Final Independent Report

For the Saskatchewan Rate Review Panel

on

SaskPower's 2014-2016 Rate Application

April 10, 2014 **Forkast Consulting**

Executive Summary

The Forkast consulting team was retained by the Saskatchewan Rate Review Panel to provide an independent review of SaskPower's multi-year General Rate Application for rates to become effective on January 1 in each of 2014, 2015 and 2016, pursuant to the Minister's order issued specific to this review on October 25, 2013. This Application is the first time that SaskPower has requested a multi-year rate increase. As well, the requested January 1, 2014 rates were implemented on an interim basis pending review and recommendation by the Panel. The review commenced immediately upon receipt of the Application in October 2013. Forkast's Final Report was submitted to the Panel on April 10, 2014.

The Application requested an overall system average increase in rates of 5.5% effective January 1, 2014, 5.0% effective January 1, 2015 and 5.0% effective January 1, 2016. The rate increases would generate additional revenue of $103.2 million in 2014, $209.6 million in 2015, and $328.7 million in 2016 for a total of $641.5 million. This would result in net incomes of $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016 for a total of $107.2 million. The rate increases would also achieve a return on equity of 1.3% in 2014, 2.0% in 2015 and 1.9% in 2016, well below SaskPower's mandated long-range ROE target of 8.5%.

SaskPower filed a Mid-Application Update which revised the expected 2014 the net income from the initial application forecast of $26.9 million to $66.0 million, an improvement of $39.1 million. SaskPower's revised ROE is now forecast to be 2.9% for 2014. ROE forecasts for 2015 and 2016 were not changed with the February Mid-Application update. However, SaskPower confirmed that as a result of revised load forecasts, 2015 net income is forecasted to increase by $18 million with a further net income increase of $6 million in 2016.

The two major cost drivers underlying the request for increased rates were: finance, depreciation and asset disposal costs associated with SaskPower's Capital program (72% of 2014 forecast cost increase); and Fuel and Purchased Power Costs (16% of forecasted 2014 forecast cost increase). The remaining 12% in increased costs is for all other operating and administrative components.

Consistent with past reviews, Forkast's review encompassed all elements of estimated revenue: Saskatchewan Electricity Sales; Export Sales; Net Trading Revenue; and all Ancillary Revenues. All categories of expenses were also reviewed. The major expense categories were: Fuel and Purchased Power (F&PP) including periodic fuel cost updates; Operating, Maintenance, and Administration; Depreciation and Amortization; Finance Charges and Debt Obligations; Foreign Exchange; Capital Program Impacts on Operating Costs; Municipal and other Taxes; and subsidiary Operations. The analyses incorporated data from the original Application as well as from periodic updates, as provided by SaskPower, in confidence, to the end of March 2014. It also included an overview of historic costs and revenues as well as some limited future outlook data, performance ratios, and comparative information from other Canadian Electric Utilities.

As well System Operation, Load Forecasting, Planned Maintenance Programs, Future Generation Resource Planning and Future Capital Programs were examined, as were Environmental Plans and Demand Side Management Programs. Forkast also reviewed SaskPower's most recent Cost of Service Study including the methodology used and all updated forecasts and rate structure. The rate structure remained unchanged from those used in the 2013 Application.

The most recent Cost of Service Study (COSS) was completed in 2012, the results of which were presented in a report in January 2013. The report concluded that SaskPower's cost of service model and rate design methodologies were consistent with generally accepted electric utility practices. The report also recommended some enhancements. The two most significant recommendations were implemented as part of this Application.

Additionally, this Application included the results of SaskPower's internal load research program, with the initial installation of a representative number of real time meters for residential, farm, oilfield and commercial customers to determine the load profile (hourly demand) for those classes. Power and Reseller Customer Class profiles were already available. Where the incorporation of the results of the two programs resulted in relatively larger increases to certain customer classes, SaskPower proposed to phase these in over a 3 year period, such that the revenue to revenue requirement ratios for all customer classes were expected to fall within a range of 0.98 to 1.01 by 2016.

To the extent possible, without compromising confidentiality, the latest overall results provided by SaskPower were used in our assessment of the necessary rate increase while being mindful of the Panel's Terms of Reference and basic objective. This objective is to "…provide an opinion of the fairness and reasonableness of SaskPower's proposed rate change…" In arriving at its determination, the Panel was to consider a number of factors under the specific Terms of Reference for the review while some other factors were to be outside the Panel's purview.

The review also considered responses to numerous information requests from Forkast on behalf of the Panel and those of several interested parties, as well as submissions made by the public at meetings or through various other exchanges.

We have made specific observations regarding all components of revenue and operating expenses throughout the report, as well as all other matters explored during the review. Our observations are included in the body of the Report and our recommendations as well as additional comments are detailed in Section 16.

We consider the 5.5% system average January 1, 2014 Interim Rate increase to be reasonable and justifiable and that the Panel recommend that it be confirmed and finalized.

Our specific recommendation respecting the 2014 Revenue Requirement is that it be approved based on the Mid Application Update should and subject to the following:

a) The revenue requirement be set to allow SaskPower to generate sufficient revenues to earn the requested 2.9% Rate of Return, to produce a net income for 2014 of $66.0 million.
b) The natural gas AECO C forward forecast price of $4.08 / GJ be used for purposes of setting 2014 rates for an estimated updated consumption of approximately 60 million GJ.
c) The Panel accept the updated 2014 F&PP forecast cost of $622.0 million.
d) The Panel accept the total OM&A expense forecast of $647.7 million (unchanged in the Mid-Application update) as filed in the original application.
e) The Panel accept the updated forecast for Amortization and Depreciation expense of $399.3 million.
f) The Panel accept the updated forecast for net finance charges of $340.1 million.
g) The Panel accept the forecasted Municipal Tax, Corporate and Other Taxes Obligations of $57.0 million as filed in the original application.
h) The Panel accept the forecasted other costs at $16.5 million as originally filed.
i) Lastly, the Panel accept a SaskPower expense total of $2,082.5 million as filed in the Mid-Application update.

In our view there are three main drivers for SaskPower's increased revenue requirement. The three major expense categories are i) Increased fuel and power purchase costs, ii) increased finance costs association with past and current capital spending plans, iii) the increased depreciation costs associated with new capital assets. To a much lesser degree OM&A cost increases to reflect inflationary cost increases and costs associated with additional staff, benefits, material and supplies costs associated with maintaining new capital assets.

OM&A expense forecasts are $648 million for 2014, $672 million for 2015, and $698 million for 2016. This results in net increases of $27 million, $24 million and $26 million for an accumulated increase of $77 million relative to 2013 representing percentage increase of 12.4% or approximately 4.1% annually for each of the three years. Excluding the costs associated with power production overhauls and other system improvements as detailed above, the OM&A cost increases relative to other operational needs clearly demonstrate, in our view, that operational costs are being contained. The cost containment is evident considering the major capital improvement and re-investments being made to generation, transmission, distribution and operational infrastructure, including AMI, all requiring increased maintenance. In addition, the increased costs associated with new staff salary & wages, benefits, materials and supply and external services, confirms that the Business Renewal and Service Delivery Renewal Programs are generating a positive net financial result for SaskPower's base cost structure.

We urge SaskPower to continue to provide a detailed overview respecting each Business Renewal Initiative respecting steps taken to date, the costs and savings generated, in a format so as to easily discern the progress made and the program expectations on a year- over- year basis.

SaskPower's long term debt grew from $2.449 billion at the end of 2005 to $3.16 billion at year-end 2011. SaskPower's debt is now forecasted to be $5.67 billion year end 2013 and grow to $7.572 billion at year end 2016. SaskPower current legislated borrowing capacity is $8 billion. SaskPower has a significant advantage in being able to use the credit facility and favourable rating of the province to acquire the necessary funds at a more attractive rate than what would otherwise be the case. The province does not impose a fee or charge for this advantage but the debt is issued in the name of the Province of Saskatchewan and reassigned under the same issuing terms and conditions to SaskPower.

No dividend payments are anticipated or currently forecasted during this capital extensive planning cycle and specifically for this 2014-2016 Rate Application. The "dividend holiday" is a significant advantage for SaskPower and its ratepayers. Being able to retain the equity in the corporation provides an opportunity to have lower debt levels, lower finance charges, and a stronger equity position than if dividends were demanded. The long term financial benefits of the "dividend holiday" are significant for SaskPower in being able to lessen the financial impact on its ratepayers during this intensive capital reinvestment period.

Although the capital program of SaskPower is beyond the mandate of the Panel to submit recommendation with respect to the Capital program and rate base, the impacts flowing from such programs significantly influence SaskPower's annual expenses and thus have a direct impact of requested rates. Based on an assumed borrowing rate of 4% and an average useful asset life of 25 years, SaskPower states that, as a rule of thumb, a $1 billion capital expenditure would increase annual expenses by approximately $80 million, which would translate into a rate increase of approximately 4.2%.

The three year capital budget plan (2014-2016) is in excess of $3 billion and is a major issue. Considerable concern was expressed by the interested stakeholders in this regard. The capital program plan total impacts over the next decade are even more significant. While we recognize this is beyond the mandate of the Panel on which to make recommendations, we would urge SaskPower to consider entering into a public dialogue with the stakeholders and the Saskatchewan Rate Review Panel wherein greater detail demonstrating need and transparency of those capital plans could be shared or disclosed. From our examination we are satisfied that the principle considerations and directions used by SaskPower are appropriate and necessary but because the financial impacts on the ratepayers, both today and in the future, are so significant, from a public interest perspective, greater public disclosure should occur.

The Panel has a variety of options that it can consider for the Multi-Year Rate Application. These include recommendations that only January 1, 2014 interim rates be approved (or amended); that January 1, 2014 rates be finalized as well as, subject to conditions, rates as filed for 2015. Another option is to finalize rates for 2014, and approve subject to conditions, rates for 2015 and 2016. The last option is to recommend final approval of the multi-year application as filed. We cannot recommend the latter. We are of the view that this option is not in the best interest of any of the interested parties including SaskPower.

There are many variables and uncertainties in the assumptions underpinning the 2014 forecasts and these become less certain for both the cost and revenue forecast accuracy into the future. With the complimentary financial risks, both positive and negative to the utility as well as its ratepayers, it is very difficult for us to secure the interests of all parties by recommending final approvals for all three years from 2014 to 2016.

It is our view that the nature of these variables (largely beyond the control of SaskPower), as well as the size of the Capital Program (a main cause of the requested rate increases) and the inherent possibility of not being able to complete the total program in any given year will result in significant change in the application assumptions and forecasts. These will only be exacerbated with the passage of time. While it may be acceptable to stipulate that the criteria for amending future rates be the fact that SaskPower's ROE not exceed the allowed 8.5%, other issued must, in our view, also be considered.

As noted above, while the Panel has four options in considering this application we cannot recommend unconditional approval of the three year application. Being sensitive to the financial needs of SaskPower, the stated interests of the stakeholders and ratepayers including the transparency of the three remaining options, we are of the view that it would be prudent to only recommend approval of the 2014 rate application and conditional approval for the 2015 test year application. As suggested by SaskPower an updated filing would be required that could secure the interests of all parties (utility-ratepayer-public) for the 2015 rate application.

With the current size of the planned capital program and its impact on the financial revenue requirements of the utility, the less than stable economic outlook and future load forecasts, continued upward movement in fuel and purchase power costs as noted in the Mid-Application Update (including the forward natural gas market pricing) and hydraulic generation availability, there are, in our opinion far too many uncertainties' to provide the comfort necessary to be able to recommend to the Panel approval of the 2016 test year application.

Table of Contents

1.0 Introduction

1.1 Terms of Reference

On October 25, 2013 the Minister responsible for Saskatchewan's Crown Investments Corporation released the Terms of Reference for SaskPower's 2014, 2015 and 2016 Rate Application to the Saskatchewan Rate Review Panel. The Panel, a Ministerial Advisory Committee, was appointed by the Minister on January 1, 2013 pursuant to Section 16 of *The Government Organization Act.*

The Saskatchewan Rate Review Panel was asked to conduct a review of SaskPower's request for an increase to its electricity rates to be effective on January 1, 2014, January 1, 2015, and January 1, 2016. It was noted that the Cabinet is authorized to implement any rate change adjustment on an interim basis pending receipt of the Panel's recommendation(s).

The Panel's general mandate and operational terms of reference are as specified in the Minister's Order dated January 1, 2013. Specifically with respect to this Application, the Panel is to provide an opinion of the fairness and reasonableness of SaskPower's proposed rate change while giving consideration to the following:

- The interests of the Crown Corporation, its customers and the public;
- Consistency with the Crown Corporation's mandate, objectives and methodologies;
- Relevant industry practices and principles; and
- The effect of the proposed rate change on the competitiveness of the Crown Corporation related to other jurisdictions.

In conducting this proposed multi-year electricity rate change review, the Panel is to consider the following:

A) The reasonableness of the proposed changes to the rates in the context of SaskPower's forecasted cost of service for 2014 to 2016 inclusive, which is comprised of:

i. anticipated costs for fuel;
ii. anticipated hydro facilities availability;
iii. load forecasts;
iv. planned maintenance programs;
v. operating, administrative and maintenance expenses;
vi. depreciation and finance expenses; and
vii. corporate capital tax.

B) The revenue requirement resulting from the cost of service.

C) The reasonableness of the current rate structure and all components (basic charge, energy charge and demand charge) comprising the rate.

D) The future impact of the proposed rate change on different customer groups.

E) The Panel is to consider the following parameters as given:

i. the budgeted capital allocation, the rate base and established corporate policies over the period 2014 to 2016 inclusive;
ii. the long term Return on Equity target of 8.5%;
iii. the existing service levels;
iv. any existing supply contracts; and
v. the revenue to revenue requirement ratio target range of 0.95 to 1.05.

SaskPower is to provide the Panel with its application package immediately. SaskPower is also to provide the Panel with any supplementary information as the Panel may require in fulfilling its mandate and the terms of reference.

SaskPower is to provide the Panel with a mid-application update, including any material updates, by no later than mid-February 2014 if a business factor(s) vital to formulating the multi-year rate application has changed significantly from the original business factor(s) used in the application.

The Panel shall determine a public consultation process for the rate change application that is appropriate and cost effective under the circumstances and within the review timeline as established by the Minister of Crown Investments.

The Panel shall provide members of the public with the opportunity to review and comment on SaskPower's rate change submission outside any public meeting, to the extent reasonable and within the review timeline as established by the Minister of Crown Investments.

The Panel shall provide an opportunity to SaskPower to make a presentation to it and to the public as the Panel considers appropriate to discuss noteworthy rate application issues.

The Panel shall, in a timely and efficient manner, forward to SaskPower for response questions that the Panel receives from the public, individual Panel members and its technical consultant.

The Panel shall provide SaskPower with the opportunity and reasonable time to review the technical consultant's preliminary report prior to its finalization to ensure there is no error in data or in the interpretation of data. The preliminary report should include the consultant's observations, but not the consultant's recommendations.

The Panel must include in its final report an explanation of how, in its opinion, implementation of the Panel's rate recommendations will allow SaskPower to achieve the performance inherent in the parameters outlined in section E), where the Panel's recommendations are different from SaskPower's proposed rate changes.

Consistent with the "Confidentiality Guidelines" for the Panel (March 11, 2010), the Panel will not publicly release or require SaskPower to publicly release Confidential Information supplied by the Crown Corporation to the Panel during the course of the rate change application review.

As part of its report, the Panel will release the results of the review of SaskPower's rate request as conducted by an independent third party. By doing so the Panel shall ensure there has been no indirect release of any of SaskPower's confidential information.

The Panel will present its primary report detailing its analysis and recommendations on SaskPower's proposed multi-year electricity rate change request to the Minister of Crown Investments no later than April 28, 2014. The reporting date may be modified by the Minister of Crown Investments in consultation with the Panel Chairperson.

1.2 Changes in Terms of Reference

The Minister's Terms of Reference (TOR) for the Panel's review of SaskPower's 2014, 2015 and 2016 Rate Application were updated from those issued for SaskPower's last (2013) Rate Adjustment Application review.

The last TOR was for a one year rate change application while the current terms relate to the first ever multi-year application filed by SaskPower.

The 2013 Application TOR indicated that the Panel was to consider as a given factor that the final rate change would be applied uniformly to all customer classes (except the Power - Contract Rate Class), as would the three rate components: basic monthly charge, energy charge and demand charge. In accordance with the TOR for this review, the Panel is no longer required to consider the rate structure and all components comprising the rate as a given. Rather the Panel is to consider the reasonableness of the entire rate structure during the review.

For this Application, the Panel is to consider as a given that the long-term Return on Equity (ROE) target is 8.5%, while in the previous TOR, the ROE target of 8.5% was to be considered for the specific year of the application, that is for 2013.

Additions to the current TOR that were not specifically a part of the previous terms include:

- SaskPower is still to provide the Panel with a mid-application update. However, the update will only be required if a vital factor(s) used in the formulation of the multi-year rate application change significantly.
- The Panel is to determine a public consultation process for the rate change application that is appropriate and cost effective under the circumstances and within the review timeline.
- The Panel is to provide members of the public with the opportunity to review and comment on SaskPower's rate change submission outside any public meeting, to the extent reasonable and within the review timeline.
- The Panel is to forward to SaskPower, in a timely and efficient manner, questions for response that the Panel receives from the public, individual Panel members and its technical consultant.
- The Panel is still required to provide SaskPower the opportunity and reasonable time to review the technical consultant's preliminary report including observations prior to its finalization. However, the consultant's recommendations are specifically not to be included in SaskPower's review.
- The Panel is still required to present its primary report to the Minister of Crown Investments, but no longer to the Minister responsible for SaskPower.

All other terms remained unchanged from the last Terms of Reference.

1.3 Conduct of Review

1.3.1 Overview

In order to complete a comprehensive review of this application and to assist the Panel in achieving its objectives and fulfilling its obligations, Forkast Consulting (Forrest & Kostelnyk) met with the Panel and officials of SaskPower on several occasions concluding with meeting the Panel to discuss and explain the consultant report in general, particularly the observations, recommendations and conclusions. In the course of the review process, substantial information provided by SaskPower was examined and tested. After the initial meeting with SaskPower, Forkast submitted 208 information requests (IRs) in the first round, 47 in the second round, and 4 questions relative to the Mid-Application update. Prior to submitting the second round IRs, Forkast met with SaskPower staff to review first round IR responses, and to clarify issues that arose as a result of Forkast's review of these responses. Forkast also reviewed formal IRs submitted by SIECA (50 in the first round and 21 in the second round). As well formal submissions, general comments and questions submitted by corporations and individuals at the public hearings, by phone or electronically, were considered in the preparation of this report. All final written submissions received by the Panel, including those submitted by SaskPower were also reviewed and considered in the preparation of this report.

1.3.2 Specific Activities

The main activities conducted by Forkast as part of its independent review and project milestone dates are shown in the following table:

Table 1.1 - Conduct of Review Activities

Date	Activity
Oct 25/13	Minister's Terms of Reference submitted to the Panel
	SaskPower submitted Application, MFR to Panel and Consultants
Oct 30/13	Panel and Consultants participated in SaskPower application overview presentation
	Consultants met with Panel to discuss initial impressions, potential issues & process schedules
Nov 15/13	Consultants and SIECA submit first round information requests to SaskPower
	Consultants commence preparation of draft report
Nov 25 - Dec 4/13	Panel held public meetings at Prince Albert, North Battleford, Saskatoon, Regina & Yorkton
Dec 6/13	SaskPower respond to all first round IRs and Consultants commence review
Dec 16 & 17/13	Consultants and Panel Chair met with SaskPower executive and staff to review and discuss IR responses and obtain additional information
Dec 27/13	Consultants submit second round IRs to SaskPower
Dec 28/13	Consultants met with Panel to review IR responses & additional info from SaskPower meeting
Dec 31/13	SIECA submit second round IRs to SaskPower
Jan 13/14	SaskPower submit 2013 year end final results
Jan 23/14	SaskPower responds to all second round IRs
Feb 7/14	Deadline for Stakeholder final submissions
Apr 4/14	Consultant submit Draft report to Panel
Apr 9/14	Consultants met with Panel to review draft report
Apr 10/14	Consultants submit Final Report to Panel
Apr 28/14	Panel to submit report to Minister

2.0 SaskPower 2014, 2015 and 2016 Rate Application

2.1 Background, Governance and Historical Rate Changes

SaskPower, Saskatchewan's leading energy supplier, is a vertically integrated electric utility that provides generation, transmission, distribution, and retail services to its customers in Saskatchewan. SaskPower derives its mandate from *The Power Corporation Act*, and has been in existence for over eighty years since commencing its operation in 1929. The Act provides SaskPower the exclusive franchise and obligation to supply, transmit and distribute electricity, as well as related retail services, to all parts of Saskatchewan except for a portion of the Cities of Saskatoon and Swift Current. The Cities of Swift Current and Saskatoon purchase bulk power from SaskPower, but utilize their own distribution systems and provide customer services to customers within defined geographic areas. Their service areas do not include all customers within the city limits, as new customers are generally fully serviced by SaskPower. Both cities are in SaskPower's Reseller Customer Class.

SaskPower's mission is to deliver electricity in a safe, reliable and sustainable manner to its customers. This requires a customer-service-oriented organization that is trained and equipped to handle customer inquiries and calls, as well as being able to respond to a growing demand for new products and services throughout the province. SaskPower must plan its electrical transmission and distribution systems to meet the growing electrical demand from its existing customers and to supply its new customers with reliable, safe and affordable electricity. SaskPower uses the most economic sources of generation at its disposal and must be flexible enough to respond to contingencies and emergencies as a result of severe weather, weather fluctuations, planned equipment maintenance programs and unexpected equipment and other plant failures throughout the province in a timely manner.

In terms of governance, SaskPower's management is directly responsible to its Board of Directors, appointed by the Government of Saskatchewan. The SaskPower Board is responsible to the Board of Directors of the Crown holding company, Crown Investments Corporation of Saskatchewan (CIC). The CIC Board, responsible to Cabinet, is composed of Cabinet ministers and board members appointed by the Government of Saskatchewan.

The CIC Board provides broad direction to SaskPower, including the establishment of appropriate financial targets (such as the expected rate of return), dividend rates, and the setting of public policy. A key element of public policy that SaskPower must achieve is the provision of safe, reliable electrical services to the people and businesses of Saskatchewan at a reasonable cost.

SaskPower services one of the largest geographical areas in Canada, providing electricity generation, transmission, distribution and retail services to approximately 500,000 customers in 2013. According to SaskPower's 2012 Annual Report, this is an increase of approximately 10,000 customers from 2012. SaskPower's customers are dispersed over approximately 652,000 square kilometers. SaskPower manages over $6 billion in assets to provide these services.

In addition to serving its customers in a vast geographical area, SaskPower operates and maintains the grid providing transmission and distribution lines throughout all of Saskatchewan (approximately 151,000 km of power lines). The transmission grid is made up of 12,298 km of power lines and 51 high voltages switching stations used to transport large volumes of electricity from generation stations to load centres such as cities, towns or large industrial and commercial customers. The distribution grid is comprised of 138,959 km of power lines, 185 distribution centres and approximately 156,000 pole and pad mounted transformers which provide power in smaller quantities to residential users and small commercial customers.

SaskPower operates three coal-fired power stations, seven hydroelectric stations, six natural gas stations and two wind stations. These combined facilities can generate 3,451 megawatts (MW) of electricity supporting the services SaskPower provides to its customers.

In addition to generating power, SaskPower also purchases power from multiple facilities including the North Battleford Energy Centre, Red Lily and SunBridge Wind Power Facilities, Prince Albert Pulp, Spy Hill Generation Station, the Meridian and Cory Cogeneration stations and NRGreen heat recovery facilities at Kerrobert, Loreburn, Estlin and Alameda. SaskPower's total available generation and purchase power available capacity is 4,302 MW including 851 MW of purchase power. SaskPower has added 801 MW of new power generation capacity in the last five years.

SaskPower continues to expand its generation facilities to support its growing customer base. The Integrated Carbon Capture and Storage (ICCS) upgrade project at Boundary Dam (BD) Power Station Unit # 3 is now expected to begin operation May 1 2014, with full commercial operation of the Carbon Capture and Storage (CCS) system scheduled for July 1 2014. This will be the world's first commercial CCS facility, supporting power generation in an environmentally responsible and cost competitive way. Additionally, SaskPower expands its transmission and distribution facilities as necessary to attach new customers and rehabilitate aged facilities that are at or near the end of their useful lives. SaskPower faces significant challenges over the next decade to meet growing demands for electricity while containing costs and improving internal efficiencies so as to keep rate increases within a reasonable range.

SaskPower last changed its rates effective January 1, 2013 when a system-wide average increase of 5.0% was implemented (4.9% rate increase for all customer classes except the Power Contract Rate Class which was an increase of 6.1%). As more fully discussed in Section 11.2, SaskPower rate increases were approved and implemented in 2010 (August 1, 4.5%), 2009 (June 1, 8.5%) and 2007 (February 1, 4.2%). This represents a compounded rate increase of about 24% over 6 years.

2.2 Financial Requirements and Impacts

SaskPower is requesting a system-average rate increase of 5.5% effective January 1, 2014, 5.0% effective January 1, 2015 and 5.0% effective January 1, 2016. As was the case with the 2013 Rate Application, rates for the Power – Contract Rate class are established in accordance with the pricing terms of their contracts. With these rate increases SaskPower would achieve net incomes of $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016 for a 3 year total of $107.2 million. The requested rate increases would also achieve a return on equity of 1.3% in 2014, 2.0% in 2015 and 1.9% in 2016, well below SaskPower's mandated long-range ROE target of 8.5%.

Monthly rate increases for each of the major customer classes (480,080 of approximately 500,922 forecasted total accounts for 2014 or 95.8% of the total) would be:

- $5/month in 2014, $5/month in 2015 and $5/month in 2016 for a residential customer (362,882 accounts – 72.5%);
- $7/month in 2014, $10/month in 2015 and $9/month in 2016 for a farm customer (60,630 accounts – 12.1%); and
- $35/month in 2014, $31/month in 2015 and $32/month in 2016 for a commercial customer (56,568 accounts – 11.3%).

These increases exclude municipal surcharges and taxes. The remaining accounts consist of 17,992 for the Oilfield customer class, 2,747 for the streetlight class and 103 for the Power and Reseller customer classes (together totaling 4.2%). The following table provides a complete breakdown of average rate increases in dollars per month for all customer classes:

Table 2.1 - 2014, 2015, 2016 Average Monthly Revenue Impacts per Customer Class

Class of Service	2014 Revenue Change (%)	2014 Revenue Change ($/ Cust/Month)	2015 Revenue Change (%)	2015 Revenue Change ($/ Cust/Month)	2016 Revenue Change (%)	2016 Revenue Change ($/ Cust/Month)
Urban Res	5.3%	$5	4.5%	$4	4.5%	$4
Rural Res	5.3%	$8	4.5%	$7	4.8%	$8
Tot Res	**5.3%**	**$5**	**4.5%**	**$5**	**4.6%**	**$5**
Farms	3.5%	$7	4.5%	$10	4.0%	$9
Urban Com	7.0%	$36	5.6%	$30	5.6%	$32
Rural Com	4.8%	$30	4.8%	$31	4.8%	$32
Tot Com	**6.4%**	**$35**	**5.4%**	**$31**	**5.4%**	**$32**
Power Pub	7.0%	$27,721	5.8%	$25,490	5.8%	$29,185
Power Con	6.4%	$38,379	6.7%	$42,404	5.5%	$39,813
Tot Power	**6.9%**	**$29,213**	**6.0%**	**$27,745**	**5.7%**	**$30,576**
Oilfields	3.6%	$53	3.7%	$58	3.7%	$59
Streetlights	-4.8%	$(24)	-4.8%	$(23)	-4.8%	$(22)
Reseller	7.0%	$157,478	7.3%	$177,163	7.3%	$190,721
Total	**5.5%**		**5.0%**		**5.0%**	
The rate increase for Power Contracts is for customers whose contracts are tied to published rates. There is also escalation included in the contract customer's existing rates revenue as per their specific contract terms.						

If rates were not increased over the 2014-2016 time period, SaskPower would realize net losses in each of those years as well as experiencing a negative return on equity.

SaskPower's forecasted consolidated revenues include additional revenue generated by the requested 3 year rate increase of $103.2 million in 2014, $209.6 million in 2015, and $328.7 million in 2016 for a total of $641.5 million.

Table 2.2 - SaskPower Consolidated Revenues for 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Saskatchewan Sales	$1,687.2	$1,867.7	$1,876.6	$1,944.8	$2,014.9
Revenue Lift Due to Rate Increases			103.2	209.6	328.7
Total Saskatchewan Sales	1,687.2	1,867.7	1,979.8	2,154.4	2,343.6
SaskPower Exports	49.1	68.9	27.5	34.9	38.9
Net Sales from Trading	14.4	8.5	7.2	7.5	7.9
Other Revenue	104.9	95.6	129.6	149.3	133.7
Total Revenue	**$1,855.6**	**$2,040.7**	**$2,144.1**	**$2,346.1**	**$2,524.1**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

SaskPower organizes its operating costs into the following categories of expense:

- Fuel and Purchased Power, including realized natural gas price risk management results;
- Operating, Maintenance and Administration;
- Depreciation;
- Finance Charges;
- Taxes; and
- Other.

The table below presents SaskPower's actual total operating costs by major category of expense for 2012, as well as projections from 2013 to 2016.

Table 2.3 - SaskPower Consolidated Expenses for 2012 to 2016

(in $ millions)	Actual 2012	Forecast 2013	2014	2015	2016
Expense					
Fuel and Purchased Power	$513.3	$547.3	$587.4	$678.4	$762.0
Operating, Maintenance & Admin	619.7	617.7	647.7	672.4	697.8
Depreciation	315.8	366.5	425.3	460.8	490.1
Finance Charges	203.0	272.3	383.3	416.3	452.5
Taxes	47.7	52.9	57.0	61.3	63.9
Other	26.7	9.0	16.5	17.0	17.4
Total Expense	**$1,726.2**	**$1,865.7**	**$2,117.2**	**$2,306.2**	**$2,483.7**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

SaskPower's forecasted net operating income is $26.9 million in 2014, $39.9 million in 2015, and $40.4 million in 2016, as summarized below

Table 2.4 - SaskPower Consolidated Income Statement for 2012 to 2016

(in $ millions)	Actual 2012	Forecast 2013	2014	2015	2016
Revenue					
Saskatchewan	$1,687.2	$1,867.7	$1,979.8	$2,154.4	$2,343.6
Export	49.1	68.9	27.5	34.9	38.9
Net Sales from Trading	14.4	8.5	7.2	7.5	7.9
Other	104.9	95.6	129.6	149.3	133.7
Total Revenue	**1,855.6**	**2,040.7**	**2,144.1**	**2,346.1**	**2,524.1**
Expense					
Fuel and Purchased Power	513.3	547.3	587.4	678.4	762.0
Operating, Maintenance & Admin.	619.7	617.7	647.7	672.4	697.8
Depreciation	315.8	366.5	425.3	460.8	490.1
Finance Charges	203.0	272.3	383.3	416.3	452.5
Taxes	47.7	52.9	57.0	61.3	63.9
Other	26.7	9.0	16.5	17.0	17.4
Total Expense	**1,726.2**	**1,865.7**	**2,117.2**	**2,306.2**	**2,483.7**
Operating Income	**$129.4**	**$175.0**	**$26.9**	**$39.9**	**$40.4**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

The impact of the proposed 3 year system-average rate increases on each customer class and the resultant change in Revenue to Revenue Requirement (R/RR) ratios are:

Table 2.5 - 2014, 2015, 2016 Rate Changes & R/RR Ratios by Customer Class

Class of Service	2014 R/RR Ratio (Existing)	2014 Proposed Increase	2014 R/RR Ratio (Revised)	2015 Proposed Increase	2015 R/RR Ratio (Revised)	2016 Proposed Increase	2016 R/RR Ratio (Revised)
Urban Res	0.98	5.3%	0.98	4.5%	0.98	4.5%	0.98
Rural Res	0.98	5.3%	0.98	4.5%	0.98	4.8%	0.98
Farms	1.01	3.5%	0.98	4.5%	0.98	4.0%	0.98
Urban Com	0.98	7.0%	1.00	5.6%	1.00	5.6%	1.01
Rural Com	1.03	4.8%	1.01	4.8%	1.01	4.8%	1.01
Power Pub	0.99	7.0%	1.01	5.8%	1.01	5.8%	1.01
Power Con	0.97	6.4%	0.98	6.7%	0.98	5.5%	0.99
Oilfields	1.06	3.6%	1.04	3.7%	1.02	3.7%	1.01
Streetlights	1.29	-4.8%	1.16	-4.8%	1.08	-4.8%	1.01
Reseller	0.94	7.0%	0.96	7.3%	0.97	7.3%	1.00
Total	**1.00**	**5.5%**	**1.00**	**5.0%**	**1.00**	**5.0%**	**1.00**

2.3 February 2014 Mid-Application Update

SaskPower filed a Mid-Application update on February 14, 2014. The original rate application forecasted an operating income of $26.9 million in 2014 and an ROE of 1.3% as compared to the mid-application update forecasts operating income of $66.0 million in 2014 and an ROE of 2.9%. The Mid-Application update states the improved results are due to a $4.4 million forecasted increase in revenue and a $34.7 million reduction in expense. The update did not provide any revised projections for 2015 or 2016.

With respect to the revenue component of net income SaskPower states “revenue in 2014 is expected to increase $4.4 million above the original rate application forecast. This is driven largely by an updated load forecast, which results in a $14.8 million improvement in Saskatchewan energy sales. The load forecast in the update is based on the 2013 Q4 Load Forecast adjusted for January actuals. Overall, the load in 2014 is expected to decline slightly, but will be more than offset by a change in the revenue mix. Consumption in the residential and commercial classes is expected to increase while being offset by a decline in the power class segment. The improvement in Saskatchewan sales revenue is partially offset by a $3.4 million decline in exports and a $7.0 million reduction in other revenue”.

Expenses are expected to decline $34.7 million in 2014 compared to the forecast in the original rate application. The decline is due to an expected $69.2 million reduction in depreciation and finance expenses because of the delay in the commissioning of the Integrated Carbon Capture and Storage (ICCS) facility at Boundary Dam #3. The original application had anticipated that the ICCS facility would be fully operational on January 1, 2014. However a revised operational start date of May 1, 2014 for the Power Station Island and July 1, 2014 for the carbon capture facility is now projected. As a result of the project delays there will be a corresponding decrease in both depreciation expense and finance charges, as these capital costs will not hit the income statement until the facility is operational. There has also been a decrease in the estimated pension expense for 2014 which is also contributing to the reduction in finance expense.

Offsetting these expense reductions is a forecasted $35 million increase in fuel and purchased power expense in 2014. The original application assumed a market price of $3.29/GJ in 2014 and the updated forecast, which is based on the forward price of natural gas at the end of January, assumes a forward price of $4.08/GJ.

In summary, relative to the original application, revenues are expected to increase by $4.4 million, expenses to decrease by $34.7 million, thus increasing the originally forecast net income of $26.9 million by $39.1 million to a revised net income of $66 million. The updated ROE forecast for SaskPower in 2014 is now 2.9% compared to the original ROE forecast of 1.3%. As the impact of the new information does not cause SaskPower to exceed its long-term ROE target of 8.5%, the submission recommends that the rate increase request be approved as requested in the initial submission. In a subsequent follow up clarification question SaskPower confirmed that as a result in load forecasts for 2015 and 2016 net income in each of those years is forecasted to increase by $18 million and $6 million respectively, marginally increasing the expected ROE in 2015 and 2016.

The following table is a financial summary of the Mid-Application update on the Consolidated Statement of Income:

Table 2.6 - Application Update Consolidated Statement of Income

(in $ millions)	2014 Forecast		
	Initial Submission (Jul 31/13)	**Mid-Application Update (Jan 31/14)**	**Variance**
Revenue			
Saskatchewan Sales	$1,979.8	$1,994.6	$14.8
Export	27.5	24.1	(3.4)
Net Sales from Trading	7.2	7.2	0.0
Other	129.6	122.6	(7.0)
Total Revenue	**2,144.1**	**2,148.5**	**4.4**
Expense			
Fuel and Purchased Power	587.4	622.0	34.6
Operating, Maintenance & Admin.	647.7	647.7	0.0
Depreciation & Amortization	425.3	399.3	(26.0)
Finance Charges	383.3	340.1	(43.2)
Taxes	57.0	57.0	0.0
Other	16.5	16.5	0.0
Total Expense	**2,117.2**	**2,082.5**	**(34.7)**
Operating Income	**$26.9**	**$66.0**	**$39.1**
Return on Equity	**1.3%**	**2.9%**	**1.6%**

SaskPower's Mid-Application update is included as Appendix 3 to this report.

3.0 Load Forecasts

3.1 General Methodology

SaskPower load forecasting is done annually to determine long term energy requirements and system peak demand in Saskatchewan. SaskPower's Load Forecast is used to determine capacity additions, maintenance schedules, power plant operations, fuel budgets, operations budgets and the corporate revenue forecast. The 2013 Load Forecast covers the period from 2014 to 2023 and takes into consideration the 2013 SaskPower Economic Forecast (population, household and GDP growth), historical energy sales and individual customer forecasts. Average daily weather conditions over the last 30 years are assumed for the forecast period. The forecast compiles energy sales forecasts for the Power, Oilfield, Commercial, Residential, Farm and Reseller classes as well as projections for internal corporate use, system losses, peak demand, unaccounted energy use and non-grid energy use.

The most significant variable affecting load forecasting are the forecasts obtained from key accounts which are SaskPower's large-scale industrial and commercial customers in the Power class. Their forecast information is vital as Power class customers are the primary driver for the growing energy demand in the province. SaskPower contacts each key account customer quarterly to get short and long term expansion plans in order to ensure it has up-to-date load requirement information. It is noted that the 2013 Q1 Load Forecast takes into account input from Power class customers in January and February of 2013. SaskPower establishes both a base and DSM adjusted load forecast. Upon completion of the base forecast, energy and peak demand savings are then removed to reflect the DSM adjusted forecast. In addition, SaskPower critically reviews the forecasts provided by these customers by assessing the national and international economic drivers for each of the affected industrial and commercial products that are produced in Saskatchewan.

SaskPower conducts an external review of its load forecasting methodology approximately every five years, with the last review being completed in October 2010 by Itron Inc. Itron verified SaskPower's methodology using their own forecasting expertise as well as an in depth industry survey of load forecasting processes for 3 Canadian and 6 U.S. Companies. Itron provided 4 specific recommendations for enhancements to SaskPower's methodology, 3 of which were implemented in the 2013 Rate Application, and remain unchanged for this Application.

The load forecast in the application was based on the 2013 first quarter estimates and were subsequently updated for the second and then the third quarters. All forecasts assume weather normalized data. SaskPower defined normal weather as the average daily weather conditions based on the most recent 30 year history. The definition remains unchanged from that used on the prior application, and is fairly common in the industry.

SaskPower also incorporates Corporate and Financial Service's economic forecasts (which in turn consider the most recent Conference Board of Canada forecasts and are identical to that used by the Saskatchewan Ministry of Finance) into the methodology. Information thus supplied includes estimates of population and household growth and GDP growth rates for residential, commercial and farm classes.

3.2 Economic Indicators and Forecasts

The Conference Board of Canada has published its Provincial Outlook Summer 2013 Economic Forecast. This report examines the economic outlook of the provinces in terms of GDP, industry output, and labour market conditions.

Economic Indicators

Canada's less than spectacular economic performance is expected to turn around. Although economic indicators provided few encouraging signs through the first half of 2013, recent prospects are changing for the better. Housing markets have strengthened, consumer and business confidence has picked up, and the U.S. economy is gaining speed despite the heavy drag caused by higher taxes and fiscal restraint. After two years of subpar GDP growth of 1.8% in 2012 and 1.7% in 2013, real GDP growth in Canada is forecast to be 2.4% in 2014.

Canada's regional growth profile has not changed much since the Provincial Outlook Spring 2013 Economic Forecast. Economic growth in Saskatchewan, Alberta, and Newfoundland and Labrador remains much stronger than in other parts of the country. The economy remains sluggish in Ontario. It grew by just 1% (annualized) in the first quarter of 2013, compared with 2.5% growth for the Canadian economy as a whole. The weak Ontario economy is forecast to dissipate in 2014 and the outlook should also brighten for a number of other lagging provinces as real GDP growth picks up.

Increased consumer and business confidence along with more favourable outlooks for the U.S. economy and the broader global economy will improve exporting and manufacturing throughout the provinces. The domestic economy is also forecast to improve, contributing to a stronger outlook and more evenly distributed growth for Canada. Most provinces will see economic growth of 2% or more in 2014, led by Alberta and British Columbia.

Economic Outlook - Saskatchewan

Saskatchewan's economy is expected to perform well in the near term, with the 2.2% real GDP growth realized in 2012 expected to grow to 3.5% in 2013. The goods-producing sector is expected to continue growing at a robust pace as a result of strong gains in mineral fuels production, construction and manufacturing. This strength should help create both employment gains of 3.4% and salary increase gains per-employee in 2013 (which will help support the Saskatchewan service sector). Real GDP growth beyond 2013 is forecasted to be 2.4% in 2014, 2.4% again in 2015 and then 1.3% in 2016.

Mining results are expected to be mixed over the next two years. Potash mining did not rebound in 2013 as was anticipated. Low prices prompted the mines to run at less than 75% of capacity collectively in the third quarter of 2013. As a result, an 8.5% decline in non-metallic mineral mining and quarrying is expected in 2013. However, non-metal mining should rebound by 13.2% in 2014 once the Cory and Allan potash mine expansion projects come online. There is the possibility though that there could be another decline in potash production next year because of the decision by Uralkali (one of the world's largest potash producers) to end its export sales through the Belarusian Potash Company. This could put downward pressure on potash prices and lead to lower potash production in Saskatchewan. Despite all of this, metal ore mining is expected to get a boost in 2013 upon completion of the Cigar Lake uranium mine. As a result, metal ore mining output is expected to increase from 1.1% in 2013 to 5.5% in 2014.

Construction performance over the next two years should be exceptional. Strong non-residential investment growth in structures and intellectual property (particularly with respect to mineral exploration) will support construction activity. General government fixed capital formation will grow 1.9% in 2013. However, it will decline in 2014 as the provincial government reins in its expenses.

The forecast for agriculture is also mixed. Crop production is estimated to be quite good in 2013 with over 80% of crops in good/excellent condition. On the other hand, livestock farming is not as optimistic due to strict U.S. meat labelling rules. All told, the agriculture sector is forecast to expand 1.6% in 2013 and 2.6% in 2014.

Labour markets are forecast to be strong, creating 18,400 new jobs in 2013 and 9,500 in 2014. The province will also be the leader with the lowest unemployment rates over the next two years (4.1% in 2013 and 4.2% in 2014). In addition, strong growth in household disposable income (6.2% in 2013 and 4.2% in 2014) and historically low interest rates will encourage consumer spending. Household consumption is expected to also increase an average of 2.3% during the 2013-2014 time periods.

The economic forecasts that were used to underpin this application for the years 2014 to 2016 were: inflation rates of 2.0% for all three years; short term borrowing rates of: 2014 – 1.1%; 2015 -1.5% and 2016 – 1.7%; long term interest rates of 3.7%, 3.9% and 4.1% respectively; and weighted average cost per GJ of natural gas for: 2014 - $4.22, 2015 - $4.59 and 2016 - $4.52.[1]

The 2014 – 2016 financial plans assumed wages and salaries to increase by 2% throughout all years of the plan. The 2% increase is consistent with the inflation rate assumption and is based on the Bank of Canada's long-term target range of 1 to 3 percent[2].

Conference Board of Canada Update

The Conference Board of Canada updated its Provincial Outlook 2013 Economic Forecast in the fall of 2013. This report predicts that Canada's economic performance will improve in 2014 and do even better in 2015 due to growth in the domestic economy coupled with an improvement in trade. Overall GDP growth for 2014 is now expected to be 2.3% in 2014 and 2.6% in 2015. Economic recovery in Europe, particularly Greece and Italy remains slow, but the US economy is showing indications of stronger growth in 2014 and 2015.

Production cuts in potash mining is expected to negatively impact Saskatchewan's economy in the short term, but medium and long term prospects for the industry are excellent. Nonetheless, Saskatchewan's economy remains robust with the other mining, construction, agriculture and labour components remaining much the same as predicted in the summer report. Overall real GDP growth is now expected to be 4% in 2013, slightly greater than the 3.5% previously predicted. Real GDP growth predicted for 2014 is now 2.3% and 2.5% for 2015. The summer report had predicted these to be 2.4% for both years.

3.3 Annual Energy and Peak Load Forecast Methodology

On January 30, 2013, a peak load record of 3,379 megawatts (MW) was experienced by SaskPower. A new peak record of 3,543 MW was established on December 6, 2013. The previous year's record was established on December 10, 2012 at 3,314 MW. In 2012, there were 10,345 new connects to SaskPower's system and a new record for electricity supplied of 22,129 GWh. Saskatchewan electricity sales volumes alone were 19,497 GWh in 2012, up 271 GWh or 1.4% compared to 2011. These milestones once again illustrate the importance for SaskPower to revitalize and reinforce its electrical system. The current peak loads estimated in the application for 2013 and 2016 were 3,558 MW and 3,945 MW, a 10.9% increase from 2013 to 2016. SaskPower also forecasted Saskatchewan generation to increase from 23,216 GWhs in 2013 to 26,017 GWhs by 2016, an increase of 12.1%.

Load growth over the next decade (2013-2023) is expected to increase system energy requirements by 2.6% per year. This growth is mainly in the Power class, as well as less significant increases in the Oilfield, Commercial and Residential classes. An increase of 2.2% per year over that same period of time is expected for the system peak load. This is in contrast with the 2002 to 2012 period where system energy requirements increased by an average of 2.0% per year and system peak load increased by 1.7% per year. SaskPower uses various methods to estimate its energy and peak load requirements, and the methods differ by customer class, as is summarised below. Upon completion of customer class forecasts, DSM energy savings are removed resulting in the DSM adjusted class forecasts.

Power Class – Large Commercial or Industrial Class:

[1] IR 2A First Round

[2] IR 2B First Round

SaskPower utilizes individual energy forecasts for firm and probable load supplied by customers and verified by SaskPower using industry economic indicators for the forecast period. The majority of future growth in the Power class (average annual growth of 5.1% from 2013 to 2023) is expected from the potash, pipeline pumping, chemical and northern mining sectors.

Oilfield and Commercial Classes:

SaskPower uses econometric, extrapolation and statistical regression methods to determine future load needs. The number of operating wells is used to determine customer numbers as is the future forecast of wells to be drilled, which is provided by the Ministry of Economy. The majority of future growth in the Oilfield class (average annual growth of 2.4% from 2013 to 2023) relates to increased oil and water production, while the average annual growth for the Commercial class is expected to only be 0.6% from 2013 to 2023.

Residential Class:

SaskPower uses econometric, end use, extrapolation and statistical regression methods for estimating loads for the Residential class. Residential class energy sales are forecasted based on the number of customers and average use per customer. The majority of future growth in the Residential class (average annual growth of 1.8% from 2013 to 2023) results from an expected increase in the number of customers and an increasing use per customer over time, notwithstanding savings attributable to the DSM residential programs. The increase in the average use per customer is likely due to an increase in the number of electrical appliances per household as well as the emerging “phantom” energy use related to use of energy by various electronic devices when in the sleep mode.

Farm Class:

SaskPower also uses econometric, end use, extrapolation and statistical regression methods for estimating loads for the Farm Class. The forecasted number of farm customers is determined by dividing the total number of Farm class customers into households and operations. The future number of households is obtained from the Economic Forecast while the future number of operations is forecasted using regression analysis with the number of households. Farm class energy sales are expected to decrease during the period from 2013 to 2023.

Reseller Class:

SaskPower requests and receives individual load forecasts, including DSM components, from its two Reseller customers as they are believed to be in the best position to estimate load growth given their franchise constraints. The Reseller forecasts are validated by comparing forecasted energy sales to historical sales trends. The data for these two customers is combined into a single Reseller class. The average annual growth for the Reseller class is expected to only be 0.3% from 2013 to 2023.

Corporate Use:

Extrapolation of existing data is used to estimate internal energy use, while coal mine consumption is calculated from production estimates provided internally. Upon completion of the base Corporate Use forecast, corporate use energy is expected to slightly increase during the period from 2013 to 2023.

Transmission and Distribution System Losses and Unaccounted for Energy:

System losses occur on the Transmission and Distribution systems, while unaccounted for energy is from unmetered corporate and customer use. Extrapolation methods as well as the SP Loss program are used to predict system losses. Transmission losses use the SP Loss program, while distribution losses and unaccounted for energy usage are estimated using a 5 year historical average percent of distribution sales applied to future distribution sales. The average annual growth for line losses and unaccounted for energy is expected to only be 0.1% from 2013 to 2023.

Non-Grid – Customers in 4 communities, not having access to SaskPower's electrical grid.

Energy requirements are provided by the Kinoosao diesel plant and import power transmitted by Manitoba Hydro for the other three sites not currently served by the SaskPower interconnected grid. Extrapolation is used to predict future use per customer and number of customers. The Non-Grid forecast is validated by comparing historical to forecast consumption. Energy requirements for these customers are expected to remain unchanged from 2013 (28.8 GWh) into the future for the next decade.

Peak Loads

The peak load represents the highest overall level of demand placed on the total system at a specific point in time and can occur at any time during the year. SaskPower forecasts both instantaneous and hourly interval system peak demand. Factors influencing peak requirements include time of year and day, seasonal variations, industrial load, and weather conditions. Seasonal variations consider Christmas lighting, hours of daylight, and increased shopping hours.

Historical and current sales forecast data is used to develop load patterns for all Power and Oilfield customers during the peak period. These forecasts include the customer's anticipated changes in operations during the peak period, and result in an hourly interval peak demand forecast for those customers. Peak loads for all other customer classes are estimated using coincident peak load factors developed from SaskPower's internal meter load research (which relates customer class historic contributions to system peak demand to annual energy sales). The hourly interval system peak load forecast is determined by adding the hourly interval peak load for each class. The instantaneous system peak load is calculated using the historic relationship between hourly interval and instantaneous peak demand.

Upon completion of the base system peak demand forecast, DSM peak demand savings are removed resulting in the DSM adjusted system peak demand forecast. This forecast is validated by 3 approaches: comparing historical peak load to forecast peak load; comparing forecast peak load to historical system peak loads normalized for weather conditions; and comparing historical load factor to forecast future system load factor.

The 2013 Load Forecast uses customer growth as one tool for estimating load. The following table shows the projected grid only customers by class and indicates the relative proportions of each class to total, for 2013 to 2016, based on the first quarter load forecasts.

Table 3.1 - Customer Account Projections for 2013 to 2016 - First Quarter (Application)

Class	2013	% of Tot	2014	% of Tot	2015	% of Tot	2016	% of Tot
Power	101	0.02%	100	0.02%	105	0.02%	107	0.02%
Oilfields	17,152	3.50%	17,992	3.61%	19,034	3.76%	19,608	3.81%
Commercial	56,716	11.57%	57,321	11.51%	57,939	11.45%	58,566	11.39%
Residential	355,126	72.47%	361,719	72.64%	368,457	72.78%	375,286	73.00%
Farm	60,769	12.40%	60,630	12.18%	60,481	11.95%	60,341	11.74%
Reseller	2	0.00%	2	0.00%	2	0.00%	2	0.00%
Corporate	210	0.04%	210	0.04%	210	0.04%	210	0.04%
Total	**490,076**	**100.0%**	**497,974**	**100.0%**	**506,228**	**100.0%**	**514,120**	**100.0%**

As previously discussed SaskPower updates its load forecasts on a quarterly basis. The following table shows the fourth quarter (adjusted for January 2014 actual) customer account projections.

Table 3.2 - Customer Account Projections for 2013 to 2016 - Fourth Quarter

Class	2013	% of Tot	2014	% of Tot	2015	% of Tot	2016	% of Tot
Power	100	0.02%	101	0.02%	100	0.02%	105	0.02%
Oilfields	16,446	3.38%	17,063	3.39%	17,824	3.48%	18,793	3.60%
Commercial	56,605	11.65%	58,106	11.54%	58,800	11.48%	59,503	11.41%
Residential	350,499	72.13%	366,405	72.75%	373,239	72.84%	380,164	72.91%
Farm	62,063	12.77%	61,755	12.26%	62,234	12.15%	62,671	12.02%
Reseller	2	0.00%	2	0.00%	2	0.00%	2	0.00%
Corporate	212	0.04%	212	0.04%	212	0.04%	212	0.04%
Total	**485,927**	**100.0%**	**503,644**	**100.0%**	**512,411**	**100.0%**	**521,450**	**100.0%**

Note: A single customer may have several accounts in different locations. Some oilfield and pipeline customers have many accounts as a result of the geographical dispersal of their product. Farmers may also have a number of accounts depending on the location of their facilities and home, but to a much smaller scale.

3.4 High-Low Scenarios

The 2013 Economic Forecast was the major driver in developing the most likely load forecast scenario which also assumed average weather and median hydraulic conditions. Using these criteria 2014, 2015 and 2016 estimated energy requirements of 23,124 GWh, 24,092 GWh and 25,176 GWh and peak loads of 3,686 MW, 3,818 MW and 3,945 MW were forecasted. Since uncertainty exists with long term load forecasts primarily because of economic climate and weather variations, SaskPower develops, in addition to the most likely scenario, a low case and a high case scenario using a Monte Carlo simulation model which results in a 90% confidence level.

Based on the first quarter 2013 load forecast, the DSM adjusted high forecast scenario total energy requirement and potential peak are 1,277 GWh, 2,008 GWh and 2,580 GWh and 204 MW, 318 MW and 404 MW higher respectively than the 2014, 2015 and 2016 most likely scenarios. Alternatively the low forecast scenario indicates energy and peak requirements to be 1,237 GWh, 2,050 GWh and 2,659 GWh and 197 MW, 325 MW and 417 MW lower respectively than the 2014, 2015 and 2016 most likely case. The current long range 2023 forecast (most likely) is for DSM adjusted energy needs to be 28,731 GWh and the peak load to be 4,436 MW. The 2023 high forecast scenario shows energy to be 4,990 GWh higher and demand to be 770 MW higher than the most likely scenario. The 2023 low forecast scenario shows energy to be 5,032 GWh lower and demand to be 777 MW lower than the most likely scenario.

3.5 Projected Annual and Peak Day Requirements

SaskPower's most likely energy requirement projections (in GWh) on a class-by-class basis are shown on the following table, for 2013 and 2023 as found in the 2014 Business Plan energy sales volume forecast:

Table 3.3 - 2014 Business Plan Projected Energy Requirements for 2013 and 2023

Customer Class (in GWh)	2013 Energy Requirement	2023 Energy Requirement	Change	Average Annual Change	2013 % of Total Sales	2023 % of Total Sales
Power	7,852.4	12,521.6	4,669.2	5.95%	37.9%	47.0%
Oilfields	3,516.6	4,216.8	700.2	1.99%	17.0%	15.8%
Commercial	3,625.0	3,821.9	196.9	0.54%	17.5%	14.4%
Residential	3,137.3	3,555.0	417.7	1.33%	15.1%	13.3%
Farm	1,322.1	1,232.6	(89.5)	(0.68%)	6.4%	4.6%
Reseller	1,260.6	1,294.6	34.0	0.27%	6.1%	4.9%
SK Total Sales	**20,714.0**	**26,642.5**	**5,928.5**	**2.86%**	**100.0%**	**100.0%**
SaskPower Export	741.9	914.8	172.9	2.33%		
SPC Total Sales	**21,455.9**	**27,557.3**	**6,101.4**	**2.84%**		

3.6 Observations

The accuracy of SaskPower's load forecast is critical as it forms the basis for decisions that affect several key operational and financial areas: Capital programs, Maintenance schedules, Fuel and Operations and maintenance budgets, and revenue forecasts. The methodology initially considers the economic outlook for Saskatchewan prepared by the provincial Ministry of Finance and uses the Conference Board of Canada's semi-annual economic forecasts as a major input. Average daily weather for the prior 30 years is used throughout the forecast horizon; in this case from 2014 to 2016 as weather variations can significantly impact the Residential, Commercial, and Reseller customer classes in particular. The forecasts are prepared for each customer classes using one of several approaches described above. After a base forecast is prepared it is adjusted to reflect the anticipated DSM energy and peak savings. A DSM adjusted forecast is then prepared and is the basis of rate applications. The forecasts incorporate forecasted internal energy use for SaskPower as well as estimated line losses and unaccounted for energy. SaskPower supplies one community by diesel generation (Kinoosoa) and three others (Creighton, Sturgeon Landing and Denare Beach) are supplied with power imported from Manitoba Hydro utilizing Manitoba Hydro facilities. The peak load forecasting methodology remains unchanged from that in the last application.

