3,471,063	3,543,060	4,580,552	4,910,968	5,651,732
211	FLEET & CORPORATE SERVICES	0	0	795,813	789,554	798,617
213	STORES AND SALVAGE	0	0	0	0	0
214	BUILDINGS & SECURITY	0	0	0	0	0
216	PURCHASING	394,154	417,798	342,646	392,373	461,155
Finance						
220	VP, FINANCE AND CFO	0	0	0	0	0
222	PAYMENT SERVICES	0	0	0	0	814,203
223	BUSINESS MGR. BILLING & SUPPORT	439,264	455,920	582,606	566,164	555,098
224	TREASURY	615,970	643,906	726,487	624,427	645,872
225	DISTN ACCTG, BILLING SERVICES	2,950,603	3,005,016	3,386,033	2,665,998	3,199,770
226	DISTN ACCTG, C&C/PAY SERVS	1,095,393	1,115,533	1,120,536	631,844	636,736
227	DISTRIBUTION ACCOUNTING	785,434	817,089	779,649	780,052	801,627
230	PAYROLL	0	0	0	0	0
232	CORPORATE ACCOUNTING - A/P	0	0	0	0	0
233	FINANCIAL PLANNING	270,722	281,963	59,161	58,546	59,799
Distribution Utility						
1200	V.P. DISTRIBUTION UTILITY	633,609	664,367	776,750	708,887	1,197,873
2000	DIVISION ADMINISTRATION	(34,736)	(24,765)	75,995	(42,530)	(359,460)
2200	CUSTOMER SERVICE TRAINING/DEV	261,247	265,955	322,330	315,837	328,569
1100-1110	REGINA LDC	10,613,893	10,698,025	11,757,842	12,196,952	12,108,390
1700-1722	YORKTON	8,735,471	8,838,012	9,585,823	10,162,794	10,087,845
2500-2528	SWIFT CURRENT	7,950,081	8,122,911	8,668,087	8,792,135	8,520,160
3300-3310	SASKATOON LDC	11,396,866	11,530,361	12,202,534	13,012,030	13,032,861
4300-4319	NORTH BATTLEFORD & PRINCE ALBERT	10,716,615	10,848,425	11,307,123	11,724,875	11,387,100
4000	OPERATIONS PLANNING & MTCE	1,089,183	1,131,476	1,568,005	1,758,480	2,263,838
4500	CUSTOMER SOLUTIONS	1,943,360	2,009,081	1,760,324	1,562,225	1,802,967
4600	BUSINESS POLICY & ADMIN	3,905,576	3,320,807	3,383,758	3,791,467	4,047,287
5100	SASKATOON CONSTRUCTION	(3,258)	21,123	577,342	877,052	539,177
5200	DISTRIBUTION ENGINEERING	1,515,921	1,592,121	1,151,818	1,021,671	874,604
5300	REGINA CONSTRUCTION	(5,546)	5,914	734,564	884,476	541,035
5400	DISTRIBUTION INTEGRITY	-	-	3,002,503	3,713,447	3,430,757
5410	GEOGRAPHICAL INFORMATION SYSTEMS (GIS)	-	-	-	307,500	308,750
37	METER SHOP	1,052,056	1,070,270	1,996,894	1,973,197	2,100,249
	Total Distribution	**78,359,000**	**79,214,205**	**90,465,276**	**93,114,147**	**94,226,790**
BU39	Alloc Corp BU 48-Env (H&S)	0	0	0	0	316,403
BU48	Alloc Corp BU 48-Env (H&S)	151,684	156,827	167,734	140,265	144,670
BU49	Alloc Corp BU 49-Human Res.	3,155,807	3,266,006	3,417,075	3,392,145	3,029,853
BU55	Alloc Corp BU 55-President's Office	637,368	659,981	782,930	773,589	802,489
BU201	Alloc Corp BU 201-Infor.Sys	551,938	555,879	896,909	754,449	752,310
BU203	Alloc Corp BU 203	9,725,192	9,926,914	11,625,818	12,499,064	14,207,092
BU211	Alloc Corp BU 211	745,970	766,993	-	-	0
BU213	Alloc Corp BU 213	661,780	675,654	712,210	719,034	686,515
BU214	Alloc Corp BU 214	214,413	222,173	257,746	275,368	368,142
BU226&BU222	Alloc Corp BU 226&222			-	590,348	0
BU227	Alloc Corp BU 227	332,461	345,860	376,166	351,846	357,120
BU220	Alloc Corp BU 220 - VP Fin & Admin	(123,617)	(123,957)	(30,543)	113,830	31,804
BU230	Alloc Corp BU230 - Accounts Payable	242,476	249,500	315,959	340,293	319,279
BU232	Alloc Corp BU232 - Payroll	234,684	239,077	282,534	290,588	281,113
BU233	Alloc Corp BU233 - Financial Planning	-	-	415,437	412,258	415,892
BU40	Alloc Corp BU40 - Board of Directors	363,651	378,742	-	-	-
	LDC TOTAL	**95,252,806**	**96,533,853**	**109,685,250**	**113,767,225**	**115,939,473**

9. Reference: External and Internal Recoveries

a) With reference to the table on page 1 of Tab 9, please provide a breakdown of the items included in each of external recoveries and internal recoveries for each year in the table.

External and Internal Recoveries
($ 000's)

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Test Year 2017/18
External Recoveries									
Labour	$ (1,400)	$ (1,457)	$ (1,419)	$ (1,017)	$ (1,084)	$ (1,847)	$ (1,124)	$ (1,146)	$ (1,136)
Customer Contributions for Service Alterations*	(4,071)	(1,269)	(1,990)	(1,601)	(1,470)	(1,374)	(1,858)	(1,895)	(1,877)
Vehicle and Equipment	(737)	(770)	(1,076)	(471)	(420)	(280)	(595)	(607)	(602)
General Supplies	(108)	(104)	(157)	(34)	(25)	(64)	(50)	(51)	(51)
Total	$ (6,316)	$ (3,599)	$ (4,642)	$ (3,122)	$ (2,999)	$ (3,565)	$ (3,627)	$ (3,700)	$ (3,666)
Internal Recoveries									
Labour	$ (3,052)	$ (2,449)	$ (2,534)	$ (2,509)	$ (2,770)	$ (1,684)	$ (1,511)	$ (1,564)	$ (1,535)
Service Retirement Costs/Cutbacks	(2,959)	(2,437)	(2,671)	(2,387)	(2,586)	(869)	(2,794)	(2,828)	(2,810)
Vehicle and Equipment	(831)	(368)	(455)	(385)	(487)	(36)	(410)	(418)	(416)
General Supplies	(169)	(76)	(89)	(48)	(42)	(53)	(60)	(61)	(61)
Total	$ (7,011)	$ (5,330)	$ (5,749)	$ (5,329)	$ (5,885)	$ (2,641)	$ (4,775)	$ (4,871)	$ (4,821)

*Customer Contributions for Service Alterations are recognized as cost recoveries but beginning in 2013 to accommodate the new Customer Information Billing System customer contributions for line hits, emergency repairs, and line lowering were switched to a revenue therefore the decline for this recovery.

10. Reference: Transportation and Storage Expense

a) SaskEnergy's 2016/17 3rd Quarter Report notes that "The budget assumed a 3.5% average increase to transportation and storage rates effective January 1, 2017; however, this rate adjustment was not brought forward." [Tab 5, Performance Management Quarterly Report].

i. Please confirm that a 3.5% increase was assumed in the 2016/17 test year expense forecast.

The 2016/17 test period expense forecast was based on the corporation's approved budget for 2016 which included an assumption of 3.5% average increase to transportation and storage rates.

ii. Please confirm that no transportation and storage rate increase occurred in the 2016/17 test year and that transportation and storage rates and related expense have remained at the January 01, 2016 level.

Confirmed, that no transportation and storage rate increase occurred in the 2016/17 test year and that transportation and storage rates and related expense have remained at the January 01, 2016 level.

iii. Do the transportation and storage expense forecasts for 2017/18 test year assume that the January 2016 rates will remain in place?

If not, please explain how SaskEnergy developed its forecasts for transportation and storage rates for 2017/18 test year.

It was known when the budget for 2017/18 was developed that the 3.5% average increase to transportation and storage rates which had originally been planned for January 2017 did not occur so it was not included in the expense forecasts for the 2017/18 test year. Forecasts for transportation and storage rates are based on the cost of service for TransGas.

iv. When is the next transportation and storage rate increase expected to occur? What is the expected quantum of the next forecast increase?

The approved 2017/18 budget assumed an average increase to transportation and storage rates of 5% on April 1, 2018.

v. Are expenses related to a 3.5% transportation and storage rate increase assumed in the 2017/18 test year forecast?

No, the approved 2017/18 budget assumed an average increase to transportation and storage rates of 5% effective April 1, 2018. The 2017/18 test year forecast includes 0% from November 1, 2017 to March 31, 2018 and 5% from April 1, 2018 to October 31, 2018.

b) In response to Round 1 Information Request 8 (d) from the 2016 Application, SaskEnergy noted that the 396,994 GJ/day of contracted storage withdrawal capacity for 2015 was incorrect and the actual amount contracted for 2015 was 391,478 GJ/day. If this is still accurate, please provide correct version of Schedule 1.1.

Schedule 1.1 has been updated to reflect that the 2015 Contracted Firm Deliverability was 391,478. Please find the revised schedule below.

SaskEnergy Incorporated
Delivery Transportation and Storage Expense

	2012 Actual in $ 000's	2013 Actual in $ 000's	2014 Actual in $ 000's	2015 Actual in $ 000's	2015/2016 Actual in $ 000's	2016/2017 Forecast in $ 000's	2017/18 Forecast in $ 000's	2018/19 Forecast in $ 000's	2017/18 Test Year* in $ 000's
TRANSPORTATION & STORAGE									
($000's)									
Transportation									
Transportation Costs	27,806	28,580	30,037	31,282	31,516	31,821	31,951	33,832	33,091
Storage Cost	14,051	14,777	15,830	17,265	17,569	18,355	18,377	19,338	18,937
Total Transportation & Storage Expense	41,857	43,357	45,867	48,547	49,085	50,176	50,328	53,170	52,028
Volume									
Transportation									
Contracted Demand (in GJ's/day)	570,000	575,020	585,000	590,000	595,000	600,000	600,000	605,000	600,000
Storage									
Contracted Firm Deliverability (in GJ's/day)	385,934	382,838	383,244	391,478	393,217	393,461	394,194	394,194	393,461
Contracted Storage Volume (in PJ's)	20.9	20.9	21.8	23.6	23.4	23.4	23.4	23.4	23.4

*** November 1, 2017 - October 31, 2018**

c) Please confirm that TransGas' current tariff is at the following web link: http://www.transgas.com/tariff/tgtariff/default.asp

Confirmed

d) Please provide the estimated impact to commodity and delivery rates and expenses of the added transportation costs from Alberta for the following periods:

i. November 1, 2016 to October 31, 2017;

ii. November 1, 2017 to October 31, 2018; and

iii. November 1, 2018 to October 31, 2019.

All transportation costs from Alberta are included in the commodity rate. The transportation costs from Alberta to Saskatchewan are as follows:

i. November 1, 2016 to October 31, 2017 is $19.6 million,

ii. November 1, 2017 to October 31, 2017 is $19.5 million, and

iii. November 1, 2018 to October 31, 2017 is $20.7 million.

e) Please describe any measures that SaskEnergy is taking in the test years and going forward to achieve greater efficiencies and to reduce transportation costs?

SaskEnergy is constantly striving to achieve greater efficiencies and to manage its costs. SaskEnergy reviews its contracted levels of storage and transportation on an annual basis. This review consists of examining historical usage of the contracted capacities and determining the most cost effective way of meeting our customer's future requirements. SaskEnergy strives to contract for the minimum amount of storage and transportation capacity that is required to satisfy our customer's forecasted requirements, while ensuring that SaskEnergy has firm access to a secure supply of natural gas to meet the demand of a 1 in 20 cold winter. Since there are relatively long lead times for requested increases of transportation and storage capacity with no guarantee of receiving the additional service requested, SaskEnergy must take a relatively long term view of its transportation and storage requirements. SaskEnergy believes that the quantities of transportation and storage currently contracted result in the most cost effective solution to meeting our customer's current requirements.

Despite a slight increase in both the forecasted annual and peak day customer requirements, SaskEnergy will maintain its contracted storage capacity and Alberta transportation capacity at 2016/17 levels for the test period. SaskEnergy is planning to satisfy its forecasted customer requirements by utilizing our transportation and storage contracts at a slightly higher load factor, resulting in greater efficiencies.

f) Please update the response to Delivery Service Information Request – Round 2, 6(a) from the 2016 Application, and provide a table outlining all transportation and storage rate changes between 2012 and 2017/18.

The table below lists the TransGas transportation and storage rates and percent changes for the period 2012 to 2017.

Effective Date	L11 Delivery Transportation		Storage		
	Demand Charge	% Change	Withdrawal Charge	Capacity Charge	% Change
1-Feb-12	$4.0830	7.5%	$1.6939	$0.0250	1.0%
1-Mar-13	$4.1405	1.4%	$1.8026	$0.0266	6.4%
1-Jan-14	$4.2813	3.4%	$1.8855	$0.0278	4.6%
1-Jan-15	$4.4269	3.4%	$1.9579	$0.0289	3.9%
1-Jan-16	$4.4269	0.0%	$1.7955	$0.0352	5.8%
1-Jan-17	$4.4269	0.0%	$1.7955	$0.0352	0.0%
1-Apr-18	**$4.6571**	**5.2%**	**$1.888**	**$0.0370**	**5.2%**

g) Please update the response to Delivery Service Information Request – Round 2, 6(b)(i) and (ii) from the 2016 Application, and quantify the impact that each rate change has had on transportation and storage expense;

and provide any variance between forecast rate changes and actual rates over the period from 2012 through 2017/18.

Financial Impact Transportation and Storage Rates $ in millions						
	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Forecast 2016/17	Forecast 2017-18
Financial Impact						
Transportation	$1.8	$0.3	$1.0	$1.0	-	-
Storage	$0.2	$0.8	$0.7	$0.7	$1.0	-
*There were no rate adjustments in 2010 and 2011						

Financial and Rate Impact Transportation and Storage Rates Forecast vs Actual Variance $ in millions						
	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Forecast 2016-17	Forecast 2017-18
Rate Impact						
Transportation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Storage	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Financial Impact						
Transportation	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Storage	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
*The numbers shown identify that there was no rate and financial variance between the forecast and the actual from 2012 to 2017-18						

Please note that this response does not include the impact of rate increase to receipt transportation, which is included in commodity costs.

h) Please update the response to Delivery Service Information Request – Round 2, 6(c)(i) from the 2016 Application, and provide the anticipated range of transportation and storage rate increases that SaskEnergy is assuming over the next five years. Please indicate the financial and rate impact this is expected to have going forward?

Financial and Rate Impact					
Transportation and Storage Rates					
$ in millions					
	Forecast	**Forecast**	**Forecast**	**Forecast**	**Forecast**
	2017-18	**2018-19**	**2019-20**	**2020-21**	**2021-22**
Rate Impact					
Transportation	0%	3% to 5%	3% to 5%	3% to 5%	3% to 5%
Storage	0%	3% to 5%	3% to 5%	3% to 5%	3% to 5%
Financial Impact					
Transportation	$0	$1.0 to $1.7	$1.1 to $1.8	$1.1 to $1.8	$1.2 to $1.9
Storage	$0	$0.6 to $1.0	$0.7 to $1.0	$0.7 to $1.0	$0.8 to $1.1

11. Reference: Depreciation Expense

a) Please confirm that changes in year-over-year depreciation expense relate primarily to additions to property, plant and equipment and not changes to depreciation rates or methods. If not, please provide an explanation.

Yes, the year over year changes in depreciation expense relate to additions to property, plant and equipment.

b) Round 1 Information Request 9 (b) and (c) from the 2016 Application SaskEnergy noted that a new depreciation study was originally scheduled for completion in 2015, but was deferred one year due to austerity measures, and that a depreciation study was expected to be completed in spring of 2017. Tab 13 of the current application states that a new depreciation study is targeted to be completed by March 2018. Please explain the three-year delay in completing the depreciation study, and provide any updates regarding timing for undertaking and completing this study.

The depreciation study has been deferred given the austerity measures of the last two years. It was not considered a critical initiative as the absence of a depreciation study has no impact on the safety and reliability of the system nor is it likely to result in material changes to the cost of service. Deferring the study has resulted in estimated cost savings of approximately $75,000.

c) Please explain in detail how depreciation expense is calculated for new assets, including assumed in-service date for forecast capital additions [i.e., is it assumed using a mid-year approach, etc.].

The depreciable amount of a new asset is allocated on a systematic basis over the asset's useful life. Depreciation of an asset begins when it is “available for use” and ends when the asset is either held for sale, is permanently disposed of, or has become fully depreciated. The Corporation's rates of depreciation are determined through an independent review of the Corporation's existing assets, asset acquisitions and asset retirements. These reviews are undertaken every five years or when most reasonable to do so.

Most gas distribution assets are subject to the six-month (mid-year or half year) rule. This approach assumes that assets are brought into use or taken out of use half way through the year, regardless of when they were actually acquired or retired. This allows the Corporation to avoid having to track the dates of asset acquisition or asset disposal. Tracking these dates is not feasible when the costs of most of the new distribution assets are pooled and each asset is assumed to be the same as the rest. The Corporation's larger assets are depreciated beginning with the actual in-service date.

12. Reference: Interest Expense

a) Please provide a list of outstanding long term and short term debt items, including forecast borrowings to the end of 2018/19 fiscal year, and showing outstanding balance, maturity date and interest rate.

LDC Long Term Debt			
Bond	**Maturity**	**Coupon**	
I.D.	**Date**	**Rate**	**Principal**
#		%	($)
34	05-Mar-29	5.75	25,000,000
35	05-Mar-29	5.60	25,000,000
36	02-May-20	6.67	11,814,000
37	02-Jun-20	6.70	13,572,000
38	03-Jul-20	6.57	8,585,000
40	05-Sep-31	6.40	50,000,000
51	05-Sep-17	4.65	20,000,000
52	01-Jun-40	5.19	75,000,000
56	03-Feb-42	3.40	25,000,000
57 - #1	02-Jun-45	3.90	50,000,000
57 - #1	02-Jun-45	3.90	50,000,000
58	03-Jun-24	3.20	50,000,000
59	01-Mar-19	1.95	10,000,000
60	02-Jun-45	3.90	10,000,000
63	02-Dec-46	2.75	50,000,000
65	02-Jun-48	3.30	50,000,000
Forecast	01-Jun-48	4.39	75,000,000
			598,971,000

b) With reference to Tab 14, page 3, please explain the increase in short-term debt cost from 2016/17 fiscal forecast to 2017/18 fiscal forecast and

2017/18 test year forecast. Please provide the basis for the higher forecast in 2017/18 fiscal, 2018/19 fiscal and 2017/18 test year.

The increase in short term debt cost is driven by higher short term debt rates as shown in Tab 14 page 3. The basis for the higher forecast is to be consistent to an average of the five large Canadian banks forecast for short term Canadian rates and adjusted for debt issued from the Province of Saskatchewan.

c) With reference to Tab 14, page 3, what would be the financial savings if the interest rate for 2017/18 and 2018/19 remained at 2016/17 fiscal year levels?

The approximate financial savings if the interest for 2017/18 remained at 2016/17 fiscal year levels would be $0.8 million.

The approximate financial savings if the interest for 2018/19 remained at 2016/17 fiscal year levels would be $1.5 million.

d) With reference to Tab 14, page 3, please explain the increase in average outstanding long term debt between 2016/17 fiscal forecast and 2018/19 fiscal forecast.

The forecast assumed $75 million in incremental long term borrowing June 1, 2017 and $75 million in incremental borrowing in June 1, 2018. Note that the long term debt is reported at a point in time and that it is net of any maturities that occurred during the period.

e) Please explain and detail how average interest rates are calculated for short-term and long-term debt for 2015/16, 2016/17, 2017/18 and 2018/19 and in the 2017/18 test year. Please show how long-term debt, interest expense, and sinking fund earnings are considered in arriving at average interest rates.

SaskEnergy's method for interest rate forecasts is consistent with prior year methodologies. An average of the five large Canadian banks forecast for short and long term Canadian rates is calculated and adjusted for debt issued from the Province of Saskatchewan.

The average interest rates for long term debt are calculated using the interest on notes payable to Holdings Division, the amortization of deferred charges and the debt retirement (sinking) fund earnings divided by the average outstanding long term debt.

The average interest rates for short term debt are calculated using the interest on bank indebtedness divided by the average outstanding short term debt.

f) Please update information on page 4 of Tab 14 with most recent available information [the current information showing from May 2016].

SaskEnergy Incorporated												
2017 Submission - Interest Rate Forecast												
Short Term Debt												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017						0.60	0.75	0.75	0.75	0.90	0.90	0.90
2018	1.05	1.05	1.05	1.14	1.14	1.14	1.23	1.23	1.23	1.33	1.33	1.33
2019	1.50	1.50	1.50	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75
2020	1.75	1.75	1.75	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
2021	2.00	2.00	2.00	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25
2022	2.25	2.25	2.25	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
	**0.25% increases factored in for each year beginning in April 2019											
Long Term Debt - 30 Year												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017						3.15	3.15	3.15	3.15	3.29	3.29	3.29
2018	3.51	3.51	3.51	3.66	3.66	3.66	3.81	3.81	3.81	3.93	3.93	3.93
2019	4.01	4.01	4.01	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26
2020	4.26	4.26	4.26	4.51	4.51	4.51	4.51	4.51	4.51	4.51	4.51	4.51
2021	4.51	4.51	4.51	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76
2022	4.76	4.76	4.76	5.01	5.01	5.01	5.01	5.01	5.01	5.01	5.01	5.01
	**0.25% increases factored in for each year beginning in April 2019											
Debt Retirement Funds												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017						2.80	2.80	2.80	2.80	2.86	2.86	2.86
2018	3.01	3.01	3.01	3.12	3.12	3.12	3.27	3.27	3.27	3.40	3.40	3.40
2019	3.53	3.53	3.53	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
2020	3.78	3.78	3.78	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
2021	4.03	4.03	4.03	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
2022	4.28	4.28	4.28	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
	**0.25% increases factored in for each year beginning in April 2019											

Note that the above Bank forecasts were provided prior to the recent rate increase announced by the Bank of Canada. However, it is assumed that this increase was already factored into these forecasts.

g) Please explain the material reduction in capitalized interest in 2015 through 2018/19 compared to 2012-2014 actuals. Please discuss if higher capital expenditures in recent years should increase capitalized interest.

The material reduction in capitalized interest in 2015 through 2018/19 compared to 2012 to 2014 actuals is due to the substantial Advanced Metering Infrastructure (AMI) investment being put into service in November 2014 and Customer Information System investment being put into service in July 2013. No, higher capital expenditures should not increase capitalized interest substantially as elevated capital expenditures are mostly attributable to safety and integrity initiatives which are generally smaller and completed more quickly.

h) Please confirm that the interest expense included in the 2017/18 test year revenue requirement is calculated based on 63% deemed debt of average rate base. Please quantify how much is long-term debt and how much short-term debt.