The Itron report which was filed with the 2013 Rate Application concluded that SaskPower's forecasting methodology was reasonable and conformed in all material ways with industry norms. The Itron report did recommend refinements to the methodology and SaskPower incorporated three of these into the 2012 load forecasts and are again used for 2013 as well as additional considerations for the Power Class forecasts. These refinements were to revise weather normalization respecting heating degree day and cooling degree day definitions; update the residential end-use models provided by the DSM departments; and use industry forecasts to check on customer supplied forecasts for the Power Class. (Ref. 2013 Consultant Report)

In response to the Power Class recommendation, SaskPower undertook to meet with Provincial Energy and Resources staff at least annually to review expansions of existing potash mines and potential greenfield mines, as well as to review northern mining expansion plans. For the 2012 Load Forecast SaskPower developed a forecast for potash production the only product for which SaskPower has an industry source from the Ministry of the Economy (formerly Energy and Resources) which led to a reduction in the customer originated forecasts. Discussions continue with respect to potash and northern mining.

We note that the Application incorporated the 2013 first quarter load forecast which was prepared in July using first quarter (March 3, 2013) data. The forecasts were subsequently updated quarterly throughout 2013.

The following table shows the differences between the first and last quarter 2013 forecasts.

Table 3.4 - 2013 DSM Adjusted Total System Load Forecast (First and Fourth Quarter)

Customer Class	Application (GWh)	Last Revised (GWh)	Variance (GWh)	Variance (%)
Power	7,625.8	7,862.5	236.7	3.10%
Oilfields	3,315.6	3448.3	132.7	4.00%
Commercial	3,587.5	3,663.5	76.0	2.12%
Residential	2,971.6	3,190.0	218.4	7.35%
Farm	1,301.7	1,332.2	30.5	2.34%
Reseller	1,260.4	1,256.8	(3.6)	(0.29)%
Corporate Use	110.3	105.5	(4.8)	(4.35)%
Total Sales	**20,172.9**	**20,858.8**	**685.9**	**3.40%**
Losses	1,981.0	1,905.0	(76.0)	(3.84)%
Total Energy	**22,153.8**	**22,763.8**	**610.0**	**2.75%**

The following table shows the variance between the system load forecasts for the first and last quarters (adjusted) for 2014.

Table 3.5 – Mid-Application Update Saskatchewan 2014 Sales Volume (Load Forecast)

	2014 Forecast		
(in GWh)	**Initial Submission (Jul 31/13)**	**Mid-Application Update (Jan 31/14)**	**Variance**
Saskatchewan Sales			
Residential	3,013.5	3,129.4	115.9
Farm	1,305.3	1,291.8	(13.5)
Commercial	3,609.2	3,690.0	80.8
Oilfield	3,685.7	3,682.9	(2.8)
Power	8,233.6	8,017.1	(216.5)
Reseller	1,264.1	1,267.6	3.5
Total Saskatchewan Sales	**21,111.4**	**21,078.9**	**(32.5)**

Table 3.6 shows that the variance between load forecasts and normalized loads has been, except for the Power Class, within acceptable limits for most years. However, the forecasts have consistently been greater than the actual consumption, on a normalized basis. We also note that the variance has generally shown a decline since 2005, indicating an improvement in the forecasts, again, except for the Power Class. SaskPower has recognized the inconsistencies in this class and has instituted the additional step of tempering the forecasts provided by customers in this class, primarily the Potash sector, by recognizing its own internal economic forecasts and modifying the customer's forecasts accordingly.

In response to consultant First Round IR # 136, SaskPower provided the variances between the load forecast and actual results from 2005 to 2012, on an actual basis as well as on a weather normalized basis, as summarized below:

Table 3.6 - Actual Energy Requirement vs Load Forecast with Normalization (2005-2012)

Year	Power	Oilfield	Comm	Res	Farm	Resell	Corp Use	Total Sales	Losses	Total Energy
2012 (in GWh)										
Actual	7,447.7	3,178.1	3,534.9	2,939.6	1,152.8	1,254.9	114.3	19,622.1	2,138.2	21,760.3
Forecast	8,083.4	3,296.5	3,500.5	2,986.8	1,312.8	1,274.0	110.0	20,564.1	1,923.5	22,487.6
Variance	635.7	118.4	(34.3)	47.2	160.1	19.1	(4.2)	942.0	(214.7)	727.3
% Var	7.9%	3.6%	(1.0)%	1.6%	12.2%	1.5%	(3.8)%	4.6%	(11.2)%	3.2%
2011 (in GWh)										
Actual	7,318.7	2,905.1	3,435.0	2,951.3	1,302.6	1,252.2	108.8	19,273.6	1,911.5	21,185.1
Forecast	8,006.3	3,008.0	3,466.2	2,899.4	1,275.4	1,269.1	113.7	20,038.1	1,800.8	21,838.9
Variance	687.7	102.9	31.2	(51.9)	(27.2)	16.9	4.9	764.5	(110.7)	653.9
% Var	8.6%	3.4%	0.9%	(1.8)%	(2.1)%	1.3%	4.3%	3.8%	(6.2)%	3.0%
2010 (in GWh)										
Actual	6,926.7	2,874.7	3,391.7	2,865.8	1,316.5	1,261.7	107.2	18,744.2	1,906.1	20,650.3
Forecast	7,381.1	2,805.4	3,476.8	2,884.8	1,301.9	1,265.3	110.9	19,226.2	1,755.8	20,982.0
Variance	454.4	(69.3)	85.1	18.9	(14.5)	3.6	3.8	482.0	(150.3)	331.7
% Var	6.2%	(2.5)%	2.5%	0.7%	(1.1)%	0.3%	3.4%	2.5%	(8.6)%	1.6%
2009 (in GWh)										
Actual	6,138.7	2,742.5	3,380.2	2,837.9	1,330.6	1,264.1	106.7	17,800.8	1,855.3	19,656.1
Forecast	6,995.1	2,755.0	3,281.5	2,799.0	1,256.4	1,288.0	115.3	18,490.3	1,811.6	20,301.9
Variance	856.4	12.5	(98.8)	(38.9)	(74.2)	23.8	8.6	689.5	(43.7)	645.8
% Var	12.2%	0.5%	(3.0)%	(1.4)%	(5.9)%	1.9%	7.5%	3.7%	(2.4)%	3.2%
2008 (in GWh)										
Actual	6,552.0	2,705.0	3,265.8	2,700.9	1,298.6	1,265.7	108.8	17,896.8	1,869.7	19,766.5
Forecast	7,244.3	2,668.5	3,309.9	2,764.0	1,320.2	1,346.5	119.4	18,772.8	1,831.8	20,604.6
Variance	692.3	(36.5)	44.1	63.2	21.6	80.7	10.6	876.0	(37.9)	838.1
% Var	9.6%	(1.4)%	1.3%	2.3%	1.6%	6.0%	8.9%	4.7%	(2.1)%	4.1%
2007 (in GWh)										
Actual	6,854.9	2,541.4	3,249.8	2,627.4	1,321.7	1,277.8	108.6	17,981.6	1,782.5	19,764.1
Forecast	6,861.5	2,502.0	3,272.2	2,556.4	1,329.1	1,335.4	109.6	17,966.1	1,831.8	19,797.9
Variance	6.6	(39.4)	22.4	(70.9)	7.4	57.5	1.0	(15.5)	49.3	33.8
% Var	0.1%	(1.6)%	0.7%	(2.8)%	0.6%	4.3%	0.9%	(0.1)%	2.7%	0.2%
2006 (in GWh)										
Actual	6,662.4	2,399.3	3,232.4	2,534.0	1,268.5	1,289.6	109.0	17,495.2	1,793.5	19,288.7
Forecast	6,834.8	2,366.2	3,211.4	2,553.6	1,347.5	1,274.3	114.5	17,702.4	1,795.1	19,497.5
Variance	172.4	(33.1)	(21.0)	19.6	79.0	(15.3)	5.5	207.2	1.6	208.8
% Var	2.5%	(1.4)%	(0.7)%	0.8%	5.9%	(1.2)%	4.8%	1.2%	0.1%	1.1%
2005 (in GWh)										
Actual	6,552.0	2,263.9	3,214.8	2,522.8	1,343.4	1,271.9	103.6	17,272.4	1,684.0	18,956.4
Forecast	6,632.6	2,241.5	3,169.2	2,508.9	1,345.7	1,263.4	114.3	17,275.6	1,804.7	19,080.3
Variance	80.6	(22.4)	(45.6)	(13.9)	2.3	(8.5)	10.7	3.2	120.7	123.9
% Var	1.2%	(1.0)%	(1.4)%	(0.6)%	0.2%	(0.7)%	9.4%	0.0%	6.7%	0.7%

The following table shows the impacts of weather normalization on energy requirements.

Table 3.7 - Annual Actual Load vs Normalized Load (2005-2012)

Year	Actual Load (GWh)	Normalized Load (GWh)	Variance (GWh)	Variance (%)
2005	18,912.1	18,956.4	44.3	0.2%
2006	19,308.7	19,288.7	(20.0)	(0.1)%
2007	19,826.7	19,764.1	(62.6)	(0.3)%
2008	19,837.3	19,766.5	(70.8)	(0.4)%
2009	19,748.2	19,656.1	(92.1)	(0.5)%
2010	20,623.4	20,650.3	26.9	0.1%
2011	21,257.3	21,185.1	(72.2)	(0.3)%
2012	21,748.4	21,760.3	11.9	0.1%

With respect to the forecasts for the highest potential demand the system will likely be required to supply (Peak Load), we note that SaskPower forecasts hourly interval coincident peak load factors based on internal load research for all customer classes other than Power and Oilfield Customers. Forecasts for these 2 classes use a five-year historic average if historic data is available. If not, coincident factors are used from similar customers, or the most recent history may also be used. SaskPower forecasts peak demands assuming sustained cold weather (coldest year) during December prior to the holiday season. Table 3.8 illustrates the differences between potential peaks estimates and actual peaks experienced form 2007 to 2013, as well as available generating capacity.

Table 3.8 - 2007-2016 Generating Capacity and Peak Estimates vs Actual Peaks

Year	Capacity MW	Est Peak MW	Actual Peak MW	Difference MW	Difference %	Peak as a % of Capacity
2007	3,668	3,125	2,969	(156)	(5.0)%	80.9%
2008	3,641	3,227	3,194	(33)	(1.0)%	87.7%
2009	3,840	3,214	3,231	17	0.5%	84.1%
2010	3,982	3,372	3,162	(210)	(6.2)%	79.4%
2011	4,094	3,460	3,195	(265)	(7.7)%	78.0%
2012	4,104	3,591	3,314	(277)	(7.7)%	80.8%
2013	4,312	3,558	*3,543	(15)	(0.4)%	82.2%
2014	4,314	3,686				85.4%
2015	4,552	3,818				83.9%
2016	4,749	3,945				83.1%

*Application shows 2013 peak as 3,379 MW. 3,543 MW peak occurred on December 6, 2013.

The following Table depicts the year over year growth in installed capacity and actual peak loads. In general, since 2008, increases in installed generation capacity have matched the peak load increases on average.

Table 3.9 - Capacity and Peak Year over Year Changes (2007-2016)

Year	Capacity MW	Year Over Year Change	Actual Peak MW	Year Over Year Change
2007	3,668	-	2,969	-
2008	3,641	(0.7)%	3,194	7.6%
2009	3,840	5.5%	3,231	1.2%
2010	3,982	3.7%	3,162	(2.1)%
2011	4,094	2.8%	3,195	1.0%
2012	4,104	0.2%	3,314	3.7%
2013	4,312	5.1%	3,543	6.9%
2014*	4,314	0.1%	3,686	4.0%
2015*	4,552	5.5%	3,818	3.6%
2016*	4,749	4.3%	3,945	3.3%
2007 to 2013 average % increase in capacity = 3.0% and in actual peak = 3.2% Capacity from BP , peak loads from 2013 Q1 Load Forecast * 2014-2016 forecasts				

Because of the inherent uncertainty in forecasting loads, SaskPower developed its high and low scenarios in addition to the most likely forecast, to reflect economic and weather deviations from the most likely case for the planning horizon. The model used employs percentage error by customer class for each year of previous forecasts and assumes that normal distribution occurs and is independent from forecast errors of other years and use a 90% confidence interval. These scenario thus developed contain a 90% probability that energy and peak requirements will fall between the bounds created by the High and Low forecasts. Included in Appendix 1 is a Table detailing year or year variance in the Saskatchewan Sales Volume Load Forecast by class 2012-2016.[3]

[3] Appendix 1 Table A1.1

The impacts for 2013, 2014, 2015 and 2016 and 2023 (last year in the planning period) of the energy and peak forecasts is shown below:

Table 3.10 - Energy and Peak Forecasts (Low, High and Likely)

Year	Low Energy GWh	Likely Energy GWh	High Energy GWh	Likely-High Range	Low Peak MW	Likely Peak MW	High Peak MW	Likely-High Range
2013	21,165	22,125	22,336	211	3,404	3,558	3,592	34
2014	21,888	23,124	24,401	1,277	3,488	3,686	3,889	203
2015	22,042	24,092	26,100	2,008	3,493	3,818	4,136	318
2016	22,517	25,176	27,756	2,580	3,529	3,945	4,350	405
2023	23,699	28,731	33,721	4,990	3,659	4,436	5,207	771

SaskPower stated that its probabilistic planning system reliability analysis that determines necessary generation year capacity based on every hour incorporates a 13% allowance. Wind generation and import power cannot be considered in supply planning as contributing toward system peak loads. There is a probability that the likely system forecast energy and/or peaks will be exceeded, as there is the possibility that they will not be met. Planning for peak supply must consider the high scenario as a possibility. The risks of not doing so are not prudent, in our opinion. As an example, using the high scenario for peak load of 4,350 MW and a 13% allowance in 2016 indicates a required capacity of 4,916 MW (some of which is wind and import power) while the projected installed capacity is 4,749 MW. Using the 2016 most likely peak of 3,945 MW and a 13% allowance yields a required capacity of 4,458 MW. In our view the generation capacity as planned is necessary and prudent for the term of this application.

We are of the view that, based on the historic energy and peak statistics, combined with the forecasts based on individual class needs and underpinned by current and periodic reviews of economic outlooks, the energy and peak forecasts contained in the updated last quarter Load Forecast Report are reasonable at this time. Economic and other circumstances will of course change throughout the next 3 years and beyond, and the weather will continue to vary, perhaps considerably. However, given all the unknowns inherent in any forecasts we are of the view that this forecast constitutes a reasonable basis to project future generation and related system infrastructure needs.

The Mid-Application update confirms those circumstances as the Power class load is expected to decline, offset by an increase in the residential and commercial loads. However, as further discussed in Section 7.0 there are other matters that SaskPower may consider in the budgeting and implementation of its Capital Program.

4.0 System Operations and Resource Use Strategy

4.1 System Description

SaskPower serves a geographic area of approximately 652,000 square kilometers (km).r and operates and maintains approximately 151,000 km of power lines throughout Saskatchewan. Its transmission assets include 12,298 km of power lines and 51 high voltage switching stations located across the province. SaskPower's transmission system also has interconnections with systems in Manitoba, Alberta, and North Dakota for a total transmission capacity of 793 MW (328 MW for exporting and 465 MW for importing). SaskPower's distribution assets include 138,959 km of power lines, 185 low voltage substations and about 156,000 pole and pad-mounted transformers in Saskatchewan. In 2012 SaskPower reported employing more than 2,800 employees, resulting in over 3,200 full-time equivalent (FTE) positions

SaskPower manages more than $6 billion in assets to generate and supply electricity to its customers. SaskPower services more than 500,000 accounts. Several customers have multiple accounts due to their business structure while farm infrastructures result in multiple meters.

SaskPower operates three coal-fired power stations, seven hydroelectric stations, six natural gas stations, and two wind facilities. These generate a combined 3,451 megawatts (MW) of electricity. SaskPower also purchases power (total of 851 MW) from independent power producers (IPPs), including the North Battleford Energy Centre, Red Lily Wind Power Facility, SunBridge Wind Power Facility, Prince Albert Pulp Inc., Spy Hill Generating Station, Meridian Cogeneration Station, Cory Cogeneration Station, and NRGreen Heat Recovery Facilities in Kerrobert, Loreburn, Estlin, and Alameda. SaskPower's total available generation capacity is 4,302 MW.

4.2 System Generation Capacity and Purchased Power

The following table shows the total generation capacity owned or contracted by SaskPower by fuel source in 2011 and 2013.

Table 4.1 - Total Generation Capacity for 2011 & 2013

	2011 MW	2011 %	2013 MW	2013 %
Coal	1,686	41.2%	1,624	37.8%
Hydroelectric	853	20.8%	853	19.8%
Natural Gas	813	19.9%	813	18.9%
Wind	161	3.9%	161	3.7%
Total Owned	**3,513**	**85.8%**	**3,451**	**80.2%**
Total Contracted (PPAs)	**581**	**14.2%**	**851**	**19.8%**
Total Available Capacity	**4,094**	**100.0%**	**4,302**	**100.0%**

4.3 System Dispatch Rules

SaskPower operates its various fuel sourced generation facilities to achieve optimal costs, within its physical and contractual constraints, and is dependent on energy and demand increases. Operation protocols for the generation fleet are influenced by market changes and new units being put in service.

SaskPower prioritizes its dispatching of its various fuel source options based on incremental costs of production by dispatching least cost fuel sources first and highest cost units last. The objective is to optimize its fleet generation and costs which considers factors and criteria including PPA terms and conditions; planned maintenance down times; meeting NERC system security and reliability standards; start-up costs; ramp rates; minimum run-up times; minimum down times; load following quick start; spinning reserve requirements; voltage support; and system line losses.

Accordingly SaskPower typically dispatches hydro initially, then wind, followed by coal-based generation units. Hydro is utilized based on water availability and coal generation is base loaded. Additional load is then supplied by dispatching alternate fuel resources available that have higher incremental costs relative to hydro and coal such as natural gas and natural gas cogeneration, as well as purchased power and imports, as necessary. Dispatching the various fuel sources appropriately is critical to ensuring that power is supplied to SaskPower's customers every minute of every day, at optimum cost.

Optimizing costs recognizes SaskPower's physical and contractual constraint, energy and demand growth, market prices, and new generation units being put into service. SaskPower has contractual take-or-pay obligation related to Meridian, Corey and NBEC.

The first hierarchy for SaskPower owned generation facilities are Hydro and Coal. Under median Hydro plants can produce up to 3,645 GWh/year while record generation of 4,641 was set in 2011. Coal installed capacity is 11,700 GWh/year. If required to meet additional load, based on economic considerations, Off-Peak imports (0-1,550 GWh/year), additional Meridian and Cory generation (0-1,800 GWh/year) and On-Peak imports (0-700 GWh/year) are used, based on availability and economics.

Consistent with past practice, while economics generally dictate the order of fuel source dispatch, system security and reliability as well as existing PPA obligations will override economics. SaskPower's ability to choose the most economical fuel source is limited by the nature of electricity, as it cannot be stored and needs to be consumed the moment it is created.

The following table illustrates SaskPower's actual owned and purchased annual volumes for 2012 and those forecasted from 2013 to 2016.

Table 4.2 - Generation and Purchased Power Volume

	Actual	Forecast			
(in GWh)	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense					
Gas	4,968	6,235	7,163	8,114	9,167
Coal	11,446	11,173	11,610	11,693	11,462
Wind	655	650	674	671	736
Hydro	4,240	4,447	3,645	3,644	3,607
Imports	656	496	156	316	464
Other*	164	215	262	364	581
Gross Volumes Supplied	**22,129**	**23,216**	**23,510**	**24,802**	**26,017**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					
* Other includes Biomass and Heat Recovery generation					

The following table shows the actual fuel costs by fuel type for 2012 and those forecasted from 2013 to 2016.

Table 4.3 - Annual Fuel Costs

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense					
Gas	$213.8	$230.7	$255.2	$319.1	$351.9
Coal	221.8	233.6	264.9	270.9	280.8
Wind	9.6	9.9	10.3	10.4	14.1
Hydro	19.1	21.0	18.0	18.7	19.3
Imports	31.2	25.9	8.9	18.6	26.6
Other (includes Biomass & Heat Recovery generation)	17.8	26.2	30.1	40.7	69.3
Total Fuel and Purchased Power Expense	**$513.3**	**$547.3**	**$587.4**	**$678.4**	**$762.0**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

It should be recognized that operating considerations, natural gas price volatility, hydraulic flows, weather and other factors dictate the annual mix of fuel types and these obviously affect the annual F&PP estimated and actual costs, as well as the unit fuel costs, as shown on the following table.

Table 4.4 - 2012 to 2016 Fuel Costs per Delivered MWh

	Actual	Forecast			
(in $/MWh)	2012	2013	2014	2015	2016
Fuel Expense					
Gas	$43.05	$36.97	$35.63	$39.33	$38.39
Coal	19.38	20.91	22.82	23.17	24.50
Wind	84.57	84.77	84.43	87.39	77.47
Hydro	4.50	4.72	4.94	5.13	5.35
Imports	47.46	52.21	57.05	58.86	57.33
Other	108.71	122.96	100.00	82.69	70.05
Weighted Average Fuel Price	**$23.20**	**$23.57**	**$24.99**	**$27.35**	**$29.29**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

The following table illustrates the current total capacity available by fuel type.

Table 4.5 - Fuel Source Mix (by Percentage & in MW)

Fuel Type	SPC Owned	IPP PPA	Total Net MW	Percent of Total
Coal	1,624	0	1,624	37.8%
Natural Gas	813	784	1,597	37.1%
Hydro	853	0	853	19.8%
Wind	161	37	198	4.6%
EPP	0	30	30	0.7%
Total Generation	**3,451**	**851**	**4,302**	**100.0%**

Hydro Generation

The seven hydro facilities operated by SaskPower have a generation capacity of 853 MW. An additional 50 MW of capacity is expected to be added in 2017 through a partnership with the Black Lake First Nation on the Tazi Twe hydroelectric project, which will supply much needed energy to northern Saskatchewan. Hydro currently accounts for 19.8% of SaskPower's total generation capacity.

Hydro is a low cost generation source with stable pricing, but significant potential fluctuation in availability, dependent on river flows which are difficult to predict. SaskPower pays a fee to rent water from the Saskatchewan Watershed Authority at a fixed price. SaskPower uses median hydro levels from the past 30 years as a basis for forecasting hydro availability for 2013. Hydro's cost-effectiveness and its unpredictability make it a significant factor with respect to fuel expense volatility.

Coal Generation

SaskPower's existing three coal fired facilities have a generation capacity of 1,624 MW. The Integrated Carbon Capture and Storage (ICCS) project at Boundary Dam 3, is a more environmentally effective method of coal generation, but will reduce capacity by 29 MW in 2014 (from 139 MW to 110 MW). This and the retirements of Boundary Dam unit 1 in 2013 and unit 2 in 2015 (both retirements have been advanced by one year) will result in a further 152 MW reduction in coal generation capacity by 2016. Coal currently accounts for 37.8% of SaskPower's total generation capacity.

Coal is SaskPower's largest generation source and its prices have generally been less volatile because they were based on long-term coal supply contracts. However, coal prices are now expected to increase significantly in 2014 as a result of a new long-term coal contract. Other coal supply contracts are due to expire and be renewed in 2015, 2018 and 2024 bringing the potential for additional price increases. These increases are largely due to more difficult mining conditions, the need for additional equipment and higher operating costs to deliver coal. Regardless of the price increase, coal is still a low-cost option for SaskPower.

The long-term viability of coal as a generation source is now the issue. New federal regulations effective July 1, 2015 will significantly impact SaskPower's coal generation ability. Any coal generation units that do not meet the 420 tonnes of CO2 per GWh standard will have to be retired or refurbished in accordance with the following:

- For units commissioned prior to 1975 (Boundary Dam 4 & 5), end-of-life is reached at the earliest of: a) December 31 of the 50th service year or b) December 31, 2019.
- For units commissioned from 1975 to 1985 inclusive (Boundary Dam 6, Polar River 1 & 2), end-of-life is reached at the earliest of: a) the 50th service year or b) December 31, 2029.
- For all other units (Shand), end-of-life is reached on December 31 of the 50th service year.

A decision affecting the future of Boundary Dam 4 & 5 will need to be made by 2016 or 2017 and will be impacted by the results of the ICCS project at Boundary Dam 3, the first plant affected by the new CO2 federal regulations.

Natural Gas

SaskPower's existing six natural gas facilities have a generation capacity of 813 MW. An additional 205 MW of capacity will be added to its system in 2015 through the Queen Elizabeth Power Station expansion project. SaskPower also has an additional 784 MW of natural gas generation capacity through current long-term power purchase agreements (PPA's) with independent power producers (IPP's), which includes the North Battleford Energy Centre (NBEC) that began operations in June 2013. The 20 year PPA with NBEC has a generation capacity of 260 MW. Natural gas currently accounts for 37.1% of SaskPower's total generation capacity, which is expected to increase in the near future along with SaskPower's exposure to it.

SaskPower is expecting to consume 60.5 million gigajoules (GJs) of natural gas in 2014, 69.5 million GJs in 2015, and 77.8 million GJs in 2016. Natural gas is purchased on the spot market and prices are subject to significant volatility. SaskPower manages this price volatility through long-term physical and financial hedges by locking in the price of up to 50% of its anticipated natural gas consumption. SaskPower's hedging program mitigates the impact of an increase or decrease in the price of natural gas by approximately half of what it would be if no hedging program was in place resulting in greater price stability. As well long-term physical hedging provides some supply security, while hedging less than its entire natural gas requirements allows SaskPower to take advantage of natural gas price decreases.

Wind Generation

SaskPower's existing two wind facilities have a generation capacity of 161 MW and an additional 37 MW of wind generation capacity is available through two current long-term PPA's. An additional 177 MW of wind capacity is expected to be added in 2016 through a long-term PPA with Algonquin Power on the Chaplin Wind Energy Project. Wind currently accounts for 4.6% of SaskPower's total generation capacity.

Energy produced by SaskPower owned wind facilities has no associated marginal cost, while PPA supplied wind cost is fairly stable. However, wind generation is dependent on wind conditions. While wind turbines have a relatively high capacity factor of over 40%, wind power generation is intermittent. As such, wind generation is unplanned and must be backed up by an alternative generation source that SaskPower can control.

Environmentally Preferred Power (EPP)

Environmentally Preferred Power (EPP) currently provides 30 MW of generation capacity through PPA's with small IPP's. EPP includes electricity obtained from heat recovery facilities, small wind generation, flare gas, geothermal and demand response programs. An additional 92 MW of EPP capacity is forecasted by 2016. EPP currently accounts for less than 1.0% of SaskPower's total generation capacity.

Imports

Interconnections at the Manitoba, Alberta and North Dakota borders allow SaskPower the opportunity to import electricity to meet higher internal demand or to take advantage of prices that are lower than the marginal cost of its own generation. Under normal conditions, the import capability is up to 250 MW from Manitoba, 75 MW from Alberta and 140 MW from North Dakota. SaskPower is forecasting a decreased reliance on imports over the next three years, which are based on expected market prices. SaskPower's forecast includes an agreement with Manitoba Hydro to provide 25 MW of import capacity on an annual basis from 2015 to 2022.

Demand Side Management Initiatives

Demand Side Management (DSM) is a portfolio of programs, projects and initiatives focused on customer based energy efficiency, load management and conservation. Through the SaskPower DSM portfolio of energy efficiency, load management, renewables and conservation programs, customers are able to make informed decisions about what they can do to reduce electrical consumption and thereby reduce their electricity bills. This can help customers offset the impact of rate increases as well as help SaskPower to protect the environment (i.e. fewer emissions) and put less strain on its system, particularly during peak times.

By working closely with customers to reduce and adjust electricity use, overall demand for power can decrease. Lower demand results in a lower economic requirement for financing additional infrastructure. As shown in Table 4.7, SaskPower has accumulated savings of 56 MW at the end of 2012. As shown in Table 4.8, SaskPower is expected to have accumulated savings of 100 MW by 2017. In addition, Demand Response initiatives targeting industrial customers are expected to provide 85 MW of capacity value.

Table 4.6 - Accumulated Savings from 2007 to 2012

MW	2007	2008	2009	2010	2011	2012
Accumulated Savings	8	16	23	29	38	56

Table 4.7 - Accumulated Savings Targets for 2013 to 2017

MW	2013	2014	2015	2016	2017
Accumulated Savings	63	72	81	91	100

SaskPower has a multi-faceted portfolio of programs. The current portfolio includes incentive based programs, education programs and demand response. More specifically, the Residential and Commercial programs focus on lighting, plug load, appliances and education. The Industrial programs help facilities identify energy waste and provide technical or business resources to help with energy management plans. The Renewable programs promote the use of environmentally preferred technology to generate power. Specific program information is detailed in Operations, Maintenance and Administration Section 6.

4.4 Far North Resources Supply Plan

The Far North Resources Plan, The 20 Year Supply Plan and the revised 40 Year Outlook are not expected to be completed until March 2014. SaskPower has confirmed that once those plans have received SaskPower's Board approval, copies will be provided to the Saskatchewan Rate Review Panel.

4.5 40 Year Resource Supply Outlook

On January 15, 2012 SaskPower updated its 40 Year Power Supply Outlook. The outlook, developed in 2011 provides a high level strategic view of issues and uncertainties facing the Corporation. The plan analyzes the emerging issues and growth of the electricity environment within the context of Saskatchewan and considers six pathways for the future. All aspects, including costs and risks of each pathway, are reviewed. The decisions SaskPower makes now will impact them as much as 40 to 60 years in the future.

Electricity demand is expected to more than double in the next 40 years at an average annual growth rate of about 1.3%. This growth is expected to be the highest during the first 10 years (2011-2021) with an average annual growth rate of 2.9% and 1.1% to 1.2% for the last 30 years. Each pathway considers renewable resources supply as well as gas generation (which is considered to be the most significant financial risk to SaskPower) to meet the expected demand. The different pathways address meeting the baseload requirements as follows:

1. Diversified portfolio including carbon capture and sequestration (CCS) retrofits and smaller modular reactors if:
   a. Both CCS technology and smaller modular reactors are proven and cost competitive.
   b. There is public and political support for both coal and nuclear.
   c. The liability risk for CCS is resolved.
2. CCS retrofits with gas fill-in, if:
   a. There are positive results from the Boundary Dam project and other large-scale demonstrations combined with technological advances that show CCS economic and commercial viability as well as technical feasibility.
   b. There is public and political support for coal.
   c. The liability risk for CCS is resolved.
3. Smaller modular reactors with gas fill-in, if:
   a. Smaller modular reactor technology is proven and cost competitive.
   b. CCS technology is not a viable commercial alternative.
   c. Climate change policy supports low emission options.
   d. Stakeholders accept smaller module reactors as a safe and reliable alternative.
4. Natural gas as the default baseload if:
   a. Natural gas prices and long term price expectations are maintained at recent low levels and shale gas development continues to add to natural gas reserves.
   b. There is little progress in implementing a framework in North America to price carbon or the approach adopted results in relatively low carbon prices that constrain the development of other resource alternatives.
   c. Renewable capacity is competitively priced and natural gas-fired generation additions can firm up intermittent energy.
   d. The costs and risks of smaller modular reactors and CCS are not competitive or accepted by the public.
   e. There is uncertainty regarding future market conditions in which low capital cost gas-fired generation additions are viewed as low risk, given that they don't represent a major commitment of capital and their operating performance is well known.
5. Strengthened renewable including a long term hydro import contract if:
   a. Climate change policy supports low emission options.
   b. CCS technology and smaller modular reactors are not proven commercially or not cost competitive.
6. Black Swan scenario (i.e. fuel cells, etc.) if:
   a. New technologies are introduced that provide reliable and low or zero emission power at a competitive price.
   b. Climate change policy supports low emission options.

Major factors considered in these analysed include associated costs, emissions and risks. Additional considerations are the acceptance from stakeholders and the public, and determination of operational practicalities. While a specific pathway is not recommended, the plan concludes that:

1. Increasingly stringent government regulations and policies will be implemented to limit environmental impacts, largely due to growing public concerns. Such regulations and policies will have the most influence on the value of SaskPower's current assets as well as establishing its future asset paths.
2. Enabling multiple pathways will allow SaskPower the flexibility and opportunity to respond in a cost effective manner to future outcomes associated with key factors such as natural gas prices, environmental regulations and technological advances.
3. Regardless of the pathway(s) chosen, SaskPower's ability to influence the public, stakeholders, First Nations, regulators and decision makers will affect its ability to build and deliver assets.

In addition to examining the six pathways, the 40 Year Power Supply Outlook examines the following topics:

- Fuel price uncertainty as a risk;
- Engaging influential stakeholders, regulators and public representatives;
- Protecting the strategic value of coal resources / investments, with exit points;
- Nuclear power, with exit points;
- Hydroelectric generation, with exit points;
- Deliberate hedged co-development strategy;
- Appropriate private sector participation, market structure and administrative entity mix;
- Reliance on green sources such as wind, solar, biomass and associated premium; and
- Transmission development strategy.

4.6 Observations

Every electric utility in Canada has unique operational circumstances related to generation, transmission and distribution systems, as well as customer density and geographic location. SaskPower relies heavily on coal and natural gas generation (over 75% of its total generating capacity), as its hydraulic generating availability is limited. It has a customer density of 3 customers per circuit kilometre, lowest amongst all Canadian utilities that average 12 customers per circuit kilometre. All of the coal and hydraulic generating sites as well as some natural gas plants are located considerable distances from major load centers requiring significant transmission infrastructure to deliver the energy to the major load centres. The recent much more stringent environmental regulations relating to emissions resulted in significant costs as SaskPower investigates the viability of implementing new technology to meet these regulations. This is necessary so that it can continue to evaluate the use Saskatchewan’s considerable coal reserves as a major, relatively low-cost generating fuel. The only viable short-term alternative to coal generation is the use of natural gas.

SaskPower, for various reasons, a good portion of which were beyond its control, did not have an aggressive and pro-active maintenance program for its generation, transmission and distribution infrastructure in the past, resulting in a system that is saddled with aged infrastructure that is near and even beyond its expected life.

Saskatchewan’s economy is amongst the most robust in Canada and the resulting growth in the economy and population is imposing additional demands for electricity. System stability and reliability must be maintained to meet international standards and to continue to provide reliable and safe service to the customers. This is SaskPower’s reality and imposes significant future challenges.

NorthPoint, responsible for the daily dispatch of generation units, as well as electricity trading and natural gas procurement, deals with all of the existing operational requirements on a 24/7 basis throughout the year. It must cope with weather variability, unplanned generation outages and loads, and must consider

PPA arrangements in its continuous attempts to meet the required load. It dispatches its generation units on an economic basis (least expensive first on, most expensive last on) within these constraints. We consider that the economic dispatch criteria has been consistently met and results in the most economic generation possible for the vast majority of the time.

SaskPower recognizes its challenges in respect of future meeting supply options and in 2011 developed a 40 year supply plan that evaluates these potential options. The plan is reviewed periodically and was last reviewed in 2012 with a further review planned for 2014. We consider the plan to be extensive and incorporate flexibility and consider potential contingency plans, as new technology emerges, potential for self-generation and demands for electric supply change.

The Mid Application update confirms that the Boundary Dam Unit 3 ICCS project operational date has been delayed from the original January 1, 2014 date to May 1, 2014 with full operation expected July 1, 2014. As a result, lower available coal generation is forecasted for 2014. With the increase in natural gas price forecast, SaskPower is expecting a larger reliance on imports, which are forecasted to increase by 496 GWhs and $19.5 million from the initial submission. The table below illustrates the new forecasted volumes by fuel source for 2014. Volume forecasts for2015 & 2016 were not changed and remain as filed[4] in the original application.

Table 4.8 – Mid-Application Update Net F&PP Volumes

	2014 Forecast		
(in GWhs)	**Initial Submission (Jul 31/13)**	**Mid-Application Update (Jan 31/14)**	**Variance**
Fuel Expense			
Gas	7,163	7,003	(160)
Coal	11,610	11,224	(386)
Wind	674	702	28
Hydro	3,645	3,556	(89)
Imports	156	652	496
Other	262	248	(14)
Gross Volumes Supplied	**23,510**	**23,385**	**(125)**

[4] As noted in Table 4.2 of this report

5.0 The 2014, 2015, 2016 Years Application Revenues

5.1 Revenue Forecasts

A key principle underlying any rate application is that a utility's rates should provide a reasonable opportunity of recovering prudently incurred costs of providing electrical services to all its customers as well as being able to earn an appropriate return on equity (ROE). SaskPower submits that the requested rate increases for 2014 to 2016 provide an appropriate ROE when considering the ability of its customers to absorb increases. The revenue from the rate increase is required to cover an increase in expenses caused primarily by higher capital related expenditures and anticipated rising fuel and purchased power costs.

While SaskPower's long-term ROE target is 8.5%, the requested rate increase is only expected to generate a ROE of 1.3% in 2014, 2.0% in 2015 and 1.9% in 2016. This will result in operating income of $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016 (total of $107.2 million), which includes the additional revenues generated by the requested rate increase of $103.2 million in 2014, $209.6 million in 2015 and $328.7 million in 2016 (total of $641.5 million)[5]. SaskPower's view is that a below-target ROE is reasonable, given that its strong financial position allows it to accept the short-term financial risk and protect its customers from otherwise large rate increases. The mid-application update forecasts operating income of $66.0 million in 2014 and an ROE of 2.9%. The improved forecast results are due to a $4.4 million improvement in revenue and a $34.7 million reduction in expense.

SaskPower last changed its rates on January 1, 2013 when a system-wide average increase of 5.0% was implemented (a 4.9% rate increase for all customer classes except the Power Contract Rate class which was increased by 6.1%). SaskPower is now requesting a system-average rate increase of 5.5% effective January 1, 2014, 5.0% effective January 1, 2015 and 5.0% effective January 1, 2016.

The following table summarizes the consolidated actual revenues for 2012 and those forecasted from 2013 to 2016:

Table 5.1 - SaskPower Consolidated Revenues for 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Saskatchewan Sales	$1,687.2	$1,867.7	$1,876.6	$1,944.8	$2,014.9
Revenue Lift Due to Rate Increases			103.2	209.6	328.7
Total Saskatchewan Sales	1,687.2	1,867.7	1,979.8	2,154.4	2,343.6
SaskPower Exports	49.1	68.9	27.5	34.9	38.9
Net Sales from Trading	14.4	8.5	7.2	7.5	7.9
Other Revenue	104.9	95.6	129.6	149.3	133.7
Total Revenue	**$1,855.6**	**$2,040.7**	**$2,144.1**	**$2,346.1**	**$2,524.1**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP; February Mid-Application update forecast Total Revenue for 2014 at $2,148.5 an increase of $4.4 million					

5.2 Domestic Sales

Domestic Sales represent the sale of electricity to all customer classes within the province. Saskatchewan sales are impacted by general economic conditions, number of customers, weather and electricity rates. Domestic sales are expected to grow from $1.87 billion in 2013 to $1.98 billion in 2014, $2.15 billion in 2015 and $2.34 billion in 2016 including the revenue generated from the rate changes proposed in this application. This growth in revenue will be driven by both the rate increases and the anticipated 11.8%

[5] IR 4 First Round

increase in load over the 2014 to 2016 period. The following table shows actual Saskatchewan sales for 2012 and those forecasted from 2013 to 2016.[6]

Table 5.2 - Saskatchewan Sales for 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Residential	$402.1	$445.6	$430.2	$436.8	$443.6
Farm	130.7	154.6	152.6	152.9	151.8
Commercial	365.6	387.5	382.2	384.5	389.3
Oilfields	262.7	307.7	320.6	341.7	345.7
Power Customers	449.5	491.4	510.0	547.7	603.0
Reseller	76.6	80.9	81.0	81.2	81.5
Sales Before Rate Increase	**$1,687.2**	**$1,867.7**	**$1,876.6**	**$1,944.8**	**$2,014.9**
Revenue Lift Due to Rate Increases			103.2	209.6	328.7
Total Saskatchewan Sales	**$1,687.2**	**$1,867.7**	**$1,979.8**	**$2,154.4**	**$2,343.6**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

As noted in Table 3.5, Saskatchewan sales volume (load forecast) anticipates a 32.5 GWh decline in total load relative to the original application because of an increase in Residential and Commercial loads more than offset by a decrease in Power, Farm and Oilfield class loads.

5.3 Export Revenue

Export revenue represents the sale of SaskPower's surplus generation to other provinces in Canada as well as to the United States. The bulk of SaskPower's exports are made to Alberta and to the Midwest Independent Transmission System Operator markets. Export pricing is not subject to the rate review process but is determined by market conditions in other jurisdictions. Export sales volumes are dependent on the availability of surplus SaskPower generation, market price conditions in other jurisdictions and transmission availability.[7]

SaskPower experienced strong export sales in 2013. This was primarily due to generation shortages in Alberta as well as maintenance on the BC/Alberta tie line that impacted the amount of electricity Alberta could import from British Columbia. Consequently, export revenues are forecast to reach $68.9 million in 2013 and then decrease to near average sales levels of $27.5 million in 2014, $34.9 million in 2015 and $38.9 million in 2016 as is shown in the following table.

Table 5.3 - SaskPower Export Revenues from 2012 to 2016

	Actual	Forecast			
	2012	**2013**	**2014**	**2015**	**2016**
SaskPower Export Revenues (in $ millions)	$49.1	$68.9	$27.5	$34.9	$38.9
SaskPower Export Volumes (in GWhs)	460.1	741.9	486.3	581.9	599.0
SaskPower Exports (in $/MWh)	$106.7	$92.9	$56.5	$60.0	$64.9
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

The Mid-Application update is now forecasting Export Revenue to be $24.1 million in 2014, $3.4 million less than the application forecast.

While SaskPower ensures that domestic needs are always met first, the sale of power into neighbouring jurisdictions allows temporary surplus generating capacity to be marketed at a price in excess of cost to

[6] Appendix 1 Tables A1.2-3 provide year over year revenue variances by class of customer 2011-2016
[7] IR 14B First Round

result in a profit. The ability to access the export market has enhanced SaskPower's financial performance and has assisted in reducing the level of rate increases which otherwise would have flowed through to domestic customers. Export revenues can be extremely volatile, as related transactions have numerous economic drivers and are influenced by a number of external and internal factors. The major external factors are the supply imbalances and price of electricity in SaskPower's external markets.

International market rules of reciprocity require SaskPower and neighbouring utilities to have an Open Access Transmission Tariff (OATT) which is primarily designed to retain access to external markets. Access to external markets is necessary for export sales opportunities, the continued ability to take advantage of any available economic imports, as well as for supply backup should SaskPower experience temporary shortfalls in generation. Total transmission interconnection capacity is limited to 793 MW gross (328 MW for exporting and 465 MW for importing), at Saskatchewan's eastern, southern and western borders.

SaskPower's OATT revenue from external customers has increased annually since it was first implemented in 2006. NorthPoint is a major user of OATT in Saskatchewan for moving exports outside the province. NorthPoint costs are netted against OATT revenues generated from export sales to produce the actual or forecasted net income from exports.

5.4 Electricity Trading

Electricity trading activities include the purchase and resale of electricity and other electricity-related commodities in regions outside Saskatchewan. These trading activities include real time short-term and long-term physical and financial trades in the North American market. These trading activities are carried out by NorthPoint and are intended to deliver positive gross margins to SaskPower's bottom line while operating within an acceptable level of risk.

Trading revenue is the revenue from electricity and natural gas bought in external markets and sold in other external markets. Net sales from trading represents the net contribution from trading activities which is calculated as revenues less trading costs. Net sales from trading are forecast to decrease from $8.5 million in 2013 to $7.2 million in 2014, and then remain relatively stable at $7.5 million in 2015 and $7.9 million in 2016 as shown in the following table.

Table 5.4 - Net Sales from Trading for 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Net Sales From Trading	**$14.4**	**$8.5**	**$7.2**	**$7.5**	**$7.9**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

The main reason for the expected decrease in net sales from trading is due to lower price forecasts arising from the completion of the Montana-Alberta Tie-Line (MATL) transmission project in late 2013. MATL is a 300 MW, 230 KV transmission line allowing the movement of electricity between Alberta and Montana. This transmission line is expected to negatively impact the ability of SaskPower to take advantage of market opportunities in Alberta using its firm transmission position in British Columbia.[8] Total trading revenue in 2013 is not expected to meet budget expectations as noted in the above table.[9]

NorthPoint owns firm transmission rights on the BC transmission system through the open access transmission tariff which rights allowed SaskPower to enter into a contract with PowerEx that had them deliver 50 MW per each on-peak hour to the BC-Alberta border at a contracted price. NorthPoint incurs

[8] IR 14B First Round
[9] IR 15 First Round

annual costs for this access. Through-out 2013 there were unanticipated outages on the BC-Alberta intertie and those unplanned outages caused the Alberta index price to rise. The increase in the index price provided an opportunity for SaskPower to capture more export revenue than anticipated, but reduced the opportunities to generate gross trading revenue. SaskPower has confirmed there was a reduction in trading revenue from October 31st to December 31st of $0.8 million, as the sales of electricity were not enough to cover the electricity purchase price plus the fixed transmission costs. While the trading net income for 2013 has not been finalized, it is expected to be closer to $3 million as opposed to the $8.5 million illustrated in the above table.[10]

5.5 Other Revenue

Other revenue includes various non-electricity products and services, such as gas and electrical inspection permit fees, meter reading fees, late payment charges, custom work charges and other non-energy related charges.

SaskPower is forecasting an increase in Other Revenue for 2014 related to the expected initial CO_2 sales from the Boundary Dam Integrated Carbon Capture and Storage project.[11] In addition, customer connect revenues are forecast to remain at historically elevated levels due to the province's continued growth. SaskPower also expects to earn $4.3 million in new revenues from the lease of the new Shand Clean Coal Test Facility to Hitachi in 2014. Overall, other revenues are expected to increase from $95.6 million in 2013 to $129.6 million in 2014, $149.3 million in 2015 and $133.7 million in 2016 as shown in the following table. Miscellaneous revenue is further detailed in first round interrogatories.[12]

Table 5.5 - Other Revenue from 2012 to 2016

	Actual	**Forecast**			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Gas and Electrical Inspections	$17.2	$17.9	$18.7	$18.7	$18.7
Customer Connects	50.8	39.2	50.0	50.0	50.0
CO_2 Sales	0.0	0.0	17.5	20.3	20.7
CO_2 Test Facility Revenue	0.0	0.0	4.3	17.8	10.0
MRM Equity Investment	0.0	1.6	1.1	4.5	1.9
Miscellaneous Revenue	36.9	36.9	38.0	38.0	32.4
Total Other Revenue	**$104.9**	**$95.6**	**$129.6**	**$149.3**	**$133.7**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP; 2014 CO2 sales now forecast to be $10.5 million, Total Other Revenue $122.6 million **Mid-Application update**					

[10] IR 4 & 5 Second Round
[11] IR 18 First Round
[12] IR 17 First Round

Table 5.6 - Miscellaneous Revenue for 2012 to 2016

(in $ millions)	2012	2013	2014	2015	2016
Late Payment Charges	3,422	3,869	3,947	4,026	4,106
Joint Use Charge	4,235	4,148	4,273	4,401	4,533
Connect Fees	1,062	1,215	1,239	1,264	1,289
Rental Income	251	384	385	385	385
Meter Reading	3,269	3,000	3,504	2,000	-
Custom Work	3,498	6,743	3,308	3,374	3,441
WPPI Grant	5,407	5,284	5,101	5,101	1,258
Trans Tariff Revenue - Internal *	21	-	-	-	-
Trans Tariff Revenue - External *	1,053	1,903	230	230	100
Dividend Income *	-	-	-	-	-
Other Revenue	2,124	3,598	5,788	6,029	6,134
Environmental Revenue	-	-	-	-	-
Green Power Premium	465	201	483	493	502
Flyash	7,041	6,581	9,823	10,786	10,666
Total Miscellaneous Revenue	**$31,848**	**$36,926**	**$38,081**	**$38,089**	**$32,414**
Note: The Miscellaneous Revenue total as stated on page 26 of the Rate Application included $5 million relating to the MRM equity investment. The correct amount for 2012 has been restated above.					

5.6 Observations

2013 Saskatchewan Electricity Sales are expected to be near or slightly over the budget of $1.874 billion while revenues from exports are expected to be significantly higher than the $27.4 million budget. The increase is mainly driven by increase in unit prices (per MWh) in Alberta caused by market supply outages. While final results are not yet confirmed, it is expected that Export revenue will be near $60 million in 2013. Conversely Net Trading Revenue is expected to be significantly lower than budget as there were fewer opportunities to move electricity into Alberta from the west attributable to the BC-Alberta tie-line maintenance program. Other revenue is expected to be slightly greater than the $95.8 million budget.

Overall total revenue is expected to be around $35 million greater than the 2013 budget.

As noted in Table 5.1 SaskPower Consolidated Revenues forecasts for 2014 are $2,144.1 million, 2015 are $2,346.1 million and 2016 are $2,524.1 million, all inclusive of the requested rate changes proposed to occur each year.

Saskatchewan sales actual results and forecasts for each customer class are shown on Table 5.2. 2013 Saskatchewan sales from the residential class were budgeted at $445.6 million. Preliminary year end data suggests that residential sales will generate closer to $452 million which is approximately $7 million higher than forecast whereas the farm class revenue is expected to be near budget. Overall sales revenue in 2013 is expected to exceed the forecast by approximately $10 million.

For 2014, 2015, and 2016 Saskatchewan sales revenue is to grow modestly because of expected volume increase (prior to the rate change proposed), by 0.5% in 2014, and slightly less than 4% in 2015 and 2016. Part of the reason for the modest increase in 2014 relative to 2013, is 2013 data is presented on an actual basis, while forecasts for each of the next 3 years are based on weather normalization data. The percentage change in 2015 and 2016 parallels the load forecast detailed in Section 3.0.

The Power Customer Class energy requirement accounts for over 40% of the total domestic need. As such, it is extremely important, not just for the power customers but all customers, that the forecast accurately reflects each class's future requirements. Without appropriate load forecasts a number of domino-like events could create operational, demand, service and reliability issues. In the past, SaskPower relied solely on information provided by their large customers. As discussed in Section 3.0, the variances between forecast and actual results were much greater for this class than for others. SaskPower now conducts its own internal assessment of the Power Customers forecasts and in this application several power customers' forecasts have been reduced. It is extremely important for all parties that the exchange of future plans by large customers be as accurate as reasonably possible given the current global economic circumstances.

As recognized most recently for the potash and fertilizer sectors world economics has played a significant role in determining future load demands for the Power Customer Class. As a result, SaskPower must be very sensitive to the current economic environment and future trends.

As export and trading revenue rely on the future marketplace, SaskPower capitalizes where possible to generate positive revenue but this will be dependent on the demand and price of markets external to Saskatchewan. With the outage that occurred in Alberta in early 2013, market forces pushed prices earlier in the year upward but returned to a more normal $49/MWh in the last quarter of 2013. This was because of the first commercial line (MATL) between Montana and Alberta commencing operation in September of that year. In Energy Infrastructure 2014 Outlook, Bloomberg and CIBC World Markets expect flat Alberta power prices in 2014 and 2015 ranging from $55-60/MWh.

On the basis of the foregoing, export and trading revenue opportunity into the Alberta market is not expected to be as robust as seen in the recent past.

Other Revenue, includes revenue from gas and electricity inspections, customer connects, and miscellaneous revenue (external transmission revenue, now includes CO_2 sales and CO_2 test facility revenue). As noted in Table 5.5, CO_2 and test facility revenue is forecasted to generate \$21.8 million in 2014, \$38.1 million in 2015 and \$30.7 million in 2016. Customer connect revenue is forecasted to be \$50 million in each year of the application.

With the operational start date delay associated with Boundary Dam unit 3, the Mid-Application update 2014 CO_2 sales are now forecast to be reduced by \$7 million for a revised Other Revenue total of \$122.6 million.

We consider that SaskPower's forecasts properly reflect past results and include the new revenue sources available to SaskPower. Weather normalization of the load forecast is an appropriate consideration in any utility forecast. On an actual basis, however it is expected that Saskatchewan Sales Revenue will be at or modestly greater than the weather normalized forecast. Forecasting the utilities revenue stream is difficult in a single year application, as are projecting weather trends, world and local economic conditions and a number of other circumstances that can and likely will impact customer demands. With a three year application these considerations are magnified.

6.0 Expenditure Forecasts

6.1 Operating Expenditure Summary

SaskPower organizes its operating costs into the following expense categories:

- Net Fuel & Purchased Power;
- Operating, Maintenance and Administration;
- Depreciation;
- Finance Charges;
- Taxes; and
- Other.

The table below illustrates SaskPower's actual operating costs by major category of expense for 2012 and forecasts for 2013 to 2016 as per the original applications, which are further detailed in subsequent sub-sections. SaskPower is now forecasting operating net income of $66.9 million in 2014, $57.9 million in 2015 and $46.4 million in 2016.

Table 6.1 - SaskPower Consolidated Expenses for 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Expense					
Fuel and Purchased Power	$513.3	$547.3	$587.4	$678.4	$762.0
Operating, Maintenance & Admin	619.7	617.7	647.7	672.4	697.8
Depreciation	315.8	366.5	425.3	460.8	490.1
Finance Charges	203.0	272.3	383.3	416.3	452.5
Taxes	47.7	52.9	57.0	61.3	63.9
Other	26.7	9.0	16.5	17.0	17.4
Total Expense	**$1,726.2**	**$1,865.7**	**$2,117.2**	**$2,306.2**	**$2,483.7**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP					

The Mid-Application update total expense forecast for 2014 has decreased by $34.7 million as summarized in the following table:

Table 6.2 - Application Update SaskPower Expenses

	2014 Forecast		
(in $ millions)	**Initial Submission (Jul 31/13)**	**Mid-Application Update (Jan 31/14)**	**Variance**
Expense			
Fuel and Purchased Power	$587.4	$622.0	$34.6
Operating, Maintenance & Admin	647.7	647.7	0.0
Depreciation	425.3	399.3	(26.0)
Finance Charges	383.3	340.1	(43.2)
Taxes	57.0	57.0	0.0
Other	16.5	16.5	0.0
Total Expense	**$2,117.2**	**$2,082.5**	**$(34.7)**

6.2.1 Fuel & Purchase Power (F&PP)

SaskPower operates a portfolio of coal, hydro, natural gas, natural gas co-generation, wind, import power, environmentally preferred power, and other generation sources (collectively the generation mix) in order to meet electrical demand for domestic customers. The costs for all sources of generation fuels and available energy used to meet total electrical requirements comprise the Fuel & Purchased Power (F&PP) expense category.

F&PP includes fuel costs for SaskPower owned generation and for purchased power obtained through power purchase agreements (PPAs). For 2013 these PPAs include costs for natural gas facilities at the Meridian and Cory Cogeneration Stations, Spy Hill Generation Station and the North Battleford Energy Centre which came on stream in June 2013. Also included are costs for purchased power from various Environmentally Preferred Power projects with Independent Power Producers (IPPs) located in Saskatchewan. These include the SunBridge and Red Lily Wind Power Facilities, Prince Albert Pulp Inc. (Biomass), NRGreen Heat Recovery facilities at Kerrobert, Estlin, Loreburn and Alameda, and various other smaller IPPs solicited by SaskPower pursuant to the Green Options Partners Program (GOPP).

Import Power is the cost of electricity purchased from suppliers that generate power outside Saskatchewan, such as Manitoba Hydro, utilities in Alberta and Basin Electric in North Dakota.

When there is excess energy available and it can be sold into export markets for a profit, SaskPower, through NorthPoint, takes advantage of such opportunities, and sells energy to export customers. The profits made on those export sale opportunities help to reduce the upward pressure on rates for domestic customers.

The external factors that can significantly impact the F&PP costs year over year include the availability and price of fuel sources, most notably hydro, natural gas and imports. Growth in demand and variations in weather coupled with the availability of lower cost coal and hydro sources, particularly, impact the amount of natural gas generation and imports required to meet the demand in any given year.

As discussed in Section 4.3, SaskPower manages its fleet of generation and supply options very carefully in an effort to optimize annual F&PP costs and the long-term life of the assets. While SaskPower focuses on the economic dispatch of generating units, many other factors are also considered. These include requirements to meet North American Electricity Reliability Council (NERC) standards, start-up costs, ramp rates, minimum use and down times, spinning and other reserves, voltage support, and transmission line losses. SaskPower's 2010 external review of the fuel procurement and optimization processes did not recommend nor propose any changes to the existing procurement or optimization processes.

Coal and hydro generation costs have remained relatively constant over the last decade. As previously discussed coal prices are expected to increase significantly in 2014 and into the future as a result of a new long-term coal supply contracts. Despite the increase in price, coal generation is still a low-cost option for SaskPower's vintage assets. All available coal generation is fully utilized and hydro generation, although variable is also fully utilized to the extent water flows allow in any year.

Thus, additional annual required load must be generated by higher cost fuels, unless additional coal or hydro plants are put into service which would then have a much higher embedded cost than the current heritage assets carry. In addition to its own facilities, SaskPower submits that PPA purchase decisions are also made in economic order: that is, least cost unit is generally put into operation first and shut down last.

2014, 2015, 2016 F&PP Outlook

The fuel and purchased power expense from 2013 to 2014 is forecast to increase by $40 million or 7.0%. This is due to an expected increase in input prices ($12 million price variance), an increase in demand ($7 million volume variance) and changes to the contribution of each generation source as a percentage of overall generation ($21 million mix variance). As a result of these factors total F&PP expenses are forecast to be $587.4 million in 2014, $678.4 million in 2015 and $762.0 million in 2016. Net F&PP costs from 2013 to 2016 would increase by $215 million as a result of an unfavourable price ($53 million), volume ($67 million) and mix variance ($94 million).

Increases to natural gas and coal prices are expected to create the unfavourable price variance of $53 million from 2013 to 2016. The cost of gas generation is expected to increase from $36.97/MWh in 2013 to $38.39/MWh in 2016, an increase of 3.8%. This increase in gas price is based on the forward market price and a change in the mix of gas units used to generate electricity. The cost of coal generation is also expected to increase from $20.91/MWh in 2013 to $24.50/MWh in 2016, an increase of 17.2%. This increase in coal price is the result of the previously noted increases from the new coal contract.

Expected demand is forecasted to increase by $67 million from 2013 to 2016. SaskPower is forecasting Saskatchewan generation requirements to increase from 23,216 GWhs in 2013 to 26,017 GWhs in 2016, or 12.1%.

The forecasted unfavourable generation mix variance of $94 million from 2013 to 2016 is largely due to an increased reliance on natural gas. During this period, it is anticipated that most of the additional demand beyond 2013 will be satisfied by natural gas generation, either through SaskPower generation or through PPAs. Furthermore, hydro is expected to decrease from its above-average level of 19.1% of total generation in 2013 to 13.9% of total generation in 2016. This decline will largely be replaced by natural gas generation, which is expected to increase from 26.9% of total generation in 2013 to 35.2% of total generation in 2016. While the volume of coal generation should increase slightly from 2013 to 2016, as a percentage of total generation it will decrease from 48.1% in 2013 to 44.1% in 2016.

The table shown below illustrates the 2010 to 2012 actual F&PP costs as well as those forecast for 2013 to 2016, as per the original application.

Table 6.3 – F&PP Costs for 2010 to 2016

	Actual			Forecast			
(in $ millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense							
Gas	$184	$196	$213.8	$230.7	$255.2	$319.1	$351.9
Coal	212	219	221.8	233.6	264.9	270.9	280.8
Wind	2	9	9.6	9.9	10.3	10.4	14.1
Hydro	16	20	19.1	21.0	18.0	18.7	19.3
Imports	20	24	31.2	25.9	8.9	18.6	26.6
Other	12	17	17.8	26.2	30.1	40.7	69.3
Total F&PP Expense	**$446**	**$485**	**$513.3**	**$547.3**	**$587.4**	**$678.4**	**$762.0**
2010-2012 figures based on actuals 2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP							

The Mid-Application update F&PP forecast for 2014 is summarized in the following table:

Table 6.4 - Application Update Net F&PP Expense

	2014 Forecast		
(in $ millions)	**Initial Submission (Jul 31/13)**	**Mid-Application Update (Jan 31/14)**	**Variance**
Fuel Expense			
Gas	$255.2	$292.0	$36.8
Coal	264.9	242.0	(22.9)
Wind	10.3	11.2	0.9
Hydro	18.0	17.5	(0.5)
Imports	8.9	28.4	19.5
Other	30.1	30.9	0.8
Total F&PP Expense	**$587.4**	**$622.0**	**$34.6**

Natural Gas Costs

SaskPower's exposure to natural gas will increase in the near future. SaskPower expects gas generation to significantly increase from 26.9% in 2013 to 35.2% of total generation in 2016. The two most significant factors for this expectation are that additional demand beyond the 2013 levels will be satisfied by natural gas generation, as well as an expected decline in hydro generation, which will also largely be replaced by natural gas generation.

The unit cost of gas generation is expected to increase from $36.97/MWh in 2013 to $38.39/MWh in 2016, an increase of 3.8%. This increase in price is based on the forward price of the natural gas market and a change in the mix of gas units used to generate electricity.

The SaskPower Board has approved policies (NorthPoint Risk Management Manual and SaskPower Risk Management Manual) related to natural gas management and hedging strategies which are adhered to by staff. Both Risk Management Manuals were revised in June 2012 to reflect changes in the internal calculation of credit exposure and new requirements in the U.S. ISOs credit policies prompted by FERC Order 741. These revisions do not impact the procurement and pricing of Natural Gas. No other procedural changes have been implemented since 2012.

In April 2012 SaskPower implemented a Board approved policy change allowing NorthPoint, on behalf of SaskPower, to extend its hedging program from 5 years out to a 10 year horizon. Consequently, SaskPower has hedged volumes in varying amounts until 2022. The hedged volume targets are 50% in the initial year, decreasing by 5% per year, so that the 10 year out (2022) target is 10% of volumes. The following financial and physical hedges have been undertaken based on natural gas consumption forecasts in the current business plan.

Table 6.5 - 2012 to 2022 Financial and Physical Hedges

	2012	2013	2014	2015*
Hedged Volume (GJs)	25,348,000	35,262,650	37,416,150	33,762,500
Hedged Value ($/GJ)	$5.85	$4.17	$4.28	$4.31
Total Hedged Value ($)	**$148,393,068**	**$147,141,537**	**$159,998,443**	**$145,439,269**

	2016*	2017*	2018*	2019*
Hedged Volume (GJs)	31,110,000	30,112,500	25,550,000	23,725,000
Hedged Value ($/GJ)	$4.26	$4.37	$4.72	$5.03
Total Hedged Value ($)	**$132,522,196**	**$131,538,700**	**$120,515,244**	**$119,246,869**

	2020*	2021*	2022*	2023*
Hedged Volume (GJs)	18,300,000	16,425,000	10,037,500	-
Hedged Value ($/GJ)	$5.32	$5.43	$5.56	-
Total Hedged Value ($)	**$97,320,773**	**$89,106,994**	**$55,835,876**	**-**

*Additional hedges may be placed

SaskPower manages the price volatility of natural gas by locking in the price on up to 50% of its anticipated natural gas consumption through long-term physical and financial hedges. In addition to providing price stability, the long-term physical contracts provide some security of supply to meet SaskPower’s gas-fired facility requirements. Hedging less than the full amount of SaskPower's natural gas requirements allows the Corporation to take advantage of falling market prices should that occur. SaskPower is anticipating consuming 60.5 million GJs of natural gas in 2014, 69.5 million GJs in 2015 and 77.8 million GJs in 2016. SaskPower’s hedging program reduces the impact of an increase or a decrease in the price of natural gas by approximately one half relative to the absence of any hedging program.

As Saskatchewan supply continues to decrease, SaskPower and other Saskatchewan end users have become more dependent on Alberta supply. The ability to import gas into Saskatchewan is limited going forward since TransGas has sold out of this service. SaskPower still has some contracted service but is limited to obtaining more based on TransGas’ availability.

As noted in the table below Saskatchewan sourced natural gas supplies have been steadily declining since 2010 whereas gas sourced external to Saskatchewan is steadily increasing.

Table 6.6 - Purchased Gas Inside & Outside Saskatchewan for 2010 to 2016

Year	Gas Purchased Inside Saskatchewan		Gas Purchased Outside Saskatchewan	
	Volume (Million GJs)	Price ($/GJ)	Volume (Million GJs)	Price ($/GJ)
2010	13	$4.12	10	$4.84
2011	9	$3.75	15	$5.23
2012	7	$2.72	25	$4.49
2013	8	$3.17	27	$4.19
2014	8	$3.36	28	$3.81
2015	8	$3.51	35	$3.82
2016	8	$3.63	45	$3.85

Gas purchased in Saskatchewan includes open market gas, which has been favourably priced as a result of declining gas prices. Gas purchased outside of Saskatchewan includes gas purchased as part of the hedging program on a forward basis. As a result of the increased volumes, required and external sourced gas costs have also increased significantly for intra-provincial and inter-provincial transportation and storage costs.[13]

The application update projects fuel costs to increase by a net amount of $34.6 million primarily because of an increase in natural gas costs of $36.8 million (other increases of $1.7 million are expected for wind and other sources), offset by expected decreases in coal expenses of $22.9 million and hydro of $0.5 million. Natural gas expense was forecast based on a forward price of $3.29/GJ (subsequently changed to $3.63/GJJ) at the time the application was filed, while the forward price in the update is $4.08/GJ. In 2014 natural gas units are now expected to generate 7,003 GWh, 160 GWh's less than estimated in the original application. The availability of coal fired generation is now expected to be less than originally forecast, causing a decrease in coal expenses of $22.9 million.

6.2.2 Observations

Other than OM&A, F&PP costs continue to be the largest expense for SaskPower. F&PP costs represent 29.7% of total costs in 2012, 29.3% in 2013 and 27.7% in 2014. By 2015, F&PP costs are expected to exceed OM&A costs, but will still represent a similar percentage of overall total costs as in the past. F&PP costs are expected to account for 29.4% of total costs in 2015 and 30.7% in 2016. Because of the nature and generation mix of SaskPower assets, operational practices maximize the use of low cost generation units first and then use progressively higher cost generation units and purchase power contracts (after minimum take obligations are satisfied) as required to meet load requirements.

F&PP costs reflect SaskPower's total fuel costs, but for the purpose of calculating rate increases and cost allocations to customers, SaskPower continues to use only the Fuel and Purchased Power costs necessary to satisfy the domestic load in Saskatchewan. Expected F&PP revenue associated with providing exports is deducted from the domestic F&PP expense when calculating and allocating F&PP expenses under the current Cost of Service Model. This process ensures that the rate application only considers fuel costs to service the domestic load in Saskatchewan. Net F&PP costs are determined by adjusting the totals for realized natural gas management and inventory optimization activity costs.

The most significant input for gas and co-generation is the commodity cost of natural gas. NorthPoint, on behalf of SaskPower, is responsible to forecast, manage, and secure the physical requirements as well as the price of natural gas for their own facilities and to provide the gas commodity for Cory. Meridian directly purchases its commodity supply needs. Both the market price and volumes can significantly impact the financial forecasts. Our review of the policies and processes confirm that appropriate controls are in place,

[13] SIECA IR 1-31

with proper reporting for approved risk management instruments, and strategies to be employed, and that the approved policy is being followed.

The following tables illustrate the 2010 to 2012 actual and 2013 to 2016 forecast generation mix by fuel type for total cost and total volume.

Table 6.7 - Generation Mix by Fuel Type for 2010 to 2016 Expenses

	Actual			Forecast			
(in $ millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense							
Gas	$184	$196	$213.8	$230.7	$255.2	$319.1	$351.9
Coal	212	219	221.8	233.6	264.9	270.9	280.8
Wind	2	9	9.6	9.9	10.3	10.4	14.1
Hydro	16	20	19.1	21.0	18.0	18.7	19.3
Imports	20	24	31.2	25.9	8.9	18.6	26.6
Other	12	17	17.8	26.2	30.1	40.7	69.3
Total F&PP Expense	**$446**	**$485**	**$513.3**	**$547.3**	**$587.4**	**$678.4**	**$762.0**

2010-2012 figures based on actuals
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP

Table 6.8 - Generation Mix by Fuel Type for 2010 to 2016 Volumes

	Actual			Forecast			
(in GWh)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense							
Gas	3,682	4,032	4,968	6,235	7,163	8,114	9,167
Coal	12,038	11,614	11,446	11,173	11,610	11,693	11,462
Wind	507	682	655	650	674	671	736
Hydro	3,866	4,641	4,240	4,447	3,645	3,644	3,607
Imports	518	502	656	496	156	316	464
Other	148	140	164	215	262	364	581
Gross Volumes Supplied	**20,759**	**21,611**	**22,129**	**23,216**	**23,510**	**24,802**	**26,017**

2010-2012 figures based on actuals
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP

The unit prices for the various fuel types from 2010 to 2016 are shown in the following table.

Table 6.9 – Generation Mix by Fuel Type for 2010 to 2016 Unit Prices

	Actual			Forecast			
(in $/MWh)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense							
Gas	$49.83	$48.53	$43.05	$36.97	$35.63	$39.33	$38.39
Coal	17.63	18.89	19.38	20.91	22.82	23.17	24.50
Wind	76.44	82.72	84.57	84.77	84.43	87.39	77.47
Hydro	4.10	4.30	4.50	4.72	4.94	5.13	5.35
Imports	39.19	48.56	47.46	52.21	57.05	58.86	57.33
Other	77.03	119.60	108.71	122.96	100.00	82.69	70.05
Weighted Average Fuel Price	**$21.46**	**$22.46**	**$23.20**	**$23.57**	**$24.99**	**$27.35**	**$29.29**

2010-2012 figures based on actuals
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP

The foregoing table illustrates that, since 2010, the market driven costs (with hedging impacts) for natural gas have steadily declined and are forecast to be less in 2013 to 2016 than the actual cost in 2012. The cost of coal and hydro show a consistent year over year increase. Wind, Imports and Other categories show a significant degree of variability from year to year.[14]

The fuel cost for gas fired generation owned by IPPs is lower at $30/MWh than SaskPower's gas fired fleet at $50/MWh because two of the major IPP units are fuel efficient cogeneration facilities and two other IPP units are relatively new technology which is more efficient than the older units in SaskPower's fleet. Additionally the fuel cost for IPP wind is higher at $84 than SaskPower's wind because the IPPs' price includes capital recovery and O&M costs whereas SaskPower's price only reflects fuel.

IPP "Other" includes green technologies such as biomass and heat recovery at approximately $98/MWh.[15]

Gas unit costs fluctuate because of commodity pricing, the timing and volume of gas based generation requirements, the impact of transacted hedges, and the impacts of acquiring increasing amounts of firm gas transmission capacity and related services to supply an expanding natural gas generation fleet. Coal and Hydro unit cost increases are based on contractual inflationary mechanisms. Wind and Other unit costs vary due to the weighted change in contracted capacity and contracted price. Import unit costs change based on market prices, timing and volume of imported electrical energy.

From 2006 to 2012, SaskPower's realized hedging transactions resulted in total settlement costs of $183.7 million greater than market for that period. Total natural gas costs in the same period were approximately $1,187.8 million. Thus, during the years 2006-2012 the cost of the hedging program represents approximately 15.5% of total gas costs over the 7 years.[16] In two of the seven years the program reduced costs by a total of about $8.8 million. The largest impact was in 2009 ($75.4 million in added costs) when gas markets were extremely volatile and prices unpredictable. In 2011, the hedging program resulted in a $0.90/GJ increase in the unit cost of gas for approximate 35.55 million GJ.

Natural gas markets and market prices have changed, more so over the last 5 or 6 years because of demand being less on a continental basis than available supply as new sources of gas became economical due to new retrieval techniques. Thus gas prices were near record lows in 2010, 2011, 2012 and 2013.[17] Although gas prices are currently expected to remain in this low cost range from 2014 to 2016, it is our view that gas prices are unlikely to remain at similar levels in the future. We consider that SaskPower should not be discouraged from engaging in hedging programs, especially in light of its ever increasing reliance on natural gas as a generation fuel source over the next number of years. The impact of a $1.00/GJ increase in natural gas costs would decrease net income by about $30 million based on 2013 estimated volumes and grow as volumes required increase. This equates to just less than 2% of the overall revenue requirement, but will be significant given the anticipated increase in future years. Hedging future volumes at defined prices dampens the impact and volatility of rising gas prices. Actual 2012 natural gas costs were $ 4.39/GJ as compared to the 2013 forecast of $ 3.63/GJ. The November 18, 2013 forecast for 2014 is $ 3.60/GJ and $ 39.4/GJ in 2015.[18]

Forecasting hydraulic generation is another major risk to the F&PP expense component. Hydro is forecast to decrease from its above-average level of 19.1% of total generation in 2013 to 13.9% of total generation in 2016. This decline in hydraulic generation capacity will largely be replaced by natural gas generation. The hydraulic flows are forecast to generate 4,457 GWh in 2013, 3,645 GWh in 2014, 3,644GWh in 2015 and 3,607 GWh in 2016. Should future results eclipse median flow conditions then the converse will result and less natural gas generation will be required with a reduced end cost result.[19]

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[14] Appendix 1 Table A1.4-6 shows net F&PP year over year variances in GWh, $, and $/MWh
[15] IR 76 First Round
[16] IR 84 First Round
[17] Appendix 1 Table A1.6 shows year over year variances by fuel type
[18] IR 85 First Round
[19] IR 95 First Round

The median generation calculation reflects the median energy generated with the median flow and current hydro generation capabilities. Hydro generation forecasts for the 2014-2016 periods are based on median hydro flow conditions based on a 30 year historic period. The result of the changed methodology used to forecast hydro flow used in this application is approximately 10% higher than the median forecast calculations used previously.[20]

If hydraulic generating energy production capability is decreased due to actual river flows being less than forecast, the lost capacity will have to be replaced with higher cost generation. The majority, if not all, will be by additional use of natural gas, and may be supplemented by economically available electricity imports.

The net costs for coal generation are forecasted to be $233.6 million in 2013, $264.9 million in 2014, $270.9 million in 2015 and $280.8 million in 2016. Coal is expected to generate 11,173 GWh in 2013, 11,610 GWh in 2014, 11,693 GWh in 2015 and 11,462 GWh in 2016, all within the same range as the actual amount of 11,446 GWh generated in 2012 (which is an increase of about 2.5% from 2012 to 2016). However, coal generation operating costs are expected to increase from $221.8 million in 2012 to $280.8 million in 2016, which is an increase of approximately 26.5%.

SaskPower's Mid-Application update increased Fuel and Purchase Power by $34.6 million from the original rate application forecast due to an unfavourable price variance of $20.8 million and an unfavourable fuel mix variance of $16.9 million, offset by a decrease of $3.1million in reduced consumption of 125 GWh. The unfavourable fuel price variance is primarily due to an expected increase in the forward price for natural gas from the original application of $3.29/GJ to a Mid-Application price of $4.08/GJ, as of January 31, 2014. As noted in the table above the net impact from the increase in natural gas prices is a $36.8 million increase in fuel costs. Coal costs are expected to decrease $22.9 million in 2014 as a result of a forecasted 386 GWh reduction in generation due to an expected reduction in coal unit availability. Because of the increase in natural gas prices and lower forecast coal generation, SaskPower is expecting a larger reliance on imports, which are forecasted to increase by 496 GWhs and $19.5 million (offset by other annual volume reductions) from the initial submission. In 2014 natural gas volumes for SaskPower owned units are estimated to be approximately 60.5 million GJ. Based on the forecasted unit price increase of $0.79/GJ to $4.08/GJ the cost increase would have been $47.8 million for that volume. However although natural gas consumption is expected to be somewhat less, it is primarily because of SaskPower's hedging program that dampens price volatility that the net natural gas expense increase is expected to be $36.8 million

SaskPower uses a capacity factor of over 40% for long-term energy budgeting purposes for the current installed wind power farms. On the other hand, they do use a 20% capacity value for wind facilities for supply planning purposes. Wind is considered an intermittent resource and contributes an average of 15% (20% winter and 10% summer) of net capacity as a capacity credit for generation reliability planning. SaskPower estimates that an additional 177 MW of wind generation will be added in 2016 through Algonquin Power in the Chaplin area as well as several other smaller wind generation farms through the Green Options Partners Programs (GOPP). It is noted that a wind power strategy outlining the future wind development supply plan for SaskPower was completed in 2013 by Sustainable Supply Development.

If the load forecasts and hydraulic conditions that SaskPower has estimated materialize, it is expected that there will be a decreased reliance on imported power over the next three years. SaskPower's forecast includes an agreement with Manitoba Hydro to provide 25 MW of import capacity starting in 2015 and going until 2022. This is an integral part of SaskPower's Far North Supply Strategy.

Based on the current forecast of generation mix and current market predictions, SaskPower's forecasted fuel and purchase expense is considered just and reasonable.

[20] IR 93 First Round

6.3 Operating, Maintenance & Administration (OM&A) Costs

OM&A expenses include all the expenditures required to operate a large electrical utility in a safe, reliable and responsible manner and deliver electricity to customers through the utilities generation, transmission, distribution and customer service fleet. OM&A includes administrative costs such as wages and salaries, office costs, technology and all the support services including contractor and consulting fees. Costs are impacted by many factors including staff levels, changes to wages and benefits, overhead, and all tangible assets that require ongoing maintenance which all are generally influenced by national and international markets and local inflationary factors.

SaskPower's OM&A is expected to decrease from the 2012 actual of $619.7 million to a forecast of $617.7 million in 2013 then increasing to $647.7 million in 2014, $672.4 million in 2015 and $697.8 million in 2016. Relative to 2012, OM&A is expected to increase 12.6% over the next 4 years. Over the 2013 to 2016 period, about $49 million of the $80 million OM&A increase (approximately 60%) is attributable to the Operations Business Area which includes power production, transmission, distribution, asset management other operations like fleet services and administrative staff. These OM&A total costs include Demand Side Management (DSM) costs of $19.2 million in 2012, $15.4 million in 2013, $14.3 million in 2014, $14.6 million in 2015 and $14.9 million in 2016.

6.3.1 Staffing

Labour costs including salaries, wages, premium pay and benefits comprise approximately 50% of all OM&A expenses. Full Time Equivalents (FTEs) are managed to minimize OM&A costs while supporting significant investments in infrastructure that require additional employees for current and proposed large-scale building and maintenance projects. In 2011 a 5 year Workforce Plan was introduced to provide a forward-looking FTE needs assessment and succession strategy for SaskPower. SaskPower confirms it is committed to having an appropriately sized workforce in place, while remaining mindful of the short and long term efficiency objectives.

SaskPower's 5 Year FTE Plan anticipates both the addition of new FTEs in certain areas as well as the reduction of FTEs in other areas. A FTE position is defined as an employee who works 1,800 hours per year and includes permanent, part-time, and temporary employees (but excludes overtime hours). The actual number of FTEs in 2012 was 3,152. The target for 2013 was 3,352 FTEs.

SaskPower is planning a temporary increase of 126 FTEs in 2014 (totaling 3,478) to address staffing vacancies at power plants and the new ICCS Facility; to support improved service on SaskPower's transmission and distribution network; and the repatriation of contract positions with less expensive internal employees. The increase in FTE levels in 2014 are going to be partially mitigated by a decrease of 88 FTEs in 2015 (totaling 3,390) largely due to the implementation of AMI and the retirement of Boundary Dam Units 1 and 2. FTEs are then expected to gradually increase starting with 6 additional FTEs in 2016 (totaling 3,396). All these changes result in a net increase of 44 FTEs from 2013 to 2016. It is noted that the 2016 FTE target was 3,200 in last year's application.

This expense category is influenced by the number of employees as well as wage and benefit changes that primarily flow from negotiated collective bargaining agreements, inflation increases for goods and services purchased, maintenance for new assets put into service, defined benefit pension plan financial returns and a wide range of costs necessary for a utility, including bad debt expenses. SaskPower is currently in the process of negotiating a new collective agreement with the UNIFOR employees' unions, which expired on December 31, 2012. The current IBEW collective agreement will expire on December 31, 2014.[21]

[21] IR 48 First Round

As noted above, SaskPower defines total FTE positions as being, beyond the approximately 2,675 actual full-time employees, a number determined by dividing the anticipated costs for all full-time, part-time and temporary employees by 1,800 hours. Contract FTE positions are accounted for in the External Services category of OM&A costs. Overtime costs are accounted for in Wages and Salaries. The decision was made by the Executive in 2012 to exclude overtime FTE costs from the FTE calculation for the following reasons:

- The intent of measuring FTEs is to track the actual number of employees working at SaskPower at any one time. Overtime FTEs are employees who are already counted as either permanent, part-time or temporary and due to planned or unplanned circumstances are required to work overtime.
- Overtime FTEs are quite often related to storm and outage costs which are uncontrollable in nature. Having this volatility included in the total FTE count does not properly reflect SaskPower's workforce plan.
- SaskPower continues to manage and monitor overtime budgets and limit the amount of overtime authorized to its employees.

The following table illustrates the number of FTE employees by year, customers and customers to FTE employee ratios:[22]

Table 6.10 - SaskPower FTE & Customer Comparison for 2010 to 2016

	Actual			Forecast			
	2010	2011	2012	2013	2014	2015	2016
SaskPower FTEs	3,018	3,000	3,152	3,352	3,478	3,390	3,396
# of Customers	467,835	479,656	486,805	495,031	500,922	509,228	517,172
Customers/SP FTE	155	160	154	148	144	150	152

FTE numbers for 2010 to 2012 are based on year end actual FTE levels and include permanent, part-time, and temporary FTEs (but not overtime hours). For 2013 to 2016, the numbers are based on SaskPower year-end targets and continue to include permanent, part-time and temporary FTEs (but not overtime hours). It is expected that the ratios will improve during the 2013 to 2016 period when compared to the 2010 to 2012 time frame. The following table shows the actual results for 2010 to 2012 together with the 2013 to 2016 proposed FTEs by Business Unit.

[22] IR 41 First Round

Table 6.11 - SaskPower FTEs by Business Unit for 2010 to 2016

	Actual			FTE Plan Target			
Business Unit	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
President's Office	3	3	12	16	16	16	16
Power Production	916	869	806	850	897	869	865
Transmission	-	-	290	299	307	307	310
Distribution	-	-	649	655	663	685	690
Transmission & Distribution	1,145	1,185	-	-	-	-	-
Asset Management	-	-	121	137	144	144	144
Operation's Other	-	-	130	146	169	165	165
Finance	-	-	84	114	114	114	114
Corp & Finance Services	158	134	-	-	-	-	-
Customer Services	436	444	435	413	385	337	337
Resource Planning & NRPT	-	-	63	76	75	75	77
PERA & NRPT	109	89	-	-	-	-	-
Law, Land & Reg Affairs	34	33	122	130	144	144	144
Info Technology & Security	-	-	121	170	192	194	194
Corp Info & Technology	87	99	-	-	-	-	-
Human Resources	-	-	175	187	177	174	174
HR, Safety & Corp Comm	117	123	-	-	-	-	-
Commercial	-	-	120	135	160	135	135
Business Development	0	7	7	7	7	7	7
ICCS	-	-	17	17	28	24	24
Clean Coal	13	14	-	-	-	-	-
Total	**3,018**	**3,000**	**3,152**	**3,352**	**3,478**	**3,390**	**3,396**
Annual Change	**-**	**(18)**	**152**	**200**	**126**	**(88)**	**6**

The following is a summary of the major components of SaskPower's significant reorganization in Quarter 4 of 2012: [23]

- A new business unit now titled "Operations" was formed bringing together the transmission, distribution and power productions units.
- The "Commercial" business unit was formed that combined Service Delivery Renewal, Supply Chain Management and Major Projects.
- Planning, Environment and Regulatory Affairs, NorthPoint and Fuel Supply were combined to form the new Resource Planning unit.
- Gas and Electrical Inspections were transferred from Transmission and Distribution to Legal (formerly called Law, Land and Regulatory Affairs).
- Corporate Communications was moved from Human Resources to Customer Services.[24]

This reorganization was undertaken to create a centralized structure so as to improve communication within the company and eliminate internal "silos" that can be created when there are multiple business units performing complementary functions. The reorganization will also assist in putting additional emphasis and focus on how major projects are delivered and capital is spent. No significant changes are being considered for the years 2014 to 2016.

The year over year change from 2012 to 2013 in the OM&A budgets of Commercial and Business Development were:

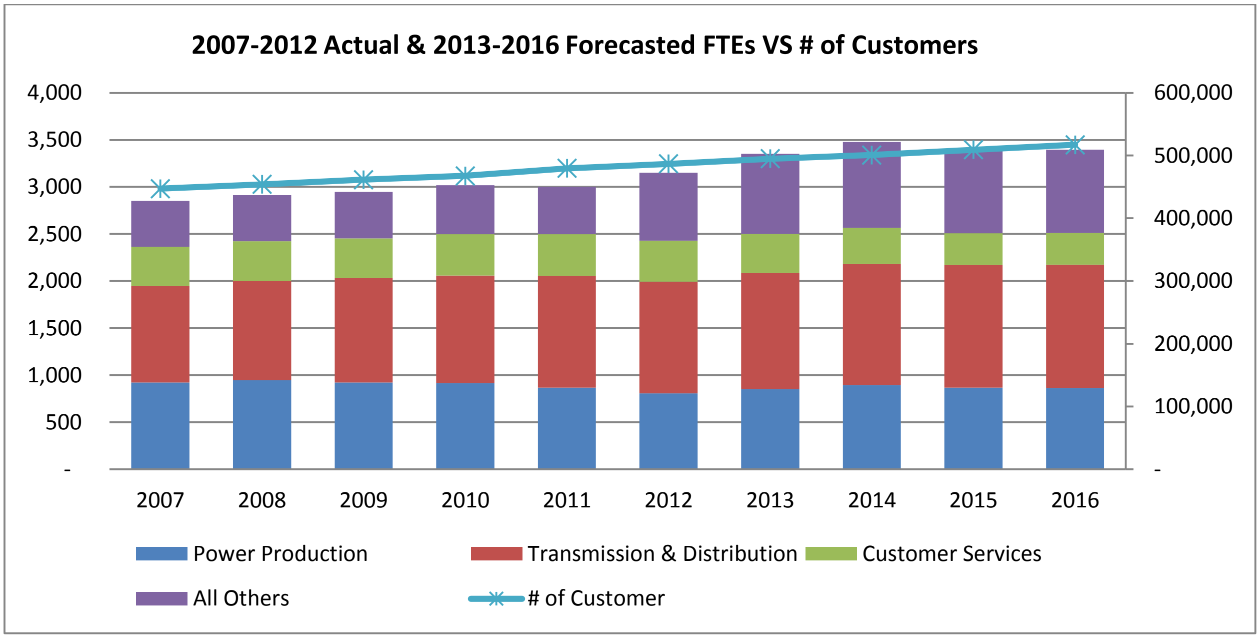
[23] IR 37 First Round
[24] IR 39 First Round

a) Commercial's OM&A budget has increased from $16.3 million in 2012 to $31.9 million in 2013 because, beginning in 2013, all building costs were centralized to Commercial's budget. Prior to 2013, building costs were charged out to each business unit based on the square footage that they each occupied. This change in methodology resulted in Commercial's budget increasing by approximately $15 million in 2013. It is important to note that this was only a reallocation of budget dollars and not an increase in OM&A.

b) Business Development's OM&A budget has dropped from $3.9 million in 2012 to $1.1 million in 2013. The reason for this decline is that most of the work being done within the business unit relates to the Tazi Twe Hydroelectric Project. As a result, wages and salaries are being charged to capital rather than OM&A.[25]

The following graph shows the total number of customers to the number of actual FTEs for 2007 to 2012 and forecasted FTEs for 2013 to 2016. It should be noted that overtime FTEs have not been included in these totals.

Graph 6.1 - SaskPower Total FTEs to Customers Comparison for 2007 to 2016



The following table illustrates OM&A cost per customers (actual) for 2010 to 2012 with the forecasts for 2013 to 2016.[26]

Table 6.12 - OM&A Cost per Customer for 2010 to 2016

	Actual			Forecast			
	2010	2011	2012	2013	2014	2015	2016
OM&A (in $ millions)	$513.2	$579.0	$619.7	$617.7	$647.7	$672.4	$697.8
# of Customers	467,835	479,656	486,805	495,031	500,922	509,228	517,172
OM&A $/Customer	$1,097.0	$1,207.1	$1,273.0	$1,247.8	$1,293.0	$1,320.4	$1,349.3

[25] IR 11B Second Round
[26] IR 40 First Round

6.3.2 OM&A Expenditures by Category

A detailed breakdown of the OM&A cost categories for the period 2012 to 2016 is shown below:[27]

Table 6.13 - OM&A Expense by Cost Category for 2012 to 2016

	Actual	Forecast			
Category (in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Salaries & Wages	252	280	292	295	302
Premium Pay	41	37	38	38	39
Benefits	58	66	67	67	68
Labour Credits & Overhead	(51)	(59)	(53)	(47)	(39)
Subtotal Wages & Salaries	**$300**	**$324**	**$344**	**$353**	**$370**
Materials & Supplies	**$36**	**$26**	**$27**	**$29**	**$30**
External Services	**$207**	**$190**	**$195**	**$204**	**$208**
Other	**$77**	**$78**	**$82**	**$86**	**$90**
Total	**$620**	**$618**	**$648**	**$672**	**$698**

As noted previously, wages and benefit costs are impacted by two specific components. The first is the number of FTE positions in the organization and the second is the employee collective agreements/contracts negotiated plus management salary increases. Market place economics also impact the actuarial valuation of the corporation's pension plan. While the current plan deficit is detailed and accounted for on the financial statements of the corporation, there are benefit and pension expenses which need to be funded as part of the annual revenue requirement.

A portion of OM&A expenses are incurred by business units for the implementation of SaskPower's capital program, which are capitalized and retired over the life expectancy (in years) of the specific asset.

The following table details the actual OM&A expenses capitalized for 2012 and those projected for 2013 to 2016 by labour, overhead and interest.[28]

Table 6.14 - Capitalized Labour, Overhead and Interest for 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Allocated Labour Costs	15.9	13.6	13.9	12.4	10.4
Labour Costs Capitalized	37.2	45.2	38.8	34.7	29.0
Interest Capitalized	29.6	46.0	22.8	21.3	10.6
Total Capitalized	**$82.7**	**$104.8**	**$75.5**	**$68.4**	**$50.0**
2012 figures based on actual, Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 interest capitalized figures based on 2014 BP, 2014-2016 labour figures based on estimates					

The major reason for the significant decrease in interest capitalized between 2013 and 2014 is the finalization of the construction associated with the ICCS project.

Total OM&A is expected to decrease $2.0 million from $619.7 million in 2012 to $617.7 million in 2013. Future OM&A costs are forecast to increase by 4.9% in 2014 to $647.7 million, 3.8% in 2015 to $672.4 million, and 3.8% in 2016 to $697.8 million. Of the OM&A forecasted increase of $80.1 million from 2013 to 2016, $49.1 million relates to increases in the new Operations business unit. Included in Operations is power production, transmission, distribution, asset management and operations other (which is primarily made up of fleet services and administrative staff). The major drivers of the increased costs in the

[27] IR 14A First Round
[28] IR 43 First Round

operations unit is associated with the overhauls planned at Shand, Boundary Dam units 4 & 6 and at Western Plants which account for 53% of the increase. The balance of the increased costs are associated with the planned staff deficiencies at Boundary Dam, Queen Elizabeth plant refurbishment, new clean coal facility and scheduling and dispatch related costs.[29] Further information is provided in Section 7.4.

The last two SaskPower Rate Applications outlined a number of factors that have contributed to rising SaskPower employee labour costs over the past several years. Briefly these factors as outlined in those Applications were:

- Existing assets are getting older – requiring more maintenance hours;
- New assets added to electric system – new maintenance hours added;
- Aging workforce – many at top of pay scale and benefits;
- Apprentice programs to prepare a skilled future workforce – four year programs to reach journeyman status; and
- Labour market forces in western Canada. SaskPower's highly skilled and professionally capable staff is being actively sought in external markets, particularly Alberta. Wage and salary levels need to be competitive to attract and retain employees.

SaskPower submits that these same conditions still exist and while the general economic conditions in Saskatchewan are very positive, they too are driving additional customer attachments and correspondingly more demand for electricity. As a result SaskPower requires additional new generation, transmission and distribution facilities and upgrades to existing facilities requiring an increased effort to provide continued safe and reliable service. However as part of the Business Renewal Initiative, a new thrust in the Asset Management Initiative is expected to result in new cost savings through improved, refocused and reengineered processes while still providing a reliable, safe, secure electrical service.

Currently additional human resource requirements must be justified to the President and decisions in this regard are the President's responsibility. This includes balancing the requirement to add staff for operational, maintenance or support functions with the impact on OM&A budgets in current and future years. Decisions have been made not to fill certain vacancies when employees vacated a position or, in some cases, the position was filled and used to support new initiatives such as the business renewal initiative intended to garner current and future cost efficiencies.

Supporting this initiative, SaskPower advises that in many cases, the increases in staff are required to meet regulatory requirements. Additionally the increase in the amount of physical assets requires additional maintenance, as there is an obligation to serve new customers and to connect them to the system. Other initiatives were identified as being strategic in nature, including apprentice programs, long-term supply planning, ICCS and customer service delivery renewal programs.

The following table illustrates the various components of OM&A actual costs for 2010 to 2012 and the forecast for 2013 to 2016.[30]

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[29] IR 46A First Round
[30] Appendix 1 Table A1.7 illustrates year over year variances in OM&A business unit costs for 2011-2016

Table 6.15 - SaskPower OM&A for 2010 to 2016

	Actual			Forecast			
(in $ millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Power Production	151.8	158.7	168.7	154.6	182.4	183.6	183.7
Transmission & Distribution	118.6	129.6	149.6	135.6	131.6	139.3	146.8
Asset Management	22.3	26.1	28.0	22.6	22.8	24.6	25.3
Operation Other	11.8	19.7	18.3	16.8	20.7	21.6	22.9
Subtotal Operations	$304.5	$334.1	$364.6	$329.6	$357.5	$369.1	$378.7
President/Board	3.2	2.7	3.5	3.4	3.5	3.4	3.6
Finance	16.8	16.2	15.2	16.3	16.7	17.0	17.8
Customer Services	41.8	44.6	45.7	48.2	46.7	43.9	45.8
Resource Planning & NorthPoint	16.1	14.7	14.4	17.6	18.3	20.0	22.6
Law, Land, Regulatory Affairs	12.7	14.0	14.8	17.4	17.0	17.6	18.4
Info Technology & Security	40.9	47.8	56.5	61.5	70.1	79.0	85.3
Human Resources	20.3	22.3	25.6	27.2	27.0	27.7	28.9
Commercial	17.8	15.9	16.3	31.9	35.9	30.4	27.0
Business Development	0.0	12.5	3.9	1.1	1.4	1.5	1.5
CCS Initiatives	0.7	33.3	2.6	10.6	6.3	10.6	11.1
Total Core Costs	$474.8	$558.1	$563.1	$564.8	$600.4	$620.2	$640.7
Demand Side Management	8.8	11.8	19.2	15.4	14.3	14.6	14.9
PPA-OMA	16.8	20.3	22.9	26.2	22.2	26.2	30.5
Other Expense	12.8	(11.2)	14.5	11.3	10.8	11.4	11.7
Total Other Costs	$38.4	$20.9	$56.6	$52.9	$47.3	$52.2	$57.1
Total OMA	**$513.2**	**$579.0**	**$619.7**	**$617.7**	**$647.7**	**$672.4**	**$697.8**
% Increase	**-**	**12.8%**	**7.0%**	**(0.3)%**	**4.9%**	**3.8%**	**3.8%**
2013 figures based on Jul 2013 forecast (Jan-Jul actual, Aug-Dec forecast), 2014-2016 figures based on 2014 BP							

Another cost component of OM&A expense is the credit card program that provides customers with the ability to pay their monthly electricity bills using a credit card. The cost of the program was $45,000 in 2011 and $51,000 in 2012. It is forecasted to be $170,000 in 2013, $180,000 in 2014, $190,000 in 2015 and $200,000 in 2016. However as part of offering convenient services to its customers, SaskPower considers this expense a cost of doing business.

Bad debt expense which is forecasted to be between $ 2.3 and $2.4 million in the years covered by this application is significantly down from the 2009 total of $3.4 million. It is difficult to factually determine if there is a direct correlation between these two issues it is expected there is a financial relationship.

6.3.3 Observations

The actual 2013 OM&A expenses now are expected to be just above $621 million approximately, $3.4 million over the application budget of $ 617.6 million. While the majority of business units expect to be under budget at year-end, the carbon capture and storage initiative is expected to be over budget mainly resulting from the asbestos delay. The recently announced $2 million sponsorship funding for the Saskatchewan Institute of Applied Science and Technology (SIAST) and the Saskatchewan Indian Institute of Technology (SIIT) is also included in the 2013 OM&A expense.

As noted in Table 6.13 OM&A expense forecasts are $648 million for 2014, $672 million for 2015, and $698 million for 2016. This results in net increases of $30 million, $24 million and $26 million for an accumulated increase of $80 million relative to 2013 representing percentage increase of 12.9% or approximately 4.3% annually for each of the three years. Specific percentage increases in OM&A costs are detailed in Table 6.13 for the period of 2010 to 2016.

The Power Production portion of the Operations Division is the main source of the incremental cost increase from the 2013 budget of $154.6 million to the forecast of $182.4 million in 2014. [31] The increase in Power Production costs are expected for the Shand, Boundary Dam unit 4 and 6 overhauls, Western Plants, BD staff deficiency, QE staffing, ICCS chemicals and materials, and BD 3 full year operational expense.[32]

All the other business unit expenses remain relatively constant except for an increase in Information & Technology (as a result of staff repatriation and AMI) and a modest increase in the Commercial Business Unit Expense forecast.

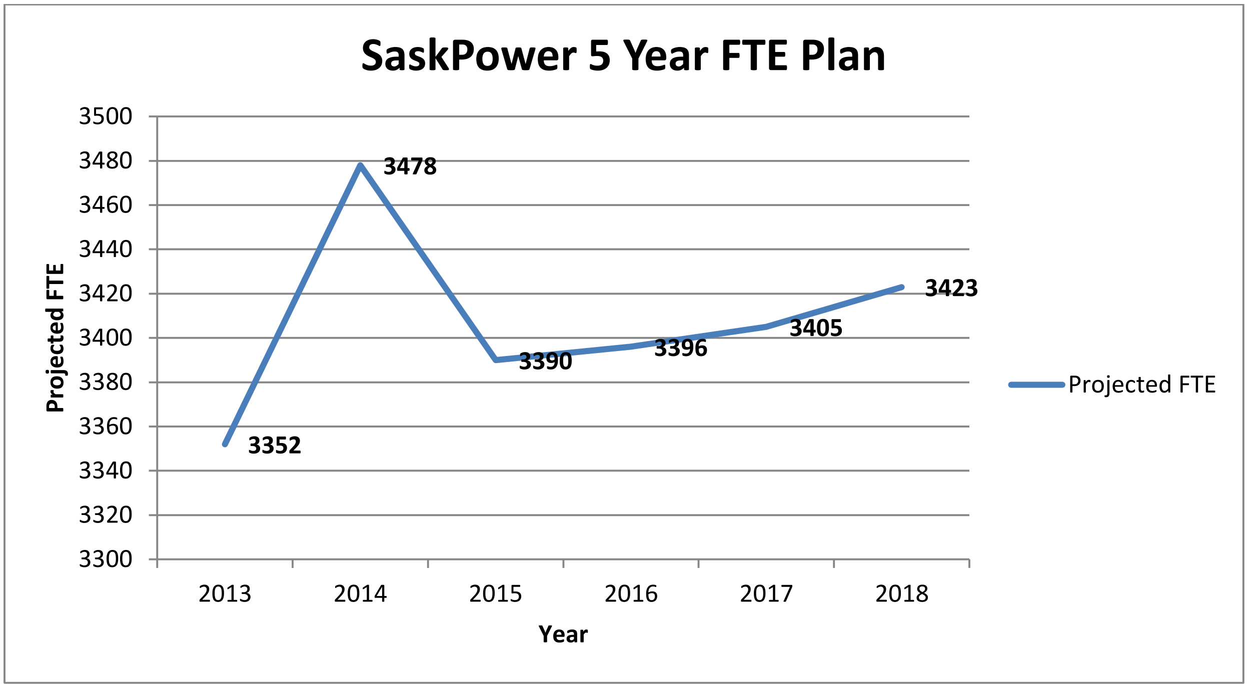
Cost increases forecasted in 2015 include improvements associated with the network communications systems and AMI, Shand Test Facility and Aquistore – ICCS and enterprise security upgrades. Inflation on base expenses and other initiatives are the primary cause of the $24 million forecasted increase.

The $26 million cost increases proposed for 2016 reflect inflationary cost increases and possible new initiatives, as well as for unforeseen expenses. Eliminating the costs associated with power production overhauls and other system improvements as detailed above, the OM&A cost increases relative to other operational needs clearly demonstrate, in our view, that operational costs are being contained. The cost containment is evident in light of the major capital improvement or reinvestments being made to generation, transmission, distribution and operational infrastructure, including AMI, which also increases the need for maintenance. In addition, the increasing costs associated with new staff, salary & wages, benefits, materials and supply and external services, confirms that the Business Renewal and Service Delivery Programs are generating a positive net financial result for SaskPower's base cost structure. Details and observations relative to Business Renewal and Service Delivery Programs are outlined in Section 6.5.

Staffing expenditures are a major driver of OM&A costs. Table 6.11 shows SaskPower five year staffing plan with 2012 actual FTE at 3152, 2013 forecast at 3352, 2014 forecast 3478, 2015 at 3390 and 2016 at 3396. In 2014 staff FTE's are expected to peak at 3,478. 2015 forecasts are for 88 less employees, and 6 additional FTEs are forecasted in 2016.[33] SaskPower provided a detailed explanation for the proposed staff changes over the next 3 years and we find the explanation reasonable, especially considering the major capital expenditures underway and being proposed.[34]

[31] IR 35 First Round
[32] IR 36 First Round
[33] IR 37 First Round
[34] IR 38 First Round

Graph 6.2 – SaskPower 5 Year FTE Plan



Internal allocated and labour costs associated with major capital projects are allocated to those projects as are direct external costs. Those costs are treated as part of the total capital costs and are retired as the asset is depreciated and amortized. SaskPower policy and the methodology respecting capitalization of these costs is commonplace in the Canadian utility industry. As noted in Table 6.14 the allocated and capitalized labour costs for 2014 are forecasted in to total $52.7 million compared to $58.8 million in 2013. These costs are forecasted to decline both in 2015 to $47.1 million and 2016 to $39.4 million. The significant driver for the decrease is the completion of the Boundary Dam ICCS project.

The Power Corporation Superannuation Board retained an independent actuary to conduct an Actuarial Valuation of the Pension Plan for Funding Purposes as at December 31, 2011 and as at December 31, 2012. For the year ending on December 31, 2012, the $290 million of the actuarial losses were recognized directly in other comprehensive income relating to SaskPower`s defined benefit pension plans. The independent report disclosed that the increased deficit was mainly associated with a change in actuarial assumptions offset in part by higher than expected investment income.

We have no further information available on the impact of these valuations on SaskPower`s 2013 financial statements. The defined benefit plan is solely the obligation of the SaskPower. SaskPower is not obligated to fund the Plan but it is obligated to pay benefits under the terms of the Plan as they come due and are expensed accordingly.

Notwithstanding the positive impact of the various cost saving initiatives employed by SaskPower, OM&A cost per customer is increasing for each of the application years 2014 - 2016. The following table summarizes the actual OM&A cost per customer for the years 2010 to 2012 and forecasted for 2013 to 2016.

Table 6.16 - OM&A Cost per Customer for 2010 to 2016

	Actual			Forecast			
	2010	2011	2012	2013	2014	2015	2016
OM&A (in $ millions)	$513.2	$579.0	$619.7	$617.7	$647.7	$672.4	$697.8
# of Customers	467,835	479,656	486,805	495,031	500,922	509,228	517,172
OM&A $/Customer	$1,097.0	$1,207.1	$1,273.0	$1,247.8	$1,293.0	$1,320.4	$1,349.3

As noted in the above table during the four year period of 2013 through 2016, the amount of OM&A expense per customer is increasing from $1,248 to $1,349, an increase of $101 or approximately 8%. During this time period SaskPower is planning to add approximately $5.2 billion to its asset base in the form of capital expenditures and PPA obligations. As SaskPower continues to add new capital assets and refurbish old or aging infrastructure the amount of OM&A dollars required to maintain these assets is expected to also increase.

For example, the I1K transmission line being built from the Island Falls Power Station to Key Lake will improve the reliability of the power being provided to the northern part of the province, but the incremental costs of maintaining the new 300 km line will be significant. Another example is the QE Repowering project where a new gas unit is being constructed and when the project is completed, additional operating costs will occur as soon as the unit comes on line.

SaskPower is projecting approximately 22,141 additional grid customers between 2014 and 2016. SaskPower also forecasts spending an average of $1billion annually over the next three years to increase the capacity and stability of the system, sustaining existing infrastructure and adapting to new technology. While some of these expenditures are driven by growth in demand and related customer attachments, the balance is considered to be necessary to fund the replacement of aging infrastructure in order to maintain and enhance the overall reliability of the grid.

An OM&A cost per customer is a criterion that historically has been used to measure and indicate cost trends. Other criteria often used include cost of staff per MW generated, customers per kilometer, a number of reliability metrics, customer per employee ratio, and total OM&A cost per dollars of revenue generated. We in the past have used costs per customers to illustrate financial trends. As with any measurement or benchmark used, unique circumstances can generate or impact final results.

As an example, the major factor for increased OM&A costs per customer is that the major portion of the growth is being driven by the expected Power Class customer sector demands. During the next 10 years, the Power Class is forecast to account for nearly 80% of SaskPower's anticipated growth. However, the number of Power Class customers is forecast to remain relatively unchanged. Therefore, the increase in SaskPower's operating costs does not reflect a corresponding percentage increase in customers. While this may be seen as a representing unit costs that do not fully or accurately portray the circumstances, any other criteria will likely have other perceived short comings. Any measure should be used not in absolute terms, but rather as an indicator of historic and anticipated future trends. An increasing trend under any measurement must recognize the particular set of circumstances giving rise to changes in the trend lines.

We are encouraged by the attention given by SaskPower, by the entire staff, to operate more efficiently and effective in an attempt to mitigate the financial impact of the significant capital initiatives and corresponding annual operating expenditures. We also note the progress made on both the Business Renewal and the Service Delivery Programs which has avoided costs that otherwise would have been required. While there have been and continue to be the anticipated costs associated with such initiatives, it is evident from the financial forecast outlooks included in this application that significant cost savings are being generated. As SaskPower stated at the outset, these initiatives would not eliminate future cost increases but would rather help to contain the rate impacts.

As noted earlier, of the total $641.5 million increase to be generated by this application, OM&A is forecasted to be $80.1 million for the period 2013-2016. Of this, $49.1 million is associated with Operations Business

Unit for overhauls at various generating sites. The $31 million balance is for other OM&A costs over the 3 year period. If SaskPower were to actually meet those forecasts at the end of 2016, SaskPower would have, in our view, met the effectiveness and cost saving challenges recommended by the Panel in 2010.

Therefore, on balance, we consider the OM&A costs, as proposed by SaskPower in this application, to be just and reasonable.

6.4 Demand Side Management

6.4.1 Programs

Demand Side Management (DSM) is a portfolio of programs, projects and initiatives focused on customer based energy efficiency, load management and conservation. Through the SaskPower DSM portfolio of energy efficiency, load management, renewables and conservation programs, customers are able to make informed decisions about what they can do to reduce electrical consumption and thereby reduce their electricity bills. This can help customers offset the impact of rate increases as well as help SaskPower to protect the environment (i.e. fewer emissions) and put less strain on its system, particularly during peak times.

By working closely with customers to reduce and adjust electricity use, overall demand for power can decrease. Lower demand results in a lower economic requirement for financing additional infrastructure. As shown in Table 6.17, SaskPower has accumulated savings of 56 MW at the end of 2012. As shown in Table 6.18, SaskPower is expected to have accumulated savings of 100 MW by 2017. In addition, Demand Response initiatives targeting industrial customers are expected to provide 85 MW of capacity value.

Table 6.17 - Accumulated Savings from 2007 to 2012

MW	2007	2008	2009	2010	2011	2012
Accumulated Savings	8	16	23	29	38	56

Table 6.18 - Accumulated Savings Targets for 2013 to 2017

MW	2013	2014	2015	2016	2017
Accumulated Savings	63	72	81	91	100

SaskPower has a multi-faceted portfolio of programs. The current portfolio includes incentive based education and demand response programs. More specifically, the Residential and Commercial programs focus on lighting, plug load, appliances and education. The Industrial programs help facilities identify energy waste and provide technical or business resources to help with energy management plans. The Renewable programs promote the use of environmentally preferred technology to generate power. The following table lists some (but not all) of the DSM customer programs currently available:

Table 6.19 - 2013 DSM Customer Programs

Program	Description
RESIDENTIAL PROGRAMS	
Refrigerator/Freezer Recycling Program	This program offers free pick-up and recycling of old inefficient refrigerators or freezers. Customers can save over $100/year by removing their old appliance.
Lighting Discount Program	This program partners with retail stores across Saskatchewan to provide point of purchase discounts on energy efficient light bulbs and fixtures. Lighting accounts for 20% of the average household power usage. CFLs and LEDs use 75% less power than incandescent bulbs.
Block Heater Timer Program	This program encourages customers to minimize the amount of time engine block heaters are plugged in during winter months. Customers can save $25 per year on their power bill by limiting their plug-in time to only 4 hours/day.
COMMERCIAL PROGRAMS	
Commercial Lighting Incentive Program	This program provides non-residential customers access to selected premium energy efficient lighting equipment at a discounted price. Commercial customers who switch to energy efficient lighting can save up to 40% on their annual lighting electricity costs as well as lower the need for maintenance resulting in reduced maintenance costs.
Energy Performance Contracting	This program allows large commercial & institutional customers to benefit from energy & facility renewals that reduce environmental impacts, reduce energy consumption & improve comfort. Plus, it is all paid for by savings on utility bills.
Municipal Ice Rink Program	This program helps municipal ice rink customers reduce their utility costs by improving the energy efficiency of their facility's equipment and operations. Participants receive a free welcome package which includes a facility assessment, a report on retrofit recommendations, best practice resources, and information about financial incentives offered by SaskPower and SaskEnergy. Retrofits can reduce utility costs by 15-40% which equates to annual savings of $2,500 to $7,000 for the average Saskatchewan rink.
Municipal Seasonal Lighting Program	This program provides municipalities the opportunity to switch their incandescent seasonal light bulbs with commercial-grade LED seasonal light bulbs at no cost to them. One LED seasonal light bulb uses less than 0.5 watts of electricity compared to 5-7 watts for an incandescent bulb.
Parking Lot Controller Program	This program offers an incentive when customers install parking lot controllers in electrified parking lots. A parking lot controller is similar to a standard outdoor electrical outlet, except that it regulates the electricity flow to the outlet based on the outside temperature. This enables customers to reduce their electricity costs associated with their parking lots by up to 50%.
INDUSTRIAL PROGRAMS	
Demand Response Program	This program provides incentives to large industrial customers in exchange for an agreement to reduce electrical demand on SaskPower systems when requested thus providing operational and economic benefits to SaskPower.
Industrial Energy Optimization Program	This program helps industrial facilities systematically identify energy waste and reduce costs associated with electrical energy use during the production process. SaskPower helps facilities identify energy waste & provide technical or business resources to help with energy management plan business cases.
RENEWABLE PROGRAMS	
Net Metering & Rebate Program	Customers can generate their own power using renewable technology up to 100 kW & bank excess electricity production up to 1 year. Net metering customers can receive a rebate with a one-time capital incentive equivalent to 20% of eligible costs with a maximum payment of $20,000
Small Power Producers	This program accommodates customers who wish to generate up to 100 kW of electricity for the purpose of offsetting power that would otherwise be purchased from SPC or for selling all of the power generated to SPC.