Correct. The amount of interest expense that is long term is $24,830 thousand. The amount of interest expense that is short term is $2,052 thousand. The total interest expense is $26,882 as per Tab 14 page 3 and as per Schedule 1.5 of the minimum filing requirements.

i) Please update the table included in the response to Round 1 Information Request 10(h) in relation to the 2016 Delivery Service Rate Application, and provide a schedule showing the calculation of accretion expense for 2015 through 2018/19, including 2017/18 test year. Please also discuss how the discount rate was quantified.

Accretion Expense Calculation						
$ in millions						
	Actual 2015	Actual 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Test Year 2017/18
Present Value of Estimated Decomissioning Liability	$ 83.3	$104.3	$100.1	$109.1	$123.3	$119.6
Discount Rate	2.4%	2.0%	2.0%	2.2%	2.4%	2.3%
Accretion Expense	$ 2.03	$ 2.05	$ 2.04	$ 2.40	$ 3.00	$ 2.75
* Discount Rates are zero curve 10 to 30 year rates calculated based on information from the Royal Bank of Canada						

j) Please update the table included in the response to Round 1 Information Request 10(i) in relation to the 2016 Delivery Service Rate Application. Please explain how the forecasts for sinking fund earnings were estimated for 2015 through 2018/19, including 2017/18 test year.

The corporation is required to make regular sinking fund payments to the Ministry of Finance for debt issues with terms greater than five years. It is the Ministry that manages these investments. SaskEnergy estimates the earnings amounts each year based on the previous year's actual results and noting any long term debt maturities that have occurred during the year which reduces the sinking fund amounts.

Average Yield for Debt Retirement Fund Earnings						
$ in millions						
	Actual 2015	Actual 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Test Year 2017/18
Debt Retirement Fund Balances	42,601	43,406	46,608	51,774	58,065	55,033
Debt Retirement Fund Earnings	2,203	1,281	1,097	1,711	2,117	1,948
Average Yield	5.2%	3.0%	2.4%	3.3%	3.6%	3.5%

k) Please update the table included in the response to Round 1 Information Request 10(j) in relation to the 2016 Delivery Service Rate Application, and provide the actual and forecast balance in the sinking funds for 2015 through 2018/19, including 2017/18 test year.

Please see response to Question 12 j).

l) Have there been any changes to SaskEnergy's long term debt and short term debt borrowing limits since the last Application?

All borrowing limits granted by the province have not changed since the last application.

13. Reference: Tax Expense

a) Please update the table provided in the response to Round 1 Information Request 11 (a) from the 2016 Application and provide a comparison of the calculation of Corporate Capital Tax for the 2016/17 through 2018/19, including 2017/18 test year.

Calculation of Corporate Capital Tax - 2017/18				
	2016/17	2017/18	2017 Delivery Rate Application Test Year 2017/18	2018/19
Net Book Value	1,065,115	1,186,342		1,303,256
less UCC (1)	702,405	802,603		879,603
Income Tax Deduction	362,710	383,739		423,653
Retained Earnings and Equity	392,733	403,069		434,294
Loans and Advances	1,272,313	1,429,775		1,534,915
Interest Payable	10,878	8,192		13,995
less: Income Tax Deduction	(362,710)	(383,739)		(423,653)
Total Paid up Capital	1,313,214	1,457,297		1,559,551
less: Standard Exemption	(10,895)	(10,895)		(10,895)
Taxable Paid up Capital	1,302,319	1,446,402		1,548,656
less Investment Allowance	(550,000)	(550,000)		(550,000)
Taxable Paid up Capital	752,319	896,402		998,656
Rate	0.6%	0.6%		0.6%
Corporate Capital Tax Expense	4,514	5,378		5,992
Test Years			5,734	
Note: UCC refers to Undepreciated Capital Cost				

b) The data in Tab 6 shows that for the last 4-5 years SaskEnergy capital expenditures increased significantly. The information from Schedule 1.4 shows that corporate tax in 2016/17 stayed at the same level as 2015/16 [both years at $4.514 million], but is forecast to increase to $5.378 million in 2017/18 and $5.992 million in 2018/19. Please explain why 2015/16 and 2016/17 tax amounts are the same and why there is a large increase for the forecast years.

The Corporate Capital tax amounts due to the Ministry of Finance are a function of Paid Up Capital. The calculation of Paid Up Capital incorporates capital investment during the year as well as retained earnings, decommissioning liabilities, the net book value of assets and numerous other variables. Adjustments to Paid Up Capital are then made based on the extent to which the net book value of assets exceeds, or is exceeded by, the undepreciated capital cost of assets.

Given the complexity of this calculation and the number of variables which impact the amount of corporate capital tax paid, the estimate for the forecast period is based on the historical amounts and adjusted for expected increases in net book values.

14. Reference: Other Revenue

a) Please detail the factors underlying the increase in Margin on Gas Marketing for 2015 and 2015/16 actuals compared to forecast and the large decrease in Margin on Gas Marketing thereafter [$2.1 million for 2017/18 and 2018/19 compared to $4 million in 2015 and 2015/16, $6.1 million in 2016/17].

The profitability of Gas Marketing activities is extremely difficult to forecast, as this profitability is dependent on many factors, the most significant of which are: (1) the volatility of gas prices, (2) the absolute level of gas prices (low vs. high), (3) the difference in the price of gas in Saskatchewan versus Alberta, and (4) the availability of underutilized capacity under SaskEnergy's storage and transportation contracts. During a colder than normal winter, for example, there may be an increase in price volatility but SaskEnergy's storage and transportation contracts would be utilized at a higher rate, therefore there would be less spare capacity to take advantage of this increased price volatility. Conversely, during a mild winter there would be more spare storage and transportation capacity, but a lack of price volatility would limit SaskEnergy's ability to generate profits from these under-utilized assets.

During 2015/16 SaskEnergy was able to take advantage of an unusual pricing environment called backwardation, where short term prices were higher than future prices. This unexpected opportunity generated greater profits than forecast. For the 2016/17 period, gas prices were extremely erratic during the spring/summer of 2016 which allowed SaskEnergy to purchase gas in the spring and sell this gas later that summer at unprecedented profit margins for that time of year. SaskEnergy was able to generate approximately $3.7 million from this opportunity. The market pricing dynamics that occurred in both 2015 and 2016/17 were two different types of market anomalies that occur very infrequently.

Gas prices and gas price volatility have continued to decline in the last few years. Since these two ingredients are critical to gas marketing profitability, SaskEnergy's forecasted profits from gas marketing activities for the next few years reflects these current market conditions. SaskEnergy believes that the forecast profit of $2.1 million for 2017/18 and 2018/19 is a reasonable and realistic expectation of profit given the market conditions.

b) Please provide an explanation for the reduction in Late Payment Charges ($0.900 million and $0.947 million in 2017/18 and 2018/19 respectively compared to $1.186 million in 2015/16 and $1.102 million in 2016/17).

Elevated collection efforts on accounts that are 30, 60, and 90 days in arrears from delivery customers were implemented in 2016/17. This resulted in a decline in arrears in 2016/17 which is expected to continue into 2017/18 and 2018/19. This increased collection effort results in lower late payment charge revenue.

c) Please explain the increase in Miscellaneous Revenues in 2016/17 forecast compared to 2015/16 actual and 2017/18 forecast.

The increase in miscellaneous revenues in the 2016/17 forecast compared to 2015/16 actual and 2017/18 forecast relates to anticipated revenue to be earned in 2016/17 related to meter move fees and energy efficiency program fees. These amounts are difficult to forecast as they are dependent on customer requests/demand.

d) Please explain what is driving the increase in Distribution Tolls in 2017/18 and 2018/19 compared to 2016/17.

The main driver to the increase in Distribution Tolls is an increase in forecasted delivered volumes from Distribution Toll customers, primarily in the Enhanced Oil Recovery (EOR) and potash sectors.

e) With reference to Tab 12, how was the $18,856 for Distribution Tolls charged to TransGas determined? Please provide detailed explanation or calculation.

Distribution tolls are calculated based on the forecast customer delivered volumes and contracted demand, provided by TransGas, and then multiplied by the D-toll rates.

15. Reference: Tab 6: Planned Maintenance Program

a) Please provide an estimate of the proportion of SaskEnergy's total operations and maintenance expenses in 2015/16 and 2016/17, and forecast for 2017/18 and 2018/19 and the 2017/18 test year that relate to the planned maintenance program.

i. Please provide both the percentage of total O&M spending that relates to the planned maintenance program, as well as the total dollar amount each year.

2015/16 Actual - $18 million – 16% of total O&M spending

2016/17 Forecast - $17 million – 15% of total O&M spending

2017/18 Forecast – $17 million – 14% of total O&M spending

2018/19 Forecast - $18 million – 14% of total O&M spending

2017/18 Test Year - $18 million – 14% of total O&M spending

ii. Please provide the portion of O&M expense each year that relates to distribution mains and service lines vs. pressure regulation stations. Please also provide the portion of O&M expense each year that relates to maintenance of customer end point gas measuring equipment in compliance with Measurement Canada requirements.

Note: Based off percentage of Total Planned Maintenance				
	% of Regulator Stations	% of Mains and Services	Labor $ of Measurement Canada	
15/16	18%	11%	$3.1 M	Actual
16/17	18%	12%	$2.5 M	Actual
17/18	17%	11%	$4.2 M	Forecast
18/19	18%	12%	$3.1 M	Forecast
*Note: Measurement Canada – Meter Exchange work has been capitalized since 2014				

iii. Page 9 of the application notes that the cost of line locating remains a substantial component of SaskEnergy's operating budget. Please provide the portion of total O&M spending that relates to line locates as well as the total dollars each year. Please indicate how the joint line locating process has helped to reduce these costs over the last 5 years.

	Percentage of total OM&A	**Dollars of total Spend**	
15/16	**10%**	**$5.2M**	Actual
16/17	**9%**	**$4.9M**	Actual
17/18	**11%**	**$5.1M**	Forecast
18/19	**11%**	**$4.9M**	Forecast

Without the utilization of the joint line locating process, the average cost per locate would be the sole cost of SaskEnergy (approx. 3x higher). Without the utilization of contractors SaskEnergy would be forced to staff up to accommodate the ever growing volume of locates that occur daily.

b) Please provide a table that provides the dollar amounts for SaskEnergy system integrity expense for 2011 to 2015 (actual); 2015/16 actual; 2016/17 actual and 2017/18 forecast (per the figure on page 13 of the Application). Please also breakout the major categories of system integrity capital spending and the major categories of system integrity operating spending for each year provided.

Risk Management – System Integrity Portions

2011 to 2017-18 Distribution Integrity Capital Investment

		Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2015-16	Actual 2016-17	Forecast 2017-18
M20	CATHODIC PROTECTION SYSTEMS UPGRADES	$577,245	$647,099	$4,606	$374,511	$448,284	$523,140	$544,061	$900,000
M21	CROSSING UPGRADES AND REMOVALS	$0	$199,129	$89,370	$131,592	$84,251	$65,867	$171,216	$250,000
M22	UNDERGROUND SERVICE ENTRANCE UPGRADE PROGRAM	$113,996	$325,388	$741,628	$748,979	$954,302	$952,875	$1,020,946	$750,000
M23-25	SERVICE TEE UPGRADES	$12,594,292	$12,158,464	$16,242,274	$12,842,962	$13,176,118	$12,684,152	$13,033,440	$13,500,000
M26	DISTRIBUTION MAIN REPLACEMENTS	$0	$1,218,719	$2,466,374	$1,103,780	$677,978	$569,489	$635,388	$1,800,000
M27	STATION PIPE STRESS	$1,874,676	$127,655	$467,023	$1,029,741	$1,579,009	$1,652,085	$529,835	$1,000,000
M28	STAINLESS STEEL BALL VALVES - METER SETS	$112,333	$43,277	$1,059	$25,193	$113,790	$84,695	$10,384	-
M29	BRIDGE CROSSINGS	$0	$1,230,977	$158,936	$2,889,694	$189,386	$9,194	-$478	-
M30	STEP/IP PIPE INSPECTIONS	$0	$0	$0	$266,164	$18,848	$31,855	$340,891	$650,000
M31	REG AND METER STN IN CORROSIVE ENVIRONMENT	$0	$0	$0	$0	$524,868	$580,953	$60,640	$550,000
M32	REG STATION PIPING - RISER INSPECTIONS	$0	$0	$0	$0	$0	$0	$1,022,445	$950,000
M33	PIPELINE PROTECTION FROM EXTERNAL INTERFERENCE	$0	$0	$0	$0	$0	$0	$1,180	$250,000
M50	INSIDE TO OUTSIDE MOVES (METER AND/OR REGULATOR)	$204,082	$360,424	$126,403	$167,778	$219,117	$209,338	$217,288	$260,000
M51	ALTERATIONS - SERVICES & SVC T UPGRADES	$0	$3,161,458	$5,359,960	$3,328,936	$4,713,565	$4,879,585	$4,524,154	$3,150,000
M69	SERVICE LINE STUB/ID REMOVE	$0	$59,436	$111,758	$217,992	$305,304	$102,851	-$289	-
M70	COMMERCIAL SERVICE RISER/METER UPGRADES	$0	$346,819	$631,770	$82,281	$422,878	$319,861	$77,714	$245,000
	TOTAL	**$15,476,624**	**$19,878,844**	**$26,401,159**	**$23,209,601**	**$23,427,697**	**$22,665,939**	**$22,188,815**	**$24,255,000**

System Integrity - Operating Expenses

	General Adminsitration	Cathodic Protection	Leak Survey
2013	$0	$1,025,978	$1,458,285
2014	$136,076	$468,637	$1,626,858
2015	$204,986	$705,299	$2,225,362
2015/2016	$257,395	$705,503	$2,390,678
2016/2017	$265,712	$1,125,258	$2,123,949
2017/2018 Forecast	$300,000	$1,200,000	$1,800,000

2011 and 2012 information not available

16. Reference: Tab 6: Capital Expenditure Program

a) With reference to the capital expenditure forecast included in the 2016/17 test year forecast – how much of the forecast capital planned to be completed in the 2016/17 test year was actually completed as forecast and was in service and included in rate base in that time period. How much was deferred and/or is planned to be completed in 2017/18 or later?

Approximately $111 million of the forecasted capital planned to be completed in the 2016/17 test year was actually completed and in service. Therefore, this amount was included in the rate base in that time period. Approximately $17 million was deferred and/or planned to be completed in 2017/18.

b) Does SaskEnergy have an accounting policy for planning costs? If so, please provide. How does SaskEnergy account for planning costs where a decision is made not to proceed with a capital project prior to project construction or in service? How does SaskEnergy account for built assets that are abandoned?

The attached Capitalization Policy document (Attachment 1) contains a section on the phases of a project (usually software development type of projects) including the accounting policies on planning costs.

When a decision is made not to proceed with a capital project prior to project construction or in service, SaskEnergy's policy is that any associated planning costs are expensed.

When built assets are abandoned, those costs are treated in accordance with International Financial Reporting Standards. That is, the Corporation includes in the cost of an asset an amount to represent the cost of its future retirement. This amount is reported on the Statement of Financial Position as a Provision (liability). When the asset is retired or abandoned, the costs to abandon the asset are charged against the accumulated liability. SaskEnergy uses the equal life group method of depreciating assets. Under this methodology, assets are amortized over the average life of all assets in a group of similar assets (e.g. pipelines) however each individual asset is recognized to have its own life, some assets within a group will provide economic life beyond the average life while others will have shorter lives. Consequently, when an asset is retired or abandoned before it has reached the average life of that asset group; it is assumed to be fully depreciated. The remaining undepreciated asset value goes into a Group Life Asset Value Depreciation account which is addressed at the next depreciation study. Effectively, it is applied against the value of assets that have exceeded the average life of the group. For example, SaskEnergy amortizes its pipeline assets over 50 years however there are pipelines that have been continuously operated since 1960 which remain in service, and there are assets which come out of service before reaching 50 years.

c) Please provide an estimate of capital spending by category, similar to the format provided in Tab 6, page 8 for the 5 year period from 2018/19 to 2022/23. Please outline and explain any major changes in forecast assumptions compared to the information provided in the response to Round 2 Information Request 10(a) from the 2016 Delivery Service Rate Application.

SaskEnergy prepares a 5 year forecast from 2017/18 to 2021/22. The major change in forecast assumptions compared to the information provided in the response to Round 2 Information Request 10(a) is attributable to elevated safety and integrity investment with a focus on addressing major infrastructure (for example, the location of Town Border Stations) in major urban centers in Saskatchewan.

Capital Expenditure Forecast ($ millions)				
	2018/2019 Forecast	2019/2020 Forecast	2020/2021 Forecast	2021/2022 Forecast
DISTRIBUTION				
Customer Connections	41.6	40.2	38.7	38.7
System Improvements	55.6	62.9	68.5	54.2
Gas Measurement	10.6	10.6	10.6	10.6
Tools/ Stations/GIS	2.0	1.9	1.8	1.8
Sub-Total	**109.8**	**115.6**	**119.6**	**105.4**
GENERAL PLANT				
Information Systems	16.3	16.3	14.1	14.8
Vehicles	3.4	3.8	4.2	4.7
Building/Furniture	8.8	13.0	16.3	4.2
Regulators	0.7	0.7	0.7	0.8
Sub-Total	**29.2**	**33.8**	**35.3**	**24.4**
Total Capital Expenditures	**138.9**	**149.4**	**154.9**	**129.8**
Customer Contributions	**(18.5)**	**(17.9)**	**(17.2)**	**(17.2)**
Net Capital Expenditures	**120.4**	**131.5**	**137.7**	**112.6**

d) With reference to the response to Round 2 Information Request 10(b) from the 2016 Delivery Service Rate Application, please provide an update regarding the work and projected capital requirements defined by the Major Growth Infrastructure (MGI) program over the period from 2017/18 through 2024/25. Please identify and explain any material changes since this was last reviewed.

Saskatoon:

An assessment of current and long term plans for the City of Saskatoon focused on the management of load growth and system reliability. There are three areas that have been identified within the City of Saskatoon and included as part of the MGI program as follows:

TBS#5:

This project consisted of installing a 5th TBS in northwest Saskatoon and also the associated pipeline and District Regulating Stations to provide the following benefits:

- Reduce the reliance on TBS #1,
- Provide future capacity to allow for growth,
- Significantly increase reliability in the Saskatoon system.

The work to complete the TBS #5 project was started in 2015/16 and is estimated to be completed in 2017/18. The capital requirement to finish this project in 2017/18 is $3.25 million.

TBS#2:

The plan for TBS#2 is to reduce the pressure of the cross city HP line impacting the inlet pressure to TBS #2. Modifications to TBS #2, equipment and piping, would be needed to accommodate the reduced inlet pressure. The work to complete these modifications was planned to take place in 2020/21 and was estimated to be $2.0 million. Further assessment of the cross city HP line and the risk of maintaining a bulk odorant tank in close proximity to residential and commercial subdivisions has resulted in a revised plan. It is now being proposed that in 2018/19, $0.55 million will be required to purchase land for a new TBS to replace TBS #2. In 2021/22, $2.1 million will be required to relocate the bulk odorant facilities outside of the city limits. The revised plan includes replacing TBS #2 in 2022/23 with a new TBS located adjacent to the existing facilities at an estimated cost of $3.75 million.

In addition, the existing City intermediate pressure (IP) pipeline that runs south from TBS #2 and supplies gas to the Willows sub-division and the rural sub-divisions located south of Saskatoon is approaching capacity. To allow for continued growth south of Saskatoon, the plan is to install an IP pipeline from TBS#2 south through the existing Commercial Area. This work is planned to be completed in 2018/19 at an estimated cost of $0.75 million.

Central Avenue IP Main:

The University of Saskatchewan has several large parcels of land located in close proximity to the University. This land has historically been used for agricultural purposes. However, the University is now developing this land for student residences and commercial/institutional facilities. To accommodate this load and future customer growth and to further balance the City IP flow between Saskatoon TBS#2 and TBS#4, additional IP pipeline infrastructure will be required at an estimated cost of $6.3 million from 2018/19 to 2022/23.

Regina:

An assessment of the City of Regina growth plans relative to existing SaskEnergy infrastructure was completed. The assessment concluded that due to continued subdivision load growth in the east (Greens, Towns, Eastbrook), northwest (Coopertown) and southwest (Harbour Landing) Regina, the current SaskEnergy distribution system is approaching capacity. In addition to load growth, the subdivision developments are located further away from core system pipelines which create additional system requirements.

The core distribution system, consisting of elevated pressure (EP) pipelines, is fed from town border stations (TBS) located on the peripheral of the city. New EP pipelines are required to ensure adequate capacity for the continued city growth.

In addition, the high pressure (HP) pipelines that supply gas to Regina TBS #1 and TBS #2 are situated within close proximity to residential and commercial areas within the City limits. The plan to address these integrity and growth related items have been separated into the following project areas as part of the MGI budget.

East Regina:

During the past several years, in addition to adding load onto the Regina system, residential construction has occurred in relatively close proximity to TBS #2. As a result, the Regina east system expansion also includes plans to relocate TBS #2. Land has been purchased in a location that will prevent future development from encroaching on this new TBS site. Planning activities associated with relocating TBS #2 in Regina are underway and is scheduled for a 2021/2022 in-service timeline. TransGas Limited (TGL) has also begun to plan for the growth in south Regina and has initiated plans for a bypass transmission pipeline. The east expansion will allow for the existing NPS12 HP TGL pipeline, feeding the existing TBS #2, to be converted to an EP pipeline. When TBS #2 is relocated, the existing regulator station can be converted to a district regulating station (DRS), which will leverage existing infrastructure and pipeline right-of-ways.

The capital requirement for this project from 2017/18 to 2021/22 is estimated to be $13.5 million.

Southwest Regina:

Similar to TBS #2, urban development has occurred in proximity to TBS #1. As a result, this project includes the relocation of Regina TBS #1 west of the City of Regina. The operating pressure of the existing HP pipelines within the residential and commercial areas will be reduced to EP and will support the existing distribution infrastructure. This work is estimated to be completed by 2023/24 with the initial acquisition of land for a TBS site scheduled for 2017/18. The capital requirement for this project from 2017/18 to 2023/24 is estimated to be $9.0 million.

Northwest Regina:

SaskEnergy is developing plans to address a new subdivision development within Regina known as Coopertown. Coopertown is currently planned to house over 20,000 residents and be a location of significant commercial growth, and is a part of the City of Regina's 300,000 population growth plan. Further, the location of Coopertown does not allow the existing SaskEnergy system infrastructure to be leveraged when serving this proposed subdivision.

The TBS #4 project will accommodate system growth in the northwest part of the city with the associated pipeline to connect to the existing EP distribution infrastructure. This work is estimated to be completed by 2023/24 with the initial acquisition of land for a TBS and pipeline right-of-way taking place in 2017/18. The capital requirement for this project from 2017/18 to 2023/24 is estimated to be $17.2 million.

North Battleford (NB):

An assessment of current and long term plans for the City of NB focused on the management of load growth and system reliability. The assessment identified security of supply to support growth potential on the east side of

North Battleford. In addition, TBS #1 is located in a flood plain and the associated pipeline from this TBS to the primary DRS in NB has been exposed twice due to runoff. The MGI review identified the need for a 3rd TBS to add additional supply on the east side of NB and to incorporate flood control measures at TBS#1. This work has been separated into the following two projects as part of the MGI budget.