One of the benefits of the DSM programs is the deferment of higher cost generation facilities through energy and capacity savings. Thus, DSM programs yield lower short-term fuel costs and/or lower long term capital costs by deferring the need for some electric system investments.

SaskPower conducts several cost-benefit tests reflected within industry standard protocols when developing and evaluating DSM incentive programs. These tests include the Total Resource Cost Test, the Utility Cost Test, the Participant Cost Test, and the Ratepayer Impact Measure.[35]

[35] IR 150 First Round

The following table lists SaskPower's existing and currently proposed DSM Programs, including SaskPower's investment and energy savings for 2012 to 2016. The investment amounts in the table below do not include salaries, office administration or specific project costs. The forecasts are estimated based on expected budget dollars and customer uptake, which are subject to change.[36]

Table 6.20 - DSM Portfolio for 2012 (Actual) and 2013 to 2016 (Forecast)

Programs (in $ Millions)	2012		2013		2014		2015		2016	
	$	MWh	$	MWh	$	MWh	$	MWh	$	MWh
Residential Programs										
Lighting	$2.32	9,600	$1.80	9,000	$1.35	7,900	$1.38	8,100	$1.40	8,200
Appliance	$2.46	12,500	$1.97	9,600	$1.50	5,900	$1.53	6,000	$1.56	6,100
Plug Load	$2.50	12,540	$0.33	10,750	$0.15	1,500	$0.15	0	$0.16	0
HVAC	$0.14	0	$0.15	200	0	0	0	0	0	0
Geothermal	$0.22	220	$0.08	400	0	0	0	0	0	0
EnerGuide	$0.00	670	$0.00	200	0	0	0	0	0	0
Retail Partner	0	0	0	0	$0.25	TBD	$0.26	TBD	$0.26	TBD
Commercial Programs										
EPC	$0.02	3,300	$0.02	2,700	$0.03	2,700	$0.03	2,700	$0.03	2,700
Lighting	$1.99	6,700	$2.00	11,700	$2.25	12,700	$2.30	13,000	$2.34	13,300
HVAC	$0.14	300	$0.07	800	$0.08	200	$0.08	200	$0.08	200
Geothermal	$0.01	200	$0.00	0	0	0	0	0	0	0
Municipal	$0.29	700	$0.44	400	$0.29	1000	$0.30	1000	$0.30	1000
Parking Lot	$0.41	1,500	$0.17	0	0	0	0	0	0	0
Refrigeration	0	0	0	0	$0.50	700	$0.51	700	$0.52	700
Industrial Programs										
Optimization	$1.00	0	$1.40	0	$3.50	11,200	$3.57	11,400	$3.61	11,700
Total EE	**$11.50**	**48,230**	**$8.43**	**46,250**	**$9.90**	**43,800**	**$10.11**	**43,100**	**$10.26**	**43,900**
Other Programs										
Internal	$3.00	1,800	$0.83	300	$0.25	TBD	$0.26	TBD	$0.26	TBD
Codes & Stds	$0.05	0	$0.09	0	$0.07	TBD	$0.07	TBD	$0.07	TBD
Education	$0.04	0	$0.02	0	$0.50	TBD	$0.51	TBD	$0.52	TBD
Renewables	$0.80	800	$0.30	400	$0.65	TBD	$0.66	TBD	$0.68	TBD

SaskPower's DSM energy forecasted savings are based on participation estimates and targeted technology, as well as industry experience and consideration of the potential markets, its barriers and technological changes. Energy savings available to offset supply requirements are determined by comparing before/after energy consumption. Meter data and modeling are also applied to specific services and are used to track and assess consumptions.

There are currently two Demand Response programs (DR1 and DR2) available to Industrial customers. The Demand Response programs are not intended to and do not achieve energy savings, but rather provide a significant value to SaskPower at a fraction of the cost to implement other system reliability program. The value is for the benefit of all customers whether they be Residential, Commercial or Industrial.

The DR1 program was fully subscribed to by the end of 2013 and has renewable annual contracts. This program has a mandate for up to 85 MW from 2012 to 2017. The program pays $52,000/MW per year, determined by average monthly available curtailable load.

The benefit of DR1 to SaskPower is that the price offered to participants was set at half of SaskPower's calculated financial benefit. This calculation was vetted through a review by DSM Operations Performance

[36] IR 144 & 145 First Round

in 2012. It was determined at that time that the cost of the spinning reserve remained essentially unchanged from the original estimate and that the previously established $52,000/MW per year provision remained appropriate and continues to provide SaskPower with like or similar net financial benefit.

The DR2 program currently has 20 MW of curtailable load secured by contract and a mandate of up to 40 MW from 2012 to 2017. There is therefore opportunity for interested organizations to subscribe to DR2.[37] The program has a fixed payment and a variable payment option:

- Fixed payment - $20,000/MW per year, determined by average monthly available curtailable load, paid monthly; and,
- Variable payment - $150/MWh when events are called.

The benefit of DR2 to SaskPower will only be proven once there are new customers enrolled. The energy saved would allow NorthPoint the opportunity to utilize it as a trading opportunity and to determine if it can be profitable. This has not properly occurred to date as the one participating customer has not been available for curtailment due to operating conditions. Currently there are two new players expressing interest in this program.

Table 6.21 - Demand Response Secured Curtailable Load for 2012 to 2016

	2012	2013	2014[1]	2015[2]	2016[2]
DR1	84.6 MW	84.6 MW	84.6-94.6 MW	84.6-94.6 MW	84.6-94.6 MW
DR2	20 MW	20 MW	28 MW	20-40 MW	20-40 MW

[1]DR1 - Additional 10 MW in negotiation stage; DR2 - Curtailable load currently in negotiation
[2]DR2 - Anticipated Curtailable Load between 20-40 MW

The costs for DSM were estimated to be $15.4 million in 2013, $14.3 million in 2014, $14.6 million in 2015 and $14.9 million in 2016. The OM&A costs of DSM are to be offset by the energy savings that are expected to occur as a result of this ongoing initiative. Program savings are calculated using an appropriate end-use load factor to determine the amount of energy savings estimated at the customer site.

In 2012, total accumulated demand savings was 56 MW. For 2013 accumulated demand savings are targeted at 63 MW, on track to achieve 100 MW of savings by 2017.

6.4.2 Observations

Demand Side Management and Demand Response Programs are terms used by electric utilities to describe programs developed to influence the electricity usage patterns of customers.

Demand Side Management (DSM) programs encourage the end user to be more energy efficient. DSM measures traditionally include lighting retrofits, building automation upgrades, re-commissioning, HVAC improvements, variable frequency drives, and other programs that use less energy but still provide similar deliverable results. Demand Response (DR) is a term used for programs intended to encourage end-users to make short-term reductions in energy demand in response to a price signal from the electricity market or as a trigger initiated by the electric utility, to offset demand strain on the generation system.

The following table shows the savings SaskPower is planning to achieve by demand-side management programming methods as a percentage of estimated growth during the next decade. [38]

[37] IR 148 First Round
[38] IR 147 First Round

The current forecast indicates the DSM portfolio will offset estimated incremental load growth as outlined in the table below.

Table 6.22 - DSM Savings to Estimated Growth for 2014 to 2023

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2.8%	2.9%	2.7%	2.8%	5.5%	11.2%	7.3%	6.1%	5.3%	12.3%

The DSM portfolio which started in 2006/2007 generated 8 MW of accumulated energy savings in 2007. The savings increased every year since then to a total savings in 2012 of 56 MW.

Table 6.23 - Accumulated Savings Targets for 2013 to 2017

MW	2013	2014	2015	2016	2017
Accumulated Savings	63	72	81	91	100

During 2013-2017 energy savings are forecasted to increase from 63 MW in 2013 to 100 MW in 2017. Depending on the size of the incremental in any one year, the DSM portfolio offsets during the application period approximately 2.8% each year.

SaskPower provided an explanation for the projected results in Energy Savings highlighting their efforts relative to new residential energy savings programs planned for 2014, 2015 and 2016.[39]

The projected reduction in energy savings is attributed to developments in two key areas: residential lighting and residential plug load. For residential lighting, the forecast for seasonal lighting emitting diodes (SLEDs) has been reduced due to reduced sales in this area and noted that customers are purchasing greater amounts of SLEDs to add to existing old technology light strings rather than replacing them, which results in significantly less energy savings.

The Block Heater Timer Program (residential plug load) which generates a significant portion of the savings terminated in 2013 and had resulted in the distribution of an additional 120,000 timers bringing the total number of timers distributed to date at 255,000. From 2014 and beyond, SaskPower's efforts in this area will be focused on customer education to reinforce the behavioural change the program was designed to achieve.

The residential area is a key component to achieving energy savings. To complement the existing collection of residential programs that have been in the market over the past few years, there are three areas under development for 2014 – 2016:

1. The Retail Partnership Program is intended to establish direct relationships with retailers and to build partnerships that will enable the conservation team to promote multiple efficiency and conservation technologies in the market to our customers. As the program is under development in 2014 promotional efforts will range from education, product information and marketing to rebates and incentives. More detailed information will be provided when the program is fully developed.
2. Renewed emphasis in other key areas under development in 2014 is energy conservation education and behavioural change programs. The intention for 2014 is to deploy SaskPower's efforts in the residential sector (mass market) to support technologies that enable behavioural change.
3. SaskPower continues to support the development and implementation of codes and standards that promote efficiency in all sectors including residential. With the implementation of the new

[39] IR 144 First Round

regulations on incandescent light bulbs, in 2014 SaskPower will continue to explore savings attributed to their contribution and efforts in the development and implementation of new codes and standards. The amount of energy savings is also being reviewed to determine the full extent of future savings.[40]

In response for more information relative to the decline in OM&A DSM expenditures SaskPower in 2013 reviewed their internal processes related to developing and delivering programs. The review resulted in new and more cost effective methods to develop and deliver future DSM programs with the key component being to bring development and delivery in-house, with a reduced requirement for external consultants and contractors by developing expertise in the department.

We continue to urge SaskPower to maximize the benefits of demand side management programs and demand response programming. This is especially critical when peak demand continues to increase causing significant expenditures to meet increased generation demand which is putting additional cost pressures on the ratepayer.

We are satisfied that SaskPower continues to use appropriate tests to measure the effectiveness of existing or new DSM initiative. However with the impact of new capital programming on consumer's rates, it is extremely important for consumers to have a variety of alternatives including energy efficient programming options, to reduce or limit the growth of their monthly electricity bills.

6.5 Business Renewal (BR) & Service Delivery Renewal (SDR)

6.5.1 Programs and Initiatives

Following the Panel's 2009 Rate Application recommendations, SaskPower undertook a number of internal and external reviews to seek out increased productivity and efficiency gains inside the entire organization. Three external reports were filed in 2010 which made a number of recommendations and suggested a number of initiatives that could be undertaken to increase the overall efficiency and effectiveness of the utility.

After a review of the recommendation SaskPower proceeded with a staged strategy to vet out the recommendations and cost saving initiatives. The program's aim was to save $2 billion or to avoid cost increases over a ten year time frame.

The first initiative was the Business Renewal Program (BRP). SaskPower has stated that it is important to recognize that BRP initiatives will reduce, but not eliminate, the need for future rate increases given the substantial investments in infrastructure renewal and growth that is required to maintain the electrical system.

This program is a long term initiative that embraces a number of separate strategies to improve processes and return positive results in all of SaskPower organization expense categories including operations, maintenance and administration, finance charges, fuel and purchased power, other expense and capital spending.

One of the external reviews analyzed all major expense categories in SaskPower's business units and identified a number of opportunities using best practices in the utility industry to improve efficiencies, capture cost savings and improve program effectiveness.

The identified opportunities were then prioritized, planned and high return initiatives were proceeded with first, resulting in almost immediate cost savings. As each initiative within the portfolio is commenced they

[40] IR 38 Second Round

are tracked and monitored to ensure the actual benefits materialize and process results are improved. The material benefits gained from the former provide the resources to proceed with other new initiatives. As a result, a continuous improvement culture is emerging and gaining momentum and is supported by building a corporate capability. This continuous business process management and business realization strategy coupled with performance benchmarking should provide management a useful tool to manage and minimize expense growth in the immediate and long term.

SaskPower has pursued specific initiatives in several major expense categories: the finance charge and capital structure; information technology; customer connect process; reduce power plant outage duration and frequencies, office space utilization; and outsourcing head office caretaking.

Procurement Transformation, Operations Material Management Transformation and Information Technology Resourcing Strategies are now being pursued to further garner improvements and realize value and/or expense savings in these major expense categories.

SaskPower's response to an inquiry[41] indicated where the 38 and 47 line locate FTEs in 2011 and 2012 were accounted for in the current organizational framework. The outsourcing of line locating services freed up district field staff time which SaskPower confirmed were reassigned to meet the growing need to implement and expand a preventative maintenance program. SaskPower additionally confirmed that the intent of this initiative was to redeploy resources to perform maintenance tasks and not to reduce the number of district field staff.

The district field staff's responsibility for performing locating services were part of Distribution in SaskPower's current organizational framework. In previous years, Distribution was part of T&D (Transmission & Distribution). Distribution FTEs are listed below. In 2013, a shift took place in SaskPower's structure resulting in some groups and their related FTEs moving out of Distribution to other sections in the Operations Unit.

Table 6.24 - Distribution FTEs for 2011 to 2016

FTEs	2011 Actual	2012 Actual	2013 Target	2014 Target	2015 Target	2016 Target
Distribution	830	822	753	761	783	788

The following is the data related to SaskPower's line locate costs for 2010-2013:

Table 6.25 - Line Locate Costs for 2010 to 2013

Year	SaskPower's Cost / Locate	Contractor's Charge / Locate	Savings / Locate	# of Locates Completed	Benefit
2010	$76.53	N/A	N/A	N/A	N/A
2011	$76.66	$36.29	$40.37	85,102	$3.4M
2012	$78.02	$35.65	$42.37	107,861	$4.6M
2013	TBD	TBD	TBD	TBD	$4.2M

SaskPower entered a joint contract with SaskTel and SaskEnergy to select a vendor in a competitive bid process and negotiated a contract with the successful bidder. The lower contractor rates are made possible because the contractor can perform multiple locates at a single location (e.g. power, telephone, and gas). Based on the amount paid by SaskPower and the volume of work performed, the contractor's charge per locate for SaskPower was calculated as shown in the table above. Actual amounts paid by SaskTel and SaskEnergy are not available.

[41] IR 35 First Round

The table below shows Business Renewal Initiative annual savings data (actual & forecast) by initiative. Initiatives are categorized by: already implemented; currently underway; and future initiatives. It is noted that not all initiatives fit neatly into only a single category. Some implemented initiatives being continuously improved and will produce current/future savings. Some ‘underway’ initiatives are being implemented over an extended period and may continue to produce future year savings.[42]

Table 6.26 - BR Program Benefits Realized (2009-2012) & Forecast (2013-2016)

As at June 30, 2013	Realized				Forecast				Grand
Initiative (in $ millions)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
Implemented									
Finance Charge - ST Borrowing	$4.6	$11.1	$5.2	$14.5	$23.3	$26.1	$24.6	$24.7	$134.1
Finance - Capital Structure		1.6	6.6	19.1					$27.3
New Connect Process Improve			16.7	19.4	17.3	14.3	14.3	14.3	$96.2
Line Locate Outsourcing			3.4	4.6	4.2	4.2	4.2	4.2	$24.7
IT&S - Sourcing Strategy		0.7	3.0	5.7	8.4	8.6	8.6	8.6	$43.7
Underway									
Strategic Sourcing & Transform				1.0	4.3	4.4	4.3	4.4	$18.4
Overhaul Maintenance Mgmt			12.7	1.6	26.9	17.0	12.7	5.7	$76.6
AMI				0.2	1.0	8.9	18.4	21.2	$49.7
T&D - Schedule & Dispatch					2.0	10.6	24.8	24.8	$62.3
Material Mgmt Process Improve					2.4	2.5	5.8	8.3	$18.9
IT&S - Other Initiatives			0.8	1.5	4.6	5.1	5.2	5.2	$22.3
Corporate - Other Initiatives			0.7	2.6	2.9	3.1	3.1	3.2	$15.7
Future									
Asset Management Program					TBD	TBD	TBD	TBD	TBD
Major Project Delivery					TBD	TBD	TBD	TBD	TBD
Initiative Estimated Totals	**$4.6**	**$13.4**	**$49.2**	**$70.2**	**$97.2**	**$104.7**	**$126.1**	**$124.5**	**$590.0**
Actual benefit realized amounts are updated annually while forecasted amounts are updated quarterly. Both actuals and forecasts are updated in the following quarter. Estimates are in millions and subject to ongoing revisions as projects proceed, markets change, and assumptions are revised. Generally the estimates have aimed to be conservative and not overstate the savings.									

Table Notes:

- SaskPower District Operations staff completed all locates in 2010
- SaskPower’s Cost per Locate is calculated by multiplying the average time it takes to complete a locate by the standard rate of a District Operator
- 2013 data gathering and analysis will be completed in 2014 first quarter.

The second major initiative was SDR. Ongoing efforts in the (SDR project which started in 2009 are to provide faster, more convenient customer service and interface, replacing vintage technology infrastructure and systems and renew internal processes.

SaskPower has many other initiatives underway to improve customer service through the SDR project. Through SDR, SaskPower is improving internal processes and information systems to increase efficiency and effectiveness. These are structured to ensure that employees are provided with the tools needed to respond to customer needs efficiently and effectively.

During 2011, SaskPower’s replaced the more than 25-year-old billing system, which had become increasingly difficult to maintain because of its vintage. The new technologically advanced Customer Relationship and Billing System now provides employees with a comprehensive view of customer information which can be adapted to changing business requirements and is capable of managing complex billing and rate structures.

[42] IR 53 & 62 First Round

The implementation of the new system allows for the introduction of additional SDR initiatives, such as Advanced Metering Infrastructure (AMI) which commenced its initial testing in 2012 and continued in early and mid-summer of 2013 with program roll out started in October 2013. Full program deployment is scheduled to be completed in 2015. AMI will provide near real-time data on electrical consumption and operations through the installation and use of 500,000 smart meters. Once AMI is fully deployed, restoring service interruptions will be quicker, power quality improved, remote customer connects and disconnects provided, and usage data that can assist in operating the grid more efficiently collected.

SaskPower has partnered with SaskEnergy who intend to roll out or upgrade their 370,000 meters.

Through AMI, customers will have access to more timely information about their power consumption, and monthly bills will be based on actual usage. AMI final testing concluded in several Saskatchewan communities in between June and October 2013 and a full provincial rollout is expected to be complete by mid-2015. SaskPower estimates that AMI will generate up to $470 million in savings over a 20-year period 2016-2036, with a total expected capital cost of $190 million.

In late 2013 SaskPower provided an update on the program which completed a number of milestones, including a Network Acceptance Test (NAT), System Acceptance Test (SAT- Phase I) and the beginning of the full scale deployment of meters. In 2014, the program plan is to complete the network deployment as well as continue with full scale deployment of the meters and gas modules. The program is on track to be completed on schedule in 2015. [43]

SaskPower has also streamlined the process to connect new customers to the system and have significantly reduced the service delivery time. SaskPower is making progress to eliminate the construction backlog in this area and are achieving improvements in on-time service delivery.

The Field Worker Project (or Schedule and Dispatch) uses centralized scheduling and dispatch functionality in two provincial locations connected to laptop computers in service trucks to optimize resources for prioritizing work, minimize travel, and shorten power outage durations. Through the implementation of an automated work scheduling/dispatch system (computers in the service vehicles), service staff productivity is forecast to improve by 25% and service staff overtime reduced by 30%. Total savings of $11.0 million are forecast by the end of 2014.[44]

Overall, SaskPower advises that the SDR program is on target to deliver planned accumulated benefits of approximately $400 million by 2020. The plan is forward looking and anticipates that labour savings achieved will be reinvested in doing more preventative and pro-active system maintenance work which will lead to improved system reliability while continuing to provide a safe environment and accommodate an increased customer base.

The operating and capital cost associated with the SDR for the 2009-2016 time period is illustrated in the table below:

[43] IR 18C Second Round
[44] IR 64 & 65 First Round

Table 6.27 - Service Delivery Renewal for 2009 to 2016

	Actual				Forecast			
(in $ millions)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
OM&A	7.9	10.9	9.7	7.8	8.0	12.0	6.4	0.0
Capital Spending	9.9	15.5	23.2	25.3	70.4	70.3	10.9	0.0
Total	**$17.8**	**$26.4**	**$32.9**	**$33.1**	**$78.4**	**$82.3**	**$17.3**	**$0.0**
2009 to 2012 figures based on actual, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 capital spending figures based on 2014 Business Plan.								

The following table provides the breakdown of each initiative in the SDR for OM&A and Capital from 2009-2016.[45]

Table 6.28 - Service Delivery Renewal OM&A and Capital for 2009 to 2016

Project Delivery Categories (in $ millions)	Actual								Forecast							
	2009		2010		2011		2012		2013		2014		2015		2016	
	OM&A	Cap	OM&A	Cap	OM&A	Cap	OM&A	Cap	OM&A	Cap	OM&A	Cap	OM&A	Cap	OM&A	Cap
DPS	1.1	2.0	1.9	2.5	1.0	7.6	1.6	6.5	0.7	2.7	1.0	1.2	0.3	4.2	0.0	0.0
CCR	0.6	1.6	3.8	11.9	2.5	13.1	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MER	1.0	6.3	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corp Infra & Plan	1.2	0.0	1.8	0.8	0.4	2.5	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Support	2.1	0.0	2.4	0.0	2.8	0.0	2.4	0.0	2.4	0.0	2.4	0.0	2.4	0.0	0.0	0.0
Svce Bus Support	1.9	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMI	0.0	0.0	0.4	0.0	3.0	0.0	3.4	18.5	4.9	67.7	8.6	69.1	3.7	6.7	0.0	0.0
Program Total	**$7.9**	**$9.9**	**$10.9**	**$15.5**	**$9.7**	**$23.2**	**$7.8**	**$25.3**	**$8.0**	**$70.4**	**$12.0**	**$70.3**	**$6.4**	**$10.9**	**$0.0**	**$0.0**
Program Annual	**$17.8**		**$26.4**		**$32.9**		**$33.1**		**$78.4**		**$82.3**		**$17.3**		**$0.0**	

Inventory of Projects by Category
DPS (Deliver Products & Services) - Schedule Dispatch: Pre Processes, New Connect, Project Delivery, Outage Mgmt: Strategy, Tactical & Strategic Solutions, GIS: Data Clean Up, SAP Integration
CCR (Calculate & Collect Revenue) - Business Process, Hosted Contact Centre, Billing System (CR&B) Replacement Project & Remediation
MER (Maintain Electrical Reliability) - Business Process, Field Worker Automation / Laptops in Trucks
Corporate Infrastructure & Planning - Technology Planning, Business Intelligence, Service Business Metrics, Hosted Contact Centre, Business Cases: AMI, Telephony Planning
Program Support - Program & Project Administration & Support, Quality Mgmt Oversight, Risk Mgmt Oversight
Service Business Support - Support for Change Mgmt, Process Mgmt, Measurement & Benefits Realization
AMI (Advanced Metering Infrastructure) - Meter Deployment, Network Infrastructure, Network Systems, Meter Systems, SAP/Billing Integration, Business Integration, Stakeholder Engagement, Change Mgmt

SDR will help transform SaskPower's service business to a performance driven organization while increasing efficiency, productivity, electrical system reliability and improving service quality to its customers. Ultimately, the work completed through SDR projects will help employees be more productive by removing barriers that create inefficiencies in the work they perform. When SDR is fully implemented in 2015, decisions about serving customers will be made both from a service business perspective and a customer's point of view.

Part of the SDR project is the Outage Management System (OMS). This is a proactive, integrated system which will identify the location of power outages and reduce the time to restore service. The roll out of this initiative which will rely on the AMI platform and infrastructure will be coordinated with the full roll out of AMI.

SDR had an approved budget of $107 million. The Service Business Measurement and Benefits Realization team has been transitioned to Operations, which has resulted in an adjusted SDR budget of $106.3 million. The AMI portion of SDR was fully approved in December 2010 with a budget of $189.5 million. SDR is on budget for completion in mid-2015.

6.5.2 Observations

In their report to the Minister related to SaskPower's 2010 rate application, the Panel noted that SaskPower had entered into a significant growth phase, requiring the replacement of aging assets and addition of new infrastructure to meet increasing load requirements. The Panel noted then that SaskPower was

[45] IR 21 Second Round

experiencing and would continue to experience increased capital, as well as operations, maintenance and administration costs. This application again reinforces that direction.

In the last few years' reports, the Panel has challenged SaskPower to become more efficient. In response SaskPower initiated the Business Renewal Program in 2010, a major new initiative to vet out cost savings which is now into its fourth year. This program is intended to increase efficiency and effectiveness, improve performance and find significant cost savings while continuing to deliver a safe and reliable electrical service to its customers.

As noted in our last year's report to the Panel SaskPower, in 2009/2010, with the assistance of independent consultants (KPMG, UMS, and Deloitte) undertook a major collaborative review and evaluation of all of its expense categories - including OM&A, finance charges, capital spending and asset management, fuel and purchased power costs – to achieve cost reductions.

SaskPower, is now in the various stages of implementation on the initiatives recommended by the consultants, identifying and vetting out a number of savings or cost reduction opportunities – that is a reduction in operating costs and other expenditures relative to those that likely would have occurred had these initiatives not been pursued or realized.

The key initiatives are:

- Procurement Process – strategic sourcing and transformation;
- Distribution Services – deliver products and services through new customer connect process improvements
- Power Production – Overhaul Maintenance Management (asset management processes);
- Automated Metering Infrastructure
- T & D Schedule and Dispatch
- Variety of smaller other initiatives/efficiencies, and
- Commercial – Major Project Delivery Transformation.

Each, when operational, are expected to produce financial cost savings and operational efficiencies. The individual benefits are measured for each of the key initiatives.[46]

In addition to a review of on-line operating departments, SaskPower is continuing to the examine and review the operational support functions; be they financial, human resource, information technology, corporate services, corporate relations and safety areas which represent a significant component of the organization. These support sections will also be impacted by changes in processes elsewhere in the organization and it is to be expected they too will need to identify opportunities to improve efficiency and effectiveness providing enhanced support services, in order to produce further cost savings/reductions.

As noted in Table 6.26 the Business Renewal program is forecasting financial savings of $104.7 million in 2014, $126.1 million in 2015 and $124.5 million in 2016. Included in the foregoing totals is the financial savings associated with the use of short term borrowing costs as compared to longer term borrowing costs. While the savings are real and significant, it is a stretch for us to concur that this is as a result of the Business Renewal Program initiative. It is in our view, rather just a good, common business practice.

At the end of 2013, the savings from these business renewal activities is forecasted to total $234 million, relative to the 2009 baseline. While SaskPower has indicated that this forecast will likely be further influenced by many factors, such as interest rates, fuel costs and the budgets available for the implementation of initiatives, it is expected the savings will be significant in the long term.

[46] IR 18A Second Round

Two major initiatives are yet to be determined the Asset Management Program and the Commercial – Major Product Delivery Transformation. We are of the opinion these two major initiatives are key to the future success of the operations unit and the sustainability of SaskPower's current and future assets. It is hoped and expected that work will be undertaken immediately on both of these significant priorities.

Academics suggest the two cornerstones of any large organization are people and processes. Repositioning these two basic elements can have dramatic effects on cash flow, service delivery and customer satisfaction. While the success of any new initiative is not guaranteed, with the leadership taking a wholesome approach, providing the general direction and specific focus, it is demonstrating to date that for the organization as a whole and their end use consumers; there are significant benefits to be gained. The Business Renewal Initiative is intended to provide improved customer service at a lower future cost than otherwise would have been the case.

SaskPower submitted that the Business Renewal initiatives are inherently long-term for organizations as complex and widely dispersed as SaskPower. SaskPower is in the early stages of implementation with much work still under development and/or in the transition phase. To effectively manage this transition, SaskPower has established a Business Renewal Office staffed by existing resources to facilitate, plan and report on the transition outcomes on ongoing efficiency improvements. Given the significant size of the undertaking, this Business Renewal Office will have a very important role to ensure and perhaps advocate further advances or progression as the renewal or reengineering continues.

As noted in last year's report it is also important for all stakeholders to recognize and understand that successful Business Renewal initiatives will reduce, but not eliminate, the need for future rate increases. Rates are driven not only be operating costs but also by the significant capital investments made on infrastructure, renewal and growth required to maintain a safe and reliable electrical system as noted elsewhere in this report.

We are satisfied with the progress that is being made on these two initiatives. With Service Delivery Renewal now scheduled to be completed by the end of 2015, SaskPower will then be able to concentrate its resource efforts on the major tasks remaining to vet out efficiencies in the Business Renewal Program.

6.6.1 Depreciation and Amortization Expense

Depreciation and Amortization expense related to SaskPower's used and useful assets is a charge to income. Depreciation expense is largely driven by capital undertakings and as assets are added to the existing plant and equipment, depreciation expense will increase accordingly.

SaskPower's asset base is depreciated on a straight-line basis over the estimated life-cycle of the asset group and includes the amortization of capital lease assets. Land is the exception and is not depreciated. Factors considered in establishing the service life of an asset include internal expert's estimates, manufacturer's guidance, past utility and industry experience, future expectations, and comparison of results to other Canadian Utilities.

The depreciation policy and study is reviewed annually and usually studied thoroughly every five years. In order to estimate the useful life of the corporate assets and the appropriate depreciation rates for each class of asset. SaskPower conducted an internal review in 2009 which was adopted effective January 1, 2010.

Additionally the Panel had previously recommended in its report to the Minister that SaskPower undertake an independent examination of its depreciation study. SaskPower complied with this recommendation and hired Gannett Fleming Inc. to undertake such a study which was filed with SaskPower in early 2011. While the external consultant did not recommend major changes, it did offer a number of recommendations to SaskPower, which were subsequently implemented with the revised rates becoming effective on January 1, 2011.

SaskPower depreciation study used for this application follows the principles and methodology recommended by Gannett Fleming and subsequently adopted by SaskPower. That study confirmed the methodology used to calculate depreciation rates and average service life of their assets as being appropriate.

The depreciation and amortization policy has not changed since the last application, except for the changes in the service life/life expectancy related to the Boundary Dam and Queen Elizabeth generating units, and the change up of the mechanical meters discussed below.

The methodology followed by Gannett Fleming is very similar to the approach used by the Corporation when the studies were performed internally. The following table confirms the actual and budgeted annual depreciation rates and amortization costs by major plant categories from 2009 to 2016.

Table 6.29 - Depreciation and Amortization for 2009 to 2013

Asset Group	Depreciation Rates	2013 Budget	2012 Budget	2011 Actual	2010 Actual IFRS	2009 Actual
Generation						
Coal	1 - 20%	72,923	72,899	73,180	72,158	77,091
Nat Gas	2 - 20%	28,266	30,012	28,474	19,204	10,160
Hydro	1 - 4%	16,408	17,185	14,933	15,128	16,711
Cogen	3.3%					4,962
Wind	2 - 6.67%	13,213	13,915	13,220	13,168	12,722
Leased	4%	38,828	21,328	16,978	15,528	
Transmission	2 - 33.33%	28,065	27,165	23,246	20,377	19,198
Distribution	2.5 - 33.33%	80,793	76,556	70,848	66,817	66,893
Other	1 - 25%	70,389	57,918	44,551	41,050	33,255
Total		**348,885**	**316,978**	**285,430**	**263,430**	**240,992**
Customer Contribution Amort						(13,675)
Asset Retirement Expense		5,215	4,269	4,269	2,750	1,201
Total Other Depr Expense		**5,215**	**4,269**	**4,269**	**2,750**	**(12,474)**
Total Depreciation Expense		**354,100**	**321,247**	**289,699**	**266,180**	**228,518**

The 2012 actual depreciation expense was $315.8 million some $6 million less than budgetted that year.

With the significant recent capital expenditures or reinvestments made by SaskPower the last few years, depreciation expense as outlined in the foregoing table was $289.7 million in 2011 with the current forecast of $354.1 million in 2013, $1.5 million greater than the original 2013 Rate Application forecast. The Rate Application forecast for 2013 of$354.1 million was increased in the September 2012 update to $363.0 million. Net Depreciation expense increased in 2012 by $26.1 million over 2011 and $39.8 million in 2013 over 2012.

There were three recommended adjustments for 2013 based on the annual review of the retirement dates and average service lives for continued appropriateness. Boundary Dam Units 1 & 2, Queen Elizabeth (QE) Unit # 3, and the electrical and mechanical meters were identified as requiring an adjustment to their retirement date and average service life. SaskPower executive advanced the retirement date of Boundary Dam Unit 1 to May 1, 2013 (from 2014) and Unit 2 to July 1, 2015 (from 2016) as a result of Environment Canada regulations coming into effect that day. QE Unit # 3 retirement date moved to 2017 from 2022.

Electronic and mechanical meters retirements dates moved ahead one year from 2015 to 2014.[47] Those changes increased the depreciation cost by $5.8 million. [48]

Boundary Dams Units 4 & 5 also must retire by 2019-12-31 if not fitted with carbon capture. The same condition applies to Boundary Dam Unit 6 which must retire 2027-12-31 if not refitted. Landis and Meadow Lake gas units were the only two assets that were identified as requiring an adjustment to their retirement dates as result of the average service life study of 2011. Both units' retirements' dates were extended to 2020 from 2014 & 2015 respectively.[49] As a result of those life extensions, depreciation expense decreased by $1.6 million.

In order to be in full compliance with IFRS reporting standards, the change in depreciation expense resulting from these recommended adjustments to the retirement dates increased the total depreciation expenses by $0.8 million in 2013.

As noted in the table below, depreciation expense is forecasted to increase from $355.6 million in 2013 to $425.3million in 2014, $460.8 million in 2015 and $490.1 million in 2016, or a total net increase of $123.6 million in this three year rate application.

6.6.2 Observations

Depreciation and Amortization expenses are forecasted to increase from the 2012 Actual of $315.8 million to a forecast of $490.1 million in 2016. The following table highlights the actual and current forecast:

Table 6.30 - Depreciation from 2011 to 2016

	Actual		Forecast			
(in $ millions)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Depreciation						
SaskPower Depreciation	268.4	289.3	323.3	367.5	399.0	424.3
Asset Retirement - Depr Expense	4.3	5.2	1.4	1.4	1.4	1.4
Total SaskPower Depreciation	**$272.7**	**$294.5**	**$324.7**	**$368.9**	**$400.4**	**$425.7**
Capital Lease Amortization	$17.0	$21.3	$41.8	$56.4	$60.4	$64.4
Total Depreciation	**$289.7**	**$315.8**	**$366.5**	**$425.3**	**$460.8**	**$490.1**
2011 to 2012 figures based on actual, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan.						

The customer contributions are funds received from certain customers for the costs of service extensions. These contributions are recognized immediately in profit or loss as other revenue when the related property, plant and equipment are available for use.

As a general rule of thumb, for every $100 million in capital expenditures, SaskPower will see its depreciation expense increase by approximately $3 million going forward.

SaskPower had actual capital expenditures of $1.3 billion in 2013 plus $700 million for the North Battleford Energy Centre (NBEC) and is projecting an additional $1.2 billion, $1.1 billion and $900 million in the years 2014 to 2016.[50] These projects when complete and are operational, all impact the depreciation expense category.

47 IR 25 First Round
48 IR 26 First Round
49 IR 26 First Round
50 IR 35B Second Round

Of the total $641.5 million revenue lift requested in this rate application, $134.5 million or 21% is required to financially discharge the additional depreciation expense during the period 2014-2016. Depreciation expense will have increased 55% during the 2012-2016 time periods.[51]

The 2014 Business Plan and the 2014 Rate Application assumed the capital cost of $1.24 billion less the Federal Contribution of $240 million for a net cost of $1.0 billion for the Boundary Dam ICCS project with an in service date at the end of 2013. Subsequent to the Application, in response to a question posed by us, the forecasted cost has increased to $1.382 billion less the Federal contribution for a net cost of $1.142 billion. This facility was expected to go into service mid February 2014 and the carbon portion was expected to go into service mid – May 2014.

In seeking clarification on the Mid-Application update, the most recent in service date for the power island is now expected to be May 1, 2014 and July 1 2014 for the carbon capture facility.

As a result of the delay, both the finance and depreciation expense will be less than the original forecast for 2014. The financial impact of the mid February delay to the depreciation expense was to be a saving of approximately $12.0 million. In the Mid-Application update the depreciation expense has been further reduced. It is now forecasted that the Depreciation Expense for 2014 will decrease to approximately $399.3 million, $26.0 million less than the Application forecast of $425.3 million. The forecast for 2015 and 2016 remain the same.

Subject to the revised in service dates noted above, and resulting financial impact, we find SaskPower's Depreciation Expense forecast to be consistent with the methodology commonly used by utilities in Canada as noted by Gannett Fleming and accordingly find it reasonable.

6.7.1 Finance Expense

Finance Expense or Charges include the net amount of interest on SaskPower's borrowing and capital leases offset in part by interest capitalized and debt retirement earnings. Net finance charges were originally forecasted to be $303.3 million in 2013. The current forecast (as at December 31, 2013) is $261.9 million mainly due to reduced finance lease interest because of the North Battleford Energy Centre (NBEC) deferral, reduced credit card charges and higher interest being capitalized.

Finance charges increased from $192 million in 2010, to $197 million in 2011and increasing to $203 million in 2012. All stated were under IFRS.

For the period 2014 to 2016 total net finance expense is forecasted to be $383.3 million in 2014, $ 416.3 in 2015 and $452.5 million in 2016.

The main driver of the increased finance charges is the increased borrowings required to finance SaskPower's capital program. SaskPower's debt as noted in the debt section is expected to grow from $5.7 billion in 2013 to $7.6 billion in 2016.

SaskPower has recently been using more short term financing options rather than long term secured debt arrangements. Using current market forecasts, SaskPower is anticipating an increase in short term interest rates over the period of this application from 1.1% in 2013 to 1.7% in 2016. While all of SaskPower's long term debt interest rates are currently fixed, long term new issues rates are forecasted to increase from 3.5% in 2013 to 4.1% in 2016.

[51] Appendix 1 Table A1.8 Depreciation variance table 2011-2016

SaskPower also noted that despite this upward trend, interest rates continue to be at historically favourable levels. SaskPower's current policy is to carry up to 15% of its debt in short term financial instruments. By using this policy SaskPower has been able to generate significant reductions in finance expenses.

As noted in the table below, offsetting the finance charges, interest capitalized represents the deferral of interest expense on capital projects under construction, and when the project is completed, those finance expenses are considered as a cost of construction. There is a significant reduction in interest capitalized in 2014 through to 2016 when the forecast is reduced to $10.6 million from $46.0 million originally forecast in 2013. This reduction in capitalized interest flows from a decision to not capitalize interest relating to the financing of the Integrated Carbon Capture and Storage Project (ICCS) beyond 2014 as it was scheduled to become operational at the end of 2013 or early 2014. Actual capitalized interest in 2011 was $11.7 million and is now forecasted to be $56.7 million in 2013 which will reduce the actual net interest expense in 2013.

The ICCS project has been delayed as noted in the Depreciation section. The power facility was scheduled to commence operations at the end of 2013 (now May 1, 2014) with the carbon capture portion of the project now scheduled to be put in serve on July 1 2014.

Debt retirement funds, commonly referred to as Sinking Funds, are monies set aside to partially offset or retire outstanding debt upon maturity. Fund earnings represent interest generated in the sinking fund account. SaskPower confirmed that while the fund had higher than normal returns on its debt retirement investments they have mostly been offset by unrealized losses on the market value of those funds, hence the revised forecast from $23.4 million in 2013 to a forecast for 2016 of $10.2 million. SaskPower stated in the rate application that the reduction of returns on the sinking fund is expected and earnings will return to more normal levels. Debt retirement earnings in 2013 are now forecasted to be around $17.9 million.

The following is a summary of the actual and forecasted components that make up finance charges for the years 2011 to 2016 as well as the budgets for the years 2011 to 2012. It is important to note that the actual 2011 to 2013 actual numbers have been restated to reflect changes relating to IFRS or other accounting policy changes[52]. The budget numbers however, have not been restated. Actual finance charges in 2011 were $ 197 million and $ 200 million in 2012.[53]

The makeup of Finance Charges for the years 2010 to 2016 are forecasted as follows:

Table 6.31 - Finance Charges from 2011 to 2016

	Actual		Forecast			
(in $ millions)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Interest on L/T Debt	180	180	195	218	237	253
Interest on Leases	41	55	119	165	173	181
Interest on S/T Debt	1	5	11	12	16	19
Interest Capitalized	(12)	(30)	(46)	(23)	(21)	(11)
Other	13	17	17	21	21	21
Finance Expense	**$223**	**$227**	**$295**	**$393**	**$426**	**$463**
Finance Inc: DRF, Interest Earning	**(24)**	**(22)**	**(23)**	**(10)**	**(10)**	**(10)**
Finance Charges	**$199**	**$205**	**$272**	**$383**	**$416**	**$453**

Three of the major drivers of the Finance Charge expense are the amount of Debt owed by the corporation, the interest rate charged on that Debt, and the amount of interest which has been capitalized. Since 2010 SaskPower, under IFRS, is obligated to include the costs associated with financing their long term leases associated with their Power Purchase Agreements. Gross interest expense changes with the gross debt

[52] IR 22 First Round
[53] 2012 Annual Report

balance and the interest rate charged. Interest during construction changes with the capital program as interest on capital borrowing is charged to the capital projects while they are being built.

Finance charges have been relatively constant over the past few years as a result of the policy decision to use short term financing but, with the major capital undertakings, debt financing costs have increased and are expected to continue to escalate.

The overall financing costs for capital spending are increasing and this trend is expected to increase as debt levels increase, as aging infrastructure is replaced and new generation facilities added. SaskPower's debt is acquired through the Province of Saskatchewan from various financial institutions at interest rates that reflect the Province's attractive credit rating. SaskPower does not pay a premium for being included in the Province's credit rating, but does pay each transaction's administrative cost.

6.7.2 Observations

As noted above, there are three main drivers for the forecasted Finance Charges for 2014-2016. First is the amount of debt, secondly is the interest charges on the debt and lastly, the amount of interest or finance costs on the debt that is capitalized, partially offset by the financial returns on the investments in the sinking fund.

Interest charges that occur during the acquisition and construction phase are capitalized when the asset becomes operational and is put into use. The carrying charges are rolled into the asset as a fixed investment cost and amortized over the life of the asset.

SaskPower is anticipating an increase in short term interest rates over the period of this application from 1.1% in 2013 to 1.7% in 2016. While all of SaskPower's long term debt interest rates are currently fixed, interest rates for new long term issues are also forecasted to increase from 3.5% in 2013 to 4.1% in 2016. As with any forecast there is uncertainty of how stable interest rates are going to be over the term of the application. It is expected that interest rates will be stable for 2014 but beyond that time frame, interest rates are currently forecasted to move upward in 2015.

As noted earlier, finance charges for 2013 are less than forecast due to the deferral of the North Battleford Energy Centre (NBEC) units that came on line in June of 2013 and not as originally estimated nearer to the start of 2013. In 2012 SaskPower confirmed the increase in finance charges for 2013 was because of an $18 million increase in the capital lease amortization due to the NBEC being commissioned earlier than originally forecasted which did not materialize. Approximately half of the decrease in finance charges in 2013 is as a result of the deferral of the start-up of the NBEC. The remainder is as result of higher capitalized interest costs and other lower than forecasted interest charges.

The current forecast for this category of expense for 2014 is $383.3 million. With the most recent forecast for 2013 of $260.7 million, the 2014 increase in finance charges is $122.6 million. Over the period of this application total finance charges are expected to increase to $452.5 million in 2016 from the 2009 amount of $139 million. During the period 2012-2016 interest costs are forecasted to increase 87%.[54]

However, as noted earlier the ICCS project did not come on line as forecast at the end of 2013. The new in service date is now forecasted to be May I, 2014 for the Power Island and July 1, 2014 for the carbon capture facility. As result of the project delay, total finance charges will be reduced and are now overstated by approximately $43.2 million. Total finance charges from the information provided in the Mid-Application update are now forecasted to be $340.1 million. Finance charges forecasts for 2015 and 2016 remain as filed in the original application.

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[54] Appendix 1 Table A1.9 2011-2016 interest charges

The Mid-Application Finance Charges for 2014 are reconciled in the following table:

Table 6.32 - Application Update Finance Charges

(in $ millions)	2014 Forecast		
	Initial Submission (Jul 31/13)	Mid-Application Update (Jan 31/14)	Variance
Finance Charges			
Interest on Borrowings	$399.9	$391.6	$(8.3)
Interest Capitalized	(22.8)	(42.8)	(20.0)
Debt Retirement Fund Earnings	(9.4)	(18.1)	(8.7)
Other Interest and Charges	15.6	9.4	(6.2)
Total Finance Charges	**$383.3**	**$340.1**	**$(43.2)**

In reconciling the forecasted interest charges supplied by SaskPower, we note some power purchase agreements on sourced leased facilities carry a much higher interest rate as compared to SaskPower's long term interest rate on its own debt.

As with in service dates being revised or rescheduled, the cost estimates are based on the above information and could materially change if the start or operational dates materially change.

A year over year change in finance charges in excess of $100 million is significant. This increase is notwithstanding the corporation's decision to carry a significant amount (upwards of 15%) of debt in short term financial instruments with significantly more favourable interest rates. While interest on long term debt (as one specific category) has remained relatively stable, increased reliance on power purchase agreements has increased interest on finance leases significantly as borrowing costs (interest rates) for external projects are not as near favourable as SaskPower's borrowing rates.

SaskPower issued new long term debt in February and October of 2013 in the amount of $200 million and $400 million respectively. With the exception of the above issues the financing of recent capital programs has been with short term financial instruments. At the end of 2013, should current arrangements continue, SaskPower could be holding near its policy limit of 15% of debt by short term instruments, which in itself, carries a risk profile. In addition SaskPower is authorized to have up to $800 million for temporary financing in floating debt instruments. SaskPower uses this temporary short term borrowing until a long term borrowing is put into place to replace the short term obligations.

The legislature has placed a cap on the credit capacity on SaskPower. This cap currently is more than that required during the term of this application. SaskPower's Board needs to satisfy itself that this risk profile between short and long term debt is appropriate and falls within its stated policy guidelines.

Again, with the substantial capital program forecast for SaskPower, this category of expenses is expected to grow substantially over the next decade. While the 2013 interest coverage ratio is 1.4 it is forecast to decline to 1.1 as the overall rate of return is less than their target during the time period 2014-2016 which is very close to the minimum requirement. Should the net income materialize as forecasted in the Mid Application Update there will also be a modest increase in the interest coverage ratio.

The total revenue expected to be generated if this application is approved as filed is $641.5 million over the period 2014-2016. Of this amount $180.2 million is required to fund the forecasted increase in finance interest expense during this period.

We are satisfied that the methodology used to generate the forecasted interest charges over the three year period of this application is reasonable, but the actual financial forecast results will be contingent on the progress made on the capital infrastructure plans. There are two significant issues that will impact the actual results. One is the actual interest rates at the time of project completion, and the second is whether the Capital undertakings are completed on time and on budget.

6.8.1 Debt, Capital Structure and Return on Equity

SaskPower's total financial liabilities at the end of 2012 were slightly in excess of $5.1 billion up from $4.4 billion in 2011. At the end of calendar year 2013 total liabilities are forecasted to be $6.68 billion net of equity.[55] The $6.68 billion includes the total current liabilities, long and short term debt, finance lease obligations, employee benefits liabilities, and provision for decommissioning and environmental remediation costs, risk management and other outstanding liabilities.

Outstanding long term debt as of December 31, 2012 was $2.9 billion up from $2.7 billion in 2011.Outstanding short term debt or advances in the same time period was $763 million, up from $ 667 million in 2011 for total debt outstanding of $3.7 billion in 2012. The comparable total number for 2013 is $4.5 billion consisting of $3.5 billion in long term debt and $1.0 billion in short term debt. In addition there is $1.1 billion of capital leases booked to comprise the total outstanding debt forecast of $5.6 billion by year end 2013.[56]

As a result of the current and estimated near future significant capital reinvestment in infrastructure and new generation required to meet the growing load, SaskPower has approved a new Capital structure target range consisting of 60% - 75% debt during this period of high reinvestment. The current debt ratio for 2013 is forecasted to be 71.4 % up from 67.4% in 2012 and 63.0% in 2011.

The following table illustrates the actual and forecasted debt-equity ratio for the period 2007-2016:

Table 6.33 - Debt / Equity (D/E) Ratio for 2007 to 2016

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
% Debt	59.7%	60.7%	61.4%	62.7%	62.6%	67.1%	71.4%	74.6%	76.4%	77.0%

Debt is a measure of SaskPower's financial leverage within the capital structure. A high D/E ratio indicates that a high percentage of debt rather than equity has been used, to finance operations and capital programs. SaskPower has maintained a long-term debt target of 60% for the last decade. During periods of high capital expenditures in the 1970s and 1980s, when several additional generating units were added, debt exceeded 80%. In the mid-1990s, the corporation focused on reducing debt to 60% from approximately 75% by curtailing capital expenditures.

SaskPower remains in a period of high capital expenditure for new generation and transmission facilities that are needed to meet higher than normal load growth, environmental and emissions requirements and to replace aging facilities. Capital budgets for the next three years are expected to be slightly in excess of $3.1 billion, exclusive of capital lease obligations.

The D/E ratio is expected to be at the high end of SaskPower's capital structure target range in 2014 and to exceed that target range in 2015 and 2016. The current forecast does not foresee SaskPower returning to within the current target range until near the end of this decade. SaskPower's long term plan is to work to reduce the debt ratio to at least the mid-point of the long term target range.

SaskPower's historic expenditures for infrastructure and capital programs annually have been in the $300 - $400 million range during the period 2000-2008. However, starting in 2009 SaskPower budgeted annually for a significant capital program totalling around $1.0 billion and that trend is continuing for at least for the next few years. Increasing capital expenditures impose the need to undertake borrowing which add to both the long-term and short term debt necessary to fund these projects.

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[55] 2014 Business Plan page 26
[56] IR 21 First Round

Table 6.34 - Total Debt from 2007 to 2016

(in $ millions)	2007	2008	2009	2010	2011	2012	2013*	2014*	2015*	2016*
L/T Debt	2,225	2,571	2,567	2,778	2,774	2,879	3,477	4,169	4,763	5,107
Capital Leases	0	0	0	291	434	430	1,138	1,139	1,336	1,330
S/T Debt	0	0	272	159	251	763	1,052	1,052	1,067	1,136
Total Debt	**2,225**	**2,571**	**2,839**	**3,228**	**3,459**	**4,072**	**5,667**	**6,360**	**7,166**	**7,572**

* Summary of actual total debt for the years 2007-2012 and forecasted total debt for the years 2013-2016.

As outlined above under Capital Leases, the Corporation has a number of Contractual Power Purchase Agreements (PPAs), which must be financially satisfied over the term of the contracts. As such they fall under IFRS proprietary contracts and must be shown as lease obligations. While they are incurred long term liabilities of the corporation, the financial obligations of SaskPower are discharged annually as the power is purchased and delivered.

All of SaskPower's long-term borrowings are arranged through the Finance Department of the Province of Saskatchewan. SaskPower is an agent of the Crown and its debt securities are held by the Province of Saskatchewan. Therefore, any financial ratings assigned to SaskPower's obligations are a flow-through of the ratings of the Province. While the debt is issued in the name of the Province, it is reassigned to SaskPower under the same issuing terms and conditions. This process provides SaskPower with direct access to the Province's enhanced credit rating which allows for a lower cost of financing.

The following table summarizes the long term debt outstanding and is similar to the one found in SaskPower's 2012 annual report. There were a number of long-term debt issues that occurred in February and October of 2013 as noted in the following table:

Table 6.35 - Current Long Term Debt Outstanding as of October 31, 2013

Issue Date	Maturity Date	Effective Interest Rate	Coupon Rate	Par Value	Unamortized Premium (Discount)	Outstanding Amount
Feb 4, 1992	Feb 4, 2022	9.78%	9.6%	$150,000,000	($1,452,683.59)	$140,000,000
Nov 2, 1993	Feb 4, 2022	8.50%	9.6%	$100,000,000	$7,267,462.91	$100,000,000
May 8, 1995	May 30, 2025	8.82%	8.75%	$100,000,000	($481,017.43)	$100,000,000
Aug 8, 2001	Sep 5, 2031	6.49%	6.4%	$200,000,000	($1,806,403.16)	$200,000,000
Jan 15, 2003	Sep 5, 2031	5.91%	6.4%	$400,000,000	$5,708,324.57	$400,000,000
May 12, 2003	Sep 5, 2033	5.90%	5.8%	$100,000,000	($1,176,572.79)	$100,000,000
Jan 14, 2004	Sep 5, 2033	5.68%	5.8%	$400,000,000	$2,930,735.48	$400,000,000
Oct 5, 2004	Sep 5, 2035	5.5%	5.6%	$400,000,000	$2,795,782.61	$400,000,000
Feb 15, 2005	Mar 5, 2037	5.09%	5.0%	$150,000,000	($1,723,124.83)	$150,000,000
Apr 12, 2005	Dec 15, 2020	10.06%	9.96%	$128,797,500	($597,559.82)	$128,797,500
May 6, 2005	Mar 5, 2037	5.07%	5.0%	$150,000,000	($1,372,951.50)	$150,000,000
Nov 15, 2005	July 15, 2022	9.00%	8.94%	$256,320,000	($946,291.86)	$256,320,000
Feb 24, 2006	Mar 5, 2037	4.71%	5.0%	$100,000,000	$4,236,202.07	$100,000,000
Mar 6, 2007	Jun 1, 2040	4.49%	4.75%	$100,000,000	$4,082,953.57	$100,000,000
Apr 2, 2008	Jun 1, 2040	4.67%	4.75%	$250,000,000	$3,013,428.17	$250,000,000
Dec 19, 2008	Jun 1, 2040	4.71%	4.71%	$100,000,000		$100,000,000
Sep 8, 2010	Jun 1, 2040	4.27%	4.75%	$200,000,000	$15,867,403.59	$200,000,000
Nov 15, 2012	Feb 3, 2042	3.22%	3.40%	$200,000,000	$6,828,469.63	$200,000,000
Feb 28, 2013	Feb 3, 2042	3.54%	3.40%	$200,000,000	($4,865,944.70)	$200,000,000
Oct 9, 2013	Jun 2, 2045	3.97%	3.90%	$400,000,000	($5,061,754)	$400,000,000

As an affordability repayment matrix SaskPower is expected to have an interest coverage ratio (the ratio of earnings before interest and taxes to annual interest expense) of 1.4% for 2012. It is currently forecasted to be 1.4% in 2013, reducing to approximately 1.1% from 2014 to 2016. While SaskPower's debt is held in the name of Province of Saskatchewan, this is at the lower end of a reasonable target range for crown owned utilities.

The Crown Investment Corporation, in late 2011 declared a special dividend of $120 million to be paid in 2012. No dividend payments are anticipated or currently forecasted during this capital extensive planning cycle.[57]

Equity

Equity of a crown utility usually only grows when the utility generates positive net income. SaskPower's equity as noted on page 72 of its 2012 annual report was $1.858 billion. With the net income forecast for 2013 of approximately $140 million (after unrealized market value adjustments) it is expected SaskPower's current equity at the end of 2013 will be close to $2 billion.

In this Application SaskPower is budgeting for a net income of $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016 for a three year positive net income of $107.2 million. Should that forecast materialize, SaskPower equity would grow to just over $2.1 billion by the end of 2016.

Return on Equity (ROE) measures the rate of return on the ownership investment in the utility. Since it measures a firm's efficiency at generating profits from every dollar of net assets, ROE is viewed as one of the most important financial ratios by the investment community. ROE is equal to the fiscal year's net income divided by total equity.

SaskPower's Application indicates that the key principle behind the requested rate increase is that SaskPower should have the opportunity of recovering prudently incurred costs for providing electrical services to all its customers and an appropriate return on the investment made. Achieving an adequate return is a prerequisite for it to maintain an adequate capital structure through increases in retained earnings to provide the financial ability to serve and to discharge its debt obligations.

According to the long-term business plan, the long-term return on equity target is 8.5%. However, in this 3 year rate application the forecasted ROE is expected to be less than an average annual return of 2%. As noted in discovery, should the revenue and expense forecast materialize as stated in the rate application, it would require a rate increase of 13.5% in 2014, 4.3% in 2015 and 4.9% in 2016 to generate a return on equity of 8.5%.[58] To generate a return on equity to deliver the target result in each of the years of the application would have required rate to raise an additional $150.3 million in 2014, $153.2 million in 2015 and $170.4 million in 2016 based on the current forecasts.[59]

Table 6.36 - ROE and Operating Income for 2007-2016

(in $ millions)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Actual Op Inc	$150	$94	$96	$216	$228	$129	-	-	-	-
Actual Op ROE	10.1%	6.2%	6.1%	13.0%	12.6%	7.0%	-	-	-	-
Forecast Op Inc	$135	$131	$138	$134	$119	$157	$126	$27	$40	$40
Forecast Op ROE	9.0%	8.5%	8.5%	7.9%	6.7%	7.6%	6.4%	1.3%	2.0%	1.9%

The following table provides the continuity schedule showing the Gross and Net Plant, Depreciation, plant additions and plant retirements since 2011:

[57] IR 31 First Round
[58] IR 8 First Round
[59] IR 2A Second Round

Table 6.37 - Plant in Service Continuity Schedule (x $000)

	Sep 2013	2012	2011
Plant in Service Beginning of Year	$9,577,872	$9,050,608	$8,518,060
Additions	$1,021,053	$589,028	$572,830
Removals	$(82,941)	$(61,764)	$(40,282)
Plant in Service End of Year	**$10,515,984**	**$9,577,872**	**$9,050,608**
Accum Deprn Beginning of Year	$(4,363,389)	$(4,098,199)	$(3,845,928)
Depreciation Provision	$(256,676)	$(310,576)	$(285,430)
Accum Deprn on Retired Assets	72,272	$45,386	$33,159
Accum Deprn End of Year	**$(4,547,793)**	**$(4,363,389)**	**$(4,098,199)**
Net Plant in Service	**$5,968,191**	**$5,214,483**	**$4,952,409**
Customer Contributions			
Other Property Plant & Equip includes:	**$1,380,893**	**$816,128**	**$434,383**
Asset Retirement Assets & Construction in progress			
Total Property Plant & Equipment	**$7,349,084**	**$6,030,611**	**$5,386,792**

6.8.2 Observations

As noted in the above section SaskPower's long term debt grew from $2.449 billion end of 2005 to $3.46 billion at year-end 2011. SaskPower's debt is now forecasted to be $5.67 billion at year end 2013 and grow to $7.572 billion at year end 2016. SaskPower current legislated borrowing capacity is $ 8 billion.

If the forecast shown in Table 6.34 materializes, SaskPower's debt will have more than tripled by 2016 relative to 2007. This outstanding debt is the main driver of the finance charges of the corporation. The debt-equity (D/E) ratio is expected to increase from 59.7/40.3 in 2007 to 77.0/23.0 in 2016. While this ratio is not completely foreign for integrated electric utilities (SaskPower's forecasted D/E ratio is stronger than many other Crown owned utilities), it is certainly moving to the higher end of the comparisons. Many electric Crown Corporations in Canada have to undertake similar significant capital improvements which are driving the ratio results upwards.

It is significant that under IFRS SaskPower must record all contractual Power Purchase Agreements which must be financially satisfied over the term of the contracts (IFRS proprietary contracts), on their financial statements as a finance lease. SaskPower fully complies with that obligation and as noted in the above table lease obligations are forecasted to total $1.3 billion.

SaskPower has the significant advantage of being able to use the credit facility of the province to acquire the necessary funds at a more attractive rate than what would be otherwise. The province does not impose a fee or charge for this advantage but the debt is issued in the name of the Province of Saskatchewan and reassigned under the same issuing terms and conditions to SaskPower.

As noted in the debt schedule no further higher cost debt is scheduled to be retired until 2022. New issues undertaken in 2013 have an effective rate between 3.54% and 3.97% relative to the 9.78% and 8.5% on the debt due to retire in 2022. One positive effect of capital spending and issuing debt obligations undertaken today is that they can be financed at significantly less interest costs than earlier issues.

While the D/E ratio has been increasing in the last couple of year, it still can be considered reasonable, especially in the time of construction of major high cost capital projects. It is expected that once the period of intensive capital expenditures has been completed, the D/E ratio will slowly return to the lower end of SaskPower, approved target range. Based on our review of the material filed and our analysis based on the forecasts, the D/E ratio is expected to return to near the 70/30 ratio by the end of this decade. While the interest coverage ratio is forecast to be 1.4 in 2013, the future ratio during the term of this application is closer to 1.1, which is considered to be low.[60]

The current equity ratio target of 8.5% provides SaskPower with internally generated resources to enable it to fund part of the new capital through internally generated funds. Reducing the ROE to near 2% lessens the ability to internally fund capital projects. SaskPower is forecasted to have interest coverage ratio of 1.1. For SaskPower that means it is maintaining a 10% cushion of annual cash availability over and above its forecasted cost of interest.

While there is significant saving to be gained using short term financial instruments to fund capital projects as discussed in the finance charge section above, there is also an offsetting risk element in the event interest rates move sharply upwards or change significantly. We would expect SaskPower's Board as well as the shareholder (Crown Investment Corporation) is monitoring this issue and will, when the time is appropriate, move some of this short term secured debt into long term secured debt instruments to protect the utility and its consumer's from the vagaries and volatilities of the financial markets.

The long-term target range for return on equity is 8.5% which, when compared to other utilities in Canada and recent regulatory decisions, is at the lower end of the median returns for similar utilities. Since the annual returns expected results for this application during 2014-2016 is closer to 2% a year, it is significantly lower than the long term target. SaskPower fully recognizes this application does not generate the rate of return close to the required 8.5% target, but did so to mitigate rate increases than would have otherwise been necessary, to cushion the financial impact on the consumers during this period of capital reinvestment and renewal.

As an example to increase rates by an additional 1.5% on July 1, 2014 over and above the 5.5% effective January 1, 2014 would raise an additional $ 14 million in 2014. That would result in the ROE moving from the forecast of 1.3% to approximately 2%. The issue is one of rate affordability in a period of significant infrastructure reinvestment. SaskPower's rate proposal blends the financial need of the utility with rate mitigation for its ratepayer. That coupled with the shareholder decision to not impose a need for the dividend, provides both SaskPower as well as its ratepayers an opportunity over time to transition to a stronger balance sheet, not solely at the expense of today's customer. This is a decision under the current circumstances that we can support.

The net impact of the revised forecasts (from the Mid-Application Update) is that SaskPower's operating income for 2014 is expected to improve from the initial application forecast of $ 26.9 million to $66.0 million. SaskPower's revised ROE is now forecasted to be 2.9% for 2014.

6.9.1 Foreign Exchange

As of December 31, 2012, SaskPower had a small $15,000 gain on their foreign currency exposure on the trading side of the electricity trading transactions.

NorthPoint operation has foreign exchange exposure for electricity trading transactions originating in the U.S. While the monetary significance of foreign exchange is modest, there is a foreign exchange risk in the electricity trading financial category. However, NorthPoint indicates that they use U.S. funds to discharge US obligation thereby limiting or removing this exposure. At the current time with the current volatility of the US – Canadian dollar it is expected there will be a modest negative result.

Revenues and expenditures resulting from transactions in foreign currencies are translated into Canadian dollars at the exchange rates in effect at the transaction date. Any resulting foreign currency transactions gains and losses are included in the consolidated statement of income in the current period.

[60] IR 11A First Round

6.9.2 Observations

Since SaskPower has a very limited exposure to foreign exchange costs, should any exposure materialize, it is expected to be less than $100,000 for the year 2013. As a result no budget line has been anticipated for the application years under review. With the recent decline of the Canadian dollar and since SaskPower does not hold any foreign currency debt, no additional exposure is expected.

6.10.1 Municipal, Corporate and Other Tax Obligations

Taxes and other tax obligations for 2013 are forecasted to total $52.9 million, up from the actual total tax cost in 2012 of $47.7 million. This represents a year over year increase of approximately 11%.

This category of expense is made up mainly of two components, Corporate Capital Tax and Municipal Grants-in-Lieu of Taxes. As illustrated in the following table as SaskPower invests more capital in its generation, transmission and distribution system there is an expected and complementary increase in the capital tax obligation to the Province. Corporate capital taxes are calculated on the paid portion of corporate capital, which are driven by increased capital spending and borrowing. As SaskPower continues to invest heavily in new and refurbished/upgraded infrastructure, there is an expectation that Corporate Capital Tax Expense will increase significantly as these new capital investments are put into service.

The following table summarizes SaskPower's total tax expense for the years 2012 to 2016.

Table 6.38 - Tax Expense from 2012 to 2016

	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Corporate Capital Tax	26.2	31.2	34.0	36.9	38.1
Grants In Lieu	20.8	21.2	22.5	23.9	25.3
Miscellaneous Tax	0.7	0.5	0.5	0.5	0.5
Taxes	**$47.7**	**$52.9**	**$57.0**	**$61.3**	**$63.9**

As noted above, the overall capital tax expense category increased from $18.7 million in 2009 to the current forecast for 2013 of $31.2 million. Corporate Capital Tax expense is expected, as noted in the table to increase to $38.1 million in 2016 more than double the total capital tax expense in 2009.

Grants-in-lieu of taxes (similar to municipal property taxes) is paid to 13 cities based on the land and buildings situated in those communities.

SaskPower also collects a municipal surcharge on behalf of 402 municipalities and forwards the revenue collected directly to those municipalities.

6.10.2 Observations

Since both of these tax obligations are legislatively mandated they must be funded by the revenue requirement. Year end results for 2013 are expected to be greater than originally budgeted. This is mainly associated with higher than anticipated capital and municipal tax obligations and with the corresponding result that forecasts for 2014-2016 maybe understated.

As more capital is invested in new or refurbished infrastructure the obligation under the Corporate Capital Tax will continue to increase. Corporate capital taxes are calculated on the paid portion of corporate capital, which is driven by increased capital spending and borrowing.

SaskPower is forecasting municipal grant in lieu of taxes will increase approximately 5% per year over the period covered by this application which forecast represents a similar trend line of past experience since

2009. Based on our review this is a reasonable expectation of the combination of both municipal tax increases and grant in lieu obligations on investment in new assets in those 13 communities.

On the basis of the foregoing, both the Corporate Capital Tax and Municipal Grants-in-Lieu of Tax forecasts are deemed to be just and reasonable. Even though the year over year increase is significant,[61] as is the capital reinvestment, and the resulting revenue requirement may be underestimated. Additionally, as noted in the last report, there is an expectation that this category of expense will significantly increase as the planned capital program and complimentary capital investments are made and these capital investments are put into service.

6.11.1 Affiliated Company Transactions

Effective January 1, 2009 all the assets, liabilities, contracts, and operations associated with the fly-ash business formerly conducted by SaskPower International (SPI) and the Centennial Wind Power Facility owned and operated by SPI were transferred to SaskPower. Also, all the employees of SPI were reassigned to positions in SaskPower.

SPI has no active operations beyond its joint venture interests in the Cory Cogeneration Station and the Cory Cogeneration Funding Corporation and its investment in the MRM Cogeneration Station. After the transfer the only assets remaining in SPI are the current power project investments that are located in Saskatchewan and Alberta. These are the 228 MW Cory Cogeneration Station, near Saskatoon, and the 172 MW MRM Cogeneration Station located near Fort McMurray, Alberta which was developed in partnership with ATCO Power and began operations in January of 2003. The Cory Cogeneration facility which began operations in January of 2003 is jointly owned with ATCO Power. These investments are jointly influenced by SaskPower and ATCO.

The 150 MW Centennial Wind Power Facilities near Swift Current, Saskatchewan which was built under SaskPower International is now owned and operated within SaskPower`s generation fleet. This wind farm began commercial operation on March 15, 2006.

Additionally the SPI fly-ash business line has been in existence for a number of years and sells its output for use in ready-mix concrete in Saskatchewan and Manitoba. The fly-ash business is also now operated directly by SaskPower.

However, NorthPoint continues as a wholly-owned subsidiary of SaskPower. It was formed in October 2001 to meet the Standards of Conduct requirement as part of SaskPower’s Open Access Transmission Tariff (OATT) to separate electricity trading transactions from the rest of the vertically integrated utility operations. Under OATT, the SaskPower transmission system is open for third party use, and in a reciprocal way, NorthPoint gains access to the transmission capacity of other jurisdictions.

As a result NorthPoint is able to undertake electricity trading activities which include the purchase and resale of electricity and other electricity related commodities and derivatives in regions outside of Saskatchewan. These trading activities include both real time as well as short to long term physical and financial trades in the North American market and are intended to deliver positive gross margins to SaskPower while operating at an acceptable level of risk. NorthPoint continues to build on the knowledge gained as an energy marketing agent for SaskPower and uses this experience to provide economic value to its shareholder.

As noted in the NorthPoint 2012 Financial Statement net trading revenue was $28.8 million while net trading earnings were $14.3 million.

[61] Appendix 1 Table A1.10

Effective January 1, 2005 SaskPower's Gas Management group joined NorthPoint and managed, as the agent for SaskPower, the natural gas requirements, purchases, transportation, storage and price management transactions for SaskPower. This group also managed the natural gas requirement for the Cory Cogeneration Station located at the Potash Corporation of Saskatchewan's Cory Potash Mine outside of Saskatoon.

On January 1, 2012 SaskPower and NorthPoint terminated the transfer price agreement related to generation and load management services, electricity export and import functions for the generation assets of SaskPower, and management of SaskPower`s natural gas supplies for its natural gas-fired power plants. As Generation and Load Management are essential services to SaskPower, the energy management services unit is now part of SaskPower. This unit provides essential services 24 hours a day, 7 days a week and calls for the economic dispatch of SaskPower's generating units to ensure that the units are utilized, based on the lowest marginal cost. In addition this unit develops operating plans based on the latest load forecast, hydro conditions, planned generation maintenance, fuel price forecasts, and market information.

NorthPoint has a new service agreement effective January 1, 2012 with SaskPower where it provides electricity export (when surplus electricity is available) and imports purchase electricity needs (when demand is higher than existing capacity) to meet that demand. NorthPoint performs a variety of functions related to the generation assets of SaskPower but in addition provides SaskPower with economic load and generation management services, purchased power agreement management, and manages SaskPower`s natural gas supplies (including storage arrangements) for its natural gas-fired power plants.

Accordingly all of the costs and benefits are now recognized as SaskPower`s expenses. These expenses are now allocated to the utility directly and not through an inter-company affiliate transaction with NorthPoint.

NorthPoint was funded by a $10 million dollar equity injection from SaskPower. Since 2010 all staffing FTE's and OM&A costs are included directly in the SaskPower budgets and expenses.

As a result of the termination of the transfer pricing agreement and direct assignment of administration expenses NorthPoint residual administrative costs were reduced from $7.9 million in 2011 to $2.1 million in 2012.[62]

It is with the knowledge gained by managing SaskPower's operations in electricity trading which has allowed NorthPoint to obtain value by trading in markets external to Saskatchewan including Alberta, Manitoba, Ontario, US Pacific Northwest, US Mid-continent markets, and the US Northeast markets. These trading transactions are intended to deliver positive gross margins to SaskPower`s bottom line while operating within an acceptable level of risk. Annually SaskPower has NorthPoint perform a VAR analysis (Value at Risk) to ensure it is at an acceptable risk level and is within the risk management guidelines as approved by the Board of Directors.

The new 2013 Business Plan for NorthPoint builds on the previous two years of expanding into new markets and products, while continuing to adjust resources to better reflect an increased emphasis on meeting the growing requirements of SaskPower's services. With SaskPower as NorthPoint's main business focus, NorthPoint added resources in response to the increasing demands for natural gas, power contract management, and the potential for implementing market-based emission mitigation solutions.

Between 2007 and 2011 NorthPoint has been able to generate a profit from trading activities totalling $49 million. NorthPoint paid dividends of $18.8 million and $5.5 million relative to operational profits generated in 2011 and 2012.

[62] 2012 NorthPoint audit report

On December 31, 2012 SaskPower announced that it would dissolve the Power Greenhouse Inc. legal entity effective January 2013. The Power Greenhouse Inc. personnel and assets/liabilities were transferred on that date to SaskPower. The Shand Greenhouse continues to operate within SaskPower following dissolution of the legal entity.

6.11.2 Observations

With SaskPower as NorthPoint's main business focus, managing the increasing requirements for natural gas, power contract management, and the potential for implementing market-based emission mitigation solutions the relationship is intrinsically tied to the operational needs of the utility. As a result of the organizational change that occurred at the beginning of 2012 a number of the operational costs are directly assigned to SaskPower, significantly reducing inter-company transactions.

Also with the change that occurred in 2009 relative to SPI the needs to observe transactions are very limited both in nature and content. Shand Greenhouse continues to operate a greenhouse to supply tree seedlings for the purpose of reforestation. The Shand Greenhouse subsidiary has an agreement with SaskPower, such that it operates the greenhouse and in turn SaskPower funds the greenhouse corporation for all costs incurred.

As noted in our 2012 report as a result of the financial relationship between SaskPower and NorthPoint, NorthPoint provides a dividend to SaskPower to the benefit of the ratepayers, and considering the limited affiliate transactions that do occur, the strict rules of affiliate transactions are significantly mooted.

We are satisfied that appropriate recognition has been given to this matter and where needed, formal agreements are in place to ensure each transaction is appropriately recorded. As a result of the foregoing we are satisfied measures are in place to ensure costs are tracked and allocated appropriately.

NorthPoint continues to work jointly with SaskEnergy to pursue structural efficiencies or other economies related to the gas procurement processes using all of their infrastructures to generate value and synergies for their ratepayers. Both SaskPower and SaskEnergy purchase, move and put into storage significant quantities of natural gas for subsequent use by their ratepayers. Accordingly, those assets and processes need to operate efficiently and effectively for the benefit of both ratepayers.

NorthPoint confirmed that it will continue to work together with both utilities to explore operational efficiencies to better manage both companies fixed and operating costs. As the natural gas volumes required are increasing significantly for SaskPower there is a constant need to effectively manage the procurement, transmission and storage arrangements efficiently.

6.12.1 Other Costs

SaskPower has an "Other Expense" category for items such as Asset Disposal costs, Asset Retirements costs and Environmental Expense. In 2011 the actual costs for this category was $7.7 million and was forecasted to be $13.2 million in 2012 but the actual results of $26.7 million were substantially over budget as noted in the following table.[63]

The following table is a summary of Other Expense for the years 2012 to 2016

Table 6.39 - Other Expense from 2012 to 2016

[63] IR 33 First Round

(in $ millions)	2012	2013	2014	2015	2016
G/L on Asset Retirement	15.1	5.8	13.2	13.7	14.0
Cost of Asset Disposal	8.6	3.2	3.2	3.3	3.4
Environmental	3.0	0.0	0.0	0.0	0.0
Total Other Expenses	**$26.7**	**$9.0**	**$16.4**	**$17.0**	**$17.4**

For 2013 the forecasted costs for these expenses is $9.0 million of which $8.0 million is forecasted for Asset Disposal costs. For the period covered by this application, specifically the 2014-2016 calendar years asset retirement costs are going to be significantly higher mainly as a result of retiring two coal generating units, Boundary Dam Units 1 & 2. However no environmental expenses are expected or forecasted to require remedial expenses.

No dividend payments to CIC have been made since the last special payment from 2011 net income and future forecasts do not anticipate any dividend payments being required or made during this application.

The benefit to SaskPower of the “dividend holiday” permits a greater proportion of SaskPower’s capital investments to be self-financed by cash flow, hence reducing borrowing requirements and the associated interest expense. However, as noted in our last report, with SaskPower’s current capital investment forecasts for the next number of years, the expected investments is such that the decision to forego the dividend will only help reduce, but will not eliminate, the need for significant borrowings and rate increases in future years.

The financial benefits to SaskPower and its ratepayers for the exclusion of a dividend payment for the years 2013 to 2016 are outlined below:

- Lower debt levels – If SaskPower, as an example, paid a dividend of 50% of operating income each year, debt levels would increase by $137 million by 2016. This would result in the debt ratio increasing from 77% to 79% in 2016. If the dividend was up to the maximum 90%, the impact would be substantially greater.
- Lower finance charges – Using the same example Finance charges would be $2.2 million per annum higher by the year 2016. This assumes that all new borrowings would be done at short-term rates, double if long term rates were used.
- SaskPower’s equity position is enhanced by the amount of dividend that would have otherwise been paid.[64]

SaskPower pays water rental charges to the Province which are a function of the use of water in SaskPower hydraulic generation facilities. These fees are included in the energy charge for hydraulically generated electricity. Water rental charges are calculated on the basis of $/MWh of hydraulic generation. These payments have averaged between $15 million and $20 million annually over the past few years depending on hydraulic generation MWhs produced during those years.

The following table shows the water rental fee rate paid or forecasted to be paid in the years 2010 to 2016:

Table 6.40 - Water Rental Fee for 2010-2016

(in $/MWh)	2010	2011	2012	2013	2014	2015	2016
Water Rental Fee	4.07430	4.27802	4.47053	4.69406	4.89355	5.10153	5.31835

[64] IR 10 Second Round

Also included in the F&PP expense category are the royalties paid for coal. Coal royalties paid were $22.3 million in 2011 and $24.8 million for 2012 and are expected to be $24.2 million in 2013, $26.2million in 2014, $26.5 million in 2015 and $24.9 million in 2016. It should be noted that SaskPower has a number of coal supply contracts, yet to be signed for 2014 and 2015 which could impact future royalty expenses.

Included in the revenue requirements are fees paid to the Province of Saskatchewan. The table below illustrates the total payments made during the 2007-2016.

Table 6.41 – Payment to the Province of Saskatchewan

	Actual						Forecast			
(in $ millions)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Water Rentals	$15.2	$14.4	$11.5	$15.8	$20.0	$19.1	$21.0	$18.0	$18.7	$19.3
Capital Taxes	17.5	18.7	20.4	22.1	22.4	26.9	31.7	34.5	37.4	38.6
Coal Royalties	19.4	21.1	21.5	22.6	22.3	24.8	24.2	26.2	26.5	24.9
Dividends	97.0	46.0	0.0	0.0	0.0	120.0	0.0	0.0	0.0	0.0
Total Payments	**$149.1**	**$100.2**	**$53.4**	**$60.5**	**$64.7**	**$190.8**	**$76.9**	**$78.7**	**$82.6**	**$82.8**
2007 to 2012 figures based on actual, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan.										

Lastly, the Power Corporation Superannuation Board retained an independent actuary to report on the Actuarial Valuation for Funding Purposes as at December 31, 2011 and as at December 31, 2012. The December 31, 2011 evaluation of the accrued financial position of the plan showed a deficit of $261.8 million while the results of the current (December 31, 2012) evaluation disclosed a deficit of $290.0 million. The independent report disclosed that the increased deficit was mainly associated with a change in actuarial assumptions offset in part by higher than expected investment income.

For the year ending on December 31, 2012, $290 million of the actuarial losses were recognized directly in other comprehensive income relating to SaskPower`s defined benefit pension plans. We understand the International Accounting Standards Board on September 2011 amended version IAS 19 ``Employee Benefits" eliminating the option to defer the recognition of gains and losses and streamlining the presentation of changes in asset and liabilities arising from defined benefit plan evaluations with the intent to enhance the disclosure requirements for such plans. We have no further information available on the impact of the amended version of IAS 19 on SaskPower`s 2013 financial statements.

The defined benefit plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the Plan but it is obligated to pay benefits under the terms of the Plan as they come due.

6.12.2 Observations

Asset disposal and retirement costs are a normal part of a utilities operation and need to be funded when a particular asset has reached the end of its useful life. SaskPower obligations in this respect are forecasted to be $9.0 million in 2013 as compared to the actual of $26.7 million in 2012. The annual forecasts for each year contained in this application are noted in the table above.

Water Rental Fees, Coal Royalties and Pension Costs are all obligations of SaskPower which impact the corporation's annual revenue requirement over which they have no control. As noted earlier, an Actuary undertakes an annual actuarial evaluation on the pension plan and depending on market forces; the positive or negative effects of the economic marketplace determine whether the plan has an actuarial surplus or unfunded liability which SaskPower must reflect on their balance sheet. Notwithstanding the defined benefit pension plan is a legacy plan, there is a continuing legal obligation on SaskPower to fund any unfunded liabilities as they come due.

Similarly, water rates and coal royalties are determined elsewhere. SaskPower is obligated to fund those costs and they are recognized in the unit generation cost under fuel and purchased power costs.

6.13.1 Future Financial Outlook

SaskPower load growth from 2013 to 2023 is projected to increase at significantly greater rates than experienced in the recent past. Total system energy requirements are expected to increase 29% over the next ten years with the Power, Commercial and Oilfield classes responsible for 76% of this growth. During the next decade, system peak demand requirements is expected to increase approximately 2.2% per year, double the 1.1% per year recorded between 2000 and 2010. In 2012 SaskPower spent $226 million to add 10,345 new connects, 71% greater than recorded in 2011.

Within the current 10 year planning horizon, SaskPower projects annual energy requirements to increase by an average of 2.6% per year, with the majority of the increase related to the Key Accounts, primarily for the Power Customers. Peak loads are expected to increase by 2.2% per year over this time period compared to 1.7% experienced between 2002 and 2012. While the expected annual system average growth is expected to be 2.6%, the Power Class growth is forecast to be 5.1%. In order to supply the expected growth, SaskPower has analyzed the generation, transmission and distribution needs over the next decade and beyond, in its 40 year Supply Outlook. Capital expenditures are expected to average near $1 billion over 10 years, as more fully discussed in Section 7.0. With increased infrastructure in place annual operating costs will also increase, as will revenues, as more energy is consumed by a larger number of customers. To somewhat mitigate the unavoidable cost increases, SaskPower has embarked on its Business Renewal initiative that is expected to achieve efficiency and productivity improvements over the longer term resulting in either reduced cost savings or cost avoidance.

SaskPower has stated that every $100 million spent on capital projects results in increased financing costs and depreciation expenses of $7.0 – $8.0 million per year. Given the current capital budget is in excess of a billion dollars this impact alone would translate into an annual increase in rates in excess of 4%.

As discussed in Section 7.0, the only realistic short term approach to meeting the immediate increase in load expected in 2014 and during the planning horizon is to lease or construct and operate natural gas fired generation units. As well, it may be necessary to lease diesel generating units to supply the far north energy requirements in the near future to meet the requirements of the mining load. Both of these fuels are at the higher end of fuel type costs, and would result in overall increased F&PP costs in total and on a unit cost basis. OM&A costs are expected to increase due to increased infrastructure maintenance requirements and customer service costs, but will be somewhat off-set by efficiencies and productivity improvements flowing from the Business Renewal initiatives.

The expected growth will require additional capital and operating costs and will likely increase the financial requirements and risks faced by SaskPower. A significant load increase is anticipated in the Power Class. Customers in this class are, to a large extent, involved in production of products that are extremely cost competitive, not only nationally but also globally and are thus sensitive to global price pressures. The recent downturn in the potash industry highlights the uncertain circumstances the utility faces when forecasts are made, especially recognizing the need to have sufficient generating capacity and mandated reserve allowances to meet peak hourly loads.

This, combined with the need to preserve company confidentiality, makes it difficult for any projected expansion plans to remain firm and as planned. As circumstances change, world markets and economics change, often several time per year. This in turn makes it extremely difficult for SaskPower to accurately estimate load requirements, and the requirements display significant volatility from quarter to quarter in any given year.

Such variations in loads increase the risk associated with load demand and sales income as well as other risks primarily related to fuel purchasing requirements and costs. As a greater portion of generation fuel becomes natural gas, the risk, although mitigated by hedging programs, has the potential to be greater because of the current price regime and greater historical price volatility of natural gas. That coupled with the reliance on more natural gas purchases outside the provincial boundaries, raises other issues such as transmission and storage availability and costs.

The current forecasts have seen a decrease in electricity demand relative to the early 2013 forecast primarily in the Power Customer Class mainly as a result of the decline in potash and commodity sector production, offset in part by the increase in demand by the Oilfield customers. The decline in the potash requirements has resulted in delays of a number of major projects and which it is difficult to speculate on when these projects may be restarted.

In the recent forecast for 2014 SaskPower used a 2% inflation rate, 1.1% increasing to 1.7% in short term borrowing rates, together with long term interest rates of 3.7% as compared to 3.5% in the 2013 forecast. Adjusting the forecast for natural gas cost as at November 18, 2014 has been reduced from the $4.39/ GJ used in 2012, to $3.63/GJ in 2013, $ 3.60/GJ for 2014 and $3.94/GJ for 2015.[65] The Mid-Application update now forecasts forward natural gas market prices for 2014 at $4.08 /GJ.

The following table demonstrates a partial snap-shot of the projected growth in revenue and expenses from 2010 to 2016. Although forecasting in the current environment is challenging, the foregoing table is helpful in demonstrating the trending of expenditure growth during the past three years. Future forecasts will be contingent on many factors, primarily the state of the economy from 2014 forward of both Saskatchewan and Alberta.

Table 6.42 - Total Capital Requirements from 2010 to 2016

Description (in $ millions)	2010	2011	2012	2013	2014	2015	2016
Revenue	$1,691	$1,837	$1,847	$2,040	$2,144	$2,346	$2,524
Expenses	$1,468	$1,598	$1,682	$1,866	$2,117	$2,306	$2,484
Net Income	$204	$248	$165.9	$126	$ 26.9	$ 39.9	$ 40.4
OM&A Expense	$513	$575	$603	$618	$648	$672	$698
Past & 2013 Rate Increase	4.50%	0.0%	0.0%	5.0%	5.5%	5.0%	5.0%
Sales (GWh)	18,682	19,675	20,275	21,456	21,598	22,615	23,758
ROE	13.4%	13.2%	8.8%	6.4%	1.3%	2.0%	1.9%
Net Debt	$2,995	$3,166	$3,646	$5,286	$5,941	$6,701	$7,053
Average Equity	$1,758	$1,864	$1,921	$2,047	$2,074	$2,114	$2,154
Debt Ratio	63.0%	63.0%	66.4%	71.3%	74.6%	76.4%	77.0%
Dividends Declared (Expected)	$0	$0	$120	$0	$0	$0	$0
Capital Generation	$568	$624.5	$515	$490	$ 448	$ 366	$ 267
Other	$309	$276	$483	$660	$ 752	$ 707	$ 630

* Information gathered from 2014 BP

6.13.2 Observations

As noted in Section 3.0, during the next decade SaskPower electricity peak demand is forecasted to grow at 2.2% per year during the 2013-2023 time periods, double the 1.1% recorded between 2000 and 2010. Within this next planning horizon SaskPower projects annual overall energy requirements to increase by 2.6% per year with the majority of the increase related to its key customers, primarily in its Power Class, which is expected to grow by 5.1% per year.

In order to meet this increased demand, SaskPower has considered a variety of options. They have spent considerable efforts preparing a number of plans, a near term ten year plan, a twenty year plan, a forty year plan and the far north strategy in an effort to consider all the options available to meet that increased demand and be able to maintain pathways options should the forecasts and needs change.

Those plans detail their specific needs at specific junctures for generation, transmission and distribution to ensure system reliability. The commentary analysis examines the financial requirements of the variety of options or pathways.

[65] IR 85 First Round

As part of our review we were privy to a variety of documents which assisted us in examining the particular consequences of these plans. Specifically we examined in greater detail the 2014 Business Plan which highlights the forecasts and financial needs relative to the 2014-2016 Rate Application.

As SaskPower has stated, the major cost driver of this application is the capital program investments and reinvestments made in the energy infrastructure to deliver a safe and reliable electricity service. As a result of decisions made on capital during the prior year(s) the resulting costs are now being expensed through Finance charges, Depreciations and Taxes (Corporate and Property tax). The increased costs flowing to those three categories of expenses during the rate applications years 2014-2016 totals $312.8 million, all attributable to installed capital investments made prior to January 1, 2014.

We also received and reviewed information on future revenue and expenditure trends, some of which will need to be offset by future rate increases. The future revenue streams assume a ROE of 8.5%, being the long term target established by CIC, but dividends are not anticipated to be paid and are not included as part of the financial assumptions.

During SaskPower's current planning period capital spending is expected to remain above normal, in the $700 million to $1.3 billion range annually. With the significant capital expenditures required by the corporation, relief from the need to pay dividends will eliminate some financial stress but the overall need will, however, remain substantial. With this growth in electricity demand and related expenditures, there is a financial consequence. As part of the Panel's examination of the Rate Proposal, the future financial outlook is an integral part of this examination and an essential ingredient in the consideration of its recommendations.

In the original Application SaskPower forecasted net income of $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016 for a three year positive net income of $107.2 million. The forecasted rate of return in each of those years was 1.3%, 2.0% and 1.9%, far short of the long range target of 8.5%. The return on equity for years beyond 2016 is forecasted to return to more normal target returns of 8-8.5% for the planning period.

The 2014 forecast provided for net income in the Mid-Application update for 2014 is now expected to be $66.0 million for a forecasted ROE of 2.9% up from the original forecast noted above of 1.3%. Additionally, with the revised load forecast for 2015 and 2016, net income in each of those years is marginally forecasted to increase $ 18 million and $ 6 million respectively.

The fuel and purchased power expense from 2013 to 2014 is forecast to increase by $40 million or 7.0%. This is due to an expected increase in input prices ($12 million price variance), an increase in demand ($7 million volume variance) and changes to the contribution of each generation source as a percentage of overall generation ($21 million mix variance). As a result of these factors total F&PP expenses are forecast to be $587.4 million in 2014, $678.4 million in 2015 and $762.0 million in 2016. Net F&PP costs from 2013 to 2016 would increase by $215 million as a result of an unfavourable price ($53 million), volume ($67 million) and mix variance ($94 million). This upward trend is expected to continue through-out the planning forecast period.

With the delay of the in service date for the ICCS project and mainly the increase in natural gas costs resulting from the new forward market prices the Mid-Application now forecasts FF&P at $622.0 million for 2014.

Total interest costs over the planning period are expected to increase in the short term but level off near the end of this decade. This forecast is predicated on long term interest rates for SaskPower remaining between 3.7% and 5%. Depreciation expense costs however are going to continue the upward trend resulting from the capital spending on new or rebuilt infrastructure which is expected to continue for the next decade.

The possible rate increases required, beyond 2014-2016, will be influenced by capital reinvestments in plant, by the market price of natural gas, and load growth that can be expected or materialize on the SaskPower system somewhat offset by the benefits of SaskPower's DSM efficiency programs. To meet the targeted 8.5% rate of return, the necessary net income will require rate increases to be greater that inflation between 3% and 5%, if fuel input and interest costs remain relatively stable. Any upward movement beyond those forecasted for this application in these areas would continue to place further upward pressure on consumer's rates.

The D/E ratio is expected to be at the high end of SaskPower's capital structure target range in 2014 and to exceed that target range of 75/25 in 2015 and 2016 as noted in Section 6.8.1. The current forecast does not foresee a return to the current target range until near the end of this decade. SaskPower's long term plan is to work to reduce the debt ratio to at least the mid-point of the long term target range.

The Corporation's interest coverage ratios are forecasted to deteriorate from 1.4 in 2013 to 1.1 for 2014-2016 and then slightly improve over the next decade to near 1.4, which is in the acceptable range. The financial wellness of the utility will be weakened by the addition of the debt associated with the extensive capital program plans, but will certainly continue to remain within the range of other electric utilities.

SaskPower continues to face significant financial challenges in the near and long-term. The current aging infrastructure requires higher operating costs, a higher standard of maintenance, and higher capital spending. The increased capital infrastructure funding for new generation, the transmission and distribution system as well as possible future CO_2 tax and other emission mitigation costs are significant future risks. These risks could negatively affect the Corporation's financial flexibility and its subsequent ability to withstand future demands and/or negative results. SaskPower's modest forecasted net incomes of $26.9 million in 2014 (Mid-Application forecast now is $ 66.0 million), $39.9 million (now $57.9 million in 2015 and $40.4smillion (now $46.4 million) in 2016 for a 3 year original application total of $107.2 million leaves limited flexibility to respond to possible negative financial results during that period. The new forecast as a result of the Mid-Application update and subsequent information net income over those three years is forecasted to be $ 170.3 million.

In the past we have commented that SaskPower recognized it had not been operating at optimum efficiency. Since 2010 significant effort has been focused on new initiatives to streamline processes, eliminating duplication and inefficient efforts and leveraging technology to improve the cost effectiveness of the corporation. They have spent significant effort (human & financial) with the support of outside experts in this transition period and we believe we are now seeing the results of those initiatives. We discuss the progress made in seeking out cost savings, streamlining customer services and operating more efficiently in greater detail in Section 6.3 but overall we are satisfied with the progress made to date. This application quantifiably demonstrates that real savings are being generated which have reduced rate increases that would otherwise have been required.

This by no means suggests that SaskPower is not without significant financial challenges. There are numerous risks going forward some of which are likely to be realized. How well SaskPower handles those risks could materially affect the financial outcome. We are however comforted by the leadership's ability to recognize those risks and manage them for the mutual benefit of the corporation and its ratepayers.

The impact of this application is significant for ratepayers and may present a financial hardship for some. Unfortunately there is no magical solution. The integrated electrical system needs to be upgraded. SaskPower is not alone in having to spend large amounts and the US are faced with the same requirement.

Saskatchewan's economy relative to others is growing at a much faster pace. However, for SaskPower this is a "good news, bad news" result. Not only must it maintain or replace vintage infrastructure, but system load growth demands new generation or transmission infrastructure sufficient to supply the new demand while delivering a safe and reliable electricity service. To do so comes at a cost, a cost that must unfortunately be paid for by the ratepayer.

7.0 SaskPower Historic and 2014-2016 Capital Program

7.1 Purpose and Capital Budgeting

SaskPower's capital program entails the construction of additional generation, transmission and distribution assets to meet growing demands for energy. The program also consists of projects that refurbish and upgrade existing infrastructure for purposes of capacity, reliability service improvement, and environmental mitigation. Annual capital expenditures are the most significant component of any increase in SaskPower's rate base. SaskPower's capital program, including new generation, is projected to be $1,200 million in 2014, $1,073 million in 2015 and $898 million in 2016 for a total of $3,171 million over the 3 years. Depreciation, finance charges, taxes and other expenses (primarily asset retirement costs) are considered capital-related as they are driven by capital spending and are expected to account for about 72% of the expense increase in 2014. These categories of expenses are expected to increase by $181.4 million in 2014, $73.3 million in 2015 and $68.5 million in 2016 (3 year total increase of $323.2 million. The full financial impact of capital expenditures are deferred as interest and depreciation charges do not take effect until the assets are completed and put into service.

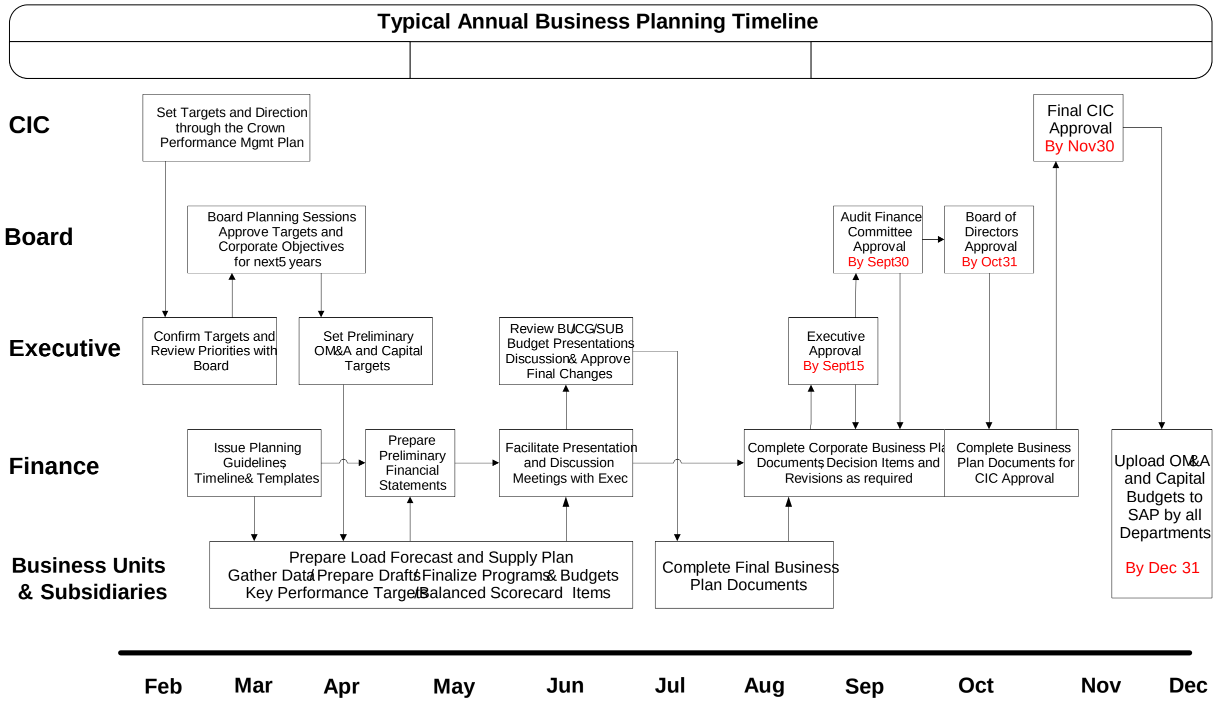
Costs for capital projects ultimately impact rates when capital assets are put into service and the Return on Equity (ROE) component is added to the annual revenue requirement. Other related components in the annual revenue requirement are customer contributions, depreciation expense, and finance charges. SaskPower's Board approved capital program budget process is a part of the overall detailed annual spending plan for the first year of the planning period. It is a combination of a top down and bottom up approach. This process remains unchanged from that followed in the previous 2013 Application.

SaskPower submits that it continues to focus on balancing the competing needs of operating concerns with the desire to maintain fair and equitable rates while at the same time providing a reasonable return to its shareholders.

Preliminary budgets are revised as required, as are the organization's projected revenues and expenses... The major functional areas impacted by the capital program are Generation, Transmission & Distribution, Customer Service, and Other. The annual business plan is reviewed and approved by both SaskPower's Executive and its Board. The Plan must further receive final approval by Crown Investments Corporation, normally in December of each year.

All business units, corporate support groups and subsidiaries are required to deliver programs within the approved budget levels, with appropriate controls exercised by the VP, Corporate and Financial Services. Corporate financial statements are subject to audit by external auditors and the Provincial Auditor. SaskPower's capital expenditure approval process is shown in the chart on the next page.

Diagram 7.1 - Capital Expenditure Approval Process



Detailed financial analyses identifying the cost and benefits, as well as costs and benefits of alternatives are conducted, as are facility needs justification, cost estimates, financial benefits (where applicable and quantifiable), intangible benefits, and a discussion of the implications and risk inherent in the project implementation or deferral. Each project must meet or exceed SaskPower's cost of capital requirements and have a positive net present value before the project is undertaken.

If an annual capital program is unable to be completed as projected, there is no carryover of the remaining funds to build on that years previously approved program. Rather, the year 2 program, including any carry-over projects must be justified and approved in its entirety, and budgetary limits may eliminate some year 2 projects included in the original year 2 estimates. As previously discussed for every $100 million in capital expenditures, SaskPower's depreciation expense will increase by $4 million and finance charges also by $4 million at current interest rates. Additionally, the amount of ROE incremental revenue requirement would also increase by the allowed ROE rate of the capital expenditure. Based on SaskPower's long-term ROE target of 8.5%, a $1.0 billion capital spending program would equate to a 4.4% overall rate increase related to depreciation expense and finance charges. The actual capital expenditures for 2012 and the forecast for 2013, 2014, 2015, 2016, as well as the total for 2014 to2023 are as follows

Table 7.1 - Capital Program for 2012, 2013, 2014, 2015, 2016 and 2014-2023

Capital Expenditures (in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**2014-2023**
Transmission & Distribution	393	449	603	592	467	4,701
Power Production	123	118	140	140	140	1,400
Other	82	165	171	143	166	1,265
Total Infrastructure & Capital Programs	**$598**	**$732**	**$914**	**$875**	**$773**	**$7,366**
New Generation (& Carbon Capture)	$383	$618	$286	$198	$125	$2,057
Total Capital Expenditure	**$981**	**$1,350**	**$1,200**	**$1,073**	**$898**	**$9,423**

7.2 Infrastructure Renewal Capital Spending

As noted in the above table, SaskPower's infrastructure and capital programs, including new generation increased from the actual 2012 capital expenditure of $981 million to a projected $1,350 million in 2013, $1,200 million in 2014, $1,073 million in 2015 and $898 million in 2016. This is significant when also taking into consideration that the actual capital expenditure was just recently $538 million in 2010 and $625 million in 2011.

The Infrastructure and Capital Program expenditures are forecast to be $732 million in 2013, $914 million in 2014, $875 million in 2015 and $773 million in 2016. Included are major expenditures for Power Production; Transmission & Distribution; Information, Technology & Security; SDR; and the Global Transportation Hub operations center.

Power production expenditures are for generation plant renewals (capacity sustainment). The following table breaks down the Power Production Capital Expenditures for 2014, 2015, 2016 and 2014-2023.

Table 7.2 - Power Production Capital Expenditures

Power Production (in $ millions)	2014	2015	2016	2014-2023
Boundary Dam	49	24	33	168
Northern Hydro	39	52	58	221
Poplar River	46	78	20	304
Shand	13	6	15	149
QE / Western Plants	14	5	10	113
Other	2	4	6	14
Contingency	(22)	(28)	(2)	432
Total	**$140**	**$140**	**$140**	**$1,400**

Transmission and Distribution projects include capacity increases; infrastructure sustainment; customer connects; vehicles & meters; and the Island Falls / Key Lake (I1K) transmission line. The following table breaks down the Transmission and Distribution Capital Expenditures for 2014, 2015, 2016 and 2014-2023.

Table 7.3 - Transmission and Distribution Capital Expenditures

Transmission & Distribution (in $ millions)	2014	2015	2016	2014-2023
Distribution Capacity Increase	34	21	29	139
Distribution Infrastructure Sustainment	116	114	103	1,084
Transmission Capacity Increase	210	206	129	599
Transmission Infrastructure Sustainment	210	207	188	1,053
Transmission Other	7	4	2	30
Vehicles & Meters	26	27	24	241
Contingency	(368)	(343)	(239)	(795)
Transmission Customer Connects	98	91	82	615
Distribution Customer Connects	150	150	150	1,500
I1K Transmission Line	120	116	0	236
Total	**$603**	**$592**	**$467**	**$4,701**

Other Capital Expenditures include the development of the new operations center at the Global Transportation Hub; Information, Technology & Security; SDR Automated Metering Infrastructure (AMI) project; head office refurbishment; and buildings, land & furniture. The following table breaks down these other Capital Expenditures for 2014, 2015, 2016 and 2014-2023.

Table 7.4 - Other Capital Expenditures

Other Capital (in $ millions)	2014	2015	2016	2014-2023
Operations Center	12	50	80	265
Head Office Refurbishment	0	0	0	130
Buildings / Furniture / Land	35	35	35	350
Service Delivery Renewal	70	11	0	81
Information, Technology & Security	54	47	51	439
Total	**$171**	**$143**	**$166**	**$1,265**

7.3 New Generation Expenditures

SaskPower is forecasting significant additional load requirements are being during the 2013 to 2023 period for the Power class (primarily the potash, pipeline pumping, chemical and northern mining sectors) as well as for the Oilfield, Commercial and Residential customers. A record peak load of 3,379 MW was recorded on January 30, 2013, breaking the previous record of 3,265 MW established on January 18, 2012.

During the next decade, system peak demand is expected to increase by approximately 2.2% per year, double the 1.1% per year recorded between 2000 and 2010. A record of 22,129 GWh for electricity supplied in 2012 was just set as well while provincial load growth forecasts indicate the need for an additional 5,929 GWh over the next decade. Most recently a new peak of 3,543 MW was set on December 6, 2013. Peak load is expected to be 3,945 MW by 2016, while total existing generation capacity for SaskPower owned facilities and PPA entitlements is 4,302 MW. Recognizing the reality of potential generation plant breakdowns and reserves as well as reliability requirements and security of supply, the current generating capability is rapidly approaching, if not already at available capacity. Accordingly, more emphasis is being given to construction of new generation and new or upgraded transmission facilities to convey power to the market.

Capital investment for new generation is expected to be $618 million in 2013, and then drop to $286 million in 2014, $198 million in 2015 and $125 million in 2016. The major Capital Expenditures during this period are for repowering the Queen Elizabeth Power Station, completing the Carbon Capture Test facility, and construction of the Tazi Twe (Elizabeth Falls) hydroelectric project. The following table breaks down the New Generation Capital Expenditures for 2014, 2015, 2016 and 2014-2023.

Table 7.5 - New Generation and Carbon Capture Capital Expenditures

New Generation & Carbon Capture (in $ millions)	2014	2015	2016	2014-2023
QE Repowering	225	118	25	368
Elizabeth Falls	40	80	100	400
Carbon Capture Projects	21	0	0	1,290
Total	**$286**	**$198**	**$125**	**$2,057**

The North Battleford Energy Centre (NBEC) commenced operations in June 2013 providing 260 MW of natural gas capacity. SaskPower commissioned the NBEC under a 20 year PPA (2013 - 2033). For accounting purposes the PPA is treated as a capital lease, which is recorded on the balance sheet as an asset and a corresponding liability upon commissioning. The capital lease amount for the NBEC was $700 million which was booked in 2013. In addition to this, SaskPower has also entered into a 20 year PPA with Algonquin Power to build and operate a new 177 MW wind facility, which is expected to be operational at the end of 2016.

SaskPower is developing a wind power plan outlining the utilities expectations for future wind power development. That plan is expected to be completed in 2014[66].

[66] IR 29B Second Round

7.4 Planned Maintenance, Life Extensions and Shutdowns

SaskPower's planned maintenance programs do not form a part of the annual capital program, but are budgeted for and expensed in the year they are carried out. They are capital type projects, at times requiring significant funding, and the vast majority are intended for rehabilitation of coal, hydraulic and natural gas generating units and/or components. Projects may also include miscellaneous projects on various components of the transmission and distribution system during certain years. The planned maintenance program will impact the daily real time dispatch of the various generating units, as some of these units are shut down for maintenance. Other replacement generation must be in place to ensure adequate supply, including reserves are available throughout the year.

SaskPower uses the following criteria as the basis for determining and budgeting for this program on an annual basis:

- Minor overhauls of boilers and auxiliary equipment occur every 24 months with duration times of 21 to 28 days.
- Major turbine and generator overhaul of lignite coal units occur every 8 to 10 years depending on conditions and resources available, with all optimized schedules of all inputs being considered.
- Gas generation combustion turbine overhauls are based on equivalent operating hours which are a combination of on line service hours, start/stop cycles and rapid load change cycles, with consideration of OEM warranties and/or best industry practices for older units.
- Hydraulic units undergo life extension studies which lead to reliability and capacity increase projects, which must be approved by the Board.

The planned maintenance program carried out and charged to the OM&A budget in 2012, currently ongoing for 2013 and planned for 2014, 2015 and 2016 are shown in the following table:

Table 7.6 - Projects Charged to OM&A for 2012 to 2016

Year	Site and Description
2012	Shand generator and auxiliaries- 8 year major; Poplar River(PR) #1 & #2- Minor routine; Boundary Dam (BD) #4 & #6- Minor routine; Queen Elizabeth (QE) #4, #5, & #6 – Overhauls
2013	PR #1 & #2 – Minor overhauls; BD #1 retired; QE #7,8, & 9 – Overhauls
2014	BD # 2,4,5 &6 - Minor overhauls; PR #1 – Minor overhaul; Shand #1 – Minor overhaul; BD #3 –Inspection
2015	PR #1-Minor overhaul; BD #3 & #5 – Minor overhaul; PR #2 – Turbine major overhaul
2016	PR #1 & #2- Minor routine; BD#4 & #6 –Minor routine; Shand #1 – Minor routine; Ermine #2- hot gas path rebuild.

The following table illustrates the budgeted costs for the program.

Table 7.7 - Budgeted Planned Maintenance OM&A Costs for 2012 to 2016

Year	Location	Cost (in $ millions)
2012	Shand	$ 12.6
	Poplar River	10.9
	Boundary Dam	12.8
	Queen Elizabeth	
Total		**$ 36.3**
2013	Poplar River	$ 9.7
	Boundary Dam	0.0
	Queen Elizabeth	1.4
Total		**$ 11.1**
2014	Boundary Dam	$ 12.4
	Poplar River	8.2
	Shand	5.2
	Queen Elizabeth	7.4
Total		**$ 33.2**
2015	Poplar River	$ 17.7
	Boundary Dam	10.4
	Queen Elizabeth	6.0
Total		**$ 34.1**
2016	Poplar River	$ 7.6
	Boundary Dam	14.3
	Shand	5.1
	Queen Elizabeth	1.1
Total		**$ 28.1**

7.5 Observations

SaskPower's Capital program is driven by the need to replace or refurbish existing generation, transmission and distribution infrastructure, while its planned maintenance program is intended to refurbish generation plant. In accordance with SaskPower's current capitalization policy, a project can:

- Be recognized as an asset only if it is probable that future associated economic benefits flow to SaskPower; and the project cost can be measured reliably

The eligible costs for an asset can only be capitalized (rather than being expensed) only if the following conditions apply:

- Expenditure results in identifiable economic benefits, improved environmental performance or associated with the obligation to serve for a service life of three or more years and ownership or a right to utilize the asset are assured.
- Economic benefits are those that directly or indirectly result in a reduction of operating expenses or an increase in revenues by a sustainable and quantifiable amount and primarily include
    - Reliability, capacity or efficiency improvements
    - Life extensions
    - Improved quality
    - Compliance with regulatory requirements
    - Other supportable reasons for specified business policy or engineering standards

Infrastructure projects not meeting the above criteria are expensed in the year they are constructed.

Capital Program

SaskPower confirms that the capital budgeting process described above remains unchanged from that utilized for the last application[67]. SaskPower provided considerable material, consisting of approximately 130 pages in support of the proposed capital program for the 3 year period [68]including cost/benefit analyses for all capital projects planned for 2014.