NB TBS#3:

This project consists of installing a 3rd TBS on the east side of NB and also the associated pipeline and District Regulating Station. The capital requirement for this project from 2017/18 to 2023/24 is estimated to be $7.25 million. TBS #3 was previously planned to be completed in 2021/22 but the plan is to defer this portion of the project until 2022/23.

NB TBS#1:

This project previously proposed re-building TBS #1 adjacent to the existing location. In 2017/18, an initial flood survey was reviewed which indicated there is a high probability of the station site being flooded during the life of the asset. The initial survey used data collected from 1990. A more detailed report will be completed in 2017/18 with current survey information to further quantify the flood risk. This work has been moved from 2022/23 to 2023/24 and estimated to be $4.00 million.

Prince Albert (PA):

An assessment of current and long term plans for the City of PA focused on the management of load growth and system reliability. The security of supply and reliance on the sole TBS (TBS #1) impacts the anticipated growth on the east side of Prince Albert. The MGI review identified the need for a 2nd TBS for additional supply on the east side of PA.

PA TBS#2:

This project consists of installing a 2nd TBS on the east side of PA and also the associated pipeline and District Regulating Station. The capital requirement for this project from 2017/18 to 2020/21 is estimated to be $9.5 million. TBS #2 was previously planned to be completed in 2019/20 but the plan has been revised to complete this project in 2020/21.

Moose Jaw:

An assessment of current and long term plans for the City of Moose Jaw focused on the management of load growth and system reliability. The security of supply and reliance on the sole TBS (TBS #1) impacts the anticipated industrial growth on the southeast sector of Moose Jaw. The MGI review identified the need for a 2nd TBS for additional supply on the south side of Moose Jaw.

MJ TBS#2:

This project consists of installing a 2nd TBS on the south side of Moose Jaw and the associated pipeline. The capital requirement for this project from 2017/18 to 2023/24 is estimated to be $9.2 million. TBS#2 in Moose Jaw was previously planned to be completed in 2020/21 but the plan has been revised to complete the project over a two year span targeted for completion in 2023/24.

Humboldt:

Humboldt TBS#2:

This project consists of replacing TBS#2 and also the associated pipeline to provide the following benefits:

- Reduce the reliance on TBS #1,
- Provide future capacity to allow for growth,
- Increase reliability in the system,
- Allow TGL to remove HP pipeline from within the urban limits.

The capital requirement for this project from 2017/18 to 2019/20 is estimated to be $1.18 million.

e) With reference to page 12 of the application, please describe in further detail the risk identification protocol and asset management strategy referenced. Please also indicate any major updates or changes in processes or approach to decision making that have occurred over the past year and detail any planned changes or assessments in this regard going forward.

Risk identification protocol ties to our management system, which lists the different ways each threat and hazard is identified, and then how they are prioritized for work. The past year, the focus has been to standardize a corporate approach for station integrity work, this is being accomplished by bringing all prioritization into system integrity to ensure the same risk strategies are being implemented across the organization. With a big system with lots of similar pieces installed in various locations across the province, an asset management approach is taken to deal with issues that arise, because if a problem is identified in one location, there is a potential that this same problem could be in 100's or 1000's of other locations, so a prioritized program approach to risk management is important. Asset Management changes over the past year include the formalization of an asset management committee, with a focus to bring consistent approaches to assets of the same type, and define risk, criticality, and other common approaches across the organization. This approach is at its infancy with expected results adding value over the next few years.

f) Please detail and specify by location and program type the key areas where safety and infrastructure renewal activities have been, or are planned to be, undertaken from 2015/16 through 2018/19.

Service Upgrade Program: Regina, Regina Beach, Septre, Abbey, Sovereign, Rosetown, Elrose, Shackleton, Lancer, Drinkwater, Beatty, Delisle

Urban Infrastructure Growth: Regina, Saskatoon, Prince Albert, North Battleford, Humboldt, Moose Jaw, Gull Lake

Mains Replacement Program: Chitek Lake, Saskatoon Rural residential areas, White City, Waldeck, Silton, Debden, Yorkton, Shellbrook, Buffalo Pound, Belle Plaine, Rosetown, Jansen, Swift Current, Dundurn, Moosomin, Schoenfeld, Delisle, Porcupine Plain, Blumenhoff, Beatty, Tugaske, Saskatoon, Radisson, Laura, Prince Albert

Station Integrity Program: Various locations throughout province, up to 40 locations per year.

g) Please provide a more detailed update on the distribution main replacement program, including a description of key activities being undertaken or planned to be undertaken from 2015/16 through 2018/19; please explain further how these activities were identified, justified and prioritized and provide forecast spending on these activities over this period.

Last year a review of our plastic resins was undertaken by a specialized consultant, and it was determine most of our plastics have a very long life span, however there are a few of the early vintage plastics, specifically PVC, and our original PE resin, known as Black PE in our system that have a limited life and need to be replaced. Concurrently, a review of our leak trends identified a few areas with these resins are close to the end of life. This information is used to prioritize specific areas for replacement.

The areas scheduled for replacement are:

Chitek Lake, Saskatoon Rural residential areas, White City, Waldeck, Silton, Debden, Yorkton, Shellbrook, Buffalo Pound, Belle Plaine, Rosetown, Jansen, Swift Current, Dundurn, Moosomin, Schoenfeld, Delisle, Porcupine Plain, Blumenhoff, Beatty, Tugaske, Saskatoon, Radisson, Laura, Prince Albert

h) Please provide the annual costs for the damage prevention program (described in Tab 6, page 7) from 2015/16 through 2018/19. What are key elements of these costs and where are these costs included in the capital or operating budgets?

The Sask 1st Call Safety Patrols operates three vehicles, based out of Regina, Saskatoon and Moose Jaw. The program is run on an annual budget of $180,000, shared evenly between SaskEnergy, SaskPower and SaskTel, so SaskEnergy's direct costs are $60,000 annually, and paid for by SaskEnergy Operations.

Distribution Daily Ground patrols of higher risk pipelines in Regina and Saskatoon - $38,400 per year under contract and remaining consistent. Modest increase may be required to patrol new EP lines that are in planning phase.

Capital damage prevention will increase beginning this year and will include planning and testing of new urban pipeline markers. Phase two of the marker trial will see a roll out in urban centers throughout the province in 2018/19.

	Damage Prevention Capital	Damage Prevention Operating
2015/16	0.00	$60,000.00
2016/17	$1,180.00	$98,400.00
2017/18	$100,000.00	$98,400.00
2018/19	$250,000.00	$98,400.00

i) With reference to page 14 of the application, please provide a more detailed description of the urban infrastructure program being undertaken. Please further describe key projects planned for the next 5 years, the rationale for these projects and expected results, costs for each major project and schedule for commencement and completion of work. Please also indicate urban centres [other than Regina and Saskatoon] where upgrades to support growth are planned within the next 5 years.

Refer to response 16 (d) which outlines details associated with the Major Growth Infrastructure Plans.

j) Please quantify any expected operating and maintenance savings from the safety and infrastructure renewal investments and any benefits included in 2017/18 test year revenue requirement or anticipated going forward.

Renewal of infrastructure through the Capital Expenditure Program may produce some gains in the operating and maintenance budgets due to new equipment having a less frequent failure rate. That being said, this impact is offset by the remaining aging infrastructure that still exists in the system that has rising costs due to unplanned maintenance and call outs. To date we have not been tracking the direct offset in the operating and maintenance budget vs. the capital expenditure program. The main capital expenditure areas that can result in lower O&M costs are as follows:

- Regulator/Meter Station Upgrades
- Line heater Upgrades
- Service Upgrades
- Distribution Main Replacement

k) Please expand the information on page 8 of the Application regarding the total number of customer connections to include 2016/17 (actual) through 2018/19 (forecast).

Yearly Increase in Active Customers	
2011	5,803
2012	7,386
2013	7,687
2014	7,332
2015	5,090
2016	4,140
2016/2017	4,000
2017/2018 Forecast	4,500
2018/2019 Forecast	4,500

For 2016/17, the actual number of net new customers was exactly 4,000 (this is not an error).

l) Please provide customer connection costs per customer connect for 2012 through 2016/17 actuals, 2017/18 and 2018/19 forecast.

SaskEnergy cannot easily provide a cost per customer connection. Some of the customers are large potash mines, while others are residential customers; and the Labour and Materials Management application does not distinguish between customer classes. Also the customer connection capital shown in Tab 6 includes infrastructure enhancements to support future growth, some of which is not customer specific.

m) Please explain why Custom Work expenditures increase from $0.117 million in 2015 to $0.402 million in 2015/16, to $1.471 million in 2016/17 and then decline to $0.1 million for 2017/18 and 2018/19 [page 3 of Tab 6].

The increase in the Custom Work expenditures was the result of the work completed to accommodate the Regina Bypass Project. In order to accommodate the routing for this highway project, design and construction activities were required to complete alterations to existing pipeline facilities during 2015/16 and 2016/17 that were impacted by the project.

n) Please provide an explanation for the increase in Rural Mains and Services expenditures in 2017/18 and 2018/19 compared to 2016/17 [$23.7 million and $21.0 million respectively compared to $15.0 million in 2016/17].

The increases in 2017/18 and 2018/19 compared to 2016/17 are due to urban and rural service alterations. In 2014 and 2015, the Ministry of Highways requested urban and rural service relocates and alterations to accommodate their plans that were not anticipated by SaskEnergy in those years. These expenditures were not realized in 2016/17 and are now forecasted for 2017/18 and 2018/19. This combined with elevated investment to provide natural gas distribution service for the SaskPower Chinook power station (a 350 megawatt (MW) combined cycle natural gas facility in Swift Current) drive the increase in 2017/18 and 2018/19 compared to 2016/17.

o) Please detail costs typically included in New First Nation Reserves line item and explain the expenditure in 2017/18 (of $1.5 million) compared to previous years.

The costs included in the New First Nation Reserves line item include all costs related to serving First Nation Reserves; such as mains, services, meters, etc. The expenditure of $1.5 million in 2017/2018 relates to a specific reserve that was expected to have service implemented during the 2017/2018 year.

p) With reference to page 4 of Tab 6, please provide an explanation for the increase in actual and forecast expenditures in Regulator/Meter Station Upgrades [increase from $5.8 million in 2014 to $11.7 million in 2015, $8.5-$9.5 million level for 2015/16 through 2017/18 and increase to $11.4 million in 2018/19].

The Regulator/Meter Station Upgrades category includes work completed on existing stations located throughout the province and can be performed to address integrity or system growth requirements. The work can include performing design and construction activities to replace or upgrade existing station equipment such as regulators or relief valves to accommodate load growth. This type of work can also include remedial design and construction activities to address integrity issues and can result in upgrading or replacing station facilities such as valves or piping. As a result of continued system growth and integrity programs focused on aging infrastructure, there has been an increase in capital work associated with regulator and meter station upgrades to reduce overall risk and is expected to continue as per the annual forecasts.

q) With reference to page 4 of Tab 6, please provide an explanation for the increase in actual expenditures in Area-Misc. Projects [about $9 million in 2016/17 compared to average $2 million for 2015, 2015/16, 2017/18 and 2018/19].

SaskEnergy provided funding support of $8.17 M of capital associated with transmission facilities to address delivery service requirements and provide reinforcement for load growth. The 4 projects are listed below:

- Saskatoon North – SaskEnergy contributed $2.95 M towards the installation of mobile compression facilities to address low pressure issues on the system north of Saskatoon.

- Pilot Butte Lateral – SaskEnergy contributed $3.06 M towards the installation of a transmission pipeline to address low pressure issues
- Lumsden Interconnect – SaskEnergy contributed $0.7 M towards transmission line interconnect facilities located between the Lumsden NPS6 lateral and the Rosetown to Regina NPS16 pipeline.
- Albertville Compressor Station – SaskEnergy contributed $1.46 M towards the installation of a compressor station facility to address low pressure issues situated north of Prince Albert, into the La Ronge area.

r) With reference to page 4 of Tab 6, please provide an explanation for the increase in U/G Entrance Program in 2016/17, and forecast decline in expenditures in 2017/18 and 2018/19.

The underground entrance program had been created with a time line to complete the work. 85% of the program will be completed in 2017/18. We will focus on completing the U/G Entrance Program over the next two years. This budget will continue to decline.

s) With reference to page 4 of Tab 6, please provide further detail regarding the increase in actual and forecast expenditures in Bridge Crossings/Major Infrastructure [increase from $2.0 million in 2015/16 to $10.3 million in 2016/17, $8.7 million in 2017/18 and $9.5 million in

2018/19]. Please list major projects impacting this increase and how much each project is contributing to the increase in expense.

The Bridge Crossings/Major Infrastructure category consists of the following budget codes within the LDC System Improvement Capital Plan:

- M05 – Major Growth Infrastructure (MGI)
- M29 – Bridge Crossings

The actual and forecast expenditure increase is a result of the MGI program. In 2015/16, a $2.0 million expenditure was the result of purchasing land and long lead material items for the Saskatoon TBS#5 project. In 2016/17, the $10.3 million can be attributed to the installation of the Saskatoon TBS#5 regulator station and an associated NPS16 distribution pipeline.

Forecasted budgets have been developed to complete MGI projects in multiple urban centers. Further details for each of these planned projects can be found in the response provided in Information Request 16(d).

t) The Application notes that "at the end of March 2017 Advanced Metering Infrastructure (AMI) natural gas modules had been installed on 87% of customer meters." [Page 10 of Application]. Please explain further the forecast increase in spending for the Meter Exchange Program from $2.5

million in 2016/17 to $4.2 million in each 2017/18 and 2018/19 forecast years.

2016/17 Meter Upgrade

The $2.5M expenditure in the 2016/17 Meter Exchange Program is the labour component to carry out the Measurement Canada identified ‘meter maintenance/meter exchange’ requirements consisting of sample meters and recalled meters totaling approximately 14,000 meters and rural AMI conversion completed by meter exchange of approximately 22,500 meter exchanges.

The urban AMI conversion work expenditure was done under the AMI Project budget.

2017/18 Meter Upgrade

The AMI Project budget ended the end of 2016. The 2017/18 budget of $4.2M consists of the labour component to carry out the Measurement Canada identified ‘meter maintenance/meter exchange’ requirements of sample and recalls totaling approximately 30,000 meters, complete remaining rural AMI conversions by meter exchange of 6500 meters ($2.9M budget), a urban AMI conversion program of approximately 17,000 meters ($1.0M budget) and 1st year of large diaphragm meter upgrade program ($0.3M).

2018/19 Meter Upgrade

The 2018/19budget is $4.2M and consists of the labour component to carry out the Measurement Canada anticipated ‘meter maintenance/meter exchange’ requirements of sample and recalls totaling approximately 16 to 18,000 meters ($1.4M), complete approximately 10 to 12,000 urban AMI conversions ($0.9M) and 1st year (start of program deferred to 18/19) of large diaphragm meter upgrade program($0.8M).

u) With reference to page 8 of Tab 6, please explain the increase for Buildings/ Furniture in 2017/18 [$23.4 million] and the ongoing increased expense in 2018/19 [of $8 million].

The increase for Buildings/Furniture capital in 2017/18 is attributable to the planned purchase of SaskEnergy Place for $19.4 million. The increase in planned capital expenditures for 2018/19 of $8 million is to begin to address the replacement of the existing customer service center in Regina.

v) Please provide an update regarding the status of legal issues related to the head office building and when outstanding issues are expected to be resolved. Please confirm whether there has been any change in foregone savings due to delay in resolving issues related to the head office building [see response to Round 2 Information Request 10(q) in relation to the 2016 Delivery Service Rate Application].

Confidential Response

w) With reference to page 8 of Tab 6, please provide an explanation for the forecast increase in Information Systems expenditures [$16.7 million in 2017/18 and $16.3 million in 2018/19].

i. Please provide an update regarding projects reviewed during the 2016 Delivery rate application proceeding [Distribution Work Management System; Hardware Lifecycle Initiatives; Capital Project Portfolio Management; Records Information Management; Geographical Information Systems]. Were these projects completed in 2016/17? If not completed, what is the forecast completion date for each project and what are the forecast costs included in the 2017/18 test year?

The RIM Technology Project ended December 2016 as expected; therefore no capital costs for the project were forecasted for 2017/18. The associated hosting costs are categorized as operating expense.

CPPM is an ongoing initiative to implement enterprise-wide Capital Project Portfolio Management at SaskEnergy. This project involves changes to processes and information systems which will take place over a number of years. SaskEnergy is currently implementing a Capital Portfolio Planning Solution (CPPS) to assist in the identification, selection and execution of its capital program. This project recently transitioned to the Elaboration Phase. This is the stage of the project where the proposals of software vendors are evaluated, the corporation selects the proposal that best fits its requirements and a plan is developed to implement the solution. The CPPS project is currently expected to be completed in 2018/19.

The GIS Project is on-going and its purpose is to convert the Distribution assets into the GIS as a starting point. This project is considered 'foundational' with future projects based on the GIS foundation anticipated to provide efficiencies and positive returns.

The Distribution Work Management project is still in progress and in the Construction Phase at this time. The team is currently working through the System Integration Testing phase and will be moving to User Acceptance Test phases in the coming months. Project close is scheduled for January, 2018 when it is planned to move into production.

Hardware Lifecycle Initiatives are ongoing activities required to ensure the necessary availability of information technology such as laptops, desktops, and servers remain in a vendor supported state. Investments are made each year dependent on business growth and the lifecycle stage of the hardware.

ii. Please list and describe any other major projects included in the forecast (including the rationale for undertaking the project, schedule and forecasts costs).

The CIS Upgrade project will begin in 2017-18 and complete in 2018-19. This project will bring the CIS (distribution billing and customer care) to a current state ensuring continued vendor support.

The Unified Communications & Collaboration (UC&C) initiative will begin in 2017-18. UC&C includes transition from legacy software to best practice systems to support enhanced communication and collaboration between SaskEnergy and key stakeholders.

iii. Do any of the forecast cost increases for Information Systems relate to safety? Please describe or quantify. Please also describe and quantify any related productivity and efficiency costs or savings for these projects.

The CPPS project does not directly relate to safety. There are currently no efficiency or productivity gains identified for this project post implementation. The expectation is that this solution will allow the corporation to more effectively deploy its capital for optimal return.

The Geographical Information Systems project in this foundational stage does not directly relate to safety although the system will eventually support safety initiatives. No efficiencies are forecast to be achieved in this phase of the project.

Distribution Work Management System project does not directly relate to safety. Efficiency gains are forecast to be achieved when this system is fully deployed. Given the partial year of operation planned in 2017/18, the estimated savings in the fiscal year are $140,000.

The Records Information Management project does not relate to safety and no efficiency or productivity gains were identified for this project post implementation. This project was implemented in compliance with the Government of Saskatchewan's record management legislation.

Hardware Lifecycle Initiatives do not directly relate to safety. Hardware is a foundational component to any system that does support safety related systems.

x) With reference to page 8 of Tab 6, please explain and provide further detail regarding the decrease in Gas Measurement costs in 2016/17 [from $14.1 million in 2015/16 to $7.0 million], and the increase forecast for 2017/18 and 2018/19 [of $10.6 million].

The decrease in Gas Measurement costs in 2016/17 [from $14.1 million in 2015/16 to $7.0 million], was due primarily to the completion of mass AMI deployment at the end of 2015. Although AMI deployment efforts have been ongoing since this time, it has been on a significantly smaller scale.

The increased forecast for 2017/18 and 2018/19 [of $10.6 million] is due to metering costs associated with a proposed initiative to replace large diaphragm meters (800 scfh and larger) with a newer, more compact and lightweight meter technology in order to realize efficiencies and reduce potential for injury during handling.

y) Please provide an update to Round 1 Information Request 14(q) in relation to the 2016 Delivery Service Rate Application, and detail the impact of the annual safety and infrastructure renewal expenditures to rate increases and to capital structure [actual debt/ equity ratio] of the corporation since 2012.

Annual Safety and Infrastructure Renewal Impact to Rate Changes and Debt/Equity Since 2010								
Impacts by Year								
	2012	2013	2014	2015	2015/2016	2016/2017	2017/2018	2018/2019
	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast
Impact to Rate Changes - Increase/(Decrease)	1.0%	1.3%	1.2%	1.4%	1.4%	1.7%	1.5%	1.6%
Impact to Debt/Equity - Increase/(Decrease)	1.5%	1.7%	1.5%	1.7%	1.8%	2.4%	2.0%	1.9%

z) Please explain how Customer Contributions are forecast for 2017/18 and 2018/19.

Customer contributions are forecast for 2017/18 and 2018/19 based on 45% of the total capital expenditures for all customer connections forecast for 2017/18 and 2018/19.

17. Reference: Safety & Reliability

a) Annual safety and infrastructure renewal investment is forecast to increase to $51 million for the application period and SaskEnergy states that this trend will continue.

i. Please provide a comparison of annual spending on existing infrastructure renewal to meet regulatory and industry standards as a percentage of the distribution utility rate base compared to peer utilities.

The SaskEnergy annual spending for safety and infrastructure renewal accounts for 5% of the distribution utility rate base. Each peer utility in the Canadian Gas Association (CGA) is structured differently; private ownership, publicly traded and Crown owned. Based on results provided by the CGA, the average distribution company in Canada spent 8% of their rate base on similar safety and infrastructure renewal.

ii. How long is the increased annual level of investment in safety and infrastructure renewal investment expected to continue [$51.3 million in application period]? What portion SaskEnergy assets have been renewed since 2010? What portion of assets are expected to be upgraded over the next 5 years? Please discuss.

The annual investment in safety and infrastructure is expected to continue for some time. The five year forecast shows continued elevated spending levels in these areas. Only a small portion of the SEI system is upgraded at a time any given time. SaskEnergy strives to upgrade 1% of the infrastructure on a yearly basis. This is a direct correlation to the number of KM's of pipeline in addition to the total number of customers. A maximum of 5% of the SaskEnergy system has been upgraded since 2010. This will continue into the future at the same rate of renewal.

b) Please update the table included in the response to Round 1 Information Request 23(f) in relation to the 2016 Delivery Service Rate Application and provide the actual spending on safety and integrity measures for each year from 2012 through 2015, 2015/16 and 2016/17 fiscal and forecasts for 2017/18, 2018/19, the 2016/17 test year and the 2017/18 test year.

Safety and Integrity spending included in OM&A for cathodic protection and leak surveys is as follows:

2012 Actual: $2.1 million

2013 Actual: $2.5 million

2014 Actual: $2.2 million

2015 Actual: $3.1 million

2015/16 Actual: $3.1 million

2016/17 Actual: $3.2 million

2017/18 Forecast: $3.0 million

2018/19 Forecast: $ 2.8 million

2016/17 Test Year Forecast: $3.0 million

2017/18 Test Year Forecast: $2.8 million

c) Please provide an update regarding the 10 year service upgrade plan.

i. Please provide a description of key activities forecast to be undertaken as part of the plan (including location), and how these are prioritized, as well as annual spending for these activities each year over the period from 2015/16 through 2018/19 forecast.

The locations that upgrades will be undertaken are Regina, Regina Beach, Septre, Abbey, Sovereign, Rosetown, Elrose, Shackleton, Lancer, Drinkwater, Beatty, Delisle These sites are prioritized by historical leak rate on a 3 and 5 year rolling average basis.

ii. Please quantify operating and maintenance costs and savings as a result of implementing the 10 year upgrade plan over this period.

The service upgrade program is credited with saving approximately 50 leaks since 2011, and targeting 30 leak savings from 2015/16 to 2018/19, which will saves about $10,000 per leak repair costs.

iii. Please discuss any impacts on leak rate, the lower target leak rate in 2016, and targeted and actual reduction in leaks per year.

The leak rate in 2016/17 Fiscal was 5.25 leaks/1000 kms of main. This was against a target of 5.80 leaks/1000 kms of main. For calendar year the leak rate was 4.93 leaks/1000 kms. This is the lowest year on record since the early 1980s. We target between 5 and 10% leak reduction per year.

d) Please update the information provided in the response to Round 1 Information Request 23(c) and (d) from the 2016 Deliver Service Rate Application, including any updates explaining year over year changes in actual leak rate per 1,000 km of mains from 2012 through 2016.

Leak Survey stats only			**Total U/G Leaks Reported including Customer and Line Hits from REO** Cause of Leak (other includes lightening, rodents, grease plugs, flange gaskets, line hits)						
Year	Services	kms	km's of main	Pulled Service	Material & Construction Defects	Corrosion	Other	Total	Leaks/1000km
2012	63784	12173	68092	117	0	0	233	350	5.14
2013	95688	13586	68612	134	20	10	244	408	5.95
2014	86000	11000	69015	142	28	14	227	411	5.96
2015	129131	16579	69015	86	35	14	271	406	5.88
2016	105977	20855	69015	73	33	17	217	340	4.93

*Weather impacts leak rates substantially. Rainfall and snowmelt correlate well with leak increases in our system, especially in geotechnical sensitive areas, such as Regina (heavy clay) and Last Mountain Lake (slope).

**Since 2013 leak classification has been expanded so trends can be identified more easily, and earlier. Since comparing to 2012, old stats were used.

2012 – In 2011, the service upgrade program increased, starting with a targeting of services around the known affected area. In 2012, a risk based approach was adopted, which targeted the areas in the province with the highest leak rate, bringing substantial gains to leak counts.

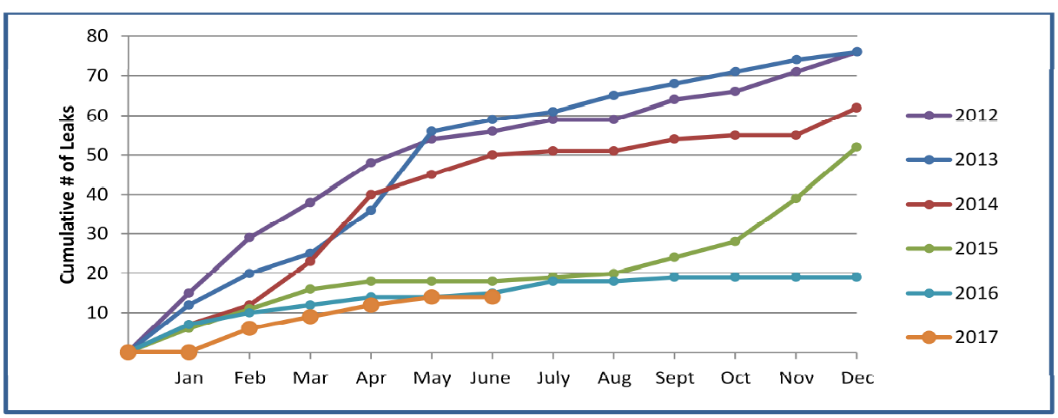
2013 – Material and Construction defects showed up in the leak statistics, adding 20 additional leaks by this factor. These were from a type of fitting that is no longer used by SaskEnergy. A high snowmelt and wet year also resulted in more pulled services.

2014 – Geotechnical leaks at last Mountain Lake increased substantially, with wet weather, high snow fall and subsequent snow melt along with extreme cold weather throughout winter months. These wet and freezing conditions caused a high reported geotechnical leak rate.

2015 – Line hits increased outside of the two major centers, causing an increase in leaks. A damage prevention program has started for these areas.

2016 – All categories are down, credited to dry year, service upgrade program and damage prevention efforts.

The service upgrade program is targeted to reduce 6-8 leaks per year, and has been mostly focused in Regina. The graph for Regina below, shows that the program is working.



e) Please update the table included in the response to Round 1 Information Request 23(e) in relation to the 2016 Delivery Service Rate Application and provide a breakdown of the causes or categories of leaks for 2012 through 2016 and 2017 to date. Please also provide a more detailed breakdown of the "other" category (include breakout of lightening, rodents, grease plugs, flange gaskets and line hits).

Leak Survey stats only			**Total U/G Leaks Reported including Customer and Line Hits from REO**						
			Cause of Leak (other includes lightening, rodents, grease plugs, flange gaskets, line hits)						
Year	Services	kms	km's of main	Pulled Service	Material & Construction Defects	Corrosion	Other	Total	Leaks/1000km
2012	63784	12173	68092	117	0	0	233	350	5.14
2013	95688	13586	68612	134	20	10	244	408	5.95
2014	86000	11000	69015	142	28	14	227	411	5.96
2015	129131	16579	69015	86	35	14	271	406	5.88
2016	105977	20855	69015	73	33	17	217	340	4.93

Other break down:

Other	217	External Interference	154	Line Contact	148
				Fire	6
		Equipment Malfunction	30	mechanical Fitting (not a pull)	27
				Valve	1
				Other	2
		Incorrect Operation	23	Missed/Wrong Locates	21
				Other	2
		Unable to Classify	10		

f) Please provide a table that shows the number and type of leaks by community for 2015, 2016 and 2017 year to date. Please provide in format similar to response to Delivery Service Information Request – Round 2, 18(c) from the 2016 Application.

The following table shows the leaks by type of community for 2015.

	External Interference	Equipment Malfunction	Material, Manufacturing or Construction (MMC)	Natural Forces	Corrosion / Degradation	Incorrect Operation	Unable to Classify	TOTAL
ASSINIBOIA	5		1					**6**
CANORA	1			1				**2**
CARLYLE	2							**2**
DAVIDSON	4					2		**6**
ESTEVAN	2			2				**4**
FORT QUAPPELLE	4						1	**5**
GRENFELL	3							**3**
HUMBOLDT	1			2				**3**
KINDERSLEY	3	2		4	1			**10**
LA RONGE	1							**1**
LUMSDEN	4			7			2	**13**
MAIDSTONE			1			2		**3**
MAPLE CREEK	4							**4**
MEADOW LAKE		2						**2**
MELFORT	3		1			2	1	**7**
MELVILLE	1							**1**
MOOSE JAW	2	2	1	3		1		**9**
MOOSOMIN								**0**
NIPAWIN	1	1	1	1			1	**5**
NORTH BATTLEFORD	1			1				**2**
PRINCE ALBERT	6	1	3	2	1	2		**15**
REGINA	27	5	7	40	3	1	1	**84**
ROSETOWN	4		1	1			1	**7**
ROSTHERN	4		1			1	1	**7**
Saskatoon	38	3	6	7		14	2	**70**
SHAUNAVON	2				1	1		**4**
SHELLBROOK	5	1						**6**
SWIFT CURRENT	7	1	1			1	1	**11**
TISDALE	1	2						**3**
TURTLEFORD	2							**2**
UNITY	1	1		1		1	1	**5**
WADENA	6			1			1	**8**
WATROUS	1			2	2			**5**
WEYBURN	3				1		1	**5**
White City	11							**11**
WYNYARD				1				**1**
YORKTON	4			1				**5**
Unknown	14	1	3	5	2	1	2	**28**

The following table shows the leaks by type by community for 2016.

Row Labels	Corrosion / Degradation	Equipment Malfunction	External Interference	Incorrect Operation	Material, Manufacturing or Construction (MMC)	Natural Forces	Unable to Classify	Grand Total
Assiniboia			3	1	1	3		8
Canora			6		1			7
Carlyle			3	4			1	8
Davidson	2		4		3	3		12
ENTER MANUALLY			5		1	1		7
Estevan			1					1
Fort Qu'Appelle	1		5	1		3		10
Grenfell			1				1	2
Humboldt		1	2	1	2	11		17
Kindersley	1	1	5					7
La Ronge			1					1
Lumsden			3		1	3	1	8
Maidstone			5	2		2		9
Maple Creek		1	3	1				5
Meadow Lake			2					2
Melfort		1	3	1		1		6
Melville			2					2
Moose Jaw		2	10		1	1		14
Moosomin			1			1		2
Nipawin			1			1		2
North Battleford		3				1		4
Outlook			1					1
Prince Albert			5	1	1	1	2	10
Regina City	2	4	19	1	8	19	3	56
Rosetown	1	9	4	1	1	2		18
Rosthern			3	1				4
Saskatoon City	3	1	8	3	3	5	2	25
Saskatoon East			1		1			2
Saskatoon North	1	1	3	4	1	1		11
Saskatoon West	1		1					2
Shaunavon			1		1			2
Shellbrook		1	4		2	2		9
Swift Current	2	2	6		3	2		15
Tisdale			1		1	3		5
Unity			3		1			4
Wadena			6					6
Watrous						1		1
Weyburn		1	3					4
White City			3					3
Wynyard			4					4
Yorkton			3			3		6
Saskatoon	3	2	5	1		2		13
Regina/Lumsden/Whitecity			3			1		4
MooseJaw			1					1
Grand Total	17	30	154	23	33	73	10	340

Information is compiled on an annual basis, therefore 2017 is not yet available.

g) Have there been any leaks in 2016 or 2017 to date that resulted in injuries or damage to public or private property? Please describe, including comparing the number of incidents to total number of leaks per year; and legal costs or penalties associated with incidents or any ratepayer impacts that resulted from incidents.

No.

h) Please update the table included in the response to Round 1 Information Request 23(g) in relation to the 2016 Delivery Service Rate Application and provide the actual lost time injury, medical aid and preventable vehicle collisions statistics for 2012 through 2016.

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2016/17**
Lost Time Injuries (LTI)	20	13	11	10	7	12	11
Medical Aids (MA)	11	15	13	12	11	6	4
Preventable Vehicle Collisions (PVC)	23	39	30	22	20	26	22
*Total Recordable Injury Frequency Rate	3.24	2.91	2.46	2.22	1.86	1.93	1.63
**PVC Frequency Rate	1.83	2.94	2.35	1.69	1.48	2.04	1.74

$$\text{* Corporate Recordable Injury Rate} = \frac{\text{(Lost Time Injuries + Medical Aid) X 200,000}}{\text{Total Hours Worked}}$$

$$\text{** Corporate PVC Frequency Rate} = \frac{\text{Preventable Vehicle Collisions X 1,000,000}}{\text{Total Kilometres Driven}}$$

i) Please update the table included in the response to Round 1 Information Request 23(h) in relation to the 2016 Delivery Service Rate Application, and provide SaskEnergy's actual average response time to safety incidents for 2012 through 2016.

The previous information provided related to the response time for incidents where a special investigation report was created (about 1000 calls per year). With the continual improvement of the work management system aggregate statistics are now available on the response time to all safety service calls (whether or not a subsequent special investigation report (SIR) was required – 25,000 to 30,000 calls per year). The previously supplied information is included to help with continuity of the time series.

	Response Time Minutes SIR required	**Response Time Minutes All Safety Calls**
2011	39	24
2012	40	24
2013	44	24
2014	45	23
2015		22
2016		23
2017(end of June)		23

j) Please update the table included in the response to Round 1 Information Request 23(i) in relation to the 2016 Delivery Service Rate Application, and provide SaskEnergy's actual average response time to safety incidents in rural areas vs. larger urban centres and towns for 2012 through 2016.

The response time data was examined for the seven largest centers in Saskatchewan (Saskatoon, Regina, Moose Jaw, Prince Albert, North Battleford, Swift Current and Yorkton) versus the rest of the province.

	Rural Response Time Minutes	**Urban Response Time Minutes**
2011	34	16
2012	34	16
2013	33	16
2014	32	16
2015	29	15
2016	33	17
2017 (Jan-June)	33	16

k) In response to Round 1 Information Request 23 (j), SaskEnergy stated that it "uses this metric as a relationship between system age versus integrity spending. We deem that the first 15 years of an asset's life typically requires minimal spending to keep it within an acceptable level of safe and reliable. So the ratio we use is a percentage of the book value from 15 years ago." Given the increased spending on system integrity since 2010, and the quality of new material being used, is there a need to update this measure?

We believe this metric is still relevant to compare where our system integrity spend is trending compared other years. But the main part of this metric is for actual budget year spending. It is to ensure that the money that is set aside for safety and integrity spending is actually spent there.

This is especially important in years of fiscal restraint, where a lot of initiatives are being cut back. The metric for that given budget year is set at 95% of budgeted amount for safety and integrity spending, ensuring that this money is spent where it was initially intended.

l) With reference to the table included in the response to Round 1 Information Request 23(k) in relation to the 2016 Delivery Service Rate Application, please provide any updates to comparisons of SaskEnergy's safety and reliability measures with other available industry metrics (for target leak rate and level of spending directed at safety and integrity initiatives). If relevant, please explain any differences or changes in results between SaskEnergy and industry metrics provided.

Incidents – SaskEnergy vs Industry

Industry Leaks

Per 1000 Services = 1.1
Per 1000 km Mains = 8.0

SaskEnergy Leaks

Per 1000 Services = 0.73
Per 1000 km Mains = 1.25

Spending– SaskEnergy vs Industry

Services

Industry - $18.1M

PE = 68%
Steel = 30%
Other = <1%

SaskEnergy - $18.0M

PE = 68%
Steel = 30%

Mains

Industry - $44.8M

PE = 70%
Steel = 30%
Other = <1%

SaskEnergy - $13.8M

PE = 70%
Steel = 30%

SaskEnergy feels this amount of spending is defendable in both cases.

Services: The spending aligns with industry, and SaskEnergy has a lower leak rate than industry.

Mains: The spending is lower than industry, but our system is relatively newer (most PE was installed in the 1980's), and SaskEnergy's leak rate is significantly lower than industry.

m) Please provide more information regarding the annual customer satisfaction research referenced at page 2 of Tab 7. Please provide the most recent survey and results.

SaskEnergy contracted Insightrix Research Inc. to conduct annual customer satisfaction research from June 22nd to July 2nd, 2016. A total of 803 surveys were completed through the SaskWatch Research® online panel. Demographic quotas were representative of Saskatchewan and SaskEnergy's customer base.

The following statements were rated on a 7-point scale where a rating of 7 indicates respondents are 'very confident' in SaskEnergy's commitment to safety. Results are reported based on a combined total of respondents who rated a 5, 6, or 7.

- 92% of respondents believe 'SaskEnergy makes safety a number one priority'.

- 90% of respondents believe 'SaskEnergy has qualified employees who behave in a safe and responsible manner'.
- 86% of respondents believe 'SaskEnergy is continually making improvements to their natural gas pipeline and distribution system to enhance safety'.

The following statements were rated on a 7-point scale where a rating of 7 indicates respondents believe SaskEnergy is doing an 'excellent job' related to safety initiatives. Results are reported based on a combined total of respondents who rated 5, 6, or 7.

- 87% of respondents believe SaskEnergy does a great job of 'educating and informing the public on how to detect a natural gas leak'.
- 86% of respondents believe SaskEnergy does a great job of 'educating and informing the public on what to do if there is a natural gas leak'.
- 84% of respondents believe SaskEnergy does a great job of 'educating and informing the public on safety around natural gas pipelines'.

18. Reference: Net Income

a) Please explain and quantify factors underlying the lower actual net income for 2015/16 (of $1.743 million) compared to the previous actual years.

The lower net income for 2015/16 was primarily attributable to warmer than normal weather. In 2015, weather was 6% warmer than normal. In the first three months of 2016, weather was 14% warmer than normal. Delivery revenue earned though the basic monthly charge and the volumes delivered to customers totaled approximately $204 million in 2015/16 which yielded a result well below the targeted return. Another contributing factor to the 2015/16 net income result was SaskEnergy's safety and infrastructure renewal spending which was temporarily elevated in response to events at the time. The result was that a lower return on equity was accepted. It is important to note that SaskEnergy applied for an 8.6% delivery service rate adjustment effective November 1, 2016 which was considered by SaskEnergy management and the SaskEnergy Board as a necessary step change (approximately $20.2 million) in order to restore SaskEnergy's return on equity to an industry comparable return.

b) Please explain and quantify factors underlying higher actual net income for 2016/17 (of $29.713 million).

SaskEnergy applied for an 8.6% delivery service rate increase effective November 1, 2016. This represented a considerable adjustment (approximately $20.2 million) that was necessary to restore SaskEnergy's return on equity to an industry comparable return. In addition, SaskEnergy's cost restraint measures on discretionary expenditures in response to the restraint directives from the Province of Saskatchewan also favourably impacted net income for 2016/17. Operating savings were achieved due to vacancy and overtime management, as well as reduced advertising, professional fees, travel, training and vehicles expenditures in 2016/17.

c) Please provide the weather adjusted net income for 2015/16 and 2016/17.

The following net income results assume weather normalized delivery revenue for 2015/16 and 2016/17.

2015/16 - $20.8 million

2016/17 - $37.5 million

19. Reference: Tab 17 - Calculation of Ratebase

a) Please confirm that Plant in Service at Cost figures are net of customer contributions.

Confirmed.

b) Please update the table included in the response to Round 1 Information Request 16(b) in relation to the 2016 Delivery Service Rate Application. Please provide a continuity schedule of the Plant in Service and Accumulated Depreciation, including opening balance, additions and other adjustments [e.g., disposals] for the period 2015/16 through 2018/19. In the table please also include removal of customer contributions.

SaskEnergy Distribution Division
Continuity Schedule - 2015/16 to 2018/19

	2015/16 Actual ($000s)	2016/17 Forecast ($000s)	2017/18 Forecast ($000s)	2018/19 Forecast ($000s)
Description				
Plant In Service At Cost Opening Balance	1,281,399	1,386,701	1,487,826	1,620,575
Customer Contributions - Opening Balance	(208,443)	(230,191)	(248,832)	(269,024)
Additions - Plant in Service	105,921	113,719	137,929	144,099
Disposals and Adjustments - Plant In Service	(619)	(12,594)	(5,180)	(6,295)
Additions Customer Contributions	(21,748)	(18,641)	(20,192)	(18,272)
Plant In Service At Cost Ending Balance	1,386,701	1,487,826	1,620,575	1,758,379
Customer Contributions - Ending Balance	(230,191)	(248,832)	(269,024)	(287,296)
Plant in Service at Cost Ending Balance (net)	1,156,510	1,238,994	1,351,551	1,471,083
Check				
Accumulated Depreciation - Opening Balance	430,118	471,339	503,928	548,961
Amortization of Customer Contributions - Opening Balance	(47,201)	(52,527)	(58,321)	(64,503)
Depreciation Expense	41,843	45,169	50,213	53,812
Disposals & Adjustments - Accumulated Depreciation	(622)	(12,580)	(5,180)	(6,295)
Amortization of Customer Contributions	(5,326)	(5,794)	(6,182)	(6,568)
Accumulated Depreciation - Closing Balance	471,339	503,928	548,961	596,478
Amortization of Customer Contributions Closing Balance	(52,527)	(58,321)	(64,503)	(71,071)
Accumulated Depreciation (net)	418,812	445,607	484,458	525,407
Net Book Value	737,698	793,387	867,093	945,676

*The opening balance in the 2017/18 Forecast incorporated June 2016 actual results as a opening balance not March 2017 actual results

*Plant and Service and Depreciation expense detail within ratebase excludes decommissioning assets as the asset is a non-cash asset and is not subject to a return on investment.

c) Please update the table included in the response to Round 1 Information Request 16(c) in relation to the 2016 Delivery Service Rate Application, and provide a table that shows the calculation of cash working capital requirements for 2017/18 test year for each expense/revenue category.

SaskEnergy Incorporated				
Cash Working Capital Allowance				
Test Year 2017/2018				
				**** Working**
	Lead/Lag		**$ 000's**	**Capital**
	Days*	**$ 000's**	**per day**	**Allowance**
Description				
Transportation	(45.60)	33,091	90.66	(4,134)
Storage	(45.60)	18,937	51.88	(2,366)
Labour	(7.60)	73,137	200.38	(1,523)
Other Operating & Maintenance	(30.00)	54,938	150.51	(4,515)
Corporate Capital Tax	(15.20)	5,948	16.29	(248)
Short Term Interest Expense	(15.20)	1,601	4.39	(67)
Long Term Debt Interest	(91.30)	22,815	62.51	(5,707)
Revenue - Non Farm	40.00	267,738	733.53	29,341
Revenue - Distribution Tolls	82.90	18,789	51.48	4,268
Totals		496,994	1361.63	15,049
				15,049

* Lead/Lag Days represents the time difference between the average date of revenue (or expenses) incurrence and the average date of cash receipt (or disbursement).

** $ 000's/day times Lead/Lag Days

d) Please provide an update to the table included in the response to Round 1 Information Request 16(d) in relation to the 2016 Delivery Service Rate Application, and provide a table that shows the calculation of the Natural Gas in Storage amount included in rate base for 2017/18 test year.

Natural Gas in Storage Included in 2017/18 Rate Base - $39,489 thousand - 13 Month Average

	2017	2017	2017	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	13 Month
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Average
Gas in Storage	64,801	59,620	46,458	30,346	16,943	10,213	12,069	20,135	30,579	41,844	53,176	62,000	65,177	39,489

e) Please explain why the Natural Gas in Storage amount included in rate base for the 2017/18 test year is higher compared to 2017/18 and 2018/19 forecasts.

This is a function of the backwardation in the natural gas market. Natural gas prices for the summer of 2017 and the winter of 2017/18 are the highest prices on the curve. At the time the application was prepared, natural gas prices were lower in 2017/18 and 2018/19.

f) Please detail what is included in Inventories of Material and explain the increase for 2017/18 and 2018/19.

The majority of inventory included in Inventories of Material is pipe inventory (other than polyethylene pipe which has moved to a just in time inventory model) that has been purchased but has not been assigned to a specific capital project. Pipe costs typically increase year over year. Another item included in inventory is odorant which has increased in both volume and price in the last number of years. As a result, the Inventories of Material amounts for 2017/18 and 2018/19 are reasonably forecast to increase.

g) Please confirm inventories included in Plant in Service cost [if any] are not included in working capital requirement calculations.

Confirmed. Inventories included in rate base cost are not included in working capital requirements.

20. Reference: Capital Structure and Return on Equity

a) Please confirm if the return on equity figures provided in Tab 15 are actual return on equity or weather normalized return on equity.

The return on equity figures provided in Tab 15 are actual return on equity figures.

b) Please update the response to Round 1 Information Requests 17 (b) from the previous application, and provide SaskEnergy's actual and weather normalized return on equity for each of the past 10 years for both the distribution utility and the consolidated company.

Note that the ROE results provided below for the Distribution Utility and the consolidated entity are not directly comparable. The Distribution Utility return as provided is the regulated return while the consolidated ROE results are reported based on International Financial Reporting Standards beginning in 2010. Prior to 2010, the consolidated ROE as provided is consistent with Canadian Generally Accepted Accounting Principles.