The Minister's Terms of Reference for the Panel for this review specify that "the budgeted capital allocation, the rate base, and established corporate policies over the period 2014 to 2016 inclusive" are to be considered as a given factor. However, the requested rate increases result, in large part, from annual expenses for depreciation, Finance charges, Corporate and other taxes and other related expenses flowing from the capital program. As well once an asset is included in rate base it earns the ROE. We appreciate SaskPower's openness and co-operation in submitting significant detailed data respecting the Capital Program, not only for 2014, but also until 2023, the time frame contained in the current Business Plan. Therefore we, and the Panel, can better understand the needs for and impacts on requested rates flowing from the program and as a result are able to make better and more informed recommendations.

The Capital program is carried out in 5 major categories: Power Production (Generation); Transmission; Distribution; Customer Service; and Other. Each of the major categories includes projects that refurbish, replace or enhance existing infrastructure to continue to provide the necessary existing levels of service. As well projects are included in the program that are required to serve increased energy and demand placed on the system because of additional load and customer growth, including customer connects. The ICCS project at Boundary Dam is also included in this program

The following illustrates the major components of the actual results for 2012, the current projections for 2013 and the forecast for 2014, 2015 and 2016 capital program:

Table 7.8 - SaskPower Capital Spending for 2012 to 2016

(in $ millions)	2012	2013	2014	2015	2016
Power Production					
Capacity sustainment	$123	$118	$140	$140	$140
QE repowering	26	94	225	118	25
Tazi Twe (Elizabeth Falls)	0	14	40	80	100
ICCS	357	510	21	0	0
Total Power	**$506**	**$736**	**$426**	**$338**	**$265**
Transmission & Distribution					
Capacity increase/sustainment	$167	$260	$235	$235	$235
Customer Connects	226	189	248	241	232
I1K line	0	0	120	116	0
Total T&D	**$393**	**$449**	**$603**	**$592**	**$467**
Other Capital					
Operations Centre	$0	$0	$12	$50	$80
Buildings/Furniture/Land	26	62	35	35	35
Service Delivery Renewal	25	70	70	11	0
Information Technology & Security	31	33	54	47	50
Total Other	**$82**	**$165**	**$171**	**$143**	**$165**
Total Capital Program	**$981**	**$1,350**	**$1,200**	**$1,073**	**$897**

[67] IR 116 First Round
[68] IR 33 Second Round

The above expenditures can be further generally categorized as projects being necessary for new generation to supply incremental load and for overall system refurbishment, capital maintenance and/or replacement and/or enhancement.

Table 7.9 - New Generation, Customer Connects & Other Capital Expenditures

Category	2012	2013	2014	2015	2016
New Generation	$26	$108	$265	$198	$125
Customer Connects	226	189	248	241	232
ICCS	357	510	21	0	0
All other Capital	372	543	666	634	540
Total	**$981**	**$1,350**	**$1,200**	**$1,073**	**$897**

During the budgeting process, all projects in excess of $1 million must be substantiated and supported by extensive analyses. For example in 2014 there are expected to be in excess of 100 individual projects, not including customer connects. An example of the type of analyses conducted by SaskPower in support of a capital project funding is summarized in Appendix 4.

Although it is beyond the mandate of the Panel to submit recommendations with respect to the Capital program and rate base, the impacts flowing from such programs significantly influence SaskPower's annual expenses and thus have a direct impact on requested rates. Based on an assumed borrowing rate of 4% and an average useful asset life of 25 years, SaskPower states that, as a rule of thumb, a $1 billion capital expenditure would increase annual expenses by approximately $80 million, which would translate into a rate increase of approximately 4.2%. While this is an oversimplification of the actual impacts on expenditures and net income, it does clearly illustrate the impact on rates of a capital program.

We have reviewed the load forecasts, the demonstrated growth in annual energy and peak load requirements, as well as the budgeting process and various stepped approvals mandated by SaskPower's Executive and Board, and all supporting documentation willingly supplied by SaskPower supporting the Capital Program Project requests. Although beyond the Panel's mandate, we nonetheless are satisfied that the capital programs proposed by SaskPower in this application are reasonable and properly reflect funding necessary to sustain and enhance the infrastructure so as to assure continued safe and reliable electricity to all customers. We are not able, however, within the time frame and budget for this review able to assess the matter of whether SaskPower's programs represent the least cost approach, if one were to consider only that aspect of the capital program, not considering the desire to introduce more wind generation and other EPP projects, or to expand the PPAs in the future.

There is certainly risk that load will not materialize to the extent forecasts and some temporary surplus capacity may be created. There is, however, an offsetting risk that the load may increase more than forecast, weather may be colder than normal, and river flows will surely be other than median. SaskPower does not have the ability or the luxury to merely "pull a switch" to bring generation units on stream. New generation is costly and requires lead time, often many years, from identified need to the point of constructing and bringing units on stream.

In its approved budget SaskPower includes a contingency allowance. Throughout the year the program is refined or revised when firmer estimates become known the contingency will be adjusted accordingly. At year end the contingency as with the total capital program, if not used, is not transferred to the following year. The next year program must again be justified and budgeted for, with a new contingency allowance being included.

The customer attachment budget does not include customer contributions; rather these are accounted for as other Income in SaskPower's financial statement. Therefore, the impacts of the capital program are somewhat less than would be indicated by considering only the actual construction costs for customer attachments. Thus, to the extent a capital program cannot be completed in any given year, there is no negative consequence to the rate payer, as this would delay the inclusion of those projects not completed into rate base by an additional year.

Planned Maintenance Observations

As a part of its asset management review an initiative to optimize SaskPower's planned maintenance program was implemented in 2012. At that time SaskPower estimated that the resultant OM&A savings would be approximately $27 million for 2013, calculated at $800,000 per outage, on average, based on reduced planning time, outage durations, mobilization and demobilization and labour and overtime costs. As well reductions for higher cost of replacement fuels, where coal and hydraulic facilities are taken out of service, is considered.

In this application[69] SaskPower stated that 28 maintenance days were avoided in 2012, with 56 anticipated for 2013. Fuel cost savings are estimated based on the avoided cost of natural gas generation for the number of maintenance days avoided. SaskPower is currently developing a more sophisticated model to more accurately quantify actual savings and forecast future savings. SaskPower has many additional initiatives to be implemented for specific projects between 2014 and 2015, all designed to improve efficiencies and reduce or avoid maintenance costs for several of its coal, hydraulic and natural gas units. On this basis actual savings for 2012 were $1.0 million and $26.9 million for 2013. Of the $ 26.9 million savings in 2013, OM&A accounted for $4 million while fuel savings were calculated to be $ 22.9 million.

SaskPower's Planned Maintenance planning process considers and attempts to properly balance minor maintenance and refurbishment as well as periodic major overhaul needs, warranty coverage, OEM recommendations and industry accepted practices. SaskPower must also recognize its generation supply obligations requiring optimization of economic fuel dispatch on a real time basis, workplace environment (primarily ambient temperature) for major overhauls, potential for weather extremes and the occurrence of unplanned outages.

We consider that a properly planned and implemented economically sound program is critical to the efficient operation of the electric system. We note that SaskPower has realized substantial reduced or avoided costs relative to 2011 and further that a new model is currently being developed[70] to better quantify actual cost savings and more accurately estimate future savings. We are satisfied that SaskPower's Planned Maintenance Program properly balances all factors and has and continues to take steps to optimize savings and reduce risks to system reliability and integrity in the future.

[69] IR 107 First Round
[70] IR 31 Second Round

8.0 Environmental and Sustainability Report Update

SaskPower's most recent sustainability report was issued in 2011, and an overview was provided in the consultant's last independent report issued in late 2012. SaskPower indicated this report is now scheduled to be updated in 2014.

In the 2011 report, SaskPower indicated that the development of the Boundary Dam Power Station unit # 3 integrated carbon capture and sequestration facility (ICCS) was crucial in meeting the Federal and Provincial Greenhouse Gas reductions targets and reducing its carbon footprint. As noted in the 2014-2016 application the addition of carbon capture and storage represents the largest environmental upgrade ever contemplated for a coal fired power generation facility in Canada.

The basic objective of this project is to reduce CO2 emissions by 90% or 1 million tonnes per year (the equivalent to taking more than 250,000 cars off the road each year). The new facility was expected to be operational end of 2013, with full commercial operation of the CCS system now scheduled for July 1, 2014.

Integral to the project is the sale of captured CO2 which has recently been contracted to a major oil producer in the region for a 10 year period. When operational 100% of the CO2 anticipated to be captured has been contracted to a third party to be used to enhance oil recovery with residual (if any) CO2 being stored in deep saline aquifers. The CO2 will be supplied once the pipeline is completed and the commercial operations are underway which is forecast to occur April 2014. Additionally, once operational and until 2016, SaskPower will lease The Shand Carbon Capture Test facility jointly developed by SaskPower and Hitachi.

The ICCS facility is also expected to capture almost 100% of sulphur dioxide emissions which is intended to be used in production of sulphuric acid.

As a province that is heavily reliant on fossil fuel (coal) for power generation, SaskPower faces significant challenges in developing new sources of generation supply to meet the province's electricity demands while recognizing the need to reduce greenhouse gases and other emissions. SaskPower continues to emphasize the reduction of greenhouse gas as well as other emissions by adding low or non-emitting forms of generation such as biomass, coal with CCS (clean coal), natural gas and wind. SaskPower estimates that an additional 177 MW of wind generation will be added in 2016 through Algonquin Power in the Chaplin area as well as several other smaller wind generation farms through the Green Options Partners Programs (GOPP). It is noted that a wind power strategy outlining the future wind development supply plan for SaskPower is to be completed in 2014 by Sustainable Supply Development.

Environmental regulation is a mandatory component of the energy industry. Emission mitigation, site assessments and environmental studies account for a significant part of the costs for environmental compliance. Those ongoing activities coupled with education, research, and identifying and managing emerging environmental issues, are all associated with SaskPower's vertically integrated operations. In September 2012, the long awaited federal regulations to curtail emissions from coal fired generation plants were published.

These federal (Canada) regulations are expected to come into force on July 1, 2015. Under these regulations the definition of "useful life" was adjusted to allow up to 50 years of operation for existing units. This was formerly restricted to 45 years. The proposed emissions intensity standard was also increased from 375 to 420 tonnes of CO2 per Gigawatt hour net produced (t/GWh).

These final regulations provide SaskPower with additional but still limited time to confirm the viability of CCS technology. For units commissioned prior to 1975, the end-of-life status is reached on the earliest of December 31 of its 50th year of service or December 31, 2019. This guideline applies to Boundary Dam Units 4 & 5 and means that they must meet the standard of 420 tonnes per GWh of CO2 emissions by the end of 2019 or be retired. Conversely, the constraints within the regulation do not allow SaskPower to receive any credit for the early adoption of the CCS technology with respect to Boundary Dam Unit 3.

The regulation limits the useful life for Power Resource Boundary Dam Plants Service Units 1 which retired in 2013 (originally scheduled for 2014) and 2 now scheduled for 2015 instead of 2016.

For units commissioned between 1975 and 1985, the end-of-life status is reached at the earliest of the 50th year of service or December 31, 2029. These guidelines apply to Boundary Dam Unit 6 and Poplar River Units 1 & 2. For all other cases, the end-of-life is reached on December 31 of the 50th year of service. These regulations will also apply to the Shand Power Station.

SaskPower is continuing to work closely with the Provincial Ministry of Environment to ensure a Saskatchewan/Federal Equivalency Agreement appropriately recognizes SaskPower's efforts to reduce CO_2 emissions. The Saskatchewan Greenhouse Gas Regulations and the Saskatchewan/Federal Equivalency Agreement to achieve a sustainable supply of electricity for its customers while minimizing rate increases were both expected to be finalized by mid-2013 but that has been delayed.

To guide future decisions SaskPower has developed a Sustainable Energy Strategy to meet the provinces growing electricity needs. This strategy balances the economic, social and environmental needs of the people of Saskatchewan.

As part of the information exchange, SaskPower provided the 2012 Sustainable Electricity Annual Report prepared by Canadian Electricity Association.

9.0 Cost of Service

The purpose of a Cost of Service Study (COSS) is to provide the basis necessary to properly design rates for each of a utility's customer classes to ensure that each class is paying its share of the revenue requirement to provide them the service they require. Its end result is an appropriate allocation of all the components of a utility's revenue requirement, including a return of investment, to each of its customer classes.

The COSS takes into consideration historic rates, customer class development and utility cost drivers when determining the revenue requirement from each customer class. It is forward looking on a prospective or forecast cost basis. Principles followed in a typical COSS include effectiveness in yielding total revenue requirement; revenue and rate stability and predictability; efficient use of rates and rate blocks; conservation; fairness of all rates without undue discrimination between rates for the various customer classes; consideration of historic rate attributes; simplicity and customer understanding; and freedom from controversy as to proper interpretation.

SaskPower's COSS endeavors to ensure rates charged to customers are fair, reasonable and economically efficient. As SaskPower's system and infrastructure expands, aged facilities are decommissioned and generation facilities are built to replace and generate more power all these routine developments require constant monitoring and evaluation to ensure the rates charged to customers are accurate and current. The COSS identifies all accounting costs; functionalizes these into generation, transmission, distribution and customer services; classifies each functional cost into demand, energy and customer components; and allocates the functionally classified costs to the customer classes. Allocated forecasted costs and revenues for each customer class are calculated to determine the R/RR ratios for each class. The R/RR ratio for SaskPower, as a whole, always equal 1.00 – revenues exactly match costs.

To this end SaskPower previously reviewed its COSS in 2008 and concluded that a more detailed study was required, as suggested by the Panel. The most recent COSS was completed in 2012 by Elenchus Research Associates (Elenchus).

In 2001 SaskPower also commenced its Load Research program, with the initial installation of a representative number (to ultimately total about 1,200) of real time meters for residential, farm, oilfield and commercial customers to determine the load profile (hourly demand) for those classes. Installation of the meters was completed in 2006, and by 2012 five years of data had been recorded. Power and Reseller Customer Class profiles were already available. Load profiles, at that time, were based on the data from an electric utility in Alberta, as SaskPower did not have sufficient credible data to establish their own internal profiles. The intent was to refine assumptions used in its COSS for demand-related costs for allocating such costs to the various customer classes. The 5 year average results from the load research coincident peak load factors relative to those previously used (based on winter peak only) are summarized on the following table. Load factors are displayed for winter peak, summer peak and 2CP data (Note that the 2 CP methods are used for the 2014 to 2016 COSS in IR 165). Coincident peak is defined as the load factor of all customer classes that occur when the system peaks, either summer or winter

Table 9.1 - Internal Load Research – Resulting Load Factors

Customer Class	2013 Year %	Winter Peak %	Summer Peak %	2 CP %
Residential	52.4	53.1	59.6	56.2
Farms	58.0	54.1	98.0	69.7
Oilfield	86.9	89.7	103.3	96.1
Streetlights	47.7	47.7	0.0	95.6
Commercial	66.1	81.3	64.5	71.9

This application includes the 2014-2016 Test Embedded COS studies completed by SaskPower's Corporate and Financial Services Pricing and Costing Department, and incorporates Elenchus recommendation respecting cost allocation factors as well as the internal load research results.

Elenchus submitted a report in January 2013 based on its 2012 review. That report concluded that SaskPower's cost of service model and rate design methodologies were consistent with generally accepted electric utility practices. The report also recommended some enhancements, the most significant of which were implemented. Those two significant enhancements are as follows:

1. Use the customer classes' contribution to the SaskPower's most likely winter peak as opposed to potential (i.e. worst case – very cold weather in December) peak when SaskPower switches from Alberta to Saskatchewan based load research.
2. Change the demand allocator used to allocate generation, transmission and most of the distribution demand related costs from the contribution to SaskPower's winter peak to a combination of SaskPower's winter and summer peak.

In its study, Elenchus also advised that revenue to revenue requirement (R/RR) ratios close to 1.00 are deemed not to represent cross-subsidization since conducting a cost allocation study involves utilizing the best available, yet nevertheless imprecise, information with respect to the manner in which shared assets are used by various customer groups.

The R/RR ratio range of 0.95 to 1.05 that is used in many jurisdictions as being acceptable for cost allocation studies is considered to reflect that the customer group is paying their fair share of costs. Hence, an R/RR ratio that is slightly above or below unity does not demonstrate that one customer class necessarily subsidizes or receives subsidy from other customer classes. Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

The following table summarizes the impact of both Elenchus' recommendations to the COSS when applied to the 2013 Customer Class Test rates and the internal load research results:

Table 9.2 - Impact to Customer Rates of Methodology Reviews

Customer Class (2013 Test)	Before Changes	Winter Peak - Sask Load Research	Winter & Summer Peak - Sask Load Research	Variance from Before to Winter & Summer
Urban Residential	0.97	0.95	0.97	0.00
Rural Residential	0.96	0.95	0.96	0.00
Farm	0.97	0.89	0.99	0.02
Urban Commercial	0.98	1.05	0.98	0.00
Rural Commercial	1.00	1.10	1.01	0.01
Oilfields	1.05	1.04	1.05	0.00
Power	1.02	1.01	1.02	0.00
Streetlights	1.00	0.99	1.16	0.16
Resellers	1.01	1.00	0.94	-0.07
Total Load	**1.00**	**1.00**	**1.00**	**0.00**

The COSS model and rate design is a 'zero-sum process'; that is, each customer class's rates contribute a portion of the revenue requirement necessary to provide electricity to that class while ensuring that overall all customer class rates generate revenues that match total prudently incurred system costs, resulting in the overall utility R/RR of 1.00.

SaskPower stated that any significant changes to customer class rates, as a result of the new COSS methodology and internal load research will be phased in over a 3 year period rather than being rebalanced in a single year's rate adjustment. This rebalancing recognizes that stability of rates and minimizing rate shock are important to customers and is also a fundamental principle of SaskPower's managerial philosophy and business objectives.

SaskPower indicates the largest impacts as a result of the Elenchus recommendations to customer R/RR ratios are:

- Farm class increases from 0.97 to 0.99, a slight increase to rates and related payment;
- Rural Commercial increases from 1.00 to 1.01, a slight increase to rates and related payment;
- Streetlights will have an increase from 1.00 to 1.16 and a significant increase to its class rates; and
- Resellers will have a decrease from 1.01 to 0.94 and experience a reduction in their rate increases.

A higher R/RR ratio (as for the Farm, Rural and Streetlight classes) indicates that these classes will experience lower than system rate increases, whereas a lower R/RR (as for the Reseller Class) Indicates a higher than system average rate increase.

SaskPower is committed to continuously improving its data to ensure appropriate cost –based customer rates. It periodically updates financial, customer revenue and load data to ensure the most relative and recent information is utilized in its Cost of Service model. SaskPower accepts that rates are not static and require constant diligence to ensure the information used to make rate decisions is accurate.

An R/RR ratio of 1.00 indicates, in simplest terms, that a customer is paying the appropriate amount for the service it receives. Elenchus does not consider any customer class with an R/RR ratio between 0.95 and 1.05 (the generally accepted industry range) as being either subsidized or subsidizing another customer class. SaskPower does, however, propose that the range be narrowed to between 0.98 and 1.01 by 2016.

SPC has maintained the same six step process when determining the appropriate rates customer classes pay. These six steps are:

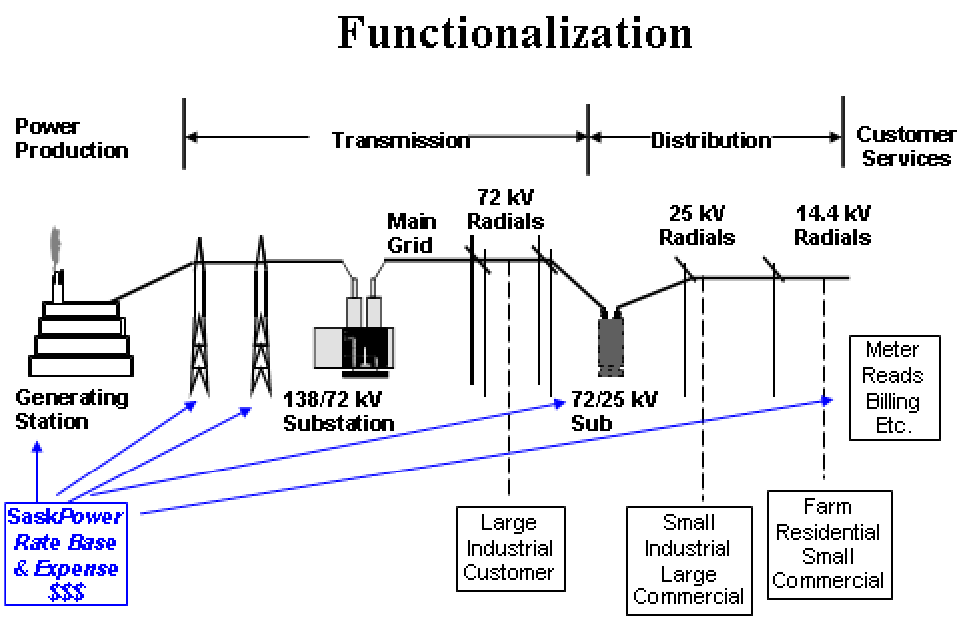
1. **Identifying** all accounting costs to be included in the COSS using forecasted consolidated financial statements for each year being tested, in this case 2014, 2015 and 2016. Accounting costs are separated into 3 account types;
   - Rate base items - investment and liabilities on SaskPower's balance sheet
   - Revenue Requirements - calculation of annual costs with return on rate base
   - Revenue items - annual domestic sales revenue as reported on SaskPower's income statement.

2. **Functionalizing** all accounting costs between 4 functions (then into sub-functions);
   - Generation - Energy related rate base and expenses allocated to each customer class using energy sales plus losses and generation and generation-Demand related rate base and expense is allocated to each customer class using the 2 Coincident Peak Method (2CP)
   - Transmission - functions classified as demand and allocated using the 2CP method.
   - Distribution - demand functions using a combination of 2CP method and the non-coincidental peak method (NCP) which allocates rate base and expenses on a ratio of the sum of the max demand of all customers within a customer classification whenever it occurs in a year.
   - Customer Service - functions of customer service allocated to each customer class based on reporting by each department of how much time is spent with each customer class.

   The following table and schematic illustrate the functionalization process as well as SaskPower's sub-functions:

Table 9.3 - Functionalized Costs

GENERATION	TRANSMISSION	DISTRIBUTION	CUSTOMER SERVICES
Load generation	Main Grid Lines	Area Substations	Meter Services
Line Losses	138 KVa Radials	Distribution Mains	Meter Reading
Scheduling & Dispatch	138/73 KVa substations	Urban Laterals	Customer Collecting
Regulation & Frequency Response	72 kv Lines radials	Unamortized Customer Contributions	Billing and Customer Service
Spinning Reserve		Transformers	Customer Service
Supplementary Reserve		Services Customer	Marketing & Key Accounts
Planning Reserve		Rural Laterals	
Reactive Supply		Meters	
Grants in-lieu of Taxes		Streetlights	
Interruptible Adjustment			

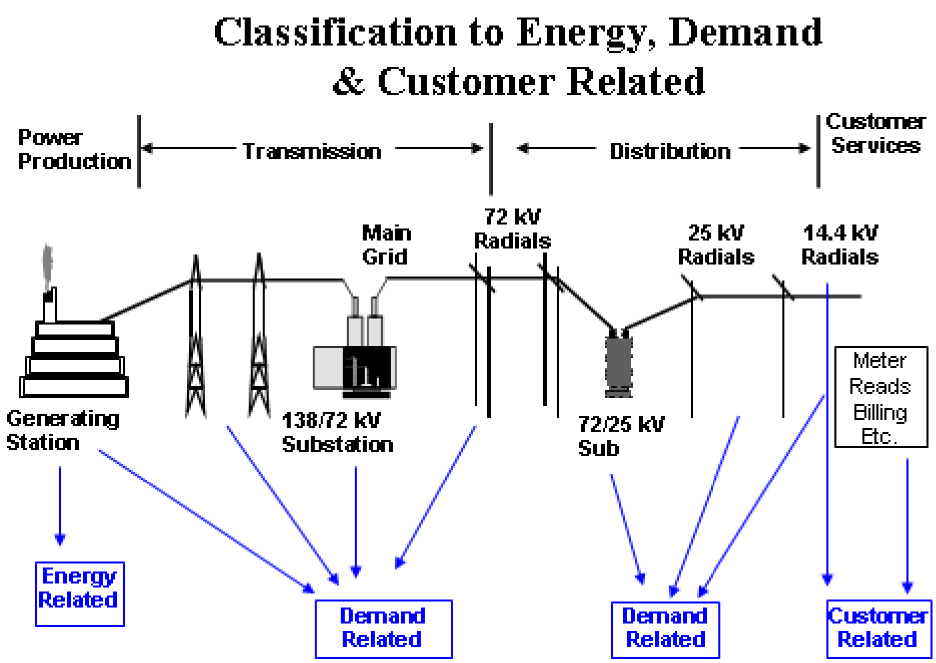


3. **Classifying** each of the functionalized costs into 3 components;
   - Demand - the costs that vary with customer demand on the system
   - Energy provided by the utility, and;
   - Customer Service - number of customers provided services such as billing and meter readings.

   The following table and schematic illustrates the classification process:

Table 9.4 - Classified Costs

Functionalized Costs	Demand	Energy	Customer
Generation Rate Base	Equivalent Peaker	Remainder	0%
Fuel	0%	100%	0%
Import/Export	0%	100%	0%
Generation OM&A	Fix/Variable by Plant Type	Fix/Variable by Plant Type	Fix/Variable by Plan Type
Coal Reserves		100%	
Shand Greenhouse	Pro-rata all generation	Pro-rata all generation	Pro-rata all generation
SPI	PP Capacity/Energy	PP Capacity/Energy payments/Fly ash	
NorthPoint	0%	100%	
Transmission	100%		
Distribution			
-Substations	100%		
-Single Phase Primary	65%		35%
-Transformers	70%		30%
-Other Distribution			100%
-Streetlights			100%
Customer			100%

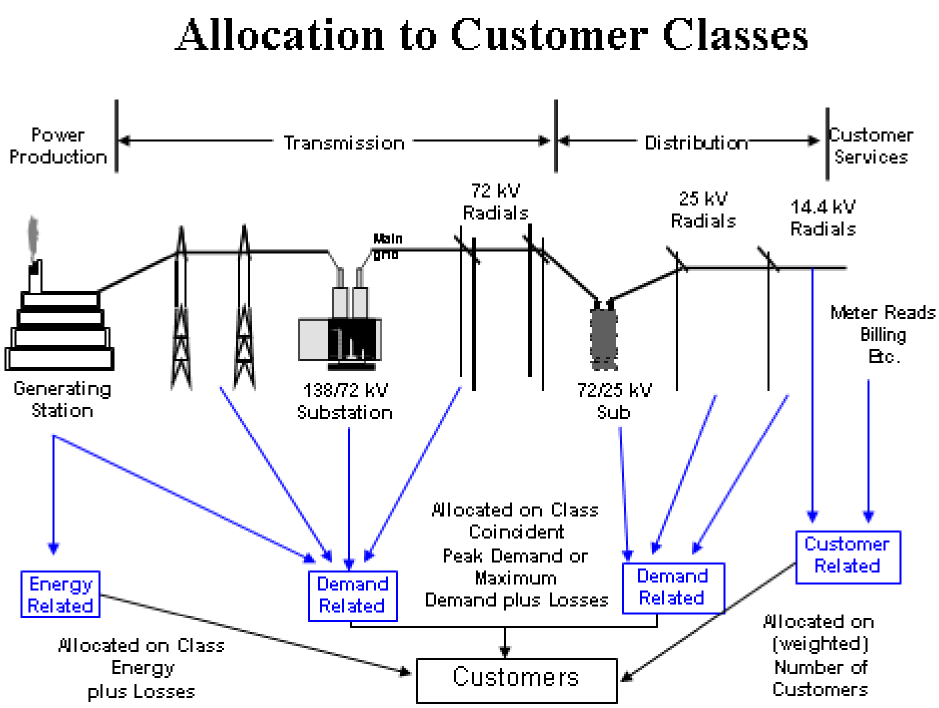


4. **Allocating** the functionally classified costs to each of the customer classes based on similar characteristics of demand. Customer classes utilized by SaskPower are:
    i. Urban Residential
    ii. Urban Commercial
    iii. Power Published
    iv. Rural Residential
    v. Rural Commercial
    vi. Power Contract Rates
    vii. Power Published Rates
    viii. Farms
    ix. Oilfields
    x. Streetlights
    xi. Resellers

The following table and schematic illustrate the customer class allocation process:

Table 9.5 - Allocated Costs

Functional Classified Costs (Rate Base designated as RB)	Customer Class Allocation Factors
Generation-Demand-RB & Expenses	Pro-rata class contribution to peak load – 2 CP
Generation –Energy – RB & Expenses	Pro-rata class energy consumed + estimated losses
Transmission –Demand – All	Pro-rata class contribution to peak load – 2 CP
Distribution–Demand-RB & Exp. – Transformers	Non-coincident Peak-Pro-rata max. class demand
Distribution – Demand – Other RB & expenses	Relative class contribution to peak load – 2 CP
Distribution – Customer	Various Factors by sub-function*
Customer Services	Pro-rata Weighted number of class customers
Customer Contributions –RB & Expenses	Direct assignment to appropriate class
Interruptible Credit – Benefit	1 CP to Interruptible Customers Class Classes
Interruptible Credit – Cost	1 CP to all Non-Interruptible Customer Classes



5. **Compare** allocated costs and revenues from customer classes to determine revenue cost ratios. SaskPower then evaluates the R/RR ratios of each class to the acceptable target ratio of between 0.95 and 1.05 while ensure the system wide (all customer sales) ratio is equal to 1.00.

6. **Calculate** "ideal" rates for each of the customer classes. SaskPower customer classes use 60 rate codes within the classes to group customers with similar characteristics such as location, size, voltage level and type of load service. The goal of determining ideal rates is to ensure that SaskPower achieves its objectives as noted at the start of this section.

The COSS provides the necessary classification, functionalization and allocation of all revenue requirement component details allowing for the design of an appropriate rates structure and rates, as more fully discussed in Section 10.0 following.

9.1 2014 to 2016 COSS Results

The COSS for each of 2014, 2015 and 2016 incorporate the results of the internal load research as well as the 2CP demand allocators flowing from the Elenchus study. The load and customer data flows from the 2013 Load forecasts and revenue requirements are as forecast in the 2013 Business Plan. The following series of tables first show the summary results of all major expense categories into the major functional areas (Generation, Transmission, Distribution, and Customer Service) for each of the 3 years. The subsequent two tables show the allocation of the functionalized revenue requirements for each year to each of the 10 Customer classes, followed by a summary of the allocation of the classified revenue requirement to each class. The last table shows the customer class R/RR ratios and the resultant revenue required to be generated by each class for each year.

2014 Results

Table 9.6 - Functionalization of Financial Account Details - in $ millions (2014)

RB & Expense Categories	SPC Total	Functional Breakdown							
		Generation		Transmission		Distribution		Cust Service	
Rate Base (RB)									
Plant in Service	13,352.2	7,769.5	58.2%	1,932.6	14.5%	3,544.7	26.5%	105.4	0.8%
Accum Depreciation	-5,156.8	-3,004.2	58.3%	-584.3	11.3%	-1,516.8	29.4%	-51.5	1.0%
Working Capital	81.0	44.6	55.0%	7.4	9.1%	17.8	22.0%	11.2	13.8%
Inventories	165.0	81.6	49.5%	22.7	13.8%	60.2	36.5%	0.5	0.3%
Other Assets	7.2	5.6	77.4%	0.3	4.5%	0.8	11.1%	0.5	7.0%
Total RB	**8,448.6**	**4,897.1**	**58.0%**	**1,378.7**	**16.3%**	**2,106.8**	**24.9%**	**66.0**	**0.8%**
Revenue Requirement (RR)									
Fuel Expense	394.3	394.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Purch Power & Imp	193.1	193.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Exp & Net Electricity	-34.7	-34.7	100.0%	-	0.0%	-	0.0%	-	0.0%
OM&A	647.7	345.2	53.3%	58.8	9.1%	146.7	22.6%	97.1	15.0%
Depreciation & Dep	441.8	262.3	59.4%	50.8	11.5%	119.3	27.0%	9.4	2.1%
Corp Capital Tax	34.0	19.8	58.1%	5.6	16.5%	8.4	24.7%	0.2	0.7%
Grants in Lieu	22.5	22.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	86.4%	0.0	0.7%	0.0	1.6%	0.1	11.3%
Other Income	-128.5	-40.8	31.7%	-13.8	10.7%	-45.7	35.5%	-28.3	22.0%
4.84% Return on RB	409.1	237.1	58.0%	66.8	16.3%	102.0	24.9%	3.2	0.8%
Total RR	**1,979.8**	**1,399.3**	**70.7%**	**168.1**	**8.5%**	**330.8**	**16.7%**	**81.7**	**4.1%**

Table 9.7 - Functionalized Revenue Requirement - in $ millions (2014)

Customer Class	SPC Total	Generation		Transmission		Distribution		Cust Service	
Urban Residential	365.5	202.7	55.5%	28.2	7.7%	90.2	24.7%	44.5	12.2%
Rural Residential	96.9	50.8	52.4%	7.5	7.8%	31.6	32.6%	7.0	7.2%
Farms	160.4	94.4	58.9%	12.8	8.0%	44.2	27.6%	8.9	5.6%
Urban Commercial	289.3	196.5	67.9%	24.3	8.4%	61.1	21.1%	7.5	2.6%
Rural Commercial	98.9	63.5	64.3%	8.4	8.5%	24.8	25.0%	2.2	2.2%
Power Published	434.4	380.7	87.6%	43.1	9.9%	6.7	1.5%	3.9	0.9%
Power Contract	110.3	98.2	89.0%	11.0	10.0%	0.4	0.4%	0.6	0.6%
Oilfields	319.6	225.6	70.6%	25.0	7.8%	62.4	19.5%	6.5	2.0%
Streetlights	13.8	3.8	27.8%	0.4	3.1%	9.1	66.0%	0.4	3.1%
Reseller	90.7	82.9	91.5%	7.3	8.0%	0.3	0.4%	0.1	0.2%
Total	**1,979.8**	**1,399.3**	**70.7%**	**168.1**	**8.5%**	**330.8**	**16.7%**	**81.7**	**4.1%**

Table 9.8 - Classified Revenue Requirement - in $ millions (2014)

Customer Class	SPC Total	Demand Related		Energy Related		Customer Related	
Urban Residential	365.5	192.0	52.5%	103.0	28.2%	70.5	19.3%
Rural Residential	96.9	55.4	57.2%	24.1	24.8%	17.4	18.0%
Farms	160.4	92.2	57.5%	49.1	30.6%	19.1	11.9%
Urban Commercial	289.3	158.6	54.8%	110.4	38.2%	20.4	7.0%
Rural Commercial	98.9	58.0	58.7%	33.7	34.1%	7.1	7.2%
Power Published	434.4	200.1	46.1%	228.4	52.6%	5.9	1.4%
Power Contract	110.3	49.9	45.2%	59.4	53.8%	1.1	1.0%
Oilfields	319.6	166.5	52.1%	137.0	42.9%	16.2	5.1%
Streetlights	13.8	2.8	20.4%	2.3	16.9%	8.7	62.7%
Reseller	90.7	46.6	51.4%	43.8	48.2%	0.3	0.4%
Total	**1,979.8**	**1,022.0**	**51.6%**	**791.2**	**40.0%**	**166.7**	**8.4%**

Table 9.9 - Revenue to Revenue Requirement Ratios (2014)

Customer Class	Revenue (in $ millions)	Revenue Requirement (in $ millions)	Revenue to Revenue Requirement Ratio
Urban Residential	358.7	365.5	0.98
Rural Residential	94.5	96.9	0.98
Farms	158.0	160.4	0.98
Urban Commercial	288.5	289.3	1.00
Rural Commercial	100.4	98.9	1.01
Power Published	437.3	434.4	1.01
Power Contract	107.8	110.3	0.98
Oilfields	332.1	319.6	1.04
Streetlights	16.0	13.8	1.16
Reseller	86.7	90.7	0.96
Total	**$1,979.8**	**$1,979.8**	**1.00**

2015 Results

Table 9.10 - Functionalization of Financial Account Details - in $ millions (2015)

RB & Expense Categories	SPC Total	Functional Breakdown							
		Generation		Transmission		Distribution		Cust Service	
Rate Base (RB)									
Plant in Service	14,606.7	8,339.8	57.1%	2,375.3	16.3%	3,773.3	25.8%	118.3	0.8%
Accum Depreciation	-5,616.1	-3,279.9	58.4%	-638.2	11.4%	-1,639.2	29.2%	-58.8	1.0%
Working Capital	84.1	46.7	55.6%	7.9	9.4%	18.7	22.2%	10.8	12.9%
Inventories	165.0	81.7	49.5%	22.7	13.8%	60.2	36.5%	0.4	0.3%
Other Assets	7.2	5.6	77.7%	0.3	4.5%	0.8	11.2%	0.5	6.6%
Total RB	**9,246.9**	**5,193.9**	**56.2%**	**1,768.0**	**19.1%**	**2,213.8**	**23.9%**	**71.2**	**0.8%**
Revenue Requirement (RR)									
Fuel Expense	441.5	441.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Purch Power & Imp	236.9	236.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Exp & Net Electricity	-42.4	-42.4	100.0%	-	0.0%	-	0.0%	-	0.0%
OM&A	672.4	362.5	53.9%	61.7	9.2%	154.2	22.9%	94.1	14.0%
Depreciation & Dep	477.7	283.5	59.3%	58.5	12.3%	126.1	26.4%	9.6	2.0%
Corp Capital Tax	36.9	20.8	56.3%	7.1	19.3%	8.8	23.7%	0.2	0.7%
Grants in Lieu	23.9	23.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	86.6%	0.0	0.7%	0.0	1.6%	0.1	11.0%
Other Income	-144.8	-58.2	40.2%	-13.8	9.5%	-45.9	31.7%	-26.9	18.6%
4.84% Return on RB	451.8	253.7	56.2%	86.4	19.%	108.2	23.9%	3.5	0.8%
Total RR	**2,154.4**	**1,522.6**	**70.7%**	**199.9**	**9.3%**	**351.3**	**16.3%**	**80.6**	**3.7%**

Table 9.11 - Functionalized Revenue Requirement - in $ millions (2015)

Customer Class	SPC Total	Generation		Transmission		Distribution		Cust Service	
Urban Residential	386.5	214.4	55.5%	32.5	8.4%	95.3	24.7%	44.2	11.4%
Rural Residential	102.8	53.6	52.2%	8.7	8.5%	33.5	32.6%	7.0	6.8%
Farms	168.2	98.8	58.6%	14.6	8.7%	46.0	27.3%	8.7	5.2%
Urban Commercial	305.9	206.6	67.5%	27.9	9.1%	64.2	21.0%	7.3	2.4%
Rural Commercial	104.5	66.8	63.9%	9.6	9.2%	26.0	24.9%	2.1	2.0%
Power Published	502.6	437.2	87.0%	54.4	10.8%	7.2	1.4%	3.8	0.8%
Power Contract	115.1	101.4	88.1%	12.6	11.0%	0.5	0.4%	0.6	0.5%
Oilfields	358.4	252.7	70.5%	30.5	8.5%	68.9	19.2%	6.3	1.8%
Streetlights	14.4	4.1	28.5%	0.5	3.4%	9.4	65.2%	0.4	2.8%
Reseller	95.8	86.9	90.7%	8.4	8.8%	0.3	0.4%	0.1	0.1%
Total	**2,154.4**	**1,522.6**	**70.7%**	**199.9**	**9.3%**	**351.3**	**16.3%**	**80.6**	**3.7%**

Table 9.12 - Classified Revenue Requirement - in $ millions (2015)

Customer Class	SPC Total	Demand Related		Energy Related		Customer Related	
Urban Residential	386.5	203.3	52.6%	111.1	28.8%	72.1	18.7%
Rural Residential	102.8	58.5	56.9%	26.0	25.3%	18.3	17.8%
Farms	168.2	96.2	57.2%	52.4	31.2%	19.6	11.6%
Urban Commercial	305.9	166.6	54.4%	118.2	38.6%	21.2	6.9%
Rural Commercial	104.5	60.8	58.2%	36.1	34.6%	7.6	7.3%
Power Published	502.6	229.9	45.7%	266.6	53.0%	6.1	1.2%
Power Contract	115.1	51.7	44.9%	62.4	54.2%	1.0	0.9%
Oilfields	358.4	185.3	51.7%	156.0	43.5%	17.2	4.8%
Streetlights	14.4	3.0	20.8%	2.5	17.6%	8.8	61.6%
Reseller	95.8	48.7	50.8%	46.8	48.8%	0.3	0.3%
Total	**2,154.4**	**1,104.0**	**51.2%**	**878.1**	**40.8%**	**172.3**	**8.0%**

Table 9.13 - Revenue to Revenue Requirement Ratios (2015)

Customer Class	Revenue (in $ millions)	Revenue Requirement (in $ millions)	Revenue to Revenue Requirement Ratio
Urban Residential	380.6	386.5	0.98
Rural Residential	100.3	102.8	0.98
Farms	165.4	168.2	0.98
Urban Commercial	306.2	305.9	1.00
Rural Commercial	105.7	104.5	1.01
Power Published	507.1	502.6	1.01
Power Contract	113.3	115.1	0.98
Oilfields	367.0	358.4	1.02
Streetlights	15.5	14.4	1.08
Reseller	93.3	95.8	0.97
Total	**$2,154.4**	**$2,154.4**	**1.00**

2016 Results

Table 9.14 - Functionalization of Financial Account Details - in $ millions (2016)

RB & Expense Categories	SPC Total	Functional Breakdown							
		Generation		Transmission		Distribution		Cust Service	
Rate Base (RB)									
Plant in Service	15,429.1	8,536.8	55.3%	2,777.1	18.0%	3,985.6	25.8%	129.6	0.8%
Accum Depreciation	-6,104.7	-3,572.9	58.5%	-702.1	11.5%	-1,763.7	28.9%	-66.1	1.1%
Working Capital	87.2	48.2	55.3%	8.4	9.6%	19.5	22.4%	11.1	12.7%
Inventories	165.0	81.7	49.5%	22.7	13.8%	60.2	36.5%	0.4	0.3%
Other Assets	7.2	5.6	77.6%	0.3	4.6%	0.8	11.3%	0.5	6.5%
Total RB	**9,583.8**	**5,099.4**	**53.2%**	**2,106.4**	**22.0%**	**2,302.5**	**24.0%**	**75.5**	**0.8%**
Revenue Requirement (RR)									
Fuel Expense	488.7	488.7	100.0%	-	0.0%	-	0.0%	-	0.0%
Purch Power & Imp	273.3	273.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Exp & Net Electricity	-46.8	-46.8	100.0%	-	0.0%	-	0.0%	-	0.0%
OM&A	697.8	375.3	53.8%	64.5	9.2%	161.4	23.1%	96.6	13.8%
Depreciation & Dep	507.5	301.8	59.5%	66.9	13.2%	129.0	25.4%	9.8	1.9%
Corp Capital Tax	38.1	20.3	53.2%	8.5	22.3%	9.1	23.8%	0.3	0.7%
Grants in Lieu	25.3	25.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	86.6%	0.0	0.7%	0.0	1.6%	0.1	11.0%
Other Income	-131.8	-47.0	35.6%	-13.8	10.4%	-46.1	35.0%	-25.0	19.0%
4.84% Return on RB	491.0	261.3	53.2%	107.9	22.0%	118.0	24.0%	3.9	0.8%
Total RR	**2,343.6**	**1,652.6**	**70.5%**	**234.0**	**10.0%**	**371.4**	**15.8%**	**85.6**	**3.7%**

Table 9.15 - Functionalized Revenue Requirement - in $ millions (2016)

Customer Class	SPC Total	Generation		Transmission		Distribution		Cust Service	
Urban Residential	410.1	225.2	54.9%	36.9	9.0%	100.8	24.6%	47.3	11.5%
Rural Residential	109.5	56.3	51.4%	9.9	9.0%	35.8	32.7%	7.5	6.8%
Farms	175.1	101.6	58.0%	16.2	9.3%	48.0	27.4%	9.3	5.3%
Urban Commercial	323.6	216.6	66.9%	31.5	9.7%	67.9	21.0%	7.7	2.4%
Rural Commercial	111.0	70.0	63.1%	10.9	9.8%	27.9	25.1%	2.2	2.0%
Power Published	587.0	506.7	86.3%	68.3	11.6%	8.1	1.4%	3.9	0.7%
Power Contract	130.9	114.3	87.3%	15.5	11.9%	0.5	0.4%	0.6	0.5%
Oilfields	381.1	267.1	70.1%	34.8	9.1%	72.6	19.0%	6.6	1.7%
Streetlights	14.9	4.3	29.2%	0.6	3.8%	9.5	64.2%	0.4	2.9%
Reseller	100.4	90.5	90.1%	9.5	9.4%	0.4	0.4%	0.1	0.1%
Total	**2,343.6**	**1,652.6**	**70.5%**	**234.0**	**10.0%**	**371.4**	**15.8%**	**85.6**	**3.7%**

Table 9.16 - Classified Revenue Requirement - in $ millions (2016)

Customer Class	SPC Total	Demand Related		Energy Related		Customer Related	
Urban Residential	410.1	214.9	52.4%	118.2	28.8%	77.0	18.8%
Rural Residential	109.5	62.1	56.7%	27.7	25.3%	19.7	18.0%
Farms	175.1	99.8	57.0%	54.6	31.2%	20.7	11.8%
Urban Commercial	323.6	175.6	54.3%	125.3	38.7%	22.7	7.0%
Rural Commercial	111.0	64.3	57.9%	38.3	34.5%	8.3	7.5%
Power Published	587.0	268.5	45.7%	312.1	53.2%	6.4	1.1%
Power Contract	130.9	58.8	44.9%	71.0	54.2%	1.1	0.8%
Oilfields	381.1	195.9	51.4%	166.5	43.7%	18.7	4.9%
Streetlights	14.9	3.2	21.4%	2.7	18.2%	9.0	60.4%
Reseller	100.4	50.8	50.6%	49.2	49.0%	0.4	0.3%
Total	**2,343.6**	**1,193.9**	**50.9%**	**965.7**	**41.2%**	**184.1**	**7.9%**

Table 9.17 - Revenue to Revenue Requirement Ratios (2016)

Customer Class	Revenue (in $ millions)	Revenue Requirement (in $ millions)	Revenue to Revenue Requirement Ratio
Urban Residential	403.9	410.1	0.98
Rural Residential	106.8	109.5	0.98
Farms	170.8	175.1	0.98
Urban Commercial	327.1	323.6	1.01
Rural Commercial	112.2	111.0	1.01
Power Published	593.3	587.0	1.01
Power Contract	129.0	130.9	0.99
Oilfields	385.2	381.1	1.01
Streetlights	15.0	14.9	1.01
Reseller	100.4	100.4	1.00
Total	**$2,343.6**	**$2,343.6**	**1.00**

9.2 Observations

In 2008, pursuant to a Panel recommendation, SaskPower undertook a review of its existing COSS methodology and requested input from all interested parties

Subsequent to further recommendations pursuant to the 2008 Panel recommendations and SaskPower's own desire to revisit its existing COSS methodology, SaskPower engaged Elenchus for the review. As discussed above, Elenchus found that SaskPower's existing methodology, by and large, was appropriate and followed the principles generally accepted within the industry. Elenchus recommended two modifications to the existing methodology:

1. Use the customer classes' contribution to the SaskPower's most likely winter peak as opposed to potential worst peak along with the adoption of SaskPower's load research.
2. Change the demand allocator used to allocate generation, transmission and most of the distribution demand related costs from the contribution to SaskPower's winter peak to a combination of SaskPower's winter and summer peak.

Also of note are the conclusions reached by Elenchus that the use of the Equivalent Peaker classify method to classify generation cost into demand and energy components is appropriate for SaskPower and is within industry norms. No change is recommended in this regard. This method results in 31% of the hydro generation being demand related, compared to six other utilities canvassed that allocate at least 35% to demand, and one allocates these costs 100% to demand. For Base load steam, combined cycle, and combustion turbine generation, 5 of the 6 utilities classify at least 35% to demand. SaskPower allocates steam generation at 52%, combined cycle at 83% and peaking generation at 100% to demand.

We also note the Elenchus report suggested that SaskPower consider the use of the minimum system size method to classify a portion of the distribution system costs as being customer related, rather than the current method of using survey results of other utility's classifications. SaskPower has indicated that they do not have sufficient data to use the minimum system size, but are reviewing the possibility of its use.

The COSS for 2014 through to 2016 incorporates the Elenchus recommendations as well as SaskPower's internal load research. The Panel has always supported and continues to support the concept that studies such as the COSS must be based on accepted principles and practices and, when those are followed, the study results whatever they may be must be accepted

In our view, the COSS adhered to the principled approach and the two recommended modifications are reasonable and more accurately portray SaskPower's operations and cost causation factors. We also note that SaskPower is continuing to study its information system's capability to support the minimum system size method to classify customer and demand costs, and expect that a report of its findings will be forwarded to the Panel in due course. We also find that SaskPower's approach to phasing in rate rebalancing in order to somewhat smooth out larger required rate increases over a three year period to be quite reasonable.

The internal load research results incorporated into the current COSS are unquestionably superior to those flowing from the hybrid system previously used by SaskPower, regardless of the “dislocation” of respective customer class rates.

We agree that a COSS requires the use of judgement throughout the various phases, and must be conducted every year to reflect new forecasts and changes in system needs, costs and customer profiles. While the COSS methodology will remain unchanged from year to year, the actual factors for customer classes as respective cost drivers (such as customer numbers, consumptions and load factors) change. Additionally, the nature and makeup of a capital program in any given year will impact the allocation factors. For example if a greater portion of a capital program expenditure is for generation and transmission than for distribution infrastructure customer classes who have little or no distribution costs allocated will see larger than average rate increases, while the reverse would follow if distribution infrastructure formed the bulk of a capital program.

Neither the results flowing from the Elenchus COSS or the internal load study impact the functionalization or the classification of costs. The changes are in the customer class allocation factors.

The following table summarizes the R/RR ratios flowing from the COSS proposed by SaskPower, incorporating the 3 major methodological changes discussed above:

Table 9.18 – Revenue to revenue Requirement ratios – 2013 to 2016

<table>
<tr><th>Customer Class</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th></tr>
<tr><td>Urban Residential</td><td>0.97</td><td>0.98</td><td>0.98</td><td>0.98</td></tr>
<tr><td>Rural Residential</td><td>0.96</td><td>0.98</td><td>0.98</td><td>0.98</td></tr>
<tr><td>Farm</td><td>0.97</td><td>0.98</td><td>0.98</td><td>0.98</td></tr>
<tr><td>Urban Commercial</td><td>0.98</td><td>1.00</td><td>1.00</td><td>1.01</td></tr>
<tr><td>Rural Commercial</td><td>1.00</td><td>1.01</td><td>1.01</td><td>1.01</td></tr>
<tr><td>Oilfields</td><td>1.05</td><td>1.04</td><td>1.02</td><td>1.01</td></tr>
<tr><td>Power Published</td><td rowspan="2">1.02</td><td>1.01</td><td>1.01</td><td>1.01</td></tr>
<tr><td>Power Contract</td><td>0.98</td><td>0.98</td><td>0.99</td></tr>
<tr><td>Streetlights</td><td>1.00</td><td>1.16</td><td>1.08</td><td>1.01</td></tr>
<tr><td>Resellers</td><td>1.01</td><td>0.96</td><td>0.97</td><td>1.00</td></tr>
<tr><td>Total Load</td><td>1.00</td><td>1.00</td><td>1.00</td><td>1.00</td></tr>
</table>

The net impact flowing from changes in COSS and Internal Load Research had little impact on the Residential, Farm and Commercial Customer classes as one or more of the changes offset other change(s). The Oilfield class, which had impacts flowing from both COSS and Load research, under the previous COSS allocation had been subsidizing the other classes. Conversely the Reseller Class was being subsidized by other classes. However, still within the accepted R/RR range of 0.95 to 1.05. The Power and Reseller class R/RR changes flow entirely from the COSS study, as load profiles had previously been known for these classes. While we can understand that there may be dissatisfaction by some customer classes with the results, we are of the view that the COSS was conducted thoroughly, reflecting SaskPower’s operating circumstances as well as industry norms. Load Research studies were planned and implemented in a logical fashion and results properly incorporated and the ensuing results are determined by entering the current statistics into the models.

10.0 Rate Design

10.1 Rate Design General

SaskPower proposes to address the revenue imbalance identified in the Cost of Service study through an energy charge for each customer class. In doing so SaskPower has enumerated six guiding principles or major objectives in setting its 2014-2016 rate structure and rate design methodology which are:

1. Meeting Revenue Requirement
2. Fairness and Equity
3. Economic Efficiency – i.e. pricing power close to marginal cost of supply
4. Conservation of Resources
5. Simplicity and Administrative Ease
6. Stability in rates and gradualism to minimize impact to customers (rate shock) when increases are required

This application is based on a new COSS and resulting rate design methodology which transforms SaskPower's historic legacy rate structure that had included significant cross-subsidies benefiting various rate classes at the expense of others. SaskPower's view is that this will, over the next three years), achieve rate equity as well as customer desires for proper price signals and address the unwillingness to pay improperly allocated costs.

In this application customer classes continue to consist of one or more rate code groupings of customers with similar use characteristics. Characteristics include location (Urban or Rural), size, supply voltage level, and type of load being supplied. Customer size is measured as the maximum customer demand, expressed in kilowatts (KW). Load factor is the ratio of annual energy to maximum demand multiplied by 8,760 hours. There have been no recent changes to SaskPower's over 60 rate codes. However, this rate application proposes to eliminate three of them. The elimination of these rate codes will not negatively affect any customer.

SaskPower's uses a rate structure consisting of either a two-part rate (Basic Monthly Charge (BMC) and an Energy Charge) or a three-part rate (BMC, Energy Charge and a Demand Charge) which has to have a meter that measurer's customer demand.

Basic monthly charges are intended to recover costs that generally have no relationship to demands placed on the system or annual energy consumption, but are specific to individual customers. Costs include onsite plant and certain general plant items in Rate Base, metering, billing, corporate support services and other direct services. While ideally all fixed costs should be recovered by the Basic Monthly Charges SaskPower, like most other Canadian utilities, recovers some portion of fixed costs through the variable energy rate in most customer classes.

Demand charges are intended to cover at least a portion of those utility costs outside of a customer's plant (or premise) which are usually fixed plant investments and operating costs that do not vary with a customer's consumption, but which are incurred to meet the customer's capacity requirements. These costs are usually for generation capacity and for the transmission and delivery of electricity. They are related to the maximum customer load the utility expects the consumer may use on a peak day.

Billing Demand is defined as the rate at which energy is delivered at a given instant, as averaged over a period of time. It is usually measured in kilowatts (KW) or kilovolt amperes (KVA). Proper measurement of this consumption involves more sophisticated and higher cost metering over a broader spectrum of SaskPower customers, mainly all classes except the residential class. SaskPower also uses a Demand Adjustment mechanism to ensure that there is no cross-subsidization between individual customers within a rate class having a three-part rate structure.

Energy Charge

SaskPower considers F&PP costs (a significant portion of SaskPower's operating costs), as well as a portion of fixed costs together with certain other variable administrative costs to be energy related and recoverable on a per unit consumption basis.

The rate design for the Residential, Small Farm and Small Commercial customers who have simple energy meters that cannot measure customer's demand levels consists of only an energy charge and a basic monthly charge. This type of rate structure will collect the appropriate revenue, regardless of size, but will not collect the appropriate revenue for customers of all load factors, only for customers at the average load factor for all rate codes. To collect the exact revenue for all load factor customers would require the use of Demand meters, much more expensive than the simple energy meter.

Commercial and Farm customers over 50 KVa demand and all Power customers have demand meters that measure energy consumed in KWh and maximum monthly demand in KVa. Thus, the rate structure consists of energy, demand and basic monthly charges and is intended to collect appropriate revenue from each customer regardless of size and load factor. To ensure that this rate design objective is met, SaskPower applies the coincident peak (CP) allocation method for a Demand Adjustment Mechanism to each customer within each specific class. SaskPower's high load factor customers contribute more to its system peak demand than do low load factor customers. In order to better recognize cost causality the energy component of rates are increased and demand components deceased.

The following Tables illustrate this methodology:

Table 10.1 - R/RR Ratio vs Load Factor - CP Allocation Method

Typical 72 kV Power Customer				
Load Factor	**40%**	**60%**	**80%**	**90%**
Customer Maximum Demand (kVA)	15,924	15,924	15,924	15,924
Customer Maximum Demand (kW)	15,000	15,000	15,000	15,000
Annual Energy Consumption (kWh)	52,560,000	78,840,000	105,120,000	118,260,000
Customer Coincident Peak Demand	8,250	10,500	12,750	13,875
Customer Annual Demand Billing (kVA)	153,248	165,860	178,471	184,777
Revenue Requirement Calculation	**3,980,161**	**5,469,842**	**6,959,523**	**7,704,363**
Total Revenue Requirement (cents/kWh)	7.57	6.94	6.62	6.51
Revenue Calculation				
Basic Monthly Charge ($/month)	5,787	5,787	5,787	5,787
Annual Customer Revenue	69,447	69,447	69,447	69,447
Energy Rate (cents/kWh)	5.355	5.355	5.355	5.355
Annual Energy Revenue	2,814,588	4,221,882	5,629,176	6,332,823
Demand Rate ($/kVA/month)	7.323	7.323	7.323	7.323
Annual Demand Revenue	1,122,306	1,214,665	1,307,024	1,353,204
Total Revenue	**4,006,341**	**5,505,994**	**7,005,648**	**7,755,474**
Total Revenue (cents/kWh)	7.62	6.98	6.66	6.56
R/RR Ratio	**1.01**	**1.01**	**1.01**	**1.01**

Note: Revenue requirement is from the 2014 Test COS model which matches SaskPower's 2014 Rate Application.

Table 10.2 - R/RR Ratio vs Load Factor - Conventional Rate Design

Typical 72 kV Power Customer				
Load Factor	**40%**	**60%**	**80%**	**90%**
Customer Maximum Demand (kVA)	15,924	15,924	15,924	15,924
Customer Maximum Demand (kW)	15,000	15,000	15,000	15,000
Annual Energy Consumption (kWh)	52,560,000	78,840,000	105,120,000	118,260,000
Customer Coincident Peak Demand	8,250	10,500	12,750	13,875
Customer Annual Demand Billing (kVA)	153,248	165,860	178,471	184,777
Revenue Requirement Calculation	**3,980,161**	**5,469,842**	**6,959,523**	**7,704,363**
Total Revenue Requirement (cents/kWh)	7.57	6.94	6.62	6.51
Revenue Calculation				
Basic Monthly Charge ($/month)	5,787	5,787	5,787	5,787
Annual Customer Revenue	69,447	69,447	69,447	69,447
Energy Rate (cents/kWh)	3.566	3.566	3.566	3.566
Annual Energy Revenue	1,874,198	2,811,296	3,748,395	4,216,944
Demand Rate ($/kVA/month)	15.122	15.122	15.122	15.122
Annual Demand Revenue	2,317,380	2,508,087	2,698,794	2,794,148
Total Revenue	**4,261,025**	**5,388,831**	**6,516,637**	**7,080,540**
Total Revenue (cents/kWh)	8.11	6.84	6.20	5.99
R/RR Ratio	**1.07**	**0.99**	**0.94**	**0.92**

Note: Revenue requirement is from the 2014 Test COS model which matches SaskPower's 2014 Rate Application.

The customer related data determinants for each of the three years that underpin the rate design are shown in the following tables. Note that customer rate design data is different than the data flowing from the 2013 load forecasts because the COSS was prior to the first quarter 2013 load forecasts. For cost allocation purposes, the differences are not material.

Table 10.3 - Customer Rate Design Data (2014 to 2016 Annual Accounts)

Customer Class	**2014**		**2015**		**2016**		**2014-2016 Change**	
	Account	**% of Total**	**Account**	**% of Total**	**Account**	**% of Total**	**Account**	**% Change**
Urban Res	314,255	62.7%	320,088	62.9%	326,001	63.0%	11,746	3.7%
Rural Res	48,627	9.7%	49,532	9.7%	50,448	9.8%	1,821	3.7%
Farms	60,630	12.1%	60,481	11.9%	60,341	11.7%	(289)	(0.5)%
Urban Com	43,601	8.7%	44,078	8.7%	44,561	8.6%	960	2.2%
Rural Com	12,967	2.6%	13,109	2.6%	13,253	2.6%	286	2.2%
Power Pub	86	0.0%	91	0.0%	93	0.0%	7	8.1%
Power Con	14	0.0%	14	0.0%	14	0.0%	0	0.0%
Oilfield	17,992	3.6%	19,034	3.7%	19,608	3.8%	1,616	9.0%
Streetlights	2,747	0.6%	2,798	0.5%	2,850	0.5%	103	3.8%
Reseller	3	0.0%	3	0.0%	3	0.0%	0	0.0%
Total	**500,922**	**100.0%**	**509,228**	**100.0%**	**517,172**	**100.0%**	**16,250**	**3.2%**

Table 10.4 - Customer Rate Design Data (2014 to 2016 Annual Revenues in $ millions)

Customer Class	**2014**		**2015**		**2016**		**2014-2016 Change**	
	$	**% of Total**	**$**	**% of Total**	**$**	**% of Total**	**$**	**% Change**
Urban Res	$358.7	18.1%	$380.6	17.7%	$403.9	17.2%	$45.2	12.6%
Rural Res	$94.5	4.8%	$100.3	4.7%	$106.8	4.6%	$12.3	13.0%
Farms	$158.0	8.0%	$165.4	7.7%	$170.8	7.3%	$12.8	8.1%
Urban Com	$288.5	14.6%	$306.2	14.2%	$327.1	14.0%	$38.6	13.4%
Rural Com	$100.3	5.1%	$105.7	4.9%	$112.2	4.8%	$11.9	11.9%
Power Pub	$437.3	22.1%	$507.1	23.5%	$593.3	25.3%	$156.0	35.7%
Power Con	$107.8	5.4%	$113.3	5.3%	$128.9	5.5%	$21.1	19.6%
Oilfield	$332.1	16.7%	$367.0	17.0%	$385.2	16.4%	$53.1	16.0%
Streetlights	$16.0	0.8%	$15.5	0.7%	$15.0	0.6%	$(1.0)	(6.3)%
Reseller	$86.6	4.4%	$93.3	4.3%	$100.4	4.3%	$13.8	15.9%
Total	**$1,979.8**	**100.0%**	**$2,154.4**	**100.0%**	**$2,343.6**	**100.0%**	**$363.8**	**18.4%**

Table 10.5 - Customer Rate Design Data (2014 to 2016 Annual Meter Sales in MWh)

Customer Class	2014		2015		2016		2014-2016 Change	
	MWh	% of Total	MWh	% of Total	MWh	% of Total	MWh	% Change
Urban Res	2,374,332	11.2%	2,408,203	10.9%	2,444,091	10.6%	69,759	2.9%
Rural Res	639,140	3.0%	648,312	2.9%	658,029	2.8%	18,889	3.0%
Farms	1,305,251	6.2%	1,308,537	5.9%	1,298,322	5.6%	(6,929)	(0.5)%
Urban Com	2,647,066	12.5%	2,662,124	12.1%	2,693,430	11.6%	46,364	1.8%
Rural Com	900,865	4.3%	906,000	4.1%	916,677	4.0%	15,812	1.8%
Power Pub	6,525,682	30.9%	7,146,271	32.4%	7,970,253	34.4%	1,444,571	22.1%
Power Con	1,707,913	8.1%	1,683,424	7.7%	1,825,902	7.9%	117,989	6.9%
Oilfield	3,685,668	17.5%	3,939,561	17.9%	4,016,868	17.3%	331,200	9.0%
Streetlights	61,308	0.3%	62,446	0.3%	63,599	0.3%	2,291	3.7%
Reseller	1,264,133	6.0%	1,267,856	5.8%	1,271,590	5.5%	7,457	0.6%
Total	**21,111,359**	**100.0%**	**22,032,734**	**100.0%**	**23,158,761**	**100.0%**	**2,047,402**	**9.7%**

SaskPower also offers two incentives related to rates: Time-of Use rates and Demand Response Program Initiatives. The time-of use rate has been offered to the Power and Oilfield Customers since 2010, but there are currently no customers on this rate. The current incentive is $0.01 per KWh and because of SaskPower's relatively high load factor, it is limited in its capacity to offer enough of an on/off peak energy financial incentive to entice customers to switch. For Commercial customers with an approved time-of-day meters, the calculation for those customer's recorded demand has been adjusted to be either the maximum demand registered in the current month or 75% of the maximum demand registered at any other time during the current month to shift the time-of-day incentive from demand to energy. SaskPower will increase this to 80% in 2015 and 85% in 2016.

The Panel has previously accepted that any annual increase in excess of 15% constitutes rate shock. This application results in rates that have a range of impacts from 4.22% to a maximum of 13.64%.

10.2 Revenue to Revenue Requirement Ratios (R/RR)

A major objective of rate structure and design is to create equity and fairness amongst each customer within each rate code, regardless of size or load factor. SaskPower designs rates to achieve this objective, measured by the R/RR ratio. By way of example, if a class has an R/RR of 1.01 then the overall rate code and each customer belonging to that rate code will have an R/RR of 1.01.

The Cost of Service Model described in Section 9.0 details allocated rate base, expenses and customer class revenues which are the basis for determining the R/RR by class. The R/RR measures revenues against the cost of service. An R/RR of 1.00 would suggest that the revenues exactly match the costs of providing the service and the customer is paying the amount that it costs SaskPower to provide them with the service. An R/RR other than 1.00 suggests that a customer class is being subsidized by others (below 1.00) or that a customer class is subsidizing other classes (above 1.00). While the R/RR may not be at 1.00 for each customer class, on a system-wide basis, it must equal 1.00 so as to enable SaskPower to recover the full amount of the revenue requirement.

Table 10.6 - Impact of Internal Load Research & Elenchus Recommended Enhancements

Customer Class (2013 Test)	Before Changes	Winter Peak - Sask Load Research	Winter & Summer Peak - Sask Load Research
Urban Residential	0.97	0.95	0.97
Rural Residential	0.96	0.95	0.96
Farm	0.97	0.89	0.99
Urban Commercial	0.98	1.05	0.98
Rural Commercial	1.00	1.10	1.01
Oilfields	1.05	1.04	1.05
Power	1.02	1.01	1.02
Streetlights	1.00	0.99	1.16
Resellers	1.01	1.00	0.94
Total Load	**1.00**	**1.00**	**1.00**

In accordance with past practice SaskPower continues to set the R/RR for Residential and Farm classes slightly below 1.00, the Reseller Class at 1.00, and all other classes slightly above 1.00 to limit the occurrences of Residential and Farm classes subsidizing other classes, which can occur, if there are significant shifts in SaskPower's cost or revenue structure between rate applications.

R/RR ratios change every year due to changes in class revenue and class revenue requirements. Class revenue requirements change due to: non-uniform escalation of Generation, Transmission, Distribution, and Customer Service costs; changes to class demand at system peak; and changes to the COSS.

SaskPower proposes to rebalance rates in each year to ensure they reflect the actual cost of service. This will provide equity among the rate classes and the customers within them. In 2014 and 2015, rates will fall between the industry standard R/RR range of 0.95 to 1.05 for each customer class, with the exception of Streetlights which will have an R/RR of 1.16 in 2014 and an R/RR of 1.08 in 2015. All rates will be fully rebalanced in 2016 and fall within SaskPower's preferred narrow R/RR range of 0.98 to 1.01.

SaskPower has chosen to rebalance the impacts of the 2012 cost of service review over a three year period to limit the maximum rate increases to any one class of customers so as to avoid rate shock. The significant impacts of the 2012 review are to the Farm class (slightly higher R/RR ratio), Streetlight class (higher R/RR ratio) and to the Reseller class (lower R/RR ratio). The implication of the higher R/RR ratio for the Farm and Streetlight classes is they will experience lower than system average rate increases. The implication of the lower R/RR ratio for the Reseller class is it will experience higher than system average rate increases.

The following table displays the Revenue to Revenue Requirement Ratios and Impacts of the overall system average proposed rate increase of 5.5% effective January 1, 2014, 5.0% effective January 1, 2015 and 5.0% effective January 1, 2016.

Table 10.7 - 2014, 2015, 2016 Proposed Rate Change % by Class and R/RR Ratio Impact

Class of Service	2014			2015		2016	
	R/RR Ratio (Existing)	Proposed Increase	R/RR Ratio (Revised)	Proposed Increase	R/RR Ratio (Revised)	Proposed Increase	R/RR Ratio (Revised)
Urban Res	0.98	5.3%	0.98	4.5%	0.98	4.5%	0.98
Rural Res	0.98	5.3%	0.98	4.5%	0.98	4.8%	0.98
Farms	1.01	3.5%	0.98	4.5%	0.98	4.0%	0.98
Urban Com	0.98	7.0%	1.00	5.6%	1.00	5.6%	1.01
Rural Com	1.03	4.8%	1.01	4.8%	1.01	4.8%	1.01
Power Pub	0.99	7.0%	1.01	5.8%	1.01	5.8%	1.01
Power Con	0.97	6.4%	0.98	6.7%	0.98	5.5%	0.99
Oilfields	1.06	3.6%	1.04	3.7%	1.02	3.7%	1.01
Streetlights	1.29	-4.8%	1.16	-4.8%	1.08	-4.8%	1.01
Reseller	0.94	7.0%	0.96	7.3%	0.97	7.3%	1.00
Total	**1.00**	**5.5%**	**1.00**	**5.0%**	**1.00**	**5.0%**	**1.00**

10.3 Meeting Revenue Requirement

The prime objective of a rate design is to ensure that the various rate structures and rates generate sufficient overall revenue equal to the total revenue requirement. SaskPower is forecasting operating income of $26.9 million in 2014 (Mid-Application update forecasts is $ 66.0 million), $39.9 million in 2015 and $40.4 million in 2016 should the application be approved as submitted. This income includes the additional revenues generated by the requested rate increase of $103.2 million in 2014, $209.6 million in 2015 and $328.7 million in 2016. This requested rate increase is now forecasted to achieve a return on equity of 2.9% in 2014 up from 1.3% in original rate application, 2.0% in 2015 and 1.9% in 2016.

As previously discussed, all functional costs are classified as being energy, demand or customer related. The following table shows the 2014, 2015 and 2016 COSS revenue requirement results for Customer, Energy and Demand by class.

Table 10.8 - 2014-2016 Customer, Energy & Demand Revenue Requirement (in $ millions)

Customer Class	2014 COSS	2015 COSS	2016 COSS	2014-2016 Change	
Urban Residential					
Demand	$192.0	$203.3	$214.9	$22.9	11.9%
Energy	$103.0	$111.1	$118.2	$15.2	14.8%
Customer	$70.5	$72.1	$77.0	$6.5	9.2%
Total	**$365.5**	**$386.5**	**$410.1**	**$44.6**	**12.2%**
Rural Residential					
Demand	$55.4	$58.5	$62.1	$6.7	12.1%
Energy	$24.1	$26.0	$27.7	$3.6	14.9%
Customer	$17.4	$18.3	$19.7	$2.3	13.2%
Total	**$96.9**	**$102.8**	**$109.5**	**$12.6**	**13.0%**
Farms					
Demand	$92.2	$96.2	$99.8	$7.6	8.2%
Energy	$49.1	$52.4	$54.6	$5.5	11.2%
Customer	$19.1	$19.6	$20.7	$1.6	8.4%
Total	**$160.4**	**$168.2**	**$175.1**	**$14.7**	**9.2%**
Urban Commercial					
Demand	$158.6	$166.6	$175.6	$17.0	10.7%
Energy	$110.4	$118.2	$125.3	$14.9	13.5%
Customer	$20.4	$21.2	$22.7	$2.3	11.3%
Total	**$289.3**	**$305.9**	**$323.6**	**$34.3**	**11.9%**
Rural Commercial					
Demand	$58.0	$60.8	$64.3	$6.3	10.9%
Energy	$33.7	$36.1	$38.3	$4.6	13.7%
Customer	$7.1	$7.6	$8.3	$1.2	16.9%
Total	**$98.9**	**$104.5**	**$111.0**	**$12.1**	**12.2%**
Power - Published Rates					
Demand	$200.1	$229.9	$268.5	$68.4	34.2%
Energy	$228.4	$266.6	$312.1	$83.7	36.7%
Customer	$5.9	$6.1	$6.4	$0.5	8.5%
Total	**$434.4**	**$502.6**	**$587.0**	**$152.6**	**35.1%**
Power - Contract Rates					
Demand	$49.9	$51.7	$58.8	$8.9	17.8%
Energy	$59.4	$62.4	$71.0	$11.6	19.5%
Customer	$1.1	$1.0	$1.1	$0.0	0.0%
Total	**$110.3**	**$115.1**	**$130.9**	**$20.6**	**18.7%**
Oilfields					
Demand	$166.5	$185.3	$195.9	$29.4	17.7%
Energy	$137.0	$156.0	$166.5	$29.5	21.5%
Customer	$16.2	$17.2	$18.7	$2.5	15.4%
Total	**$319.6**	**$358.4**	**$381.1**	**$61.5**	**19.2%**
Streetlights					
Demand	$2.8	$3.0	$3.2	$0.4	14.3%
Energy	$2.3	$2.5	$2.7	$0.4	17.4%
Customer	$8.7	$8.8	$9.0	$0.3	3.5%
Total	**$13.8**	**$14.4**	**$14.9**	**$1.1**	**8.0%**
Reseller					
Demand	$46.6	$48.7	$50.8	$4.2	9.0%
Energy	$43.8	$46.8	$49.2	$5.4	12.3%
Customer	0.3	$0.3	$0.4	$0.1	33.3%
Total	**$90.7**	**$95.8**	**$100.4**	**$9.7**	**10.7%**
All Customer Classes					
Demand	$1,022.0	$1,104.0	$1,193.9	$171.9	16.8%
Energy	$791.2	$878.1	$965.7	$174.5	22.1%
Customer	$166.7	172.3	$184.1	$17.4	10.4%
Grand Total	**$1,979.8**	**$2,154.4**	**$2,343.6**	**$363.8**	**18.4%**

10.4 Minimum and Maximum Customer Increases

Rebalancing has been incorporated into this Rate Application. Rate redesign is required to correct the imbalances within the rate codes themselves, which involves adjusting the rate components (Basic Monthly Charge, Demand Charge and Energy Charge). As a result, not all customers within a rate class will receive the same rate increase. For this application, the proposed maximum increase is less than 15% (considered to be the upper limit to avoid rate shock) to accommodate any rebalancing elements. Rate redesign is an ongoing process that will continue beyond 2016. The following table illustrates the minimum, maximum and average rate impacts for 2014, 2015 and 2016.

Table 10.9 - Minimum, Maximum and Average Rate Impacts for 2014 - 2016

Customer Class	2014 Rate Impact			2015 Rate Impact			2016 Rate Impact		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Urban Res	0.04%	5.30%	7.18%	0.04%	4.50%	5.79%	0.04%	4.50%	5.66%
Rural Res	0.02%	5.30%	5.38%	0.03%	4.50%	5.27%	0.03%	4.80%	5.65%
Farms*	0.00%	3.50%	4.22%	(8.61)%	4.50%	5.60%	3.43%	4.00%	4.16%
Urban Com	(0.62)%	7.00%	13.64%	0.73%	5.60%	8.67%	4.15%	5.60%	7.02%
Rural Com	(0.11)%	4.80%	6.64%	0.02%	4.80%	10.06%	0.02%	4.80%	5.79%
Power Pub	0.12%	7.00%	10.84%	0.07%	5.80%	6.19%	0.08%	5.80%	6.12%
Oilfields	0.05%	3.60%	8.41%	0.04%	3.70%	6.19%	0.82%	3.70%	6.09%

*does not include farm irrigation customers

10.5 Rate Design Observations

For this review, the Minister's Terms of Reference stipulated that the Panel was to consider as part of its review "The reasonableness of the current rate structure and all components (basic charge, energy charge and demand charge) comprising the rate". It is noted that SaskPower has not altered the rate structure for any of its customer classes that were utilized in the 2013 Rate Application. Customer classes having a two part rate (BMC and Energy Rate) structure remains unchanged as do those classes with a three part rate (BMC, Energy and Demand Rates) structure.

The rate design and rate determination are based on the revised COSS and SaskPower's internal load research which are proposed to remain unchanged for 2014 to 2016, other than for the phasing in of the rate rebalancing so that the R/RR range in 2016 will be between 0.98 to 1.01. While we agree that because of the amount of judgement necessary in any COSS, the use of this narrower range reduces any undue cross-subsidization between customer classes. However, SaskPower has historically established Residential and perhaps Farm class R/RR to be less than 1.00. We are of the view that, with the newly completed COSS and internal load research study, once an allocated revenue requirement is determined, a rate structure should be designed so that all classes are expected to contribute only that allocated revenue requirement, meaning that all class R/RR would be at 1.00. This will not likely ever be achieved, as actual results and customer data will invariable differ from forecasts. However, this would preserve the principle of designing cost-based rates and eliminate any perception of cross-subsidization.

The effects of the revised COSS and internal load data combined with the greater capital and maintenance expenditures specifically on generation and transmission service relative to Distribution Customer Service and Other projects result in those customers who do not rely on SaskPower's Distribution Service experiencing rate increase percentages greater than the system average over the next 3 years. SaskPower's first round response to SIECA[71] provides a rate sensitivity example to illustrate this issue and result.

[71] IR 37 SIECA First Round

The Panel has previously accepted that any annual increase in excess of 15% on an annual basis constitutes rate shock. Although it must be realized that the Panel's definition of rate shock was determined in times of relatively high inflation, and may now be out-dated, this application does not result in any customer class experiencing a rate increase approaching what Panel has determined previously to be rate shock.

We have previously recommended that SaskPower review the number of Rate Codes used, with the view of condensing these to a point where similar customer consumptions and demands are reflected in rate codes, in a more generic fashion. A similar recommendation was made by Elenchus upon completion of its cost of service and rate design methodology review in 2012. For this rate application, SaskPower proposes to eliminate or close three rate codes, the elimination of which will not affect any current customer.

11.0 Historical Rate Comparison Summary

11.1 Other Jurisdiction's Rates

The following is a summary of each jurisdiction's residential rate structures:

British Columbia – Initial block rate up to 1,350 KWh over a two month period and then a higher block rate for electricity used in that period over that amount.

Alberta – There is a retail market for residential, farm, small and medium commercial customers which is open to competition. There is a separation between generation costs and costs for transmission and distribution. The latter is still a regulated service. Customers have the option to be served under a regulated generation supply option, called the RRO option. Under that option 40% of the supplied electricity is at a fixed price and the balance is priced on a one month variable rate. Accordingly prices can and do vary from month to month.

Saskatchewan – A single Block Rate for all electricity consumed plus a Basic Monthly Charge (BMC). The Basic Monthly Charge and electricity charge are the same for customers coded as Town, Village and Urban Resort, while different rates are applicable for customers coded as being Rural or Rural Resort.

Manitoba – First block rate for the first 900 KWh per month and a second, slightly higher block rate for consumption in excess of 900 KWh per month, as well as a BMC.

Ontario – For the period May to April, the winter threshold is 1,000 KWh per month, while 600 KWh is the threshold for the summer period. One block rate applies up to the thresholds and a second, higher block rate applies for consumption over the thresholds. Consumers having three-part, time of use meters, are charged on-peak rates, shoulder rates and off-peak rates, declining from the on-peak rate.

Quebec – Generation is priced directly by decree by the Government of Quebec in consultation with Quebec Hydro. Therefore the cost of generation and the subsequent rates are not regulated. Residential consumer's delivered rates consist of a block for up to the first 30 KW per day, plus a second block rate for use in excess of that amount. A fixed daily charge is also applied.

New Brunswick – First block rate for use of up to 1,300 KWh and a second, lower rate for use above the threshold, as well as a BMC.

Nova Scotia – A BMC plus a single rate for all electricity, regardless of consumption.

Prince Edward Island – A block rate for the first 1,600 KWh and a second, lower block rate, plus a BMC that is different for urban and rural customers.

Newfoundland – A single block rate for all energy coupled with a BMC that differs for urban customers and for rural customers.

Since January 2010, the following are some rate adjustments that have occurred across Canada in other provincial jurisdictions:

BC Hydro
- Rates increased 6.11% plus a rate rider from 1.0% to 4.0% in 2010;
- Rates increased 8.0% in 2011 and 3.91% in 2012; and
- Rates increased 1.44% in 2013.

Fortis BC
- Rates increased 6.6% in 2011, 1.5% in 2012 and 4.2% in 2013; and
- Rate increase of 3.3% proposed for 2014.

Manitoba Hydro
- Rates increased 1.9% in 2010 and 2.0% in 2011;
- Rates increased 2.0% and 2.5% in 2012; and
- Rates increased 3.5% in 2013.

Yukon Energy
- Rates increased 6.4% in 2012 and 6.5% in 2013.

Northwest Territories Power Corp
- Rates increased 7.0% in 2012;
- Rates increased 7.0% on interim basis in 2013;
- Rate increase of 7.0% proposed for 2014; and
- Rate increase of 5.0% proposed for 2015.

Hydro Quebec
- Rates decreased 0.4% in 2011 and 0.5% in 2012;
- Rates increased 2.4% in 2013;
- Rate increase of 3.4% proposed for 2014; and
- Rate increase of approximately 1.2% in the heritage pool proposed from 2014 to 2018.

New Brunswick Power
- Rates increased 3.0% in 2010 and 2.0% in 2013; and
- Rates to be increased 2.0% in 2014.

Maritime Electric
- Rates decreased 14.0% in 2011;
- Rates increased 2.2% in 2013; and
- Rate increases to be capped at 2.2% for 2014 and 2015.

Nova Scotia Power
- Rates increased 5.6% in 2012;
- Rates increased 3.0% plus fuel adjustment mechanism changes in 2013; and
- Rates to be increased 3.0% plus fuel adjustment mechanism changes in 2014.

Newfoundland Power
- Rates increased 3.5% in 2010, 7.7% in 2011 and 6.6% in 2012; and
- Rate increase of 6.0% proposed for 2013.

The following table displays the above noted provincial rate changes (actual and proposed) by provincial utility since January 2010.

Table 11.1 - Provincial Rate Changes (Actual and Proposed) Since January 2010

Canadian Utility	Date	% Change	Comment
BC Hydro	2010	6.11%	Plus a rate rider from 1.0% to 4.0%
	2011 May	8.0%	Plus a rate rider of 2.5%
	2012 Apr	3.91%	Plus a rate rider of 5.0%
	2013 Apr	1.44%	Plus a rate rider of 5.0%
	2014-2016		Additional increases are forecast
Fortis BC	2011	6.6%	Increase
	2012	1.5%	Increase
	2013	4.2%	Increase
	2014	3.3%	Proposed increase
Manitoba Hydro	2010 Apr	1.9%	Increase
	2011 Apr	2.0%	Increase
	2012 Apr	2.0%	Interim increase
	2012 Sep	2.5%	Interim increase
	2013 Apr	3.5%	Increase
Yukon Energy	2012	6.4%	Increase
	2013	6.5%	Increase
Northwest Territories Power Corp	2012 Apr	7.0%	Increase
	2013 Apr	7.0%	Interim increase
	2014 Apr	7.0%	Proposed increase
	2015	5.0%	Proposed increase
Hydro Quebec	2011	(0.4)%	Decrease
	2012 Apr	(0.5)%	Decrease
	2013 Apr	2.4%	Increase
	2014	3.4%	Proposed increase & about 1.2% in heritage pool (2014-2018)
New Brunswick Power	2010	3.0%	Increase
	2010-2013	0.0%	3 year rate freeze
	2013 Oct	2.0%	Increases of 2.0% or less are not subject to review
	2014 Oct	2.0%	Increases of 2.0% or less are not subject to review
Maritime Electric	2011 Mar	(14.0)%	Decrease
	2011-2013	0.0%	Rates frozen
	2013 Mar	2.2%	Increase
	2014	2.2%	Capped Increase
	2015	2.2%	Capped Increase
Nova Scotia Power	2012 Jan	5.6%	Increase plus 3.0% from fuel adjustment mechanism
	2013 Jan	3.0%	& fuel adjustment mechanism increases or deferrals
	2014	3.0%	& fuel adjustment mechanism increases or deferrals
Newfoundland Power	2010	3.5%	Increase
	2011 Jul	7.7%	Increase
	2012 Jul	6.6%	Increase
	2013 Mar	6.0%	Proposed increase

The following table summarizes the electric utility rate data collected by Hydro Quebec as part of its recent survey. The survey compares the rates of 12 major Canadian cities/utilities (including Regina.) as of April 1, 2013.

Table 11.2 - Comparison of Electricity Prices (Monthly Bills as of April 1, 2013)

1.) Hydro Utilities ($/Month)

CITY	SERVED BY	RESIDENTIAL 750 kWh	SMALL COMMERCIAL 6 kW & 750 kWh	STANDARD COMMERCIAL 100 kW & 25,000 kWh	LARGE INDUSTRIAL 10,000 kW & 5,760,000 kWh
VANCOUVER, BC	BC HYDRO	$61.92	$79.32	$2,294.38	$295,442.78
WINNIPEG, MB	MANITOBA HYDRO	$58.90	$73.23	$1,955.80	$221,217.00
MONTREAL, QC	HYDRO QUEBEC	$52.77	$79.31	$2,493.50	$271,524.00

2.) Thermal Utilities ($/Month)

CITY	SERVED BY	RESIDENTIAL 750 kWh	SMALL COMMERCIAL 6 kW & 750 kWh	STANDARD COMMERCIAL 100 kW & 25,000 kWh	LARGE INDUSTRIAL 10,000 kW & 5,760,000 kWh
CALGARY, AB	ENMAX	$115.76	$126.84	$4,005.71	$811,221.55
EDMONTON, AB	EPCOR	$109.43	$112.34	$3,362.08	$766,693.06
TORONTO, ON	TORONTO HYDRO	$96.84	$106.24	$3,389.87	$630,569.90
OTTAWA, ON	HYDRO OTTAWA	$95.05	$98.98	$3,145.88	$598,079.37
MONCTON, NB	NB POWER	$93.61	$111.46	$3,109.23	$402,800.00
HALIFAX, NS	NOVA SCOTIA POWER	$118.55	$121.70	$3,713.40	$544,308.97
CHARLOTTETOWN, PE	MARITIME ELECTRIC	$117.65	$142.40	$3,784.47	$499,816.00
ST. JOHN'S, NL	NEWFOUNDLAND POWER	$97.97	$113.33	$3,167.52	$512,323.56

3.) Utility Rate Summary ($/Month)

CITY	SERVED BY	RESIDENTIAL 750 kWh	SMALL COMMERCIAL 6 kW & 750 kWh	STANDARD COMMERCIAL 100 kW & 25,000 kWh	LARGE INDUSTRIAL 10,000 kW & 5,760,000 kWh
Hydro Utility Average		$58.00	$77.00	$2,248.00	$262,728.00
Thermal Utility Average		$106.00	$117.00	$3,460.00	$595,727.00
Canadian Utility Average		$93.00	$106.00	$3,129.00	$504,909.00
REGINA, SK	SASKPOWER	$104.00	$105.00	$2,858.00	$351,996.00

4.) SaskPower Comparison

	RESIDENTIAL 750 kWh	SMALL COMMERCIAL 6 kW & 750 kWh	STANDARD COMMERCIAL 100 kW & 25,000 kWh	LARGE INDUSTRIAL 10,000 kW & 5,760,000 kWh
SaskPower compared to Hydro Utility Average	179.3%	136.4%	127.1%	134.0%
SaskPower compared to Thermal Utility Average	98.1%	89.7%	82.6%	59.1%
SaskPower compared to Canadian Utility Average	111.8%	99.1%	91.3%	69.7%

5.) SaskPower Compared to All Thermal Utilities (All Classes) 82.4%

11.2 Historical Rate Changes

SaskPower's last approved rate increase was a system wide average of 5.0% effective January 1, 2013. SaskPower compares its rates to the average charged nationally, including low-cost hydro jurisdictions, and by other thermal utilities in Canada. The table above gives an illustrative overview on electricity prices in Canada.

The following indicates SaskPower's rate adjustments since 2001:

Table 11.3 - SaskPower Rate Adjustments – Actual and Proposed

Date	%	Date	%	Date	%
April 1, 2001	2.00 %	February 1, 2007	4.30 %	January 1, 2014	5.50%
January 1, 2002	4.54 %	June 1, 2009	8.50 %	January 1, 2015	5.00 %
September 1, 2004	5.65 %	August 1, 2010	4.50 %	January 1, 2016	5.00 %
January 1, 2006	4.90 %	January 1, 2013	5.00 %		

SaskPower's rates from 1999 to 2013 have increased approximately 46.7% on a compounded basis. During this same period the Consumer Price Index (CPI) increased by about 36.8%. SaskPower states that the CPI does not reflect SaskPower's cost structure or experience, primarily in the area of Fuel and Purchased Power, as well as engineering goods and services.

11.3 Observations

The hydraulic portion of SaskPower's generation is expected to account for approximately 7% of total requirements. In terms of fuel costs, hydro is the most economical to operate. Thus, when comparing rates with other Canadian electric utilities, the most meaningful would be with "thermal" utilities that rely primarily on non-hydro generation.

SaskPower customers currently pay rates that are on average higher than the Canadian Utility average but approximately 18% lower than the rates of other thermal utilities in Canada. However, small commercial, standard commercial and large industrial customer's rates on average are lower than Canadian Utility average and significantly lower than Thermal Utility average. Generally, however electrical rates are rising in all jurisdictions across Canada.

We continue to caution that any comparisons must recognize that each utility has unique characteristics including generation fuel mix and related hierarchy of costs, customer density, deferral account balance disposal, geographic population distribution, timing differences and potential for export revenues.

12.0 Sensitivity Potential Impacts

12.1 Discussion

In the preparation of a rate application, a utility will make a number of assumptions and forecasts. The economic forecasts that were used to underpin this application for the years 2014 to 2016 were: inflation rate of 2.0% for all three years; short term borrowing rates of: 2014 - 1.1%, 2015 - 1.5% and 2016 - 1.7%; long term interest rates of 3.7%, 3.9% and 4.1% respectively; weighted average cost per Gj of natural gas for: 2014 - $4.22, 2015 - $4.59 and 2016 - $4.52.[72]

Additionally, the 2014 – 2016 wages and salaries were assumed to increase by 2% throughout all the years of the application. The 2% increase is consistent with the inflation rate assumption and is based on the Bank of Canada's long-term target range of 1% to 3%[73]. These economic assumptions were used to produce the main drivers of a rate application namely the load forecast, the revenue and expense forecast, the capital budget, and the depreciation and tax expense forecast.

There has been a trend in recent years of actual Power Class Customer revenues falling significantly short of budget. Since the energy required by the Power Customer Class is generally over 40% of the total domestic demand, the impact of load being 5% less than anticipated can translate into a significant shortfall of SaskPower's revenue stream. The revenue for 2013 is expected to continue this trend with the Power Class revenue now expected to be 6-7% less than the 2013 budget, mainly as a result of world economic conditions in the potash market.

Adverse global economic conditions experienced during the 2011 - 2013 period continue to slowly improve. While Saskatchewan's economy is stronger than that of most other Canadian provinces, external markets and economic data continue to send somewhat mixed signals as to the level of economic growth expected through-out 2014, 2015 and 2016. This uncertainty creates significant issues for SaskPower in forecasting load and customer demand accurately, thereby increasing the risk of financial performance. Forecasting revenue, fuel and purchase power costs and other operating and capital costs thus becomes more tenuous.

Given the potential for significant variances on SaskPower's net income if forecasts do not materialize as expected, SaskPower was requested to provide a number h of potential scenarios that might develop over the three year time period covered by the rate application.

The sensitivity analyses shown in Table 12.1 below were prepared for some of the basic cost drivers and assumptions used in the preparation of the current forecasts and planning process. These show the possible impact of changes in assumptions on operational results. The following are not strictly correlated or all-risk inclusive. As an example, if water flows are higher than the median forecast used in the application more electricity would be generated by hydraulic means, reducing the need to generate electricity by other fuel sources, primarily natural gas. The savings would result due to buying less natural gas. In the converse, if hydraulic generation was less than median conditions, then more natural gas would be required to generate the electricity, which costs more than hydro. Generally coal fired generation, being the least costly fuel source, is operated at maximum output and cannot be relied on to smooth out variances in hydraulic generation.

The following table provides a sensitivity analyses in the dollar impacts for some of the key assumptions employed in developing the 2014-2016 rate application.

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[72] IR 2A First Round
[73] IR 2B First Round

Table 12.1 - Impact of Assumption Changes on Net Income

Revenue	Impact on Net Income
1% change in the rate increase assumption	$20.0 million
100 GWh change in power customer consumption	$4.0 million
100 GWh change in residential power consumption	$9.0 million

Fuel & Purchased Power	Impact on Net Income
$1/GJ change in the natural gas price assumption	$30.0 million
10% change in the hydro assumption	$16.0 million
10% change in the coal generation assumption	$37.0 million

Capital	Impact on Net Income
$100 million change in capital budget (full year impact)	$8.0 million
1% change in short-term interest rates	$11.0 million
1% change in interest rate assumption (full year impact)	$7.0 million

12.2 Observations

Recognizing that the forecasted operating income is only $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016, any of the above impacts can result in a significant change to the net income and ROE. In the event one or more change occurs simultaneously a much different net income would result than originally forecast. It must be recognized that not all of the changes will necessarily be in the same direction. That is, some will be positive and increase net income while any negative changes will decrease the net income. The greatest financial impacts flow from changes in energy demand coupled with the resulting changes in the F&PP costs. This is illustrated by the Mid-Application update that revised the original application operating net incomes for 2014 to $66.0 million, $59.7 million for 2015 and $46.4 million for 2016. The two main reasons for this increase is the delay in the ins-service date for the ICCS project, resulting in a decrease in depreciation and finance charges of approximately $69 million for 2014, and an increase in the forward market price of natural gas which increased total F&PP expense by about $34.5 million. These two changes account for about $34.5 of the net overall increase of $40 million in the operating income.

A good example was the summer storm of 2012 which created havoc with SaskPower's transmission and distribution system and required significant additional labour and material to reinstate power service. The final cost to restore service was $12.3 million.

There is significant uncertainty surrounding this application as it requests a three year rate increase rather than for a single year as has been past practise. As noted above one item alone, for example a $1/GJ increase in the cost of natural gas, will translate to a cost variance of $30 million for SaskPower. This was confirmed in the Mid-Application Update filed February 14, 2014. The total Fuel and Purchased Power cost forecast has increased by a net of $34.6 million which was primarily due to the recent upward movement in natural gas market prices, resulting in an increase in natural gas costs of $36.8 million. This natural gas cost increase was offset by changes in projected 2014 volumes and generation fuel mix.

We are reasonably comfortable with the forecasts for 2014. However as highlighted in the Mid-Application Update, there is greater uncertainty in the projections for the remainder of the application, especially, for 2015 and 2016. This uncertainty is not necessarily attributable to SaskPower forecasting methodology, but rather with the economic circumstances that may actually prevail locally or globally during that time period over which SaskPower will have limited influence or control.

13.0 Confidentiality and Transparency

The Panel adopted confidentiality guidelines in 2010 which were intended to provide guidance to the Panel and the Crown corporations surrounding the classification, use and disclosure of confidential information supplied by SaskPower, SaskEnergy and Saskatchewan AutoFund during the course of an application to review a change in rates.

Since that time, the Minister's Terms of Reference specifically cite these "Confidentiality Guidelines" and indicate the Panel is not to publicly release or require SaskPower to publicly release confidential information supplied by the Crown Corporation to the Panel during the course of the rate change application review. The specific "Confidentiality Guidelines" are posted on the Saskatchewan Rate Review Panel's web-site: *www.saskratereview.com*.

Confidential information is defined as that which contains commercially sensitive information with a legitimate need for protection from disclosure, information the disclosure of which could reasonably be expected to result in financial loss or gain, prejudice the competitive position of, or interfere with the contractual obligations of the Crown corporation or a third party. In addition the disclosure of confidential information is prohibited by law, including The Freedom of Information and Protection of Privacy Act (Saskatchewan) (FOIPPA).

The specific guidelines state “The Crown corporation will submit to the Panel all information required for the Panel to complete its mandate, including that information required by the Minimum Filing Requirements and Terms of Reference for that specific review. Information submitted by the Crown Corporation to the Panel that is not marked as ‘Confidential’ will be treated by the Panel as available for disclosure to the public.”

SaskPower confidential information currently assessed under the guidelines are as described below:

- All commercial Power Purchase Agreements;
- Key Account Customer Contracts/Information;
- Natural Gas Purchase Policies and Protocols together with Natural Gas Price Management/Hedging Policies; and
- Current and Future Business and Strategic Plans.

Notwithstanding the assessment of any material as confidential information, the Panel may disclose confidential information to such independent experts, consultants and advisors engaged on its behalf to assist the Panel in its review and report, provided that such third parties are bound by similar obligations of confidentiality and non-disclosure as the Panel.

The fundamental principle in assessing whether or not to maintain information in confidence is to achieve an appropriate balance between the interest of the public in the disclosure and the potential harm that could result to the Crown from the public disclosure of such information. Consideration is also given as to whether or not the information is already generally available to the public.

14.0 2014 -2016 Rate Application Approval Processes

14.1 Discussion

SaskPower's rate application covers three test years:

- January 1, 2014 to December 31, 2014;
- January 1, 2015 to December 31, 2015; and
- January 1, 2016 to December 31, 2016.

This is the first multi-year application filed by SaskPower and the second multi-year application being reviewed by the Panel (the first being the SaskEnergy 2013/2014 Delivery Application).

The 2014 rate increase was implemented on an interim basis on January 1, 2014 pending the recommendations of the Panel. SaskPower stated that it "…is mindful of the Panel's recommendations from the 2010 review to have rate applications coincide with SaskPower's fiscal year, so the Corporation can receive the benefit of matching the proposed revenue requirement needs with a full year's revenue stream". SaskPower further stated that "This is of particular importance in 2014 as SaskPower is striving to maintain a positive net income with the rate increase effective at the beginning of the fiscal year" which resulted in the need to implement an interim increase pending the Panel's review.

SaskPower's reasoning for a multi-year rate request with this application was twofold. First was to ensure that their customers would benefit from knowing what their future rates are and secondly SaskPower would benefit from the financial certainty resulting from the three year rates. SaskPower stated "Knowledge of the long-term rates will enable both SaskPower and our customers to conduct long-term financial planning with greater certainty".

SaskPower confirmed it will rebalance rates in each year of this rate application to ensure that they reflect the actual cost of service, providing equity among rate classes and the customers within the rate class. SaskPower plans to have rates fully rebalanced by 2016 so that all customer classes' revenue-to-revenue requirement ratios will be narrower (0.98 to 1.01) than the industry's standard of 0.95 and 1.05.

While this three year application is a significant departure from past applications and processes the Panel has followed, multi – year test applications are becoming more common in the industry. The cost and time required with the approvals being sought through the quasi-judicial tribunal's processes is a major consideration. The Panel's mandate is not quasi-judicial but rather to act as an appointed body to advise and recommend to the Minister on the just and reasonableness of the rate applications for the three major Crown Corporations.

In view of this being the initial Multi-year application by SaskPower and notwithstanding the differing mandate of the Panel relative to quasi-judicial bodies, we have reviewed the conditions stipulated for follow-up filings when approvals were recently granted by other jurisdictions for multi-year rate change applications.

All quasi-judicial jurisdictions have the legislated authority for final approval of rates, as opposed to making recommendations, as is the case for the Panel. Our review included the following rate change applications:

1. British Columbia Utilities Commission (BCUC) in respect multi-year applications from BC Hydro Fortiss BC (Gas).
2. Alberta Utilities Review Board regarding an ATCO (Gas)3 year application
3. Manitoba Public Utilities Board in respect of a Centra Gas 2 year rate application
4. Northwest Territories Public Utilities Commission in respect of a NWT Power Corporation 2 year application.

The scope of a request is unique for every application. Some requests were for approval of matters other than rate changes, including capital spending plans, variance account clearances, and legacy rate riders among others. With respect to the multi-year rate requests, approvals were also unique for each case, primarily concerned that the allowed return on equity not be exceeded, on an overall (total approved revenue requirement), rather than individual expense item basis, over the time frame of the request. They were also significantly influenced by rate riders flowing from the disposal of various deferral account balances. Many rate approvals were on an interim refundable basis. As well, all applicants were required to submit financial and/or operating statements, again differing in scope, depending on the application, for all years for which rate increases were sought.

In 2009, the Panel recommended that SaskPower investigate the establishment of a Fuel Cost Variance Account (FCVA) to track the variance between actual and budgeted fuel costs, and deal with shortfall or surplus that otherwise would be absorbed by the utility and passed on to customers through future rate adjustments. SaskPower complied and engaged a consultant to undertake of review of the FCVA. In a subsequent report one of the reasons the consultant felt a FCVA might not be necessary was that SaskPower was assumed to likely continue with annual rate applications.

The absence of FCVA for SaskPower is one of the significant differences from other jurisdictions that all have specific variance accounts that track the positive and negative balances (like fuel or gas purchase accounts). This ensures that the customers and the utility are kept whole should market actual costs and revenues deviate from budget or application forecasts and, over time, reduces rate volatility.

SaskPower does not employ variance accounts of any type. SaskPower considers that the introduction of a FCVA would result in additional risk being transferred to the customer. Thus, rather than assuring price certainty, customers would be subject to potential rate increases, flowing from F&PP cost variations above those requested in this Application.

Therefore, while a review of the principles established in other jurisdictions is of some assistance in examining this matter, we are of the view that the uniqueness of the Panel's rate approval process in reviewing the interest of SaskPower, the ratepayer and the general public requires a "made in Saskatchewan" approach.

During this review, SaskPower was requested to recommend a process to the Panel for dealing with variances between actual and budgeted results and resultant rate impacts. SaskPower suggested, that if rates were recommend and approved for the three years, SaskPower would expect to submit a financial update to the Panel in September for each of 2014 and 2015, focusing on variances from actual to budget during the current year and variances between the most recent forecast compared to the rate application forecast for the following year.

Based on those new forecasts and variances SaskPower would recommend either that there be no change in the approved rates if the differences were deemed immaterial or recommend a further change to rates based on the new data where variances were significant. SaskPower further suggested that the financial update would be subject to a smaller review by the Saskatchewan Rate Review Panel and the Panel would likely be expected to provide a recommendation to Cabinet in a few weeks. SaskPower anticipates that all the traditional financial expenses would form part of the financial update, including future load forecasts, all expenses and capital requirements.

SaskPower provided the following details for a suggested process for a review and rate recommendation for the last two years of this multi-year application:

- SaskPower submit a limited scope filing with the Panel at the beginning of September for the subsequent year.
- SaskPower recommended that any rate change in the requested rate increase would be based on the Corporation's net income remaining within forecasted return on equity.

- The variance trigger would be on an overall basis, or by major expenditure categories, such as F&PP, OM&A, or Capital and related expenses,
- The suggested filing would include an updated summary of any changes in operating environment, latest annual report, most recent quarterly report, updated forecast for 2014, 2015 and 2016, detailed update on capital plan for the period 2014-2016, updated Business Renewal Program, , Advance Metering Infrastructure Project and Demand Side Management;
- Other information requested by the Panel.
- And lastly, the above process assumes no change in rate to the requested rate increase for 2015-2016.

Should a revised rate increase be required, SaskPower expected that a full review would be required, as is currently the case.

Four stakeholders (Saskatchewan Mining Association (SMA), Saskatchewan Industrial Energy Consumers Association (SIECA), Greater Saskatoon Chamber of Commerce (SCC) and Evraz) all expressed specific concerns relative to forecasting costs and approval of the application for three years. SMA specifically stated "SaskPower has not demonstrated how a multi-year rate application improves forecasting accuracy, provides forecasting certainty or right sizes capital investment spending. SaskPower's multi-year rate application does not have regulatory protocols or compliance mechanisms to address variances during the rate application period. SMA does not favour rate applications that fix electricity rates over a multi-year period without a proper regulatory process***."***

14.2 Observations

As noted in Section 12.0, Sensitivity Potential Impacts, a number of input assumptions are used to provide the revenue and expense forecasts for the rate application. Several of these are outside the control of SaskPower. They are driven by a number of considerations including economic markets, internal and external to Canada, as well as weather variations and river flows. Indeed world markets have significantly impacted economic considerations in Canada over the last few years, more so than any time period in the recent past.

SaskPower confirmed the need for conditional approvals[74] for the second and third years of the rate application as discussed above. Therefore in consideration of the above, the consultants view that it would be prudent to only finalize the 2014 rate application and develop a mechanism that could secure the interests of all parties (utility-ratepayer-public) for the 2015 and 2016 years of the Rate Application.

Without variance accounts or similar mechanisms to reduce price and rate volatility, forecasting accuracy is a fundamental and crucial factor in a multi-year rate application. SaskPower's overall forecasting methodology has significantly improved during the last several years and its load forecasting with respect to the Power Customer Class is expected to show continued improvement with recent forecasting refinements. However, circumstances beyond the control of SaskPower can and do have significant financial impacts.

As an example, SaskPower's budget assumed the ICCS project would commence operations by the end of 2013. That has not occurred and the project cost has increased by $120 million from the rate application forecast. Mainly as a result of the delay, the depreciation and finance expense will be approximately $69.2 million less than forecasted for 2014, offset in part by increased F&PP forecast costs(and correspondingly the 2014 net income and ROE will increase, all else being equal), but the 2015, 2016 and beyond forecasts for depreciation and finance expenses remain the same.

[74] IR 40 Second Round

Notwithstanding that SaskPower overall rate of return will still be significantly improved but less than the long-term target of 8.5% in 2014, this single event has impacted the expected financial results dramatically.

The Panel has a variety of options that it can consider for the 2014, 2015 and 2016 rate recommendations. These include recommendations that only January 2014 interim rates be approved (or amended); that January 1, 2014 rates be finalized as well as, subject to conditions, rates as filed for 2015. Another option is to finalize rate for 2014, and approve subject to conditions, rates for 2015 and 2016. The last option is to recommend final approval of the multi-year application as filed without conditions.

We certainly do not recommend the latter, as we are of the view that this option is not in the best interest of all interested parties including SaskPower. There many variables and uncertainties in the assumptions underpinning the 2014 forecasts and these become more uncertain for cost and revenue forecast accuracy into the future. With the complementary financial risks, both positive and negative, to the utility as well as its ratepayers, it is very difficult to suggest final approvals for all three years 2014-2016 while ensuring that the interests of all parties are met.

It is our view that the nature of these variables, largely beyond the control of SaskPower, as well as the size of the Capital Program (a main cause of the requested rate increases) and the inherent possibility of not being able to complete the total program in any given year will result in significant changes in 2014 from the application assumptions and forecasts. These will only be exacerbated in 2015 and more so in 2016 with the passage of time. While it may be acceptable to stipulate that the criteria for amending future rates be the fact that SaskPower's ROE not exceed the allowed 8.5%, it is our view that other cost and revenue drivers must also considered.

SaskPower has implemented many initiatives that have resulted in efficiencies and either cost savings or avoided costs. These should continue to be explored annually, as should the DSM programs and savings from year to year which would continue to improve SaskPower/Stakeholder/Consumer transparency. Additionally SaskPower confirmed it will rebalance rates in each year of this rate application to ensure that they reflect the actual cost of service, providing equity among rate classes and the customers within the rate class. To rebalance rates will require examination and a determination by the Panel.

We note that the Panel, in the 2013 SaskEnergy Delivery Application, approved the 2013/2014 application and conditionally approved the second test year (September 1, 2014/2015).

While the Panel has four options in considering this application we do not recommend unconditional approval of the three year application. Being sensitive to the financial needs of SaskPower, the stated interests of the stakeholders and ratepayers including the transparency of the three remaining options, we are of the view that it would be prudent to only recommend approval of the 2014 rate application and conditional approval for the 2015 test year application.

As suggested by SaskPower an updated filing would be required that could secure the interests of all parties (utility-ratepayer-public) for the 2015 rate application. This filing would also indicate the then current forecasts for 2015 and the prospective financial position for SaskPower going forward into 2016 and beyond. Should SaskPower financial forecasts significantly deteriorate, or alternatively the ROE were forecast to exceed the long-term target, we are of the view that it would be incumbent on SaskPower to file a rate change request for 2015. We recognize that proceeding with a rate change process is not entirely within the control of SaskPower, but are of the view that the Panel should not be influenced by external influences. The Panels' recommendations should continue to be based on an assessment of SaskPower's forecasted financial circumstances and impacts on all rate payers so as to preserve the interest of SaskPower, its customers and the public at large.

With the current size of the planned capital program and its impact on the financial revenue requirements of the utility, the less than stable economic outlook and future load forecasts, continued upward movement in fuel and purchase power costs (including the forward natural gas market pricing) and hydraulic generation availability, there are, in our opinion just too many uncertainties' to provide the comfort necessary to recommend approval of the 2016 test year application.

SaskPower suggested that a filing[75] warrants consideration as an update filing process, but the filing should include COSS and Rate Design information. The issue however that is concerning to us, is the limited scope and suggested schedule where updated financial data cannot support a rate change. The Panel must not be seen as being able to fulfill its mandate, it is important that ratepayers also have an opportunity to examine and express their views, and the Panel must be able to fully discharge its mandate.

[75] IR 40 A, B, C, D & E Second Round

15.0 Public and Stakeholder Submissions

15.1 Public Meetings

Public meetings occurred in Prince Albert on November 25, 2013, North Battleford on November 26, 2013, Saskatoon on November 27, 2013, Regina on December 3, 2013, and Yorkton on December 4, 2013. Each meeting started with an introduction of the SRRP and their role in the review of SaskPower's 2014-2015-2016 Rate Application. A formal presentation was then made by SaskPower regarding its application at the Prince Albert, Saskatoon, Regina and Yorkton meetings. No formal presentation was made at the North Battleford meeting, as only a single member of the public attended. A summary of SaskPower's formal presentation is provided at the end of Section 15.1 - "Public Meetings".

Formal presentations were also made at some of the public meetings by representatives of various organizations. The presentations, accompanied by submissions, from the Greater Saskatoon Chamber of Commerce, the Saskatchewan Industrial Energy Consumers Association (SIECA), and the Saskatchewan Mining Association (SMA) are summarized under Section 15.2 - "Public Meeting Submissions".

There was also a presentation (but no submission) from ERCO Worldwide. ERCO was described as a high-load factor industrial customer that used electricity efficiently. The ERCO representative suggested that this was not being recognized by SaskPower and that their proposed rate increases were improperly targeting industrial customers like ERCO. The ERCO representative also suggested that there was minimal demand growth, which did not warrant the proposed increases. It was further suggested that Saskatchewan rates were not competitive with those in other jurisdictions, impacting ERCO's ability to be competitive in Saskatchewan. ERCO's position was that the rate increases proposed by SaskPower should be lessened and that their focus should be on lowering costs and operating more efficiently.