SaskEnergy Incorporated - Distribution Utility Return on Equity - 10 Years Historical										
	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2015/16 Actual
Actual ROE	7.2%	8.5%	8.5%	10.6%	7.9%	8.3%	12.4%	10.2%	3.3%	0.6%
Weather Normalized ROE	9.5%	8.2%	2.4%	10.6%	6.3%	9.7%	9.0%	4.5%	8.0%	7.0%

SaskEnergy Incorporated - Consolidation Return on Equity - 10 Years Historical										
	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2015/16 Actual
Actual ROE	15.4%	12.5%	13.5%	10.8%	13.6%	11.0%	11.0%	6.5%	12.3%	11.6%
Weather Normalized ROE	16.3%	12.4%	11.2%	10.8%	13.1%	11.4%	10.0%	2.4%	14.2%	13.9%

c) Please provide the expected actual and weather normalized ROEs for the 2016/17 test year for the distribution utility and comment on the drivers of any differences.

SaskEnergy Incorporated - Distribution Utility Actual & Weather Normalized	
2016/17 Test Year Actual	2016/17 Test Year Weather Normalized
8.3%	8.3%

The weather normalized result and the actual result are the same despite warmer than normal weather during the period. The reason for this result is that expense management efforts that occurred during 2016/17 off set the reduced delivery service revenue.

21. Reference: Cost of Service Study

a) Does SaskEnergy monitor the Revenue-to-Cost ratio on an actual basis? If yes, please provide the most recent actual Cost of Service study and Revenue-to-Cost ratio based on actual revenues.

SaskEnergy does not monitor the Revenue-to-Cost ratio on an actual basis.

b) Please confirm if SaskEnergy's 2017/18 cost of service study was prepared using the same methods reviewed by Chymko Consulting in 2013 and 2015/16 cost of service study. If not, please itemize any differences between the methods used in the 2017/18 cost of service study and the methods reviewed by Chymko Consulting in 2013 and 2015/16 cost of service study.

Yes. The same methods were used.

c) Please confirm that the change in cost of service allocation factors from the 2016/17 test year cost of service study are solely due to the change in customer class peak and usage characteristics.

Confirmed.

d) In response to Round 2 Information Requests 10 (l) from the previous application SaskEnergy stated that the allocation factors for mains for large and medium industrial customers were updated in 2015, reflecting an increase in the number of large industrial customers requiring stations that are not connected to the distribution system through the distribution mains. Please detail if there are any other changes to allocation factors compared to the allocation factors used in the Chymko Consulting report.

There are no other changes to allocation factors compared to the allocation factors used in the Chymko Consulting report.

e) Please explain how Peak Day Load Factors in Schedule 3.2.1 are calculated. Please explain changes compared to the 2016/17 Cost of Service study.

The Peak Day Load Factors in Schedule 3.2 are the peak day use per customer and the number of customers. Similar to the load forecast, this calculation is done for each customer class and the total from each class is added together.

The peak day use per customer is calculated using regression, which calculates the statistical relationship between variables, which in this case is the peak day use per customer given a certain number of degree days. The historical actual peak day use per customer and the associated number of degree days are applied through regression to calculate the 1-in-20 colder than normal peak day use per customer and that is multiplied by the number of customers.

The number of customers come from the load forecast.

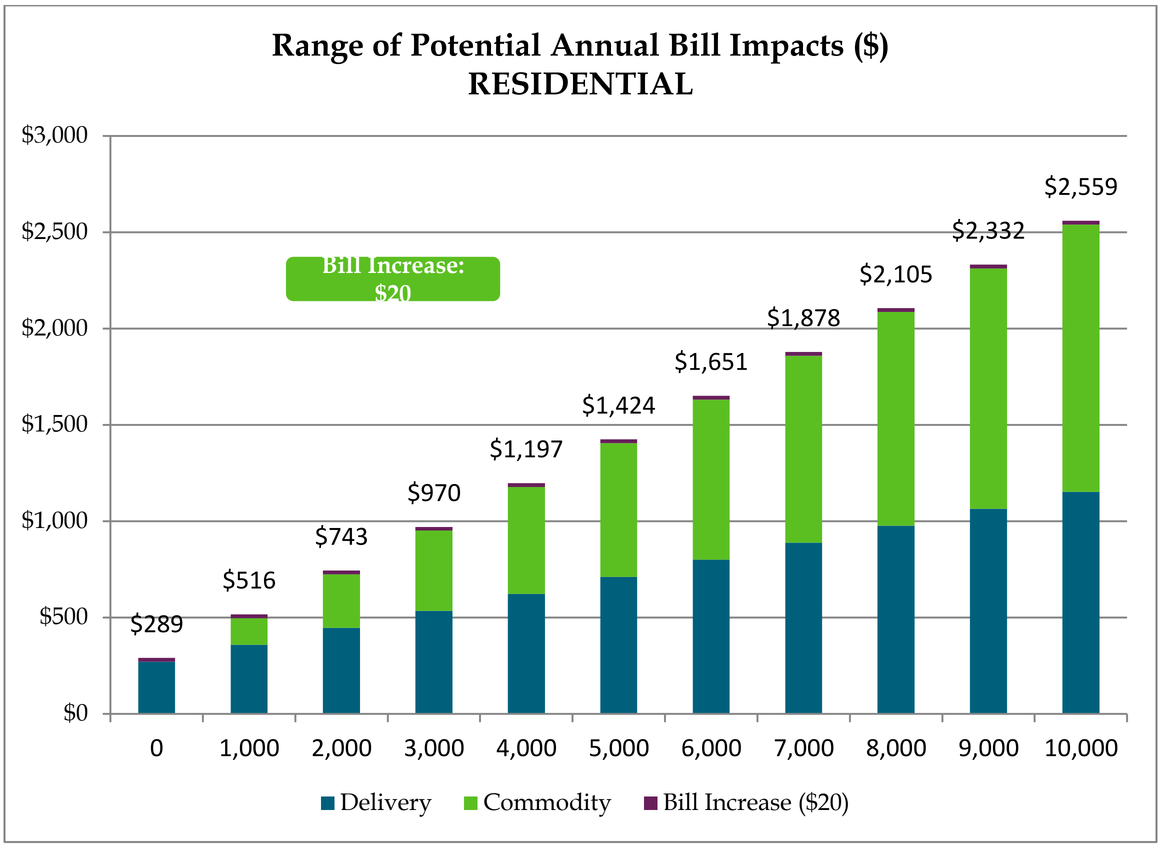
There has been no change to the forecast peak of 600,000 GJs/day from last year.

f) Please explain why a higher average rate increase is required for residential customers compared to the other rate classes while the Revenue-to-Cost ratio for residential customers is forecast to be at 2016/17 cost of service study level [98.8% in 2017/18 compared to 98.9% in 2016/17].

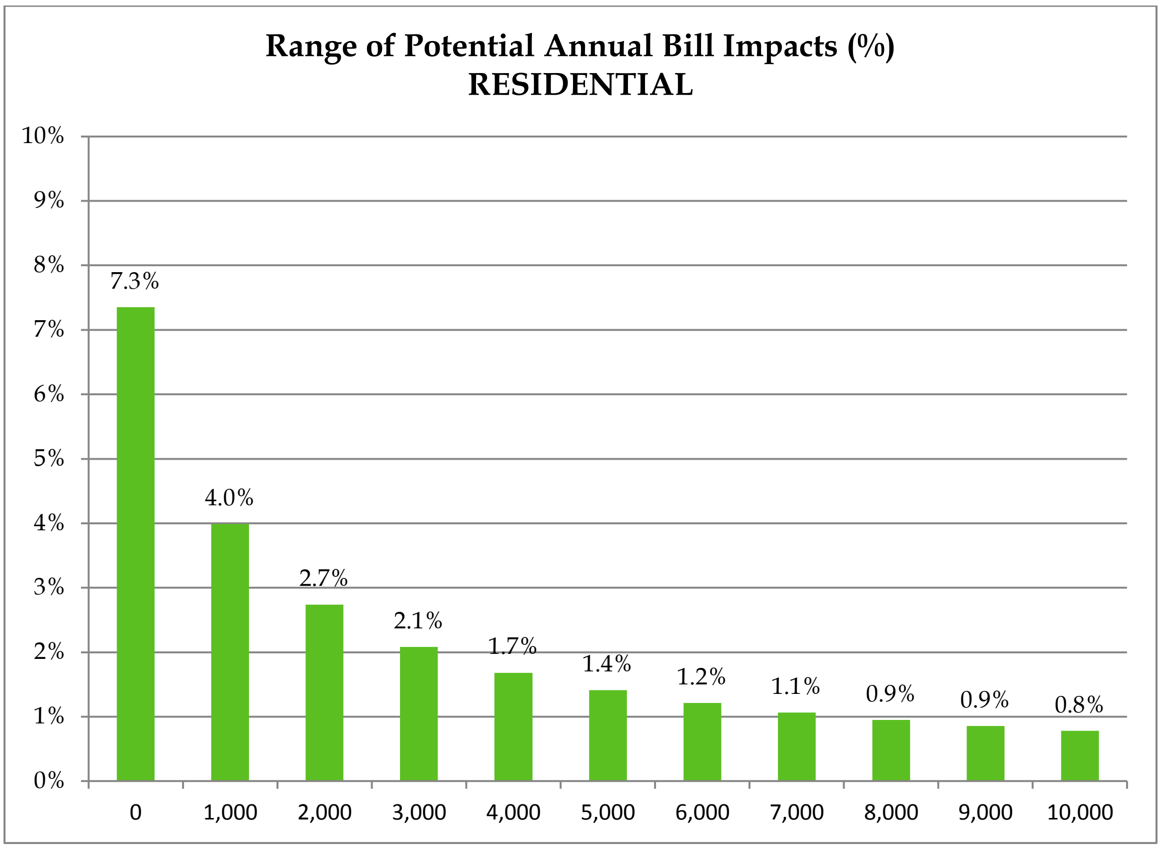
A higher rate increase is required for the Residential customer class as the majority of integrity investment and safety related operations have been associated with this rate class.

22. Reference: Customer Bill Impacts

a) With reference to Tab 19, page 4, please provide a version of the figure for residential annual bill impacts that shows the total bill based on use, and includes both the commodity and delivery portion of the bill.



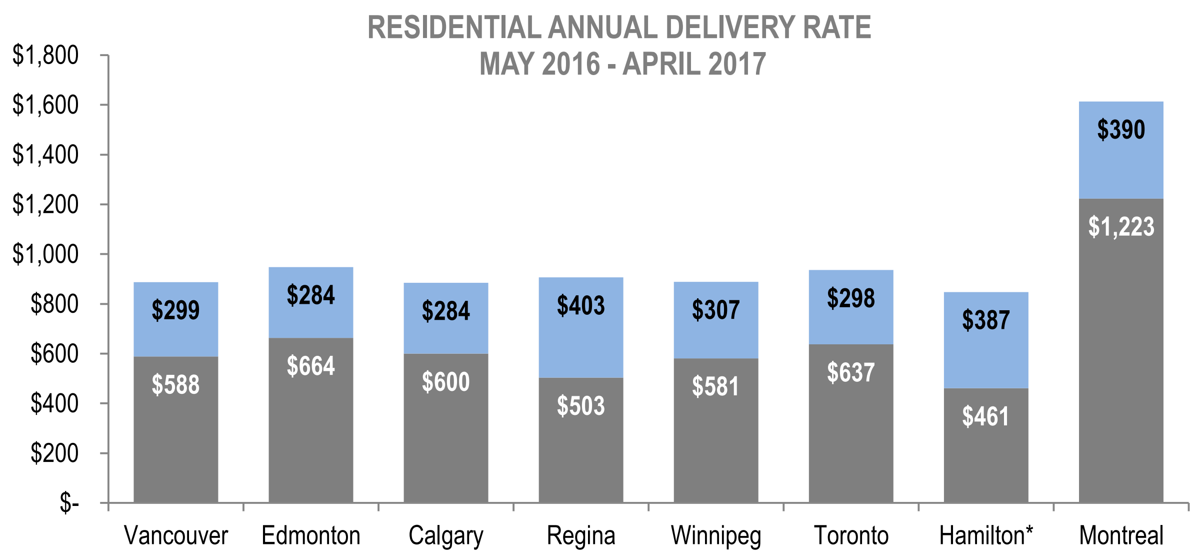
b) With reference to Tab 19, page 4, please provide a version of the residential annual bill impact figure that shows the range of percentage impact that the $20 BMC bill increase will have on residential customer bills based on use/volume used.

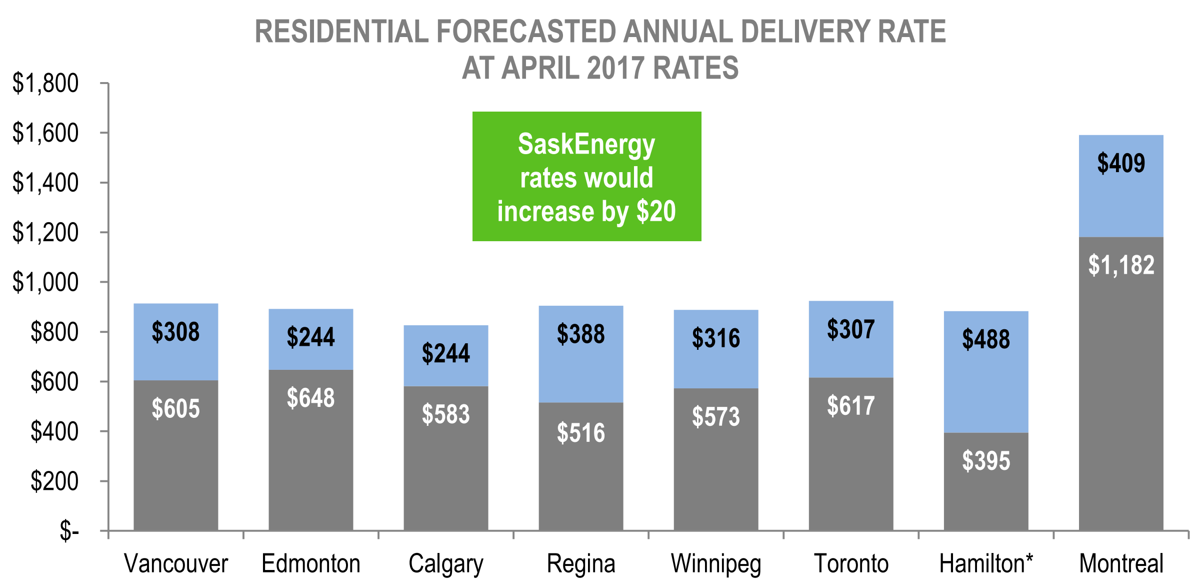


23. Reference: Competitiveness

a) With reference to the figures provided in Tab 20, please provide a version of each of the figures that includes both the commodity and delivery portion of the bill.

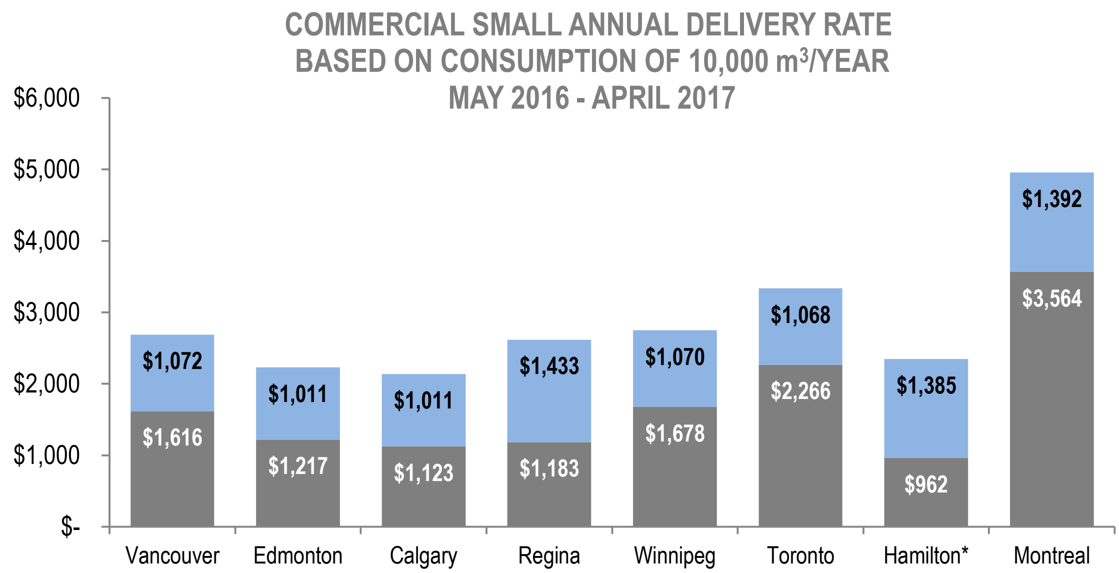
RESIDENTIAL

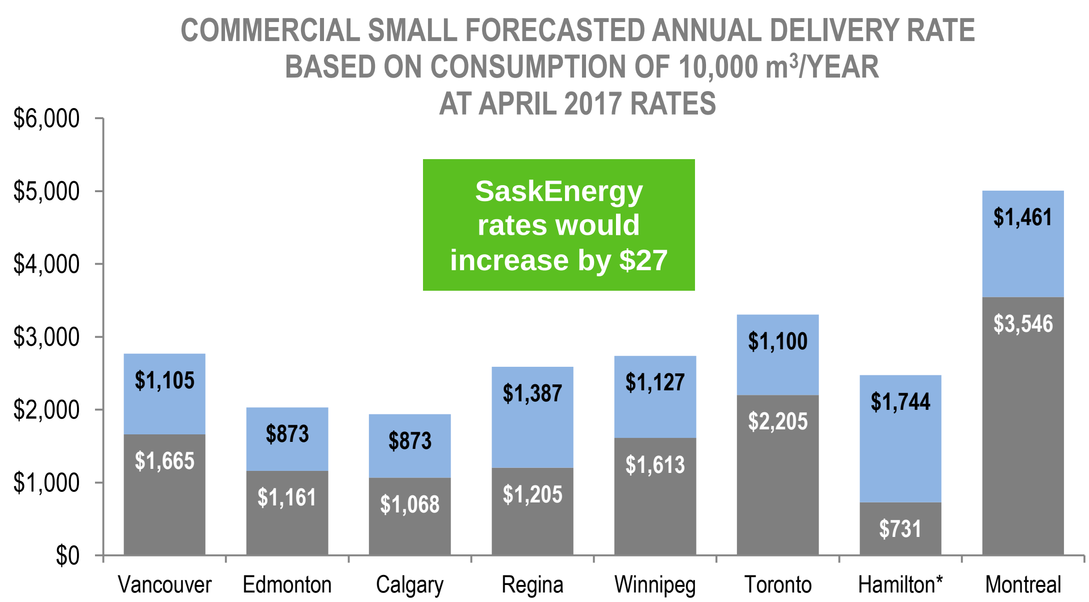




**Union Gas no longer includes a transportation cost. As of January 1st, 2017 transportation costs are included in the commodity rate.*

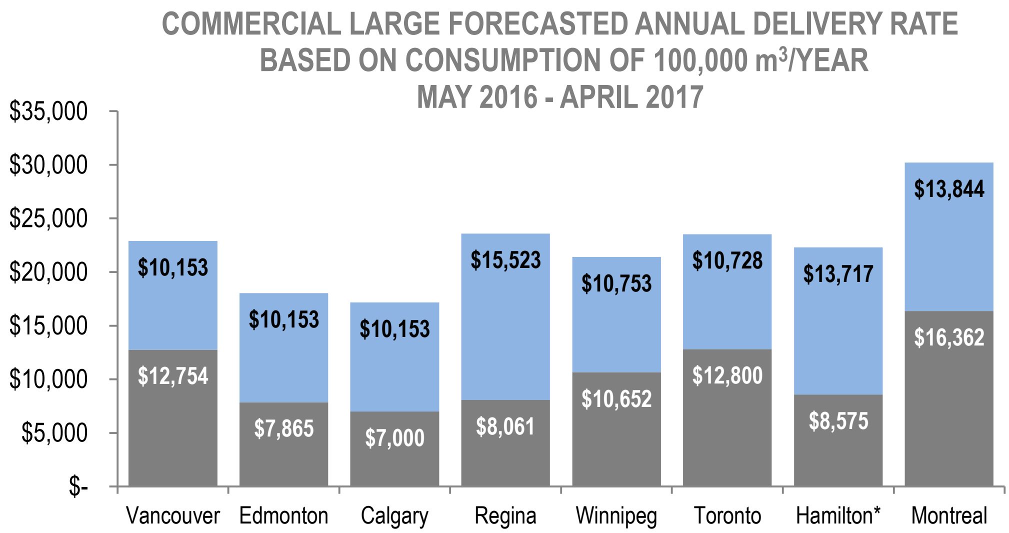
COMMERCIAL SMALL

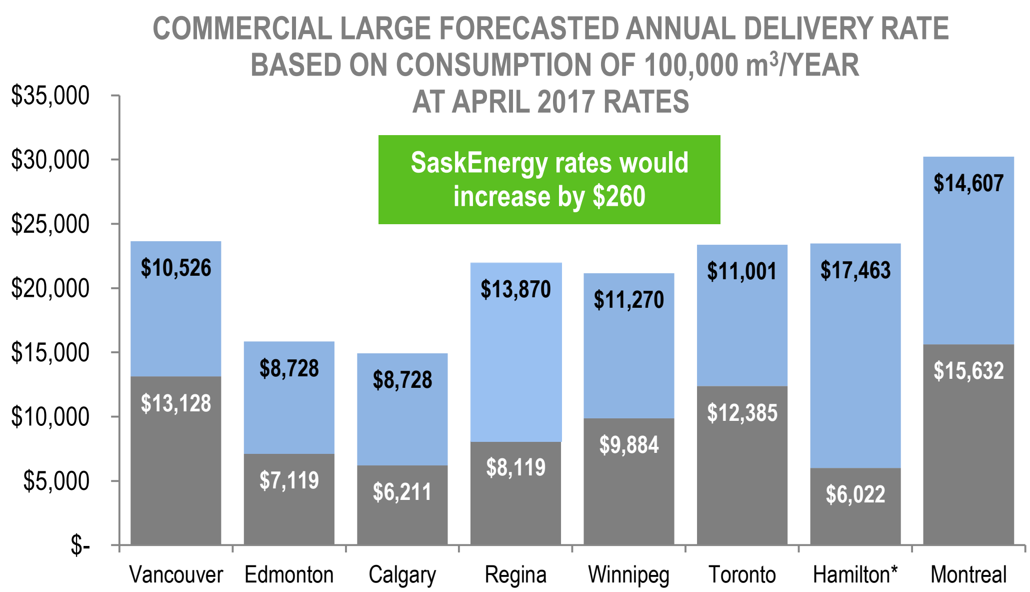




**Union Gas no longer includes a transportation cost. As of January 1st, 2017 transportation costs are included in the commodity rate.*

COMMERCIAL LARGE





**Union Gas no longer includes a transportation cost. As of January 1st, 2017 transportation costs are included in the commodity rate.*

24. Reference: Load Forecast and Peak Load Requirements

a) Please provide a version of the load forecast model and regression analysis in Microsoft excel format with all formulae intact.

Confidential Response

b) Please provide an updated version of the response to Round 1 Information Request 21 (a) and (b) from the previous application. Please discuss the impact of 87% AMI implementation as noted in the Application to the load forecast accuracy. Has implementation of the AMI improved forecast accuracy?

Comparison of Weather Normalized Loads (Forecast to Actual)

	2013			2014			2015			2015/2016			2016/2017		
000’s / GJs	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Residential	34,391	34,706	-1%	35,816	35,746	0%	35,474	35,550	0%	35,241	34,970	1%	35,745	35,756	0%
Commercial Small	18,795	18,283	3%	19,960	19,193	4%	19,675	18,980	4%	19,551	19,099	2%	19,947	19,230	4%
Commercial Large	9,165	10,097	-9%	9,571	9,231	4%	8,827	9,314	-5%	8,684	9,259	-6%	9,899	9,308	6%
Small Industrial	1,193	1,016	17%	728	811	-10%	671	901	-26%	722	901	-20%	950	1,329	-29%
Total	**63,544**	**64,102**	**-1%**	**66,075**	**64,981**	**2%**	**64,647**	**64,745**	**0%**	**64,198**	**64,229**	**0%**	**66,541**	**65,623**	**1%**

Comparison of Number of Customers (Forecast to Actual)

	2013			2014			2015			2015/2016			2016/2017		
000’s / GJs	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Residential	328,330	325,827	1%	336,305	332,915	1%	341,421	341,017	0%	342,508	342,441	0%	346,218	346,450	0%
Commercial Small	37,814	37,658	0%	38,469	38,194	1%	38,838	38,484	1%	38,940	38,555	1%	39,380	39,648	-1%
Commercial Large	1,417	1,490	-5%	1,390	1,322	5%	1,430	1,332	7%	1,440	1,333	8%	1,437	1,388	4%
Small Industrial	18	18	0%	18	18	0%	27	18	50%	27	18	50%	29	27	7%
Total	**367,579**	**364,993**	**1%**	**376,182**	**372,449**	**1%**	**381,716**	**380,851**	**0%**	**382,915**	**382,347**	**0%**	**387,064**	**387,513**	**0%**

With AMI now 87% implemented, the monthly consumption recorded in the customer billing system is closer to the actual customer consumption in the month, however, the customer reads are done on different days of the month. Once AMI is fully implemented, the possibility of creating a process that would read all meters at month-end would more accurately record the volume of natural gas consumed in a specific month. For the purpose of forecasting, it is expected that at least five years of accurate historical AMI data will first be required in order to show an improvement to load forecasting.

c) Please provide details of the forecast method for new customer additions. Please confirm whether or not the same method was used for all customer classes, if not, please provide details for each customer class.

Economic indicators are used to forecast customer growth in the load forecast. The CMHC housing outlook is used to perform a customer growth forecast. The customer growth forecast is based on a review of single detached and multi-family housing starts, migration statistics (Saskatchewan net migration, interprovincial migration breakdown, net migration by major center), economic activity (building permit values, net job creation in Saskatoon and Regina, Saskatchewan real GDP growth), and attractiveness of Saskatchewan (labour market comparison to other provinces, costs to own and rent homes). Additional sources of information include the Government of Saskatchewan and Statistics Canada websites. Yes, the same method is used for all customer classes.

d) Please explain the large increase in the Commercial Large customer class load forecast compared to the previous application [10,126 thousand GJ compared to 9,306 thousand GJ or about 8.8% increase].

The load forecast considers the number of customers in the customer class and the use per customer in that class. In the Commercial Large class, both the number of customers and the use per customer increased, resulting in the noted increase. The actual number of customers in this class has increased in the year prior to completing the load forecasts as well as the actual use per customer, which is calculated based on historical weather-normalized consumption.

e) Please provide the calculation showing the derivation of the forecast peak shown in Schedule 2.6.

Heating Load (Residential, Commercial)	602,111 GJ
Small Industrial	4,370 GJ
Total Peak	606,481 GJ
Peak Day	600,000 GJ

The heating load is forecast using regression analysis based on last 30 years of data to estimate heating load.

f) Please provide the 30-year Environment Canada weather statistics for Regina and Saskatoon used in the peak day forecast [page 26 of the application].

Peak Day Date	Degree Day Provincial Average
16-Jan-16	46.1
4-Jan-15	46.7
5-Jan-14	50.4
30-Jan-13	48.4
18-Jan-12	47.1
24-Feb-11	46.8
14-Dec-09	47.1
14-Dec-08	48.8
29-Jan-08	52.9
11-Jan-07	48.8
16-Feb-06	48.1
13-Jan-05	52.2
27-Jan-04	56.3
22-Jan-03	45.6
28-Jan-02	45.6
20-Dec-00	47.3
19-Dec-99	43.0
7-Jan-99	47.7
12-Jan-98	50.3
9-Jan-97	50.9
1-Feb-96	51.3
10-Feb-95	39.1
17-Jan-94	50.9
28-Dec-92	50.3
14-Jan-92	43.4
28-Dec-90	50.5
20-Dec-89	55.3
1-Feb-89	54.1
4-Feb-88	47.6
12-Nov-86	36.8
26-Nov-85	47.3
30-Jan-85	47.9
23-Dec-83	54.0
7-Dec-82	43.6
15-Jan-82	49.1
10-Feb-81	46.6
8-Jan-80	49.8
Probability	**DD**
1 in 20	54.7

g) Please reconcile the weather normalized consumption forecast for the small industrial customer class provided in Schedule 2.2 of the application to the weather normalized consumption forecast provided in Tab 20 of the application. Please explain any differences.

The Small Industrial Customer Class is forecasted to be 27 customers during the test period. An error was made in Tab 18 when inputting the forecast average number of customers and the Small Industrial customer number should have been 27, not 29.

h) Please provide heat values [energy content] for each year used in the Tab 20 tables for each customer class. Please explain any differences in heat values.

	Heat Value (MJ/m^3)			
Year	**Residential**	**Commercial Small**	**Commercial Large**	**Small Industrial**
2013	38.42	38.42	38.42	38.42
2014	38.36	38.36	38.36	38.36
2015	38.79	38.79	38.79	38.79
2015/16	38.76	38.76	38.76	38.76
2016/17	38.52	38.52	38.52	38.52
2017/18*	38.50	38.50	38.50	38.50
2018/19*	38.50	38.50	38.50	38.50
2019/20*	38.50	38.50	38.50	38.50

*Forecast

25. Reference: Rate Design Principles and Objectives

a) On page 21 of the current application SaskEnergy states that it "has a long-term objective to recover at least 75% of its customer care related costs through its BMC." It also notes that the gradualism "principle allows rate realignments to occur more gradually, over several rate applications as opposed to all at once."

i. Please provide the Basic Monthly Charge (BMC) portion of the revenues for each rate class for the last three actual years.

		Residential	Commercial Small	Commercial Large	Large Industrial	Total
2016-17 (Apr 16 - Mar 17)	12 months	$ 88,501,411	$ 17,532,841	$ 2,343,962	$ 79,782	$ 108,457,996
2015 Total (Jan to Dec)	12 months	$ 77,408,807	$ 14,940,715	$ 2,262,731	$ 64,800	$ 94,677,052
2016 Total (Jan to Mar)	3 months	$ 20,056,366	$ 4,020,956	$ 476,716	$ 18,391	$ 24,572,429
2015-16 (Jan 15 - Mar 16)	15 months	$ 97,465,173	$ 18,961,671	$ 2,739,447	$ 83,191	$ 119,249,481
2014 (Jan - Dec 14)	12 months	76,142,879	14,715,084	2,246,723	45,360	$ 93,150,045

ii. Please discuss further the rationale and appropriateness of SaskEnergy's proposal to apply the residential rate increase to the BMC only and rate increases for all other classes applied to the volumetric delivery charge [changing the residential BMC portion from 73% at current rates to 78%, while the ratio for the commercial classes remains well below SaskEnergy's long-term objective of 75%]. Please discuss potential SaskEnergy revenue impacts as well as impacts on conservation initiatives.

SaskEnergy prepares and evaluates alternatives before recommending rates for each customer class. SaskEnergy's long-term target to recover at least 75% of customer care related costs is an on-going effort and balances the overall 75% target with changes to the volumetric delivery charge. To keep public communication simple, typically SaskEnergy will choose to apply the increase to either the BMC or the volumetric Delivery Charge (unless a substantial rate increase is applied for). For this rate application, a change to the BMC for the Residential rate class and a change to the Delivery Charge for the commercial and industrial rate classes resulted in the best fit for achieving the 75% customer care related recovery target.

b) Did SaskEnergy consider applying a portion of the residential class rate increase to the volumetric delivery charge? What allocation would keep the BMC within (or closer to) the 75% range? Please provide any analysis or assessments in this regard.

Yes, SaskEnergy considered applying a portion of the residential class rate increase to the volumetric delivery charge as a rate setting alternative. SaskEnergy prepares and evaluates alternatives before finalizing the rates for each customer class.

An increase of $0.75 to the BMC and an increase of $0.0041 to the volumetric delivery service charge would recover 75% of BMC costs.

c) On page 20 of the current application SaskEnergy notes that "[o]ne challenge for the utility and its rate design is that over 98% of the cost of delivery service consists of fixed costs." Please detail how the 98% was estimated showing calculation in table format.

SaskEnergy deems net income as a fixed cost since the required return on investment in the assets is a fixed amount (ROE of 8.3%). The 98% was taken out of SaskEnergy's cost of service model. The 2% variable costs, which are commodity related as opposed to capacity or customer related, represent odorant and natural gas used for internal usage, which are expenses that are dependent on the volume of natural gas delivered.

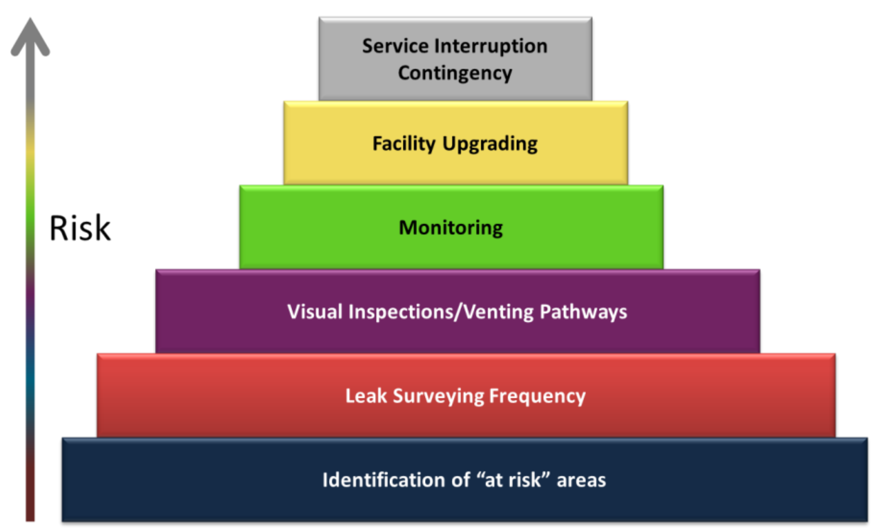
26. Reference: Corporate Geotechnical Program

a) Please provide more information regarding the Corporate Geotechnical Program described on Tab 6, page 6.

i. Please outline at risk areas identified and the enhanced leak survey, facility inspection and other activities being undertaken in each of these areas in order to mitigate risk related to pipeline infrastructure damage.

Integrity currently monitors 43 communities throughout the province for geotechnical movement.

The 43 communities are areas that with gas systems on slopes. The process for risk mitigation is:



As risk goes up more work is completed.

Leak Survey - All areas have a 1 year maximum leak survey versus, 4 years for the rest of the province, but can go as low as 2-3 day cycles based on risk.

Visual Inspection/Venting – This is done when visual risk factors show high movement rates in areas. This can be geotechnical consultant review, movement signs, extreme weather, infrastructure damage, leaks, etc.

Monitoring – This can be satellite monitoring, increased slack loop measuring frequencies, expert geotechnical review, operations concerns, etc.

Upgrading – This can be upgrades to our newest design criteria for slope communities, adding slack loops, service upgrade program, etc.

Service Interruption – This is discontinuation of service either temporary or permanent. This is always a last resort, and only occurs when safety of the public is compromised, and risk levels are above SaskEnergy's acceptable limit.

ii. What are the key factors or criteria that guide decision-making regarding removal of infrastructure? How have these been applied in practice?

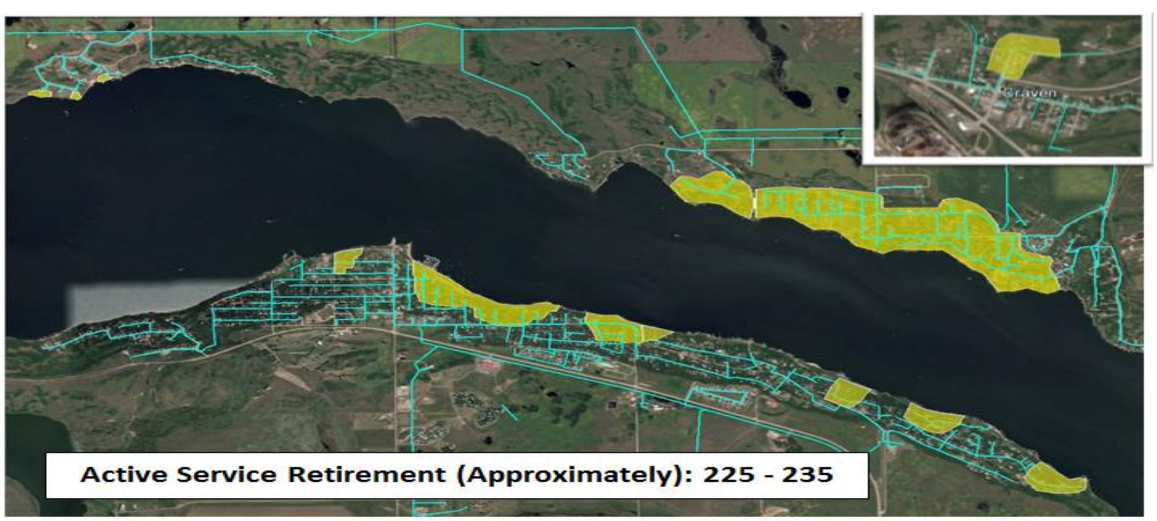
Removal of service is a last resort, and only occurs when safety of the public is compromised, and risk levels are above SaskEnergy's acceptable limit. In the Last Mountain Lake area, the key factors are high slope movement rate, high leak rates, and no safe servicing options available.

b) SaskEnergy notes at Tab 6, page 7 several small high-risk areas where gas distribution infrastructure has been removed.

i. Please outline areas where distribution infrastructure has been, or is planned to be, removed and provide further detail regarding the location, timing and number of services deactivated or removed to date and any available information regarding future planned removals.

The areas gas has been removed are on the map below.

There are no plans to remove service anywhere else in the province. Monitoring will continue and safety will remain a priority.



ii. Please provide the reasons for the deactivation of service to these customers.

Safety is the reason behind removing service. All locations showed a combination of multiple signs of the following: measured high movement rates, ground cracking, infrastructure damage (municipal, buildings, SaskEnergy, etc.), and high pipe movement rates.

iii. What processes or procedures are followed when customers are deactivated? How are customer issues/ needs addressed? How are these customers compensated? Please discuss in detail.

Affected customers were notified by mail of natural gas service discontinuation. In order to address customer issues and needs SaskEnergy set up a dedicated phone queue staffed by customer service management. In some cases customer calls were returned after business hours to provide a prompt response. Also, SaskEnergy hosted two open houses for customers to ask questions and discuss their situation directly with SaskEnergy Engineers, Management, and Executive; SaskPower Gas Inspections; Provincial Disaster Assistance Program staff; and the Natural Gas Appliance and Equipment Dealers Association. There were approximately 250-300 people who visited the open houses.

To address a safety situation such as this, SaskEnergy's Regulations provide the option to interrupt or discontinue gas service. As such, SaskEnergy has no obligation to provide compensation to affected customers. However SaskEnergy is offering assistance in three ways:

- $2500 Fuel Transition Allowance to assist all affected customers with their transition to another fuel,
- A pro-rated reimbursement of customer contributions, available to customers who received gas service within the last 10 years, and
- A full refund of costs associated with installing customer-owned piping if the customer's service line was moved to a meter stand as part of recent safety upgrades performed in Regina Beach.

iv. Please confirm if the impact of this deactivation is considered in the test year load forecast and indicate where these costs are included in the forecast (i.e., which line items). Please quantify the impact that customer deactivations have had on the test year revenue requirement (e.g., fuel transition allowances or other programs).

The impact of this deactivation is not considered in the test year load forecast because planning and implementation was completed after the budget for the test year was completed. The customer assistance program costs are estimated as follows:

Fuel Transition Allowance	$567,500
Customer Contribution Reimbursement	$ 61,079
Meter Stand Connection Rebate	$ 15,415
Total	$643,994

27. Reference: Implementation of Previous Panel Recommendations

a) Please provide the impact to net income and to the GCVA that occurred due to the change in forecast heat value [from 37.5 MJ/m^3 to 38 MJ/m^3] as a result of the Panel's recommendation regarding the 2016 Delivery Service and Commodity Rate Application.

The change in heat value has a $1.7 million impact to delivery net income and $2.7 million to the GCVA.

b) In the 2016 Commodity and Delivery Service Rate Application, SaskEnergy indicated concern regarding factors that impacted its ability to accurately forecast heat value, and heat value variances and related impacts on its revenues. Please discuss what has changed since the last application to mitigate the concerns raised by SaskEnergy in that application.

Since the last application, the straddle plant in southeast Saskatchewan was operational for a full year, as well as the supply declines in Saskatchewan have stabilized. In addition the heat value from natural gas imported from Alberta has not been as variable, as the gas plants along the border have been operating at normal capacity. With these factors more stable, the forecasted heat value has been much closer to the actual heat value in recent months.

c) With reference to Tab 22, page 2, please describe in further detail the “current economic environment and fiscal restraints” that led to postponement of the transition to billing in energy.

i. Please describe in further detail the specific conditions noted above and how they impact ability to transition to billing in energy.

With respect to fiscal restraint, staffing resources have not increased, and in some areas have declined. Over the next 18 months, key staff from the Customer Information System (CIS) Support group are committed to a major system upgrade to the CIS. These are the same resources that would be required to work on a Billing in Energy project. In addition, the same IT resources on the CIS Upgrade project would be required on the Billing in Energy.

With respect to the current economic environment, Saskatchewan’s growth has been muted by the slowdown in the energy sector, and this has particularly impacted the southeast region of the province. A change to billing in energy could result in a large bill increase for customers in this particular area of the province.

ii. How long are these conditions expected to persist?

The CIS Upgrade is expected to be completed in the spring of 2019.

iii. What conditions are required for SaskEnergy to consider transition to billing in energy?

A transition to billing in energy would require conditions conducive to adding additional financial and staffing resources as well as the support of SaskEnergy's owner.

iv. How is SaskEnergy planning to engage with customers and/or other stakeholders adversely impacted by the delay in transitioning to billing in energy? Has SaskEnergy communicated with interested stakeholders in this regard? If so, what have been the results of these discussions?

SaskEnergy has not developed a plan for communicating with customers and other stakeholders at this time. Once a decision to implement billing in energy is made, a communication strategy would then be developed.

v. As SaskEnergy proceeds with infrastructure renewal and other capital investments, what measures is it taking as part of planning for infrastructure projects to facilitate future implementation or to ensure it can proceed with billing in energy when the circumstances favour such a transition.

With respect to gas measurement, gas chromatographs are installed in city Town Border Stations.

d) With reference to Tab 22, page 2 and the Application at page 1, it is noted that the commodity portion of the bill remains unchanged.

   i. Please provide the details of Gas Cost Variance Account for November 1, 2017 and to April 1, 2018, including the expected balance of the GCVA;

      i. Please provide an updated Schedule 1.0 Forecast Cost of Gas Sold, 1.1 (Forecast Gas Prices) and 1.2 (Forecast Cost of Gas - Storage and Inventory Details) from the 2016 Delivery and Commodity Rate Application.

Schedule 1.0

SaskEnergy Incorporated

Natural Gas Commodity Rate Filing
November 1, 2017 - October 31, 2018

Forecast Cost of Gas Sold ($000's)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Line	Description	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	TOTAL
1	Purchases	$13,718	$14,175	$14,175	$12,803	$14,175	$12,269	$12,678	$12,269	$12,678	$12,678	$12,269	$12,680	$156,568
2	Price Risk Management (Inflows)/Outflows	($34)	($35)	($35)	($32)	($35)	$0	$0	$0	$0	$0	$0	$0	($172)
3	Costs upstream of TEP	$1,680	$1,736	$1,736	$1,568	$1,736	$1,680	$1,736	$1,680	$1,736	$1,736	$1,680	$1,736	$20,440
4	Cost of Purchase Gas	$15,363	$15,876	$15,876	$14,339	$15,876	$13,949	$14,414	$13,949	$14,414	$14,414	$13,949	$14,416	$176,836
5	Storage Withdrawal (Injection)	$7,283	$15,121	$17,440	$13,977	$6,882	($2,196)	($7,776)	($9,981)	($10,752)	($10,810)	($8,422)	($3,052)	$7,714
6	Gas in Storage Interest Expense	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$411
7	Gas Supply Operating Maintenance & Admin Expenses	$130	$130	$130	$130	$130	$130	$130	$130	$130	$130	$130	$130	$1,555
8	Gas Supply Related Bad Debt Expense	$50	$68	$73	$62	$50	$29	$16	$10	$9	$9	$14	$28	$419
9	Less Gas Supply Related Late Payment Charges	($28)	($36)	($52)	($68)	($69)	($62)	($53)	($42)	($34)	($29)	($26)	($25)	($524)
10	Less Cost of Internal Usage	($175)	($226)	($270)	($212)	($237)	($166)	($95)	($68)	($22)	($19)	($31)	($93)	($1,613)
11	**Cost of Gas Sold**	**$22,658**	**$30,967**	**$33,231**	**$28,262**	**$22,666**	**$11,718**	**$6,671**	**$4,031**	**$3,780**	**$3,730**	**$5,647**	**$11,437**	**$184,798**

Volume (Gigajoules - 000s)

Line	Description	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	TOTAL
12	Customer Sales	6,584	8,950	9,597	8,173	6,604	3,775	2,132	1,271	1,186	1,168	1,791	3,672	54,904
13	Purchases (less Fuel Gas & Line Loss)	4,564	4,716	4,716	4,259	4,716	4,544	4,696	4,544	4,696	4,696	4,544	4,696	55,387
14	Cost of Purchase Gas (GJ)	$3.367	$3.367	$3.367	$3.367	$3.367	$3.070	$3.070	$3.070	$3.070	$3.070	$3.070	$3.070	
15	Storage Withdrawal (Injection)	2,071	4,300	4,960	3,975	1,957	(715)	(2,533)	(3,251)	(3,503)	(3,522)	(2,744)	(994)	(0)
16	Storage Withdrawal (Injection) Rate (GJ)	$3.517	$3.517	$3.517	$3.517	$3.517	$3.070	$3.070	$3.070	$3.070	$3.070	$3.070	$3.070	
17	Internal Usage	(51)	(65)	(78)	(61)	(69)	(53)	(30)	(22)	(7)	(6)	(10)	(30)	(482)

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

Schedule 1.1

SaskEnergy Incorporated

Forecast Gas Prices for
November 1, 2017 - October 31, 2018

$/Gigajoule

		1	2	3	4	5	6	7	8	9	10	11	12
Line	**Description**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**
1	AECO Forward Prices	2.600	2.600	2.600	2.600	2.600	2.320	2.320	2.320	2.320	2.320	2.320	2.320
	COST OF PURCHASE GAS AT TEP												
2	Cost of Purchase Gas Before Hedges[1]	2.989	2.989	2.989	2.989	2.989	2.684	2.684	2.684	2.684	2.684	2.684	2.684
3	Change in Price due to Hedging	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	Costs upstream of TEP	0.366	0.366	0.366	0.366	0.366	0.368	0.368	0.368	0.368	0.368	0.368	0.368
5	Forecast Cost of Purchase Gas	3.347	3.347	3.347	3.347	3.347	3.052	3.052	3.052	3.052	3.052	3.052	3.052
6	Volume Adjusted Cost of Purchase Gas	3.367	3.367	3.367	3.367	3.367	3.070	3.070	3.070	3.070	3.070	3.070	3.070
	COST OF GAS SOLD												
7	Purchase Price	3.367	3.367	3.367	3.367	3.367	3.070	3.070	3.070	3.070	3.070	3.070	3.070
8	% of Sales met with Purchases	68.5%	52.0%	48.3%	51.4%	70.4%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
9	Inventory Withdrawal Price	3.517	3.517	3.517	3.517	3.517							
10	% of Sales met with Inventory	31.5%	48.0%	51.7%	48.6%	29.6%							
11	Cost of Gas Sold before OM&A	3.414	3.439	3.444	3.439	3.411	3.070	3.070	3.070	3.070	3.070	3.070	3.070
12	Interest, OM&A and Bad Debt Expense	0.028	0.022	0.019	0.019	0.022	0.035	0.060	0.103	0.117	0.123	0.085	0.045
13	Forecast Cost of Gas Sold	$ 3.442	$ 3.461	$ 3.463	$ 3.459	$ 3.433	$ 3.104	$ 3.129	$ 3.173	$ 3.187	$ 3.193	$ 3.154	$ 3.115

Schedule 1.2

SaskEnergy Incorporated

Natural Gas Commodity Rate Filing

November 1, 2017 - October 31, 2018

Storage Inventory Details - Forecasted Cost of Gas

		2	3	4	5	6	7	8	9	10	11	12	13
		Nov-17	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**
Line	**Gas in Storage - Volume**												
1	Opening Balance (000's GJs)	21,229	19,157	14,858	9,898	5,924	3,967	4,682	7,215	10,467	13,969	17,491	20,234
2	Closing Balance (000's GJs)	19,157	14,858	9,898	5,924	3,967	4,682	7,215	10,467	13,969	17,491	20,234	21,229
3	(Injections)/ Withdrawals (000's GJs)	2,071	4,300	4,960	3,975	1,957	(715)	(2,533)	(3,251)	(3,503)	(3,522)	(2,744)	(994)
4	(Injection)/Withdrawal Price	$3.52	$3.52	$3.52	$3.52	$3.52	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07
5	**Weighted Average Price of Gas in Storage**	**$3.52**	**$3.52**	**$3.52**	**$3.52**	**$3.52**	**$3.45**	**$3.32**	**$3.24**	**$3.20**	**$3.17**	**$3.16**	**$3.15**
	Cost of Gas in Storage												
6	Opening Balance ($000)	$ 74,650	$ 67,368	$ 52,247	$ 34,807	$ 20,830	$ 13,949	$ 16,145	$ 23,920	$ 33,901	$ 44,653	$ 55,462	$ 63,885
7	Closing Balance ($000)	$ 67,368	$ 52,247	$ 34,807	$ 20,830	$ 13,949	$ 16,145	$ 23,920	$ 33,901	$ 44,653	$ 55,462	$ 63,885	$ 66,937
8	**Cost of Storage Gas Sold**	$ 7,283	$ 15,121	$ 17,440	$ 13,977	$ 6,882	$ (2,196)	$ (7,776)	$ (9,981)	$ (10,752)	$ (10,810)	$ (8,422)	$ (3,052)

Line	Storage Inventory Carrying Costs	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	TOTAL
		<------ Previous Summer ------>													
9	Gas in Storage Closing Balance	$16,007	$17,005	$26,078	$38,423	$50,230	$62,046	$71,261	$74,650	$67,368	$52,247	$34,807	$20,830	$13,949	
10	Average Daily Balance		$16,506	$21,542	$32,250	$44,326	$56,138	$66,654	$72,956	$71,009	$59,807	$43,527	$27,818	$17,389	
11	Interest Rate		0.48%	0.50%	0.50%	0.82%	0.82%	0.82%	1.02%	1.02%	1.02%	1.27%	1.27%	1.27%	
12	Calculated Monthly Interest Charge		$7	$9	$13	$31	$39	$45	$63	$60	$52	$47	$27	$19	$411
13	Total Annual Interest														$34
14	Amortized Monthly Interest Charge														

Tables might not add precisely due to rounding.

ii. Please provided an updated Schedule 2.0 (Gas Cost Variance Account) and Schedule 2.1 (Gas Cost Variance Account - Storage and Inventory Details) from the 2016 Delivery and Commodity Rate Application.

Schedule 2.0

SaskEnergy Incorporated

Gas Cost Variance Account ($000's)
November 1, 2016 - October 31, 2017

		1	2	3	4	5	6	7	8	9	10	11	12	13
Line	**Description**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**TOTAL**
1	GCVA Balance Forward at Oct 31, 2016	$8,444												
2	Opening Cumulative GCVA Balance - Under/(Over) Recovery	$8,444	$7,389	$9,012	$10,160	$11,776	$12,744	$12,934	$13,004	$12,933	$12,715	$12,490	$12,088	$8,444
3	Purchases - Alberta	$9,401	$9,779	$9,802	$7,873	$8,708	$7,129	$7,308	$9,038	$8,069	$8,043	$7,784	$8,058	$100,992
4	Purchases - Saskatchewan	$5,737	$5,382	$5,984	$4,558	$4,637	$4,955	$5,433	$5,019	$5,080	$5,013	$4,851	$5,013	$61,662
5	Less Purchase of Other Gas Sales	($7)	$0	($2)	($4)	($1)	($2)	($7)	$0	$0	$0	$0	$0	($23)
6	Price Risk Management (Inflows)/Outflows	$628	$503	($288)	$689	$1,290	$906	$842	$702	$1,037	$1,057	$1,023	$1,057	$9,444
7	Transportation	$1,567	$1,600	$1,600	$1,648	$1,644	$1,643	$1,597	$1,770	$1,628	$1,628	$1,575	$1,628	$19,525
8	Cost of Purchase Gas	$17,326	$17,263	$17,096	$14,765	$16,278	$14,630	$15,173	$16,529	$15,813	$15,740	$15,233	$15,755	$191,601
9	Storage Withdrawal (Injection)	$241	$19,233	$16,832	$12,725	$10,242	($999)	($9,072)	($12,345)	($11,807)	($11,816)	($9,216)	($3,389)	$627
10	Gas in Storage Interest Expense	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$268
11	Gas Supply Operating Maintenance & Admin Expenses	$121	$121	$121	$121	$121	$121	$121	$121	$121	$121	$121	$121	$1,455
12	Gas Supply Related Bad Debt Expense	$56	$105	$98	$77	$77	$40	$18	$13	$13	$13	$20	$41	$572
13	Less Gas Supply Related Late Payment Charges	($49)	($43)	($78)	($89)	($100)	($79)	($95)	($46)	($43)	($37)	($33)	($32)	($725)
14	Less Cost of Internal Usage	($84)	($95)	($159)	($190)	($157)	($163)	($111)	($67)	($24)	($20)	($34)	($101)	($1,205)
15	**Cost of Gas Sold**	**$17,633**	**$36,606**	**$33,932**	**$27,431**	**$26,482**	**$13,573**	**$6,057**	**$4,228**	**$4,096**	**$4,024**	**$6,114**	**$12,417**	**$192,594**
16	Commodity Sales Revenue (Current Rate 4.30/GJ)	$18,693	$34,986	$32,789	$25,820	$25,520	$13,389	$5,993	$4,304	$4,323	$4,258	$6,525	$13,380	$189,979
17	Gain (loss) on other gas sales	(2)	0	(0)	(1)	(0)	(0)	(1)	0	0	0	0	0	($4)
18	Period GCVA Balance	($1,058)	$1,619	$1,144	$1,612	$962	$185	$64	($76)	($227)	($234)	($411)	($963)	$2,618
19	Period GCVA Interest	$3	$4	$4	$5	$5	$5	$5	$5	$9	$9	$8	$10	$73
20	Closing Cumulative GCVA Balance (Line 1+14+15)	$7,389	$9,012	$10,160	$11,776	$12,744	$12,934	$13,004	$12,933	$12,715	$12,490	$12,088	$11,135	$11,135

Volume (Gigajoules - 000s)

Line	**Description**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**TOTAL**
21	Customer Sales	4,881	9,676	9,088	7,236	7,046	3,716	1,636	1,183	1,185	1,167	1,788	3,666	52,266
22	Purchases (less Fuel Gas & Line Loss)	4,842	4,746	4,795	4,008	4,450	4,036	4,142	4,748	4,702	4,702	4,551	4,708	54,430
23	Cost of Purchase Gas ($/GJ)	$3.578	$3.637	$3.566	$3.684	$3.658	$3.625	$3.663	$3.481	$3.363	$3.347	$3.347	$3.346	
24	Storage Withdrawal (Injection)	62	4,955	4,336	3,278	2,638	(276)	(2,477)	-3,546	-3,511	-3,530	-2,753	(1,013)	(1,835)
25	Storage Withdrawal (Injection) Rate ($/GJ)	$3.882	$3.882	$3.882	$3.882	$3.882	$3.625	$3.663	$3.481	$3.363	$3.347	$3.347	$3.346	
26	Internal Usage	(23)	(25)	(43)	(50)	(42)	(45)	(30)	(19)	(7)	(6)	(10)	(30)	(329)

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

Schedule 2.1

SaskEnergy Incorporated
Storage Inventory Details - Gas Cost Variance Account
November 1, 2016 to October 31, 2017

Line		1	2	3	4	5	6	7	8	9	10	11	12
		Nov-16	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**
	Gas in Storage - Volume												
1	Opening Balance (000's GJs)	19,393	19,331	14,377	10,040	6,762	4,124	4,399	6,876	10,422	13,933	17,463	20,216
2	Closing Balance (000's GJs)	19,331	14,377	10,040	6,762	4,124	4,399	6,876	10,422	13,933	17,463	20,216	21,229
3	(Injections)/ Withdrawals (000's GJs)	62	4,955	4,336	3,278	2,638	(276)	(2,477)	(3,546)	(3,511)	(3,530)	(2,753)	(1,013)
4	(Injection)/Withdrawal Price	$3.88	$3.88	$3.88	$3.88	$3.88	$3.62	$3.66	$3.48	$3.36	$3.35	$3.35	$3.35
5	**Weighted Average Price of Gas in Storage**	**$3.88**	**$3.88**	**$3.88**	**$3.88**	**$3.88**	**$3.87**	**$3.79**	**$3.69**	**$3.61**	**$3.55**	**$3.53**	**$3.52**
	Cost of Gas in Storage												
6	Opening Balance ($000)	$ 75,277	$ 75,037	$ 55,804	$ 38,973	$ 26,248	$ 16,007	$ 17,005	$ 26,078	$ 38,423	$ 50,230	$ 62,046	$ 71,261
7	Closing Balance ($000)	$ 75,037	$ 55,804	$ 38,973	$ 26,248	$ 16,007	$ 17,005	$ 26,078	$ 38,423	$ 50,230	$ 62,046	$ 71,261	$ 74,650
8	**Net Change in Inventory ($000)**	$ 241	$ 19,233	$ 16,832	$ 12,725	$ 10,242	$ (999)	$ (9,072)	$ (12,345)	$ (11,807)	$ (11,816)	$ (9,216)	$ (3,389)

Line	**Storage Inventory Carrying Costs**	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	TOTAL
		<------ Previous Summer ------>													
9	Gas in Storage Closing Balance	$26,508	$27,312	$35,622	$45,742	$56,879	$67,965	$76,737	$75,277	$75,037	$55,804	$38,973	$26,248	$16,007	
10	Average Daily Balance		$26,910	$31,467	$40,682	$51,310	$62,422	$72,351	$76,007	$75,157	$65,421	$47,389	$32,611	$21,127	
11	Interest Rate		0.55%	0.60%	0.55%	0.52%	0.52%	0.53%	0.52%	0.53%	0.52%	0.55%	0.54%	0.50%	
12	Calculated Monthly Interest Charge		$12	$16	$18	$23	$28	$32	$34	$33	$29	$22	$14	$9	
13	Total Annual Interest														$268
14	Amortized Monthly Interest Charge														$22

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

ii. Please confirm whether or not the GCVA balance is forecast to exceed +/-$20 million before the end of the 2017/18 test period.

The GCVA is not forecast to exceed =/- $20 million before the end of the 2017/18 test period.

iii. If the GCVA balance is forecast to exceed the +/- $20 million threshold, what would be the estimated impact on rates at the time of the next commodity rate application.

N/A

iv. When does SaskEnergy expect to file its next commodity rate application?

Under the current natural gas price environment, SaskEnergy anticipates it could potentially file a commodity rate application next summer or fall for a November 1, 2018 rate adjustment.

e) Tab 22, page 2 notes that "TransGas Customer Dialogue information is not within the Terms of Reference for the rate application, therefore will not be provided to the Panel. This decision was concurred by the TransGas Customer Dialogue Committee in November."

i. Please list the stakeholders included in the TransGas Customer Dialogue Committee.

The current TransGas Customer Dialogue stakeholder participant list is on the TransGas website, at:

http://www.transgas.com/newsroom/dialogue/participantlist.asp

ii. How are the interests of the distribution utility represented in these discussions when setting transportation tolls?

A staff member from SaskEnergy's Distribution Utility has always been included as a participant in TransGas Customer Dialogue.

iii. How are the interests of stakeholders outside of those represented on the Customer Dialogue Committee considered?

The TransGas Key Account Managers, from the TransGas Customer Service department, participate on the Customer Dialogue Committee to represent the interests of all customer stakeholders.

28. Reference: Heat Value

a) Please update the response to Round 1 Information Request 27(d) in relation to the 2016 Delivery Service Rate Application, and provide the range (maximum and minimum) of heating values that SaskEnergy has observed in its system in the past 5 years by major centres and the total for the system, including for each major centre the number of customers, total annual sales, heat value, and the average bill for residential and commercial customers based on average usage per customer. Please also include sales in cubic metres for each of the ten major centres provided; and break out the basic monthly charge, delivery and commodity portion of average customer bills.

Following is a table summarizing the available information. The actual number of customers being served in each heat value region is not available, as customers are not currently attached to heat values. To estimate the number of customers in each region, the number of current customers being served in each of the major ten centers was extrapolated to include rural customers in each area. This profile was then applied to the average number of customers outstanding each year.

Actual Heat Values by Region

2012	Heat Value			
	Weighted Average	Miniumum	Maximum	Estimated Average Number of Customers
Regina	38.77	37.31	40.32	128,582
Moose Jaw	36.69	36.58	36.95	22,793
Weyburn	42.02	41.74	42.35	7,189
Estevan	41.29	40.14	42.45	7,956
Swift Current	36.79	36.63	37.44	11,173
Yorkton	39.77	39.06	40.81	11,013
Melville	39.87	38.46	42.30	3,708
Saskatoon	37.66	37.42	37.98	134,395
Prince Albert	37.73	36.80	38.71	20,622
North Battleford	37.73	36.69	38.26	12,430
System Average	38.27	37.83	38.91	359,862

2013	Heat Value			
	Weighted Average	Miniumum	Maximum	Estimated Average Number of Customers
Regina	38.68	37.99	40.37	131,333
Moose Jaw	36.75	36.63	36.88	23,281
Weyburn	42.09	41.59	42.29	7,343
Estevan	41.82	41.18	42.49	8,127
Swift Current	36.89	36.68	37.22	11,412
Yorkton	39.98	38.89	41.52	11,249
Melville	40.41	39.68	41.92	3,788
Saskatoon	37.93	37.58	38.10	137,270
Prince Albert	38.38	37.73	38.61	21,063
North Battleford	38.22	37.67	38.48	12,696
System Average	38.42	38.15	38.90	367,561

2014	Heat Value			
	Weighted Average	Miniumum	Maximum	Estimated Average Number of Customers
Regina	38.82	38.28	40.67	134,407
Moose Jaw	36.72	36.12	37.40	23,826
Weyburn	42.14	41.99	42.25	7,515
Estevan	41.80	41.35	43.15	8,317
Swift Current	37.10	36.66	37.87	11,679
Yorkton	39.92	38.01	40.90	11,512
Melville	40.05	38.82	41.16	3,876
Saskatoon	37.75	37.26	37.90	140,483
Prince Albert	38.31	38.14	38.40	21,556
North Battleford	38.06	37.32	38.44	12,993
System Average	38.36	38.18	38.95	376,164

2015	Heat Value			
	Weighted Average	Miniumum	Maximum	Estimated Average Number of Customers
Regina	39.55	38.61	41.80	135,035
Moose Jaw	37.34	36.65	37.97	23,937
Weyburn	41.34	39.52	42.49	7,550
Estevan	42.80	42.18	43.49	8,356
Swift Current	37.75	37.55	38.22	11,734
Yorkton	40.73	38.99	42.30	11,566
Melville	39.23	37.90	40.33	3,894
Saskatoon	38.22	37.92	38.48	141,139
Prince Albert	38.45	38.13	38.79	21,657
North Battleford	37.95	37.60	38.26	13,054
System Average	38.79	38.28	39.48	377,921

2016	Heat Value			
	Weighted Average	Miniumum	Maximum	Estimated Average Number of Customers
Regina	38.90	38.43	39.63	136,733
Moose Jaw	37.51	37.33	38.22	24,238
Weyburn	39.36	38.88	39.89	7,645
Estevan	43.26	43.02	43.83	8,461
Swift Current	37.74	37.43	38.40	11,881
Yorkton	40.89	39.82	43.13	11,711
Melville	38.98	37.96	41.67	3,943
Saskatoon	38.13	37.90	38.25	142,914
Prince Albert	38.82	38.68	39.45	21,929
North Battleford	38.08	37.81	38.42	13,218
System Average	38.58	38.39	38.94	382,673

Total annual sales by heat value region are also not available, as there is no heat value attached to customers in the billing system.

Sales by major centre for 2015 and 2016 are shown below. Please note this data is for the centre only, and does not include the entire region. Data is not available for major centres for previous years.

Customer Sales (m^3)		
City Center	2015	2016
Regina	316,294,425	308,475,965
Moose Jaw	57,941,282	53,938,783
Weyburn	20,571,026	19,200,726
Estevan	21,004,503	18,781,405
Swift Current	33,121,164	32,238,831
Yorkton	30,722,694	28,444,364
Melville	10,601,950	13,536,628
Saskatoon	367,673,824	362,146,931
Prince Albert	66,814,603	62,603,489
North Battleford	27,182,537	27,373,499

Average UPC used for the following tables:

Residential: 2,643 m^3 at HV of 38.5 MJ/m^3 - 102 GJ

Commercial Small: 12,631 m^3 at HV of 38.5 MJ/m^3 - 486 GJ

Commercial Large: 183,067 m^3 at HV of 38.5 MJ/m^3 - 7,048 GJ

	Average 2012 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	213	213	213	213	213	213	213	213	213	213	213
Delivery ($)	187	197	172	175	197	182	182	192	192	192	189
Commodity ($)	415	438	382	389	437	404	403	427	426	426	420
Total Bill ($)	$ 814	$ 848	$ 767	$ 777	$ 846	$ 799	$ 798	$ 832	$ 831	$ 831	$ 822
Total Bill Variance ($)	$ (8)	$ 26	$ (54)	$ (44)	$ 25	$ (23)	$ (24)	$ 10	$ 9	$ 9	$ -
Total Bill Variance (%)	-1%	3%	-7%	-5%	3%	-3%	-3%	1%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.77	36.69	42.02	41.29	36.79	39.77	39.87	37.66	37.73	37.73	38.27

	Average 2012 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 ($)	346	346	346	346	346	346	346	346	346	346	346
Delivery ($)	791	836	730	743	834	772	770	815	813	813	802
Commodity ($)	1,977	2,089	1,823	1,856	2,083	1,927	1,922	2,035	2,031	2,031	2,002
Total Bill ($)	$ 3,114	$ 3,271	$ 2,900	$ 2,945	$ 3,263	$ 3,045	$ 3,038	$ 3,196	$ 3,190	$ 3,190	$ 3,150
Total Bill Variance ($)	$ (36)	$ 121	$ (250)	$ (205)	$ 113	$ (105)	$ (112)	$ 46	$ 40	$ 40	$ -
Total Bill Variance (%)	-1%	4%	-8%	-6%	4%	-3%	-4%	1%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.77	36.69	42.02	41.29	36.79	39.77	39.87	37.66	37.73	37.73	38.27

	Average 2012 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 ($)	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265
Delivery ($)	10,017	10,585	9,241	9,406	10,556	9,765	9,741	10,312	10,292	10,292	10,147
Commodity ($)	28,648	30,272	26,428	26,900	30,188	27,927	27,859	29,492	29,433	29,434	29,018
Total Bill ($)	$ 39,929	$ 42,122	$ 36,934	$ 37,570	$ 42,008	$ 38,957	$ 38,865	$ 41,069	$ 40,989	$ 40,990	$ 40,430
Total Bill Variance ($)	$ (500)	$ 1,692	$ (3,496)	$ (2,860)	$ 1,578	$ (1,473)	$ (1,565)	$ 639	$ 559	$ 560	$ -
Total Bill Variance (%)	-1%	4%	-9%	-7%	4%	-4%	-4%	2%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.77	36.69	42.02	41.29	36.79	39.77	39.87	37.66	37.73	37.73	38.27

Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2013 Residential Bill by Heat Value										
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

Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2013 Commercial Small Bill by Heat Value										
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

Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2013 Commercial Large Bill by Heat Value										
BMC ($)	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601
Delivery ($)	10,050	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

	Average 2014 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
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

	Average 2014 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 ($)	383	383	383	383	383	383	383	383	383	383	383
Delivery ($)	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

	Average 2014 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 ($)	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601
Delivery ($)	10,123	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

	Average 2015 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
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

	Average 2015 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 ($)	383	383	383	383	383	383	383	383	383	383	383
Delivery ($)	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

	Average 2015 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 ($)	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601
Delivery ($)	10,308	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

	Average 2016 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
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

	Average 2016 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 ($)	439	439	439	439	439	439	439	439	439	439	439
Delivery ($)	875	925	808	822	922	853	851	901	899	899	887
Commodity ($)	1,934	2,043	1,784	1,816	2,038	1,885	1,881	1,991	1,987	1,987	1,959
Total Bill ($)	$ 3,248	$ 3,407	$ 3,030	$ 3,077	$ 3,399	$ 3,177	$ 3,171	$ 3,331	$ 3,325	$ 3,325	$ 3,284
Total Bill Variance ($)	$ (36)	$ 123	$ (254)	$ (208)	$ 115	$ (107)	$ (114)	$ 46	$ 41	$ 41	$ -
Total Bill Variance (%)	-1%	4%	-8%	-6%	3%	-3%	-3%	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

	Average 2016 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 ($)	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609
Delivery ($)	11,090	11,719	10,230	10,413	11,686	10,811	10,784	11,416	11,394	11,394	11,233
Commodity ($)	28,028	29,618	25,857	26,318	29,535	27,323	27,256	28,854	28,796	28,797	28,391
Total Bill ($)	$ 40,726	$ 42,945	$ 37,696	$ 38,340	$ 42,830	$ 39,743	$ 39,650	$ 41,879	$ 41,799	$ 41,800	$ 41,233
Total Bill Variance ($)	$ (506)	$ 1,712	$ (3,537)	$ (2,893)	$ 1,597	$ (1,490)	$ (1,583)	$ 646	$ 566	$ 567	$ -
Total Bill Variance (%)	-1%	4%	-9%	-7%	4%	-4%	-4%	2%	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

b) Please provide the actual heat rates compared to applicable test year forecast heat rates for 2012 to 2016; please also discuss heat value ranges in the last year, compared to the last 3 years.

Year	Actual	Test Year Forecast
2012	38.27	37.98
2013	38.42	38.02
2014	38.36	38.00
2015	38.79	37.96
2016	38.58	38.00

Over the last year the provincial heat value did not vary as much as the previous three years. This is due in part to the straddle plant in southeast Saskatchewan being fully operational, as well as the gas plants in Alberta operating at normal capacity.

c) Please estimate the impacts of heat value to Net Income and to the GCVA for the last three years and potential impact that may result from variations in heating value in forecast years.

Heat Value Impact to Commodity Revenue/GCVA balance:

Nov14-Oct 15 $2.485 million

Nov15-Oct16 $5.602 million

Nov16-May17 $0.777 million

Impact to Delivery Revenue/Net Income:

Fiscal Year

Jan-Dec 14 N/A

Jan15-Mar16 $5.531 million

Apr17-Mar17 $2.067 million

In the forecast year, a 0.5 MJ/m3 variance between forecast and actual heat value will have approximately a $2.7 million impact to the GCVA a $1.7 million to net income.

d) What heat value was used in Schedule 2.2 and in Tab 18? Please provide any updates regarding what the actual heat value in 2017/18 is expected to be and any potential impacts on actual results for the test years; and any expectation regarding future variations in heat value in the system.

A heat value of 38.5 MJ/m3 was used in both Schedule 2.2 and Tab 18. There are no changes to the expected heat value for 2017/2018.

e) Please update the response to Round 1 Information Request 27(l) in relation to the 2016 Delivery Service Rate Application, and provide a table or chart for the past 5 years that shows the quantity of natural gas sourced from outside Saskatchewan and from locally extracted sources and provide estimates of the associated heat values from each source.

The table below lists the quantity of gas sourced externally (Alberta) and from Saskatchewan for each of the past 5 years as well as the forecasted amounts for the test period. The quantity of gas “sourced” from storage is zero, as all gas in storage is a blend of Alberta and Saskatchewan sourced gas.

(All volumes in Petajoules)			
Period	Alberta	Sask.	Total
Nov. 2012 to Oct. 2013	25.6	32.7	58.3
Nov. 2013 to Oct. 2014	31.7	33.3	64.9
Nov. 2014 to Oct. 2015	26.3	34.4	60.7
Nov. 2015 to Oct. 2016	30.3	21.5	51.8
Nov. 2016 to Oct. 2017 (forecast)	31.3	21.6	52.9

The estimated heat value of Alberta and Saskatchewan sourced gas is provided in the table below. Please note that these estimated heat values are not limited to SaskEnergy's gas purchases. These estimated heat values are based on all of the gas received onto the TransGas transportation system for both the Saskatchewan gas as well as the gas imported from Alberta.

Estimated Heat Value		
Year	Sask. Production (MJ/m3)	Alberta Imports (MJ/m3)
2012	37.3	38.4
2013	37.6	38.3
2014	37.8	38.4
2015	38.8	38.6
2016	38.5	38.7

f) Please provide an update on the status of the straddle plant in southeast Saskatchewan and any impacts this has had on heat value of gas delivered. Have there been any other factors impacting heat value over the past year, or that are expected to impact heat value going forward?

The straddle plant in southeast Saskatchewan has been operational since July 2015. There have been no significant changes or updates with the plant or the quality of gas from the plant since the last application.

There are no new factors expected to impact heat value going forward.

29. Reference: Productivity and Efficiency Update

a) Please confirm that the targeted Total Corporate Savings discussed on page 1 of Tab 23 are reflected in the forecast 2017/18 revenue requirement.

Yes, the corporate savings, to the extent they impact the LDC cost of service, were incorporated into the 2017-18 revenue requirement.

b) With reference to the response to Round 2 Information Request 19(a) in relation to the 2016 Delivery Service Rate Application

i. Please provide a summary of targeted savings actually achieved for each productivity and efficiency measure identified as contributing to the $4.0 million in savings for 2016/17.

As noted previously, there are many initiatives that were planned for 2016/17 that made up the $4 million efficiency target and they are undertaken across the organization. It is important to note that not all the planned efficiency initiatives took place during the year and other initiatives that were not planned were undertaken and resulted in savings or incremental revenues. The actual efficiencies and revenue initiatives totaling $4 million were in the following areas:

Crown Collaboration - $1.0 M

- This category includes additional savings from continued AMI deployment, administrative savings associated with joint services installations, and collaboration efforts with SaskPower on postage/envelopes as well as Cathodic protection.

Business Process Changes - $2.5M

- This category includes savings from discontinuing cashiering services in Regina and Saskatoon, no longer responding to "No Heat" calls, additional mobile compression deployment, as well as savings related to the new valves and fittings agreement.

Leveraging Technology - $0.2M

- This category includes savings from the increased use of e-billing, time reporting efficiencies and savings related to the customer information system.

Revenue Initiatives - $0.3 million

- TransGas undertook natural gas diversion deals during the year that were not anticipated in the original efficiencies plan given uncertainty related to capacity and the availability of supply.

ii. Please provide any updates regarding initiatives anticipated to provide savings for the 2016/17 fiscal year that are not described in Tab 23 of the 2017 application [e.g., transportation savings (flare gas capture) and Expansion of Mobile Compression fleet, etc.]. Were these initiatives pursued and did they provide savings in 2016/17? Are they providing savings in the test year?

The planned transportation savings related to flare gas capture during the year did not materialize as the flare gas capture projects did not proceed due to the low price of natural gas which resulted in the projects being uneconomic. TransGas did grow their fleet of mobile compressors during the year which resulted in operational savings included in the "Business Process Changes" noted above.

c) With reference to page 10 of the Application, please describe the annual efficiency initiatives and incremental revenue opportunities planned for 2017/18 that are expected to result in the forecast $4.4 million in savings noted. Please provide a breakdown of forecast savings by initiative or project for each efficiency measure, and note whether the measures relate to Crown Collaboration, Business Process Changes, Leveraging Technology, etc.

There are many initiatives planned for 201718 that make up the $4.4 million target and they are undertaken all across the organization.

Efficiency initiatives that accounted for the majority of the savings are discussed further in Tab 23.

- New Revenue Initiatives (total of $2.4 Million);
- Crown Collaboration (total savings noted of $0.4 million);
- SaskEnergy Leveraging Technology (total savings noted of $0.7 million); and
- SaskEnergy Business Process Changes including operating savings related to expanded Mobile Compression (total savings noted of $0.9 million).

d) Please discuss the benefits of the Joint Service Line Initiative program described on page 4 of Tab 23.

i. Are any forecast annual cost savings anticipated for 2017 and 2018? If so, please describe or quantify and confirm whether or not these are included in the revenue requirement for 2017/18?

The cost savings that are resulting from the Joint Service Line Initiative are capital expenditure savings, not operating costs. The avoidance of capital expenditures results in smaller additions to the rate base for new customer connections which helps mitigate rate pressure.

ii. Page 9 of the Application notes that the cost of line locating remains as a substantial component of SaskEnergy's operating budget, and that these costs have been managed through the use of joint line locating process with SaskTel, SaskPower and SaskEnergy. Please provide details regarding how these costs are allocated between utilities.

Each company involved in the joint line locating process is billed per locate. The information through Sask 1st Call identifies the lines that need to be located when the locate is requested and the contract supplier verifies that the locate has been completed. Each month a bill is received by each of the joint line locating companies from Sask 1st Call that is in direct correlation the locates completed during that given month.

e) With reference to the Damage Prevention Program described at Tab 23, page 5

i. Please provide annual spending since implementation of the damage prevention program on key prevention initiatives; as well as the actual gas line contacts and related costs to SaskEnergy each year.

Please see response to IR 16 h) and 17 e).

ii. Please describe further any expected savings for 2017 and 2018.

Planned efficiency savings from merged site visits for the Safety Patrol and the Integrity Patrol are estimated at $30,000 in the 2017/2018 business plan.

f) Please provide a more detailed discussion regarding Leveraging SaskPower Third Party Transport.

i. How are the benefits generated shared between utilities, i.e., how is each utility's share of the benefit determined?

The sharing of the benefit generated from SaskPower third party transport optimization is negotiated between the parties, and is typically split equally.

ii. Please describe further the operational planning, security of supply, and sharing of market intelligence benefits that are difficult to measure.

SaskPower and SaskEnergy share information on a daily/weekly/monthly basis regarding each party's current operations, including gas requirements and capacity utilization. The parties also share market intelligence relating primarily to gas procurement and pricing. No confidential information or specific transaction details with individual counterparts is shared between the parties.

Regarding security of supply, the parties have agreed to assist each other in the event of short-term gas requirement deficits to the extent that the other party has the ability to provide assistance. This assistance can be in the form of incremental gas supply or spare transportation or storage capacity. For example, in the event that one party is in need of additional gas because of extremely high gas requirements, to the extent that the other party has underutilized access to additional gas, either from storage or transportation from Alberta, the party will utilize this spare capacity to assist the other party in meeting their short-term deficit.

iii. Are there any impacts from this program in the test years? Please quantify and explain how these are determined.

$0.35 million from these activities is included in the forecasted Margin on Gas Marketing in Schedule 1.7 – Other Revenue.

iv. Please discuss or provide an estimate of future value for SaskEnergy from this program.

SaskEnergy estimates that approximately $0.35 million per year will be generated for SaskEnergy from this collaboration.

g) Please provide a discussion of the benefits of the Enhanced Paperless Billing program.

i. Please quantify the cost of e-billing or paperless billing compared to the paper billing.

Cost savings from a customer switching to paperless billing are estimated to be $8.50/year per customer. This accounts for paper savings, postage savings, and the percentage of SaskPower and SaskEnergy bills which are mailed jointly in shared envelopes.

(Note: cost savings could change following a change in vendor for bill printing.) There are no material incremental costs to e-billing.

ii. Please provide further information regarding the long term CSR engagement strategy. What are the relative costs and benefits of this strategy?

The CSR engagement strategy is not yet developed. See the answer to (iv) for further insight.

iii. What are the relative costs and benefits related to further collaborations with SaskPower?

The 2017-2018 budget has $30K dedicated to a joint advertising campaign and promotion to encourage the adoption of paperless billing. It is typical for SaskEnergy to achieve approximately 1500 new enrollments with such a campaign. This translates to an estimated $12,750/year in incremental savings.

SaskEnergy and SaskPower have discussed having CSRs from each utility cross promote paperless billing. There are a number of system changes and upgrades that are required before this becomes possible. A critical path step is a change to a SaskPower system, so SaskEnergy is waiting for SaskPower's change to be complete before dedicating resources to plan further changes at SaskEnergy.

iv. Is SaskEnergy aware of other strategies used by industry leaders to promote uptake of paperless billing? Please discuss and describe why these strategies may or may not be applicable.

Union Gas is a leader among CGA-member companies. They were at 33% paperless penetration in October 2016. They continue to run periodic campaigns and promotions for customers. SaskEnergy runs advertising and contesting similar to Union Gas, but tends to use a more modest budget than other utilities.

Engaging their CSRs in paperless promotion was reported by Union Gas to be their most effective tactic. They put a higher priority on the promotion of paperless billing than managing call volumes. SaskEnergy has not adopted this approach but has set expectations that CSRs will offer paperless billing to customers when it fits with the inquiry. Ongoing coaching will be required. Union Gas uses contesting for CSRs to keep engagement high. SaskEnergy has discussed this strategy with the Union and the concept of having individual recognition or contesting was not accepted by the Union at this time. These types of elements are being considered in the development of CSR engagement strategy for the future.

Many other utilities have invested in their website and customer self-serve tools to improve their customers' experience, making it attractive for customers to interact with utilities online. In fact, an independent and specialized information provider for the utility industry, Chartwell, reported 40% of utilities are focusing on the redesign of customer touchpoints, which includes paperless billing. Chartwell also recently reported that 64% of customers say having a bill that is easy to read and pay is the #1 driver of satisfaction with their utility. Saskenergy.com and My Account are not yet mobile compatible and customers are moving to mobile devices at a rapid pace.

While we are continuing with plans to promote paperless billing, we feel the redevelopment on our online presence is required to meet customers' future expectations and keep satisfaction high. A redesigned and mobile compatible saskenergy.com and My Account will support paperless billing enrollments, and will be prioritized relative to competing business needs.

v. What is SaskEnergy's target for enrollments and over what time period and at what cost is this expected to be achieved?

The following represents the 2013-2016 historical uptake and a target for enrollments in paperless billing in future years. "Additions" are the additional customer enrollments in the calendar year.

	Dec 2013	Q4 2014	Q4 2015	Q4 2016	Q4 2017	Q4 2018	Q4 2019	Q4 2020	Q4 2021	Q4 2022
Total Additions	-	4,360	2,538	6,954	16,000	10,000	12,000	14,000	14,000	14,000
Cumulative Total	36,193	40,553	43,091	50,045	66,455	76,315	87,855	102,055	116,255	130,225
Customer Base	373,436	380,768	385,858	389,998	394,098	398,198	402,298	406,398	410,498	414,598
Penetration Rate	9.7%	10.7%	11.2%	12.8%	16.9%	19.2%	21.8%	25.1%	28.3%	31.4%

Over the future period it is assumed that a redesign of saskenergy.com and My Account will lead to process changes which increase enrollment as well as an improved customer experience. Requirement setting for these projects has not begun. It also assumes that SaskEnergy's CSRs will actively promote paperless billing to customers and that SaskPower will cross promote paperless billing to our mutual customers.

vi. Are there any impacts from this program in the test years? Please explain and quantify.

In 2018, enrolling approximately 10,000 customers in paperless billing is estimated to increase billing savings by $85,000/year.

h) Please provide a discussion of the potential benefits of the Field Office consolidation program (Tab 23, page 6).

i. Are these savings included in the test year forecasts? Please quantify and explain.

The savings from field office consolidation would be included in the test year forecasts for the periods in which they occur. The savings related to the property consolidations at Melfort, Maidstone and Maple Creek were included in the test year in which they were realized - $79,000 in the 2016/17 fiscal year.

ii. Are any potential savings anticipated for 2018 or future years? Please explain and quantify, if possible.

Currently, no opportunities for field office consolidation have been identified in 2018 or future years. SaskEnergy will continue to work with TransGas, SaskPower and other community based organizations to identify opportunities to consolidate office space and realize operating savings.

i) Please provide a further discussion and update regarding the status of the Advanced Metering Infrastructure Program.

i. Please provide further details and explanation regarding where deployment is to be prioritized over the next three years.

For 2017 to 2020, the main focus for AMI deployment does not relate to specific locations as AMI technology will be installed across the entire province. Rather, the focus is on installing the AMI technology where SaskPower is only reading meters manually on an annual basis. In 2017, the AMI program has targeted 31,500 meters which were largely read annually as the objective is to bill as many customers as possible based on actual usage on a monthly basis instead of billing estimates.

At the mid-point of 2017 AMI completions totaled 88% with over approximately 348,000 meters, and the program is on target to complete over 360,000 (92% of all meters) by the end of 2017.

The remaining 30,000 meters consist of residential meters disbursed across many small communities (also largely read annually), as well as meters serving large commercial and industrial applications. These meters are planned for completion in 2018 and 2020. This work will be integrated efficiently with other work completed by SaskEnergy staff.

ii. Please quantify the savings in dollars and FTE's related to the benefits from the program. Please detail how the $675,000 in meter reading cost savings were determined.

The meter reading cost savings were quantified by comparing actual meter reading costs for the 2015-16 fiscal year with the actual meter reading costs for 2016-17. The FTE savings for SaskEnergy would be minimal given that meter reading services are provided by SaskPower field employees.

j) Please provide a further discussion regarding the Overtime Management program (Tab 23, page 10).

i. Please discuss the forecast impact of Earned Day Off [EDO] on the 2017/18 test year. Please discuss any factors impacting or changing EDO measures or results.

The forecasted impact of the EDO Accrual Program on the 2017/18 test year is $605 thousand. This result is impacted by the number of full time equivalents that chose to participate in this program which can vary from year to year. However based on the results shown in question 29 (iii) the change from year to year has been minimal.

ii. Tab 23 notes that "Very strict overtime management in 2016/17 resulted in operating savings, as compared with budget, of $1.29 million" How were the $1.29 million of savings in 2016/17 determined? Were these savings included in the 2016/17 test year revenue requirements? Are these same measures expected to apply in 2017/18 (are similar savings expected)?

The operating savings as stated in Tab 23 were determined based on a comparison to the 2016-17 budget. Not all of these savings were included in the 2016-17 test year requirements. Over time was being actively managed already as it had been identified as an area of focus, however, the aggressive cost management that was requested by the Shareholder after the 2016 Delivery Rate Application was finalized required that additional over time savings be identified. Over time management efforts are on-going and the revenue requirement for the 2017-18 test year includes the associated operating savings of approximately $0.5 million. It is important to note that planned over time is within management's discretion however, unplanned over time such as emergency response is not.

iii. Please provide the costs of the EDO accrual program for the past 5 years and the forecast costs for 2017/18 and 2018/19. Is there any future financial liability associated with this program?

The EDO accrual program does not create a future liability. Employees who opt into the program are paid for their EDOs annually. Employees who do not participate in the program are required to take their EDOs within the year they are earned with no option to carry them over. The EDO accrual program is not available to in scope employees.

Management EDO Accrual Program $ in thousands							
Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016/17	Forecast 2017/18	Forecast 2018/19	Test Year 2017/2018
502	537	533	549	572	592	614	605

k) Please provide further discussion regarding No Heat Calls discussed on Tab 23, page 11.

i. Has SaskEnergy continued to monitor the number of field activities for no heat calls since January 31? If so, were results consistent with the January 15-31 period results?

Results were reviewed from January 15 – March 31, 2017 and showed a 95% drop in No Heat Calls when compared against the same time frame in 2016. This drop in no heat calls continued to decline each week that we did not provide the service.

ii. How were the savings numbers noted in the table on page 11 determined? Are these savings expected annually?

The savings related to No Heat Calls was based on anticipated reduction in responses and the time of day that the response historically occurred. This created a base line for the savings for the hard savings. The soft savings are related to the additional time that was now available during regular working hours to work on other customer, system or maintenance relate duties.

iii. SaskEnergy notes there has been very little negative feedback from customers – how has this been determined? How has feedback been sought since implementation of this change?

Although no formal survey was conducted, the dispatchers were surveyed on a regular basis to determine if there was negative feedback from the customers calling in. It should be noted that the scripting provided to the dispatchers in relation to No Heat Calls was very informative for the customer and laid out why there had been a change. Customers were very accepting of the change according to the dispatchers.

l) Please provided further discussion regarding IT Contractors – Mandatory Time Off discussed in Tab 23, page 12.

i. How was the $260,000 in cost savings determined?

The estimated cost savings were calculated using the actual hourly contractor rates for those contractors who were given the time off and then estimating the hours that would have been worked by those contractors in the final two weeks of December, 2016.

ii. Why was IT Contractors selected for this cost savings measure? Were other areas of SaskEnergy operations considered? If so, why were similar measures not applied to these other areas?

Only the IT Contractors were given the mandatory time off for the last two weeks in December. The nature of these contracts and the work that was being deferred made this area the only feasible area to institute a mandatory two week time off period.

iii. Were there any adverse effects (cost or otherwise) from halting progress on projects over the two week period noted.

The mandatory time off for contractors resulted in some delays for certain IT projects but it was only two weeks and no material negative impacts were evident.

iv. Are similar measures planned to be undertaken in the future for IT contractors or for other areas? Please discuss and explain why or why not.

No additional mandatory time off periods for any contractors are anticipated in the future. The December 2016 mandatory time off was in response to the expenditure restraint directives from the Shareholder and is expected to be a one-time occurrence.

m) Please provide further discussion regarding Retendering for Polyethylene Pipe Contract described in Tab 23, page 9.

i. Please discuss how changes in contracting to the just in time inventory model has (or will) impact inventories of materials included in ratebase [see Tab 17].

Not all materials and supplies are well suited to a just in time inventory practice. To the extent that just in time inventory practices can be expanded to other materials and supplies, the corporation would expect to realize savings related to inventory storage costs, spoilage, theft and obsolete stock. The result would be lower rate base amounts related to certain inventory items that are well suited to just in time inventory practices. Please also see the response to IR#19 f.

n) Please provide a further discussion regarding the Cashiering Function Closures program described in Tab 23, page 12.

i. Please detail how the $366,000 in estimated savings in labour resources was determined. Please reconcile to the $336,000 amount noted in the table on page 12.

The $366,000 within the text on Page 12 should read $336,000. The $336,000 is based on six Customer Service Representatives (CSRs) wages. These CSRs have been redeployed to other Customer Service duties. The wage is considered a savings as this movement meant SaskEnergy did not need to hire new CSRs where there were vacancies.

ii. Please explain what is captured in the $90,000 of CSR training and productivity amount.

The cost to train a new CSR is approximately $15,000. Included in this cost are wages – instructor and new employees, travel expenses and while training, CSRs and Instructors are in a classroom and not contributing to the overall workload.

iii. Please describe further the annual incremental expenses noted in the table at page 12.

By closing the cashiering function, approximately $48,000 in annual revenue lost represents payments SaskEnergy currently receives from SaskPower and SaskTel for accepting payments on their behalf at SaskEnergy locations. The $15,000 in incremental expenses represents a 10% increase in annual payments SaskEnergy makes to other Crowns for accepting SaskEnergy payments.

iv. Are there any other anticipated impacts on the company from this initiative (e.g., will l closure of Cashiering Services in Saskatoon and Regina have an impact on Late Payment Charges?)

SaskEnergy anticipated additional calls to our Customer Service queue to answer questions about payments. Prior to the cashiering closures, we provided walk in and call in customers with further information regarding our online My Account information and promoted paperless billing to assist in the transition.