Following any and all formal presentations made at the public meetings, questions were asked, concerns were expressed and comments were made about SaskPower's application by both organization representatives and private citizens. The following are some of the topics discussed:

- Current proposed rate increases (deemed unacceptable and unwarranted by ratepayers)
- Rate increase impacts on different customer classes (i.e. Reseller, Power, etc.)
- Rate comparisons between SaskPower and other jurisdictions (as well as inflation)
- Future rate increases and consideration to SaskPower's ROE and debt-equity targets
- Past, current and future capital investment plans and costs (including financing)
- F&PP and OM&A cost increases (including comparing actual results to those forecasted)
- Load and cost forecasting processes and challenges (including inaccuracies)
- Customer connect costs and projections
- SaskPower wages and salaries (including competitiveness)
- SaskPower advertising (including necessity)
- Dividend payments
- Smart meter benefits
- Strategy to meet current and future electricity demand (including increasing capacity)
- Over reliance on natural gas as a fuel source and the associated risk
- Transmission intertie rules, regulations and opportunities
- Power supply structures in other markets
- Power generation partnerships (including First Nations)
- Public consultation process on power generation development
- Climate change (environmental issues and considerations)
- Renewable energy strategy
- Green power generation programs
- Cogeneration power production opportunities
- Nuclear and solar power generation viability
- Demand side management (energy efficiency) programs

SaskPower 2014-2015-2016 Rate Application Public Presentation

SaskPower advised the public of proposed rate increases of 5.5% in 2014, 5.0% in 2015 and 5.0% in 2016. SaskPower explained that an interim rate increase effective January 1, 2014 was requested and granted. However, the regular review process would continue and a final decision would be made on the entire application, including the 2014 interim increase of 5.5%. SPC also outlined the average monthly bill impacts for urban residential and farm customers over the rate application period (2014-2016).

As part of its presentation, SaskPower supplied charts that provided the following information:

- All customer class rate impacts for each of the application years;
- Monthly residential rates compared to other major Canadian cities;
- Thermal rates compared to other provincial utilities; and
- The average length of power line per customer compared to other Canadian utilities.

SaskPower indicated that expenses related to capital program investment (i.e. depreciation, finance charges, taxes and other expenses), rising fuel costs and, to a lesser extent, OM&A costs were the primary drivers for the rate increase.

SaskPower highlighted its key role in the province's economic development. Electricity is expected to grow 2.6%/year (almost double the 1.4%/year during 2000-2010) to accommodate new customers and subsequent connection costs, as well as to meet the record high demand in January 2013 of 3,379 MW.

SaskPower also provided charts on its current generation capability and future capacity obligations; "hot spot" growth areas requiring investment; anticipated customer connects; and system development and sustainment projects. Major generation projects noted were the QE Power Station (205 MW of gas in 2015), Algonquin Power (177 MW of wind in 2016) and Tazi Twe (50 MW of hydro in 2018). It was also noted that Boundary Dam # 1 was retired in 2013 and Boundary Dam # 2 would be retired in 2015.

SaskPower also cited examples of their many capital projects, which included the following:

- I1K transmission line capacity and reliability improvements
- Saskatoon area reinforcement
- Infrastructure sustainment projects and Wood pole maintenance program
- Installation of over 500,000 smart meters (AMI)
- Streamlining the process to connect new customers to the system
- Automation of the work scheduling and dispatch system
- Turn-key subdivisions and joint trenching of utility systems and installations

SaskPower advised that the initiatives it has undertaken have resulted in realized savings of $137 million as of the end of 2012, thus limiting but not eliminating rate increases. These major initiatives included:

- Business Renewal Programs
- Review of all expenses for potential savings opportunities
- Continuous improvement programs

SaskPower advised of its initiatives to help customers reduce their bills through its efficiency and conservation programs, including refrigerator recycling, lighting rebates and incentives (residential and commercial), block heater timers and industrial energy optimization.

In closing, SaskPower summarized its application as follows:

- A rate increase is needed to maintain a positive net income
- SaskPower's Return on Equity (ROE) target is 8.5%
- The proposed annual rate increases will produce net income of:
    - $27 million in 2014 yielding an ROE of 1.3% and debt to equity of 74.6%
    - $40 million in 2015 yielding an ROE of 2.0% and debt to equity of 76.4%
    - $40 million in 2016 yielding an ROE of 1.9% and debt to equity of 77.0%

15.2 Public Meeting Submissions

Greater Saskatoon Chamber of Commerce

The Greater Saskatoon Chamber of Commerce (Chamber) expressed concerns about SaskPower's three year rate application.

The Chamber submitted that SaskPower's proposed rate increase is three times greater than the current CPI rate for 2013 and represents a total increase that is 2.5 times higher than the Bank of Canada's inflation target for the next three years. This would place certain Saskatoon businesses at a disadvantage with its competitors, particularly those in the United States. In support of this point, the Chamber presented a graph comparing Saskatoon's cost of electricity to Billings, Montana and Fargo, North Dakota for 2012 to 2016. The graph showed that SaskPower's electricity costs were currently higher and the gap would become even greater if SaskPower's proposed rate increases were approved.

As part of its submission, the Chamber also provided the following comments:

- SaskPower's dispersed grid serving a sparse population should no longer be used as a justification for a rate increase.
- Saskatchewan's growth should allow SaskPower to realize economies of scale and incremental efficiencies. It should not be used as a justification for a rate increase.
- OM&A costs are the largest area of increase, which are forecast to rise $80.1 million during the 2014-2016 period. This equates to a 20% total increase or a compounded increase of over 6% per year, which is much higher than inflation. OM&A costs have more than doubled from $286 million in 2002 to the projected $698 million in 2016.
- SaskPower has consistently overestimated fuel costs (which they cite as a reason for the rate increase) and underestimated OM&A costs. In the past several applications, SaskPower forecasted lower hydroelectric generation then what actually resulted. F&PP costs have essentially remained stable over the past decade, yet SaskPower is forecasting an increase of over 48% from $513 million in 2012 to $762 million in 2016.

The Chamber recommended that SaskPower's fuel consumption estimates for this application be regularly reviewed due to its history of overestimating. If actual fuel costs are found to be lower than those forecast, rebates or future rate reductions should be considered. If this recommendation is not accepted, the Chamber asked that rate increases be limited to CPI rates or the Bank of Canada target inflation rate.

Saskatchewan Industrial Energy Consumers Association

The Saskatchewan Industrial Energy Consumers Association (SIECA) expressed concerns about SaskPower's three year rate application, as broken down into the following six categories:

1. Rate Impacts for Industrial Customers - SaskPower's proposed rate increases will actually increase Power customer rates by 7.0% in 2014, 6.4% in 2015 and 6.0% in 2016. The compounded rate increase for industrial customers will be over 20% during the 2014-2016 period, which constitutes rate shock and is far in excess of inflation. This will impact their ability to be competitive, increasing the risk of business suspension or possibly closure. SIECA requested that the SRRP evaluate the reasonableness of SaskPower's capital investment spending.

2. Load Forecasting - SIECA questioned SaskPower's ability to accurately predict electricity demand growth in the province. SaskPower has a long and consistent history of over estimating load growth, resulting in premature capital investment spending. Information was provided by SIECA in support of this point. SIECA believes that forecasting problems will continue until SaskPower alters its load forecasting methodology and policies. SIECA requested that the SRRP review the extent of load forecasting over estimation and its impact on capital investments.

3. Generation Planning and Current Capacity - SaskPower already has almost 1,000 MW of excess generating capacity and is adding another 110 MW in 2014. Based on SaskPower's 2013-2016 load forecast, there is already about 2.5 times its largest single contingency for reserve capacity. Considering this and other factors, SIECA believes SaskPower has been over building generation capacity and requests a generation plan from them detailing capacity, retirements, reserves and future build requirements. SaskPower's over building is a result of its load growth over estimation and load development policies, which significantly impacts power rates and causes existing customers to bear the risks of the new load. SIECA feels that any such risk should be borne by those needing the new electricity and the provincial government. SIECA requested that the SRRP determine the extent of generation capacity over building and recommend a formal process to allow capital investment only after established criteria is met, as is done in other jurisdictions.

4. Multi-Year Rate Applications - Historically, SaskPower has consistently over estimated its costs in one year rate applications. SIECA is concerned about the variance that will result between actual and estimated costs over a three year period. SaskPower has not demonstrated how a multi-year application improves forecasting accuracy, provides forecasting certainty, controls costs or right-sizes capital spending. The application does not have regulatory protocols or compliance mechanisms to address variances during the application period. SIECA does not favour applications that fix rates over a multi-year period without a proper regulatory review process.

5. F&PP Costs - SIECA believes that F&PP costs have also been over estimated, mainly due to the generation mix arising from high forecasts. SIECA was uncertain if SaskPower followed its fuel source dispatch methodology rigidly. SIECA requested that the SRRP review SaskPower's dispatch methodology and compliance to it, as well as decisions to pursue high cost wind generation and EPP projects over natural gas fired generation.

6. OM&A Costs - SIECA commended SaskPower on its Business Renewal Program and its impact on OM&A costs. However, they remain concerned about its growth from $317 million in 2004 to $612 million in 2012 (an average annual growth rate of 8.8%). If electricity sales are growing, then the OM&A expense per unit should be falling or remaining flat, but not rising. SIECA is also concerned that the OM&A cost to total revenue ratio target of 30% is not aggressive enough and will not encourage real change. SIECA requested that the SRRP carefully review SaskPower's growing costs by benchmarking them against their peer utilities, as is done with their rates.

SIECA believes that a multi-year rate application is not appropriate under the current regulatory review process. A one year rate increase at inflationary levels is recommended by SIECA.

Saskatchewan Mining Association

The Saskatchewan Mining Association (SMA) expressed concerns about SaskPower's three year rate application. SMA supported the SIECA submission and raised the following eight issues:

1. Rate Impacts for Power Class Customers - SaskPower's proposed rate increases will actually result in increases of about 6.9% in 2014, 6.0% in 2015 and 5.7% in 2016 for the Power customer class. Taking into consideration the 6.1% increase in 2013, the compounded rate increase from 2013 to 2016 will be over 25% for most Power customers. This constitutes rate shock and is far in excess of inflation, which will impact the ability of Power customers to be globally competitive.

2. Load Forecasting - SaskPower has not demonstrated the ability to accurately predict electricity demand growth in Saskatchewan. Load forecasting over estimation by SaskPower has resulted in unnecessary capital spending. Over estimation of large customer loads has largely contributed to inaccurate load forecasting, which introduces additional risk to forecasting over a multi-year period. SMA requested that the SRRP determine the extent of load forecasting over estimation and its impact on capital investments.

3. Generation Planning and Capital Investment - SaskPower already has almost 1,000 MW of excess generating capacity and is adding another 110 MW in 2014. Based on SaskPower's 2013-2016 load forecast, there is already about 2.5 times its largest single contingency for reserve capacity. Over building results in existing rate payers (particularly Power customers) bearing a disproportionate share of the burden. A generation plan detailing capacity, retirements, reserves and future build requirements should be provided by SaskPower.

4. Multi-Year Rate Applications - SaskPower has a history of over estimating load forecasts and costs. SMA is concerned about the variance that will result between actual and estimated costs over a three year period. SaskPower has not demonstrated how a multi-year application improves forecasting accuracy, provides forecasting certainty, controls costs or right-sizes capital investment spending. This multi-year rate application does not have regulatory protocols or compliance mechanisms to address variances during the application period. SMA does not favour applications that fix rates over a multi-year period without a proper regulatory review process.

5. F&PP Costs - F&PP costs are closely linked to load forecasting, which SaskPower has a history of over estimating. As a result, F&PP costs are also over estimated mainly due to the generation mix that arises from the high forecasts. This is compounded by SaskPower pursuing high cost wind generation and EPP projects over natural gas fired generation.

6. OM&A Costs - OM&A costs have grown from $317 million in 2004 to $612 million in 2012 (an average annual growth rate of 8.8%). If electricity sales are growing, then the OM&A expense per unit should be falling or remaining flat, but not rising. SMA requested that the SRRP examine the growth of SaskPower's costs as well as their process efficiencies.

7. Amortization Period - SMA requested that the SRRP determine if the capital asset amortization period is appropriate.

8. Financial ROE and Dividend - SaskPower states that its below-target ROE will provide customers with some relief from rate shock. This was also the case in 2013. However, a $120 million dividend ended up being paid. This effectively represented an added tax to all customers, particularly those in the Power Class which contribute the most revenue to SaskPower. SMA is requesting that SaskPower be exempt from paying dividends during this application period in recognition of the significant rate increases all SaskPower customers are being faced with.

The proposed rate increases for the Power Class will result in those customers paying a disproportionate part of the capital financing. SMA encourages the Panel to recommend a one year rate increase rather than the multi-year rate increases requested, as there is no regulatory recourse to make adjustments to rates for variances during the multi-year application timeframe. SMA also strongly encourages the Panel to recommend that SaskPower be exempt from paying dividends during the rate application period.

Miscellaneous Public Submissions

There were a total of 32 submissions from the public in regards to SaskPower's 2014-2015-2016 Rate Application. These submissions were made between October 25, 2013 and December 23, 2013 through feedback forms (19), emails (8) and voicemails (5). SaskPower responded to all of the submissions.

The vast majority of the submissions suggested rates were already too high and the proposed rate increases were unacceptable, not warranted, too excessive, and or unaffordable. SaskPower indicated that the rate increases were mainly required: for new infrastructure to meet growing electricity demand; to refurbish or replace aging infrastructure; and for rising fuel costs. SaskPower tries to balance its financial requirements with the ability of its customers to absorb increases. SaskPower suggested its rates were competitive with other jurisdictions and will continue to be even with the proposed rate increases, as other utilities face similar infrastructure spending pressures. SaskPower reports that rate comparisons show

Saskatchewan residential rates are below the Canadian thermal utility average. SaskPower noted that it consistently meets its system average rate target, which is less than or equal to other thermal utility rates.

There were several other comments made and concerns / issues raised by the public not specifically mentioned here. However, all have been reviewed and considered in the preparation of this report.

15.3 Final Submissions and SaskPower Responses

EVRAZ Regina Steel, Saskatoon Light & Power, the Canadian Federation of Independent Business, the Saskatchewan Industrial Energy Consumers Association, the Canadian Association of Petroleum Producers, and the Consumer Association of Saskatchewan submitted formal positions. Those submissions along with SaskPower's responses, if any, are summarized below.

EVRAZ Regina Steel

In a written submission dated February 6, 2014, EVRAZ opposed SaskPower's proposed three year rate increases. EVRAZ suggested that the application be denied and the increases be scaled back to a more reasonable level. In support of its position, EVRAZ commented on the following three areas:

1. Competitiveness. EVRAZ expressed concerns about the detrimental impact the proposed rate increases would have on its ability to be competitive. Such increases cannot be passed onto their customers and still allow EVRAZ to remain competitive. EVRAZ manufacturing processes are highly energy intensive. Electricity is its second highest cost and directly impacts its bottom line.

2. Load Growth. EVRAZ believes that new and expanding customers should be responsible for load growth costs. Burdening existing customers with these costs is not fair or reasonable. They should not be required to subsidize new and expanding customers. EVRAZ recommended a two tier approach where load growth capital costs be assigned to new and expanding customers.

3. Multi-Year Rate Application. EVRAZ believes that a multi-year rate application is problematic, as SaskPower has had difficulty accurately predicting costs for single year applications. EVRAZ has very little confidence in SaskPower's ability to forecast costs for three years and, multi-year rate applications do not promote operational efficiency efforts.

In a letter dated March 17, 2014, SaskPower responded to the EVRAZ submission.

SaskPower noted that its system average rates in 2013 were competitive with their peers and that they currently have the lowest published rate for industrial customers of all non-hydro utilities. As in many Canadian jurisdictions, SaskPower is requesting a rate increase largely because a significant portion of its aging infrastructure must be replaced and refurbished. The renewal program along with significant load growth in the province requires capital investments of $1 billion per year for the foreseeable future. SaskPower has taken steps to lessen the impact of the required rate increases by generating below target ROE and exceeding its debt ratio target.

SaskPower also noted that the majority of load growth in the next ten years is attributed to industrial customers and, to a lesser extent, oilfields. This is a cost of provincial economic growth and not limited to electricity. New customers pay part of the system connect costs and once connected they pay the same rates as other similar customers. Cost allocation and rate design methodology does not differentiate from when a customer connects to the system. This is similar to the approach used by other electric utilities across Canada.

If a multi-year application is approved, SaskPower proposed a short annual review mechanism be considered to ensure assumptions made in the initial application are still applicable. The mechanism would require input from the SRRP and have to be approved by provincial cabinet. A full review would result if the forecasted ROE falls below 0% or increases to more than the 8.5% target in the following year's forecast. Any limited or full review would also include an operational efficiency component.

Saskatoon Light & Power

In a written submission dated February 7, 2014, Saskatoon Light & Power (SL&P) raised concerns about SaskPower's three year rate application and commented on the following five areas:

1. R/RR Ratio. SL&P feels that its R/RR ratio should be based on the mix of customers it serves. 32% of SL&P sales come from residential and 68% from commercial. The SaskPower application ratio for residential customers is 0.98 and 1.00 for commercial customers. SL&P argues that its ratio should be 0.99, ensuring SaskPower is not charging SL&P at a rate greater than the average of its customer base. SaskPower would be collecting more money than they otherwise would if SL&P did not exist as a Reseller and SaskPower sold directly to the end consumers.

2. Saskatchewan Demand Research. The recent COS methodology changes from Alberta to Saskatchewan demand research information is considered a significant improvement by SL&P.

3. Two Coincident Peaks. The recent COS methodology change to two coincident peak (2-CP) from one (1-CP) is opposed by SL&P as it significantly impacts the Reseller class. Until recently and for several years, the 1-CP method was deemed to be appropriate for use by SaskPower. There is no consistent method used by the industry and several utilities continue to use the 1-CP method. Based on 2013 rates, the Reseller ratio would fall to 0.94 from 1.00, increasing SL&P costs by about $5 million once fully implemented in 2016 and continuing to increase at that level every year going forward. The switch to 2-CP and Saskatchewan demand research appears to be deliberate in order to offset some customer class impacts and specifically target Resellers.

4. Consistent Utility Treatment. The rates charged to the two Resellers, who are electrical utilities, is unfair. SL&P believes any cost increases affecting the Resellers should have a corresponding impact on SaskPower, which is not the case. Rate class increases under the current COS methodologies are offset by other rate class decreases so that there is no impact on SaskPower. SL&P feels this is not appropriate and all electrical utilities should be impacted by the Reseller changes so as to create a level playing field. SL&P recommends establishing a new methodology for determining Reseller rates that more consistently attributes cost increases to all three utilities.

5. Load Growth. Over 50% of the $3 billion capital investment from 2014 to 2016 is due to load growth. While Reseller sales volumes are only projected to increase by 1.4% from 2012 to 2016, growth is projected in the Power class by 31.5%, the Oilfield class by 26.4%, and the Farm class by 13.0%. The cost of increasing generation capacity is inappropriately allocated. SL&P has adopted a "growth pays for growth" philosophy, recommending a greater share of the increasing generation capacity costs be attributed to those customers that are contributing to the growth.

In a letter dated February 14, 2014, SaskPower responded to the SL&P submission as follows:

1. R/RR Ratio. The 2014 and 2015 requested rate increases would result in the Reseller ratios being lower than the combined Residential/Commercial. The 2016 requested rate increase would result in the Reseller ratio being 1.00, the same as the combined Residential/Commercial. The rate increases required to increase the Reseller ratio from 0.94 to 1.00 are being phased-in over the three-year application period to avoid rate shock.

2. COS Methodology Change to 2-CP. SaskPower's COS methodology is reviewed every five years. Continued use of the 1-CP method was recommended in 2007/2008. Multiple peak use was to be considered in future reviews. The change from winter peak (1-CP) to winter/summer peak (2-CP) was recommended during the 2012/2013 review for several reasons.

3. Consistent Treatment for All Utilities in Saskatchewan. It is not clear what the costs and benefits of this recommendation would be. It is also not clear if separating the generation, transmission and distribution functions in SaskPower reporting would provide the benefits expected by SL&P. SL&P should raise this issue during the next COS methodologies review for consideration.

4. Load Growth Cost. The majority of load growth in the next ten years is attributed to industrial customers and, to a lesser extent, oilfields. This is a cost of provincial economic growth and not limited to electricity. New customers pay part of the system connect costs but once connected they pay the same rates as other similar customers. Cost allocation and rate design methodology does not differentiate from when a customer connects to the system. This is similar to the approach used by other electric utilities across Canada.

Canadian Federation of Independent Business

In a written submission dated February 7, 2014, the Canadian Federation of Independent Business (CFIB) outlined its views and concerns regarding SaskPower's multi-year rate application. CFIB is concerned that the proposed 15.5% rate increase over the next three years will negatively impact businesses in Saskatchewan. The CFIB Monthly Business Barometer for January 2014 shows that 36% of Saskatchewan small business owners cite fuel/energy costs as a major cost pressure.

SaskPower has historically overestimated costs and load forecasts. CFIB questions how a multi-year application will improve accuracy or provide more certainty in these areas. Should actual fuel costs prove to be lower than that forecasted; CFIB recommends that a rebate or future rate reduction be considered.

CFIB believes OM&A costs are the largest area of increase in the application. They note SaskPower's Business Renewal Program has helped reduce the impact of rate increases by realizing about $137 million of savings as of the end of 2012. CFIB also recognizes SaskPower's generation, transmission and distribution infrastructure is aging and will need to be rebuilt, replaced or renewed it in its entirety over the next forty years. SaskPower must continue to find efficiencies throughout its operations and ensure that the proposed rate increases are not based on overestimated costs and load forecasts.

In a letter dated February 14, 2014, SaskPower responded to the CFIB submission as follows:

1. Maintaining Competitive Rates. SaskPower system average rates in 2013 were competitive with their peers. As in many Canadian jurisdictions, SaskPower is requesting a rate increase because a significant portion of its aging infrastructure must be replaced and refurbished. The renewal program along with significant load growth in the province requires capital investments of $1 billion per year for the foreseeable future. SaskPower has taken steps to mitigate the impact of the required rate increases by generating below target ROE and exceeding its debt ratio target.

2. A Multi-Year Approach with a Built-In Review Process. If a multi-year application is approved, SaskPower proposes a short annual review mechanism be considered to ensure assumptions made in the initial application are still applicable. The mechanism would require input from the SRRP and have to be approved by provincial cabinet. A full review would result if the forecasted ROE falls below 0% or increases to more than the 8.5% target in the following year's forecast.

3. Fuel Variability. Rebates or rate reductions arising from fuel cost volatility has been considered. The appropriateness of a Fuel Cost Variance Account (FCVA) within Saskatchewan's regulatory environment was evaluated by a third party. A report outlining the findings is available on the SRRP website, including SaskPower's responses to the FCVA concept.

4. Rate Increase Drivers. Revenue increases needed for the OM&A expense represent 2% of the 15.5% requested rate increase (or 13% of total). Most of the rate increase is required for F&PP (35%), finance charges (29%) and depreciation (20%).

Saskatchewan Industrial Energy Consumers Association

In a written submission dated February 10, 2014, the Saskatchewan Industrial Energy Consumers Association (SIECA) presented its position opposing SaskPower's three year rate application. SIECA's report, which the Saskatchewan Mining Association (SMA) collaborated on, outlined the following four recommendations:

1. Implement a single year rate decision for 2014 only.
2. Eliminate the payment of dividends.
3. Create a public consultation for review of resource planning and major capital investments.
4. Reallocate ICCS and wind generation costs within the cost of service using the percent of revenue allocation method.

In letters dated February 19, 2014, SaskPower responded to both SIECA and SMA on the four recommendations noted above.

In regards to the first recommendation, if a multi-year application is approved, SaskPower proposes that a short annual review mechanism be considered to ensure that the assumptions made in the initial application are still applicable. The mechanism would require input from the SRRP and have to be approved by provincial cabinet. A full review would result if the forecasted ROE either falls below 0% or increases to more than the 8.5% target in the following year's forecast.

Certain cost categories can be either over or under budgeted when independent information from multiple external sources is used. SaskPower forecasts are prepared without bias, as has been demonstrated with the underestimating of operating income and overstating of revenue requirements. The forecasted load growth in the Power class is largely due to increased requirements in the potash sector. There is also significant growth forecasted for the northern mining sector and the pipeline pumping sector.

In regards to the second recommendation, no dividend payments are forecast for 2014.

In regards to the third recommendation, additional information on peak loads, planning reserves, and operating reserves was provided by SaskPower to address SIECA concerns of overbuilding infrastructure and ineffective fleet management. SaskPower regularly provides capital spending information in its rate applications as well as in its responses to submissions and IRs. SaskPower agrees that additional information / discussion regarding major capital investments and plans should be provided in a fashion that is consistent with the existing regulatory process in Saskatchewan. SaskPower proposes a process where long-term load forecasts, capital plans and supply plans are presented to the SRRP, its consultants and interested stakeholders as part of the Limited Scope Filing scheduled for the fall of 2014.

SaskPower does not support expanding the scope of non-disclosure agreements (NDAs) and release of confidential information, which could create a conflict of interest. Considering the competitive markets customers operate in, providing access to confidential information could unfairly benefit their competitors.

In regards to the fourth recommendation, the COS review process is the appropriate venue to raise issues such as allocation of fixed production plant costs for the ICCS project and wind power. The process would involve an independent consultant and all stakeholders. The Percent of Revenue method would provide a significant benefit to the Power and Reseller classes to the detriment of all other classes.

Canadian Association of Petroleum Producers

In a written submission dated February 12, 2014, the Canadian Association of Petroleum Producers (CAPP) opposed SaskPower's three year rate application and made the following five recommendations:

1. The Application should only be approved for 2014. SaskPower should be directed to file future rate applications for the next calendar year with a further two year outlook.

2. SaskPower's request for a lower ROE is justified in light of historical over forecasting of costs and under forecasting of revenues.
3. For the next SRRP process, the SRRP should require non-disclosure agreements, to the satisfaction of SaskPower, allowing more detailed information to be provided to organizations, like CAPP. The SRRP will be able to utilize the expertise of SaskPower's stakeholders to a greater extent during the rate review process.
4. A process for meaningful public consultation and input into major capital investments is required to ensure the needs of SaskPower customers are aligned with SaskPower's plans.
5. All rate classes should be moved to a 100% revenue to cost ratio.

CAPP continues to be concerned about the level of information provided by SaskPower. The high level overview of the forecasted cost increases provided does not give sufficient detail to allow for a proper review of an electric utility requesting increase of over $100 million per year in revenues.

In a letter dated February 19, 2014, SaskPower responded to CAPP's five recommendations as follows:

In regards to recommendation one, if a multi-year application is approved, SaskPower proposes that a short annual review mechanism be considered to ensure that the assumptions made in the initial application are still applicable. The mechanism would require input from the SRRP and have to be approved by provincial cabinet. A full review would result if the forecasted ROE either falls below 0% or increases to more than the 8.5% target in the following year's forecast.

In regards to recommendation two, cost categories can be over or under budgeted when independent information from multiple external sources is used. SaskPower forecasts are prepared without bias, as demonstrated by their underestimating of operating income and overstating of revenue requirements.

The forecasted load growth in the Power class is largely due to increased requirements in the potash sector. There is also significant growth forecasted for the northern mining and pipeline pumping sectors. The CAPP June 2012 production forecast was used to develop the Oilfield energy forecast for the Rate Application, which differed from the 2013 Saskatchewan oil production forecast that was higher.

In regards to recommendation three, SaskPower does not support expanding the scope of NDAs and release of confidential information, which could create a conflict of interest. Considering the competitive markets customers operate in, providing access to confidential information could unfairly benefit others.

In regards to recommendation four, SaskPower regularly provides capital spending information in its rate applications as well as in its responses to submissions and IRs. SaskPower agrees that additional information / discussion regarding major capital investments and plans should be provided in a fashion consistent with Saskatchewan's existing regulatory process. SaskPower proposes a process where long-term load forecasts, capital plans and supply plans are presented to the SRRP, its consultants and interested stakeholders as part of the Limited Scope Filing scheduled for the fall of 2014.

In regards to recommendation five, the R/RR ratio for all classes is not set at 1.00. The R/RR ratio for Residential and Farm classes is set slightly below 1.00 while all other classes are set slightly above 1.00. This is done to limit the occurrences of Residential and Farm classes subsidizing other classes.

Consumer Association of Saskatchewan

In a written submission dated February 3, 2014, the Consumer Association of Saskatchewan (CASK) indicated the safe, reliable supply of electricity is of the utmost concern. CASK expects SaskPower to keep expenditures at a minimum so that customer rates are reasonable, fair and as low as possible. CASK commented on the following seven points regarding SaskPower's multi-year rate application.

1. <u>Multi-Year Application</u>. If SaskPower has favorable years during the multi-year rate application period, will customers benefit or will dividends be paid out?

2. Rate Rebalancing. CASK feels that Residential customers should receive a small subsidy. Residential customers, unlike business customers, are unable to use utility expenses as deductions on their taxes. CASK supports the projection for fairness between classes by 2016.

3. Residential Classes. Rural residential customers pay higher rates than urban customers due to servicing costs. What criterion is used for determining which communities are in which class? How often are the decisions reviewed and when do customers become part of the urban residential class? Are there communities that might move the other way?

4. Service. SaskPower reports customers feel there are too many outages. When problems occur, SaskPower personnel address them, just not as quickly as one would like.

5. Buying and Selling Power. CASK supports buying and selling power in other jurisdictions.

6. Educating Consumers to Modify Use. CASK supports SaskPower programs that educate consumers on how to reduce their power consumption and billings.

7. Wind and Solar Power. CASK favours increased use of and research on wind and solar power generation. CASK believes that SaskPower should take advantage of these natural resources.

Power is an essential service and there are really no options for residential customers but to purchase it from SaskPower. CASK believes there are more savings available from wages and office expenses. SaskPower's proposed increases can be unmanageable for many customers. Saskatchewan residents are relying on the SRRP to ensure that power rates are fair and all increases are justified and necessary.

In a letter dated February 14, 2014, SaskPower responded to the CASK submission as follows:

1. A Multi-Year Approach with a Built-In Review Process. If a multi-year application is approved, SaskPower proposes that a short annual review mechanism be considered to ensure that the assumptions made in the initial application are still applicable. The mechanism would require input from the SRRP and have to be approved by provincial cabinet. A full review would result if the forecasted ROE either falls below 0% or increases to more than the 8.5% target in the following year's forecast. In regards to dividends, no payments are forecast for 2014.

2. Rate Rebalancing. The standard R/RR ratio range in the industry is between 0.95 and 1.05. All classes should fall within the tighter range of 0.98 to 1.01 by 2016. Residential and Farm classes are forecast to be at 0.98 for all three years.

3. Customer Classes. Urban describes customers in the registered limits of a city, town or village, while Rural describes customers outside those limits. SaskPower relies on the province's determination of a customer's location when classifying each customer as Urban or Rural.

4. Service. Performance improved from 2011 to 2012. On average, customers experience longer and more frequent outages than they did five years ago. Investment in infrastructure, near the end of its life or overloaded, is required. There is also focus on a number of initiatives to reduce controllable outages, such as Rural Rebuild, Wood Pole Replacement and Vegetation Management Programs. The AMI initiative (smart meters) should also help reduce outage time.

5. Buying and Selling Power. SaskPower will continue to import and export power as well as trade in other jurisdictions when advantageous to do so. Additional opportunities to expand capacity to import and export power across Saskatchewan's borders is being investigated.

6. Demand Side Management (DSM). DSM programs are on pace to meet a 100 MW reduction in demand by 2017. Ideas and opportunities to reduce power requirements continue to be looked at.

7. Wind and Solar Power. The 11 MW Cypress Wind Power Facility was commissioned in 2002. Wind generation capacity has increased to 198 MW, or 4.6% of total generation capacity since then. Another 177 MW of wind generation in 2017 will be added through a PPA with Algonquin Power (Chaplin wind power facility). Large-scale solar energy projects have not been undertaken yet due to prohibitive costs. However, solar is still being studied as a long-term option.

16.0 Summary of Consultant's Recommendations and Commentary

SaskPower filed a three year Rate Application for 2014, 2015 and 2016 on October 25th, 2013. The 2014-2016 Rate Application revenue and expense projections as well as the load forecasts were based on 2012 actual results and the 2013 Business Plan forecasts. On February 14, 2014 SaskPower filed a Mid-Application update which is attached to this report as Appendix 2. This update considered the unaudited results for 2013 in the financial forecasts and the 2014 Business Plan. In the last review of the 2013 Rate Application by SaskPower, we had recommended that the Panel support greater disclosure on future cost implications. In our view this application is a significant step in providing greater disclosure.

We have reviewed and incorporated the most recent projections from the Mid-Application Update and recommend the following for consideration by the Panel:

1. Load Forecast - We are of the view that based on the historic energy use and peak demand statistics, combined with the forecasts based on individual class needs and underpinned by current and periodic reviews of economic outlooks, the energy and peak forecasts contained in the updated last quarter Load Forecast Report are reasonable. Economic and other circumstances will of, course change throughout the next 3 years and beyond, and the weather will also continue to vary, perhaps considerably. However, given all the unknowns inherent in any forecasts, we are of the view that this forecast constitutes a reasonable basis to project future generation and related system infrastructure and operational needs.

2. System Operations -SaskPower's System Operations and Resource Use Strategy is based on the economic dispatch of its generation units (least expensive first on last off, most expensive last on first off) within other operational and contractual constraints. We consider that dispatch criteria has been met consistently and results in the most economic generation possible for the vast majority of the time. SaskPower recognizes the challenges in meeting supply options in the future and in 2011 developed a 40 year supply plan that evaluates these potential options. The plan is reviewed periodically and was last reviewed in 2012 with a further review planned for 2014. We consider that the 2012 plan was extensive and incorporated flexibility. The Plan also considered potential contingency plans, as new technology emerges, as well as changes in the potential for self-generation and demands for electricity supply. We find that SaskPower's approach on fuel dispatch is reasonable well within industry norm and is acceptable. We thus conclude that SaskPower's system operation from a fuel dispatch point of view is appropriate and should be continued.

3. Revenue Forecasts - We consider that SaskPower's revenue forecasts (domestic sales, export revenue, electricity trading and other revenue) as submitted in the Mid-Application Update properly reflect past results, including the new revenue sources available to SaskPower. Weather normalization of the load forecast is an appropriate and necessary consideration in any utility forecast. On an actual basis, however it is expected that Saskatchewan Sales Revenue will be at or modestly greater than the weather normalized forecast. Forecasting a utility's revenue stream is difficult in a single year application as projecting weather trends, world and local economic considerations and a number of other variables can and likely will impact customer demands, revenues and expenditures. With a three year application the variation in all of these factors will be magnified.

4. Revenue Requirement - The 2014 revenue requirement based on the Mid Application Update should be approved subject to the following:
   j) The revenue requirement be set to allow SaskPower to generate sufficient revenues to earn the requested 2.9% Rate of Return, to produce a net income for 2014 of $66.0 million.
   k) The natural gas AECO C forward forecast price of $4.08 / GJ be used for purposes of setting 2014 rates for an estimated updated consumption of approximately 60 million GJ.
   l) The Panel accept the updated 2014 F&PP forecast cost of $622.0 million.
   m) The Panel accept the total OM&A expense forecast of $647.7 million (unchanged in the Mid-Application update) as filed in the original application.
   n) The Panel accept the updated forecast for Amortization and Depreciation expense of $399.3 million.
   o) The Panel accept the updated forecast for net finance charges of $340.1 million.
   p) The Panel accept the forecasted Municipal Tax, Corporate and Other Taxes Obligations of $57.0 million as filed in the original application.
   q) The Panel accept the forecasted other costs at $16.5 million as originally filed.
   r) Lastly, the Panel accept a SaskPower expense total of $2,082.5 million as filed in the Mid-Application update.

5. F&PP - Other than OM&A, F&PP costs continue to be the largest expense for SaskPower. F&PP costs represent 29.7% of total costs in 2012, and forecast to be 29.3% in 2013 and 27.7% in 2014. By 2015, F&PP costs are expected to exceed OM&A costs, but will still represent a similar percentage of overall total costs. F&PP costs are expected to account for 29.4% of total costs in 2015 and 30.7% in 2016.

6. OM&A - OM&A expense forecasts are $648 million for 2014, $672 million for 2015, and $698 million for 2016. This results in net increases of $27 million, $24 million and $26 million for an accumulated increase of $77 million relative to 2013 representing percentage increase of 12.4% or approximately 4.1% annually for each of the three years. The Power Production portion of the Operations Division is the main source of the incremental cost increase from the 2013 budget of $154.6 million to the forecast of $182.4 million in 2014. The forecasted increases are for Shand, Boundary Dam units 4 and 6 overhauls, Western Plants, BD staff deficiency, QE staffing, ICCS chemicals and materials and the BD 3 full year operational expense. Cost increases forecasted for 2015 includes improvements associated with the network communications systems and AMI, Shand Test Facility and Aquistore – ICCS and enterprise security upgrades. Inflation on base expenses and other initiatives are the primary cause of the $24 million forecasted increase.

   The $26 million cost increases proposed for 2016 reflect inflationary cost increases and possible new initiatives, as well as unforeseen expenses. Excluding the costs associated with power production overhauls and other system improvements as detailed above, the OM&A cost increases relative to other operational needs clearly demonstrate, in our view, that operational costs are being contained. The cost containment is evident considering the major capital improvement and re-investments being made to generation, transmission, distribution and operational infrastructure, including AMI, all requiring increased maintenance. In addition, the increased costs associated with new staff salary & wages, benefits, materials and supply and external services, confirms that the Business Renewal and Service Delivery Renewal Programs are generating a positive net financial result for SaskPower's base cost structure.

   Staffing is a major driver of OM&A costs. In 2014 staff FTE's are expected to peak at 3,478. 2015 forecasts are for 88 less employees, and 6 additional FTEs are forecasted in 2016. SaskPower provided a detailed explanation for the proposed staff changes over the next 3 years and we find the explanation reasonable, especially considering the major capital expenditures underway and being proposed.

7. SDR/BRP - We are satisfied with the progress made by SaskPower to date on these two initiatives. With Service Delivery Renewal now scheduled to be completed and fully operational by the end of 2015, SaskPower will be able to concentrate its resource efforts on the major tasks remaining to investigate other potential improvements and efficiencies in the Business Renewal Program. Two major initiatives yet to be undertaken and finalized are the Asset Management Program and Product Delivery Transformation. Both, in our opinion, are critical program initiatives and offer significant potential operational efficiencies as well as future financial savings to SaskPower. Last year we recommended (and SaskPower complied with) tracking effective and measureable initiatives of all Business Renewal Programs. We urge them to continue to provide a detailed overview respecting each Business Renewal Initiative respecting steps taken to date, the costs and savings generated, in a format so as to easily discern the progress made and the program expectations on a year- over- year basis.

8. DSM - We continue to urge SaskPower to maximize the benefits of demand side management programs and demand response programming. This is especially critical when peak demand continues to increase requiring significant expenditures to meet increased generation demand thus putting additional cost pressures on the ratepayer.

9. Finance Charges - We are satisfied that the methodology used to generate the forecasted interest charges over the three year period of this application is reasonable but also recognize that the actual financial forecast results will be contingent on the progress and degree of completion of capital infrastructure plans and expenditures. There are two significant issues that will impact the actual results. One is the actual interest rates at the time of project completion, and secondly whether the Capital undertaking are completed on time and on budget.

10. Debt and ROE - SaskPower's long term debt grew from $2.449 billion at the end of 2005 to $3.16 billion at year-end 2011. SaskPower's debt is now forecasted to be $5.67 billion year end 2013 and grow to $7.572 billion at year end 2016. SaskPower current legislated borrowing capacity is $8 billion. SaskPower has a significant advantage in being able to use the credit facility and favourable rating of the province to acquire the necessary funds at a more attractive rate than what would otherwise be the case. The province does not impose a fee or charge for this advantage but the debt is issued in the name of the Province of Saskatchewan and reassigned under the same issuing terms and conditions to SaskPower.

    The net impact from the Mid-Application Update is that SaskPower's operating income for 2014 is expected to improve from the initial application forecast of $ 26.9 million to $66.0 million. SaskPower's revised ROE is now forecast to be 2.9% for 2014. ROE forecasts for 2015 and 2016 were not changed with the February Mid-Application update. However, SaskPower confirmed that as a result of revised load forecasts, 2015 net income is forecasted to increase by $18 million with a further net income increase of $6 million in 2016.

    No dividend payments are anticipated or currently forecasted during this capital extensive planning cycle and specifically for this 2014-2016 Rate Application. The "dividend holiday" is a significant advantage for SaskPower and its ratepayers. Being able to retain the equity in the corporation provides an opportunity to have lower debt levels, lower finance charges, and a stronger equity position than if dividends were demanded. The long term financial benefits of the "dividend holiday" are significant for SaskPower in being able to lessen the financial impact on its ratepayers during this intensive capital reinvestment period.

11. Capital Program - Although the capital program of SaskPower is beyond the mandate of the Panel to submit recommendation with respect to the Capital program and rate base, the impacts flowing from such programs significantly influence SaskPower's annual expenses and thus have a direct impact of requested rates. Based on an assumed borrowing rate of 4% and an average useful asset life of 25 years, SaskPower states that, as a rule of thumb, a $1 billion capital expenditure would increase annual expenses by approximately $80 million, which would translate into a rate increase of approximately 4.2%. While this is an over-simplification of the actual impacts of capital expenditures and net income, it does clearly illustrate the impact on rates of a capital program. The major driver of rates for the 2014-2016 rate application is in fact the capital program and the resulting Finance Interest Charges and Depreciation Expenses.

    The three year capital budget plan (2014-2016) is in excess of $3 billion and is a major issue. Considerable concern was expressed by the interested stakeholders in this regard. The capital program plan total impacts over the next decade are even more significant. While we recognize this is beyond the mandate of the Panel on which to make recommendations, we would urge SaskPower to consider entering into a public dialogue with the stakeholders and the Saskatchewan Rate Review Panel wherein greater detail demonstrating need and transparency of those capital plans could be shared or disclosed. From our examination we are satisfied that the principle considerations and directions used by SaskPower are appropriate and necessary but because the financial impacts on the ratepayers, both today and in the future, are so significant, from a public interest perspective, greater public disclosure should occur.

12. COSS - We recommend that the 2014 prospective COSS be accepted as filed. In our view, the COSS adhered to the principled approach and the two recommended modifications are reasonable and more accurately portray SaskPower's operations and cost causation factors. We also note that SaskPower is continuing to study its information system's capability to support the minimum system size method to classify customer and demand costs, and expect that a report of its findings will be forwarded to the Panel in due course. We also find that SaskPower's approach to phasing in rate rebalancing in order to somewhat smooth out larger required rate over a three year period to be quite reasonable. The internal load research results incorporated into the current COSS are unquestionably superior to those flowing from the hybrid system previously used by SaskPower, regardless of the "dislocation" of respective customer class rates. There will be a need to file a prospective COSS for 2015 and 2016 to determine final rates irrespective of the decisions relative to this Rate Application.

    We consider that the 2014 COSS properly reflects change in the various components that constitute Rate Base and Operating Expenses and that the functional classification of all items to be reasonable as submitted in the Application and the Mid-Application Update. We also note that SaskPower's R/RR range is one of the narrowest for all Canadian Utilities, on an overall basis and is within the previously accepted range of 0.95 to 1.05. By 2016 SaskPower's R/RR range is forecasted to be 98.0 to 1.01 which significantly limits cross subsidies between customer classes. We have recommended that, for purposes of rate design the R/RR be set at 1.00 so as to remove any perception of "deliberate cross-subsidization. However, we recognize that, historically the Residential and Farm Class R/RR have been below unity and that a change for these may not be acceptable from the general public.

13. Competitive Factors - SaskPower residential customers currently pay rates that are on average higher than the Canadian Utility average but approximately 18% lower than the rates of other thermal utilities in Canada. However, small commercial, standard commercial and large industrial customer's rates on average are lower than the Canadian Utility average and significantly lower than the Thermal Utility average. Generally, however electrical rates are rising in all jurisdictions across Canada.

14. Multi-Year Application Approval - The Panel has a variety of options that it can consider for 2014, 2015 and 2016 rate recommendations. These include recommendations that only January 2014 interim rates be approved (or amended); that January 1, 2014 rates be finalized as well as, subject to conditions, rates as filed for 2015. Another option is to finalize rates for 2014, and approve subject to conditions, rates for 2015 and 2016. The last option is to recommend final approval of the multi-year application as filed. We cannot recommend the latter. We are of the view that this option is not in the best interest of any of the interested parties including SaskPower. There are many variables and uncertainties in the assumptions underpinning the 2014 forecasts and these become less certain for both the cost and revenue forecast accuracy into the future. With the complimentary financial risks, both positive and negative to the utility as well as its ratepayers, it is very difficult for us to secure the interests of all parties by recommending final approvals for all three years from 2014-2016.

    It is our view that the nature of these variables (largely beyond the control of SaskPower), as well as the size of the Capital Program (a main cause of the requested rate increases) and the inherent possibility of not being able to complete the total program in any given year will result in significant change in the application assumptions and forecasts. These will only be exacerbated with the passage of time. While it may be acceptable to stipulate that the criteria for amending future rates be the fact that SaskPower's ROE not exceed the allowed 8.5%, other issued must, in our view, be considered.

    As noted above, while the Panel has four options in considering this application we certainly do not recommend unconditional approval of the three year application. Being sensitive to the financial needs of SaskPower, the stated interests of the stakeholders and ratepayers including the transparency of the three remaining options, we are of the view that it would be prudent to only recommend approval of the 2014 rate application and conditional approval for the 2015 test year application. As suggested by SaskPower an updated filing would be required that could secure the interests of all parties (utility-ratepayer-public) for the 2015 rate application.

    With the current size of the planned capital program and its impact on the financial revenue requirements of the utility, the less than stable economic outlook and future load forecasts, continued upward movement in fuel and purchase power costs as noted in the Mid-Application Update (including the forward natural gas market pricing) and hydraulic generation availability, there are, in our opinion far too many uncertainties' to provide the comfort necessary to be able to recommend to the Panel approval of the 2016 test year application.

17.0 Acknowledgements

At the start of our review process the Chair of the Panel and Forkast met with SaskPower's President and Chief Executive Officer. Through-out this process we met and interacted with officials, finding those exchanges extremely beneficial and of assistance in clarifying the Corporation's policy positions on matters under discussion. We sincerely wish to thank all staff members who participated directly or indirectly in the process, providing answers and the data in response to all our questions.

Through-out this significant review we were assisted by the co-operative efforts of a number of SaskPower/NorthPoint officials specifically led by Mr. Troy King, Director, Corporate Planning, Finance, and Mr. Tim Coucill, Rate Regulation, also in Finance, as well as Mr. Darren Foster, Manager, Rate Regulation. We wish to thank them and their staff for their patience, timely responses, scheduling meetings and ensuring that we received the information required through-out the last four months.

We would also like to thank the public for the feedback and the stakeholders for their participation and continuing support of the process. We recognize the significant amount of effort required to review the material filed and wish to thank them for their thoughtful submissions.

Lastly, we want to thank the Chair and the Panel for their input, indulgence and support during this process. We recognize that this is the first three year Application presented to the Panel by SaskPower and as such is a significant responsibility for the Panel both technically and administratively. We also recognize that in carrying out the Panel's responsibilities, it must balance the interests of all three significant parties; the utility, the ratepayer and the general public, and to provide an opinion of the fairness and reasonableness of SaskPower's 2014-2016 proposed rate changes.

We trust this report will assist them in discharging that responsibility.

Appendix 1 - Support and Analysis Tables

Table A1.1 - Saskatchewan Sales Volumes (Load Forecast) from 2012 to 2016

Customer	2012	2013		2014		2015		2016		2012-2016	
Class	GWh	GWh	Var	GWh	Var	GWh	Var	GWh	Var	GWh Var	% Var
Residential	2,937.6	3,137.3	199.7	3,013.5	(123.8)	3,056.5	43.0	3,102.1	45.6	164.5	5.6%
Farm	1,148.8	1,322.1	173.3	1,305.3	(16.8)	1,308.5	3.2	1,298.3	(10.2)	149.5	13.0%
Commercial	3,532.0	3,625.0	93.0	3,609.2	(15.8)	3,630.6	21.4	3,673.7	43.1	141.7	4.0%
Oilfields	3,177.2	3,516.6	339.4	3,685.7	169.1	3,939.6	253.9	4,016.9	77.3	839.7	26.4%
Power Customers	7,447.7	7,852.4	404.7	8,233.6	381.2	8,829.7	596.1	9,796.2	966.5	2,348.5	31.5%
Reseller	1,253.8	1,260.6	6.8	1,264.1	3.5	1,267.9	3.8	1,271.6	3.7	17.8	1.4%
Total Saskatchewan Sales	**19,497.1**	**20,714.0**	**1,216.9**	**21,111.4**	**397.4**	**22,032.8**	**921.4**	**23,158.8**	**1,126.0**	**3,661.7**	**18.8%**
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan; Var = Variance											

Table A1.2 - Saskatchewan Sales from 2011 to 2012

Customer Class	2011	2012	2011-2012	
(in $ millions)	Actual	Forecast	$ Variance	% Variance
Residential	407.3	402.1	(5.2)	(1.3%)
Farm	144.9	130.7	(14.2)	(9.8%)
Commercial	355.5	365.6	10.1	2.8%
Oilfields	241.6	262.7	21.1	8.7%
Power Customers	440.3	449.5	9.2	2.1%
Reseller	77.2	76.6	(0.6)	(0.8%)
Sales Before Rate Increase	**1,666.8**	**1,687.2**	**20.4**	**1.2%**
	-	-	-	-
Total Saskatchewan Sales	**$1,666.8**	**$1,687.2**	**$20.4**	**1.2%**
Var = Variance				

Table A1.3 - Saskatchewan Sales from 2013 to 2016

Customer Class	2013	2014		2015		2016		2013-2016	
(in $ millions)	Forecast	Forecast	Variance	Forecast	Variance	Forecast	Variance	$ Var	% Var
Residential	445.6	430.2	(15.4)	436.8	6.6	443.6	6.8	(2.0)	(0.4%)
Farm	154.6	152.6	(2.0)	152.9	0.3	151.8	(1.1)	(2.8)	(1.8%)
Commercial	387.5	382.2	(5.3)	384.5	2.3	389.3	4.8	1.8	0.5%
Oilfields	307.7	320.6	12.9	341.7	21.1	345.7	4.0	38.0	12.3%
Power Customers	491.4	510.0	18.6	547.7	37.7	603.0	55.3	111.6	22.7%
Reseller	80.9	81.0	0.1	81.2	0.2	81.5	0.3	0.6	0.7%
Sales Before Rate Increase	**1,867.7**	**1,876.6**	**8.9**	**1,944.8**	**68.2**	**2,014.9**	**70.1**	**147.2**	**7.9%**
Revenue Life Due to Rate Increase	-	103.2	103.2	209.6	106.4	328.7	119.1	-	-
Total Saskatchewan Sales	**$1,867.7**	**$1,979.8**	**$112.1**	**$2,154.4**	**$174.6**	**$2,343.6**	**$189.2**	**$475.9**	**25.5%**

2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan; Var = Variance

Table A1.4 - Annual Fuel Costs from 2011 to 2016

	2011	2012		2013		2014		2015		2016		2012-2016	
(in $ millions)	Actual	Actual	Var	Forcst	Var	Forcst	Var	Forcst	Var	Forcst	Var	$ Var	% Var
Fuel Expense													
Gas	196.0	213.8	17.8	230.7	16.9	255.2	24.5	319.1	63.9	351.9	32.8	138.1	64.6%
Coal	219.0	221.8	2.8	233.6	11.8	264.9	31.3	270.9	6.0	280.8	9.9	59.0	26.6%
Wind	9.0	9.6	0.6	9.9	0.3	10.3	0.4	10.4	0.1	14.1	3.7	4.5	46.9%
Hydro	20.0	19.1	(0.9)	21.0	1.9	18.0	(3.0)	18.7	0.7	19.3	0.6	0.2	1.0%
Imports	24.0	31.2	7.2	25.9	(5.3)	8.9	(17.0)	18.6	9.7	26.6	8.0	(4.6)	(14.7%)
Other	17.0	17.8	0.8	26.2	8.4	30.1	3.9	40.7	10.6	69.3	28.6	51.5	289.3%
Total F&PP	**$485.0**	**$513.3**	**$28.3**	**$547.3**	**$34.0**	**$587.4**	**$40.1**	**$678.4**	**$91.0**	**$762.0**	**$83.6**	**$248.7**	**48.5%**

2011 figures from SPC Annual Report (MFR Tab1, page 83); Forcst = Forecast; Var = Variance;
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;

Table A1.5 - Net F&PP Volumes from 2011 to 2016

(in GWh)	2011 *	2012		2013		2014		2015		2016		2012-2016	
	Actual	Actual	Var	Forcst	Var	Forcst	Var	Forcst	Var	Forcst	Var	Var	% Var
Fuel Expense													
Gas	4,032	4,968	936	6,235	1,267	7,163	928	8,114	951	9,167	1,053	4,199	84.5%
Coal	11,614	11,446	(168)	11,173	(273)	11,610	437	11,693	83	11,462	(231)	16	0.1%
Wind	-	655	655	650	(5)	674	24	671	(3)	736	65	81	12.4%
Hydro	4,641	4,240	(401)	4,447	207	3,645	(802)	3,644	(1)	3,607	(37)	(633)	(4.9%)
Imports	502	656	154	496	(160)	156	(340)	316	160	464	148	(192)	(29.3%)
Other	823	164	(659)	215	51	262	47	364	102	581	217	417	254.3%
Gross Volumes Supplied	**21,612**	**22,129**	**517**	**23,216**	**1,087**	**23,510**	**294**	**24,802**	**1,292**	**26,017**	**1,215**	**3,888**	**17.6%**

2011 figures from Nov 8, 2012 Forkast Consulting 2013 Rate Proposal Application Review (page 113);
* 2011 figures for Other include Wind generated volumes; Forcst = Forecast; Var = Variance;
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;

Table A1.6 - Fuel Price per Generation Source from 2011 to 2016

(in $/MWh)	2011	2012		2013		2014		2015		2016		2012-2016	
	Actual	Actual	Var	Forec	Var	Forec	Var	Forec	Var	Forec	Var	$ Var	% Var
Fuel Expense													
Gas	48.53	43.05	(5.48)	36.97	(6.08)	35.63	(1.34)	39.33	3.70	38.39	(0.94)	(4.66)	(0.11)
Coal	18.89	19.38	0.49	20.91	1.53	22.82	1.91	23.17	0.35	24.50	1.33	5.12	0.26
Wind	82.72	84.57	1.85	84.77	0.20	84.43	(0.34)	87.39	2.96	77.47	(9.92)	(7.10)	(0.08)
Hydro	4.30	4.50	0.20	4.72	0.22	4.94	0.22	5.13	0.19	5.35	0.22	0.85	0.19
Imports	48.56	47.46	(1.10)	52.21	4.75	57.05	4.84	58.86	1.81	57.33	(1.53)	9.87	0.21
Other	119.60	108.71	(10.89)	122.96	14.25	100.00	(22.96)	82.69	(17.31)	70.05	(12.64)	(38.66)	(0.36)
Weighted Avg Fuel Price	**22.46**	**23.20**		**23.57**		**24.99**		**27.35**		**29.29**		**6.09**	

2011 figures from Nov 8, 2012 Forkast Consulting 2013 Rate Proposal Application Review (page 114);
* 2011 figures for Other include Wind generated volumes; Forec = Forecast; Var = Variance;
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;

Table A1.7 - SaskPower OM&A from 2011 to 2016

	2011	2012		2013		2014		2015		2016		2012-2016	
in $ millions	**Act**	**Act**	**Var**	**Forec**	**Var**	**Forec**	**Var**	**Forec**	**Var**	**Forec**	**Var**	**$ Var**	**% Var**
Power Prod	183.0	168.7	(14.30)	154.6	(14.10)	182.4	27.80	183.6	1.20	183.7	0.10	15.00	8.9%
T&D	165.1	149.6	(15.50)	135.60	(14.00)	131.60	(4.00)	139.30	7.70	146.80	7.50	(2.80)	(1.9%)
Asset Mgmt		28.0	28.00	22.60	(5.40)	22.80	0.20	24.60	1.80	25.30	0.70	(2.70)	(9.6%)
Op Other		18.3	18.30	16.80	(1.50)	20.70	3.90	21.60	0.90	22.90	1.30	4.60	25.1%
Subtotal Op		**364.6**	**-**	**329.6**	**(35.0)**	**357.5**	**27.9**	**369.1**	**11.6**	**378.7**	**9.6**	**14.10**	**3.9%**
Pres/Board	1.2	3.5	2.30	3.40	(0.10)	3.50	0.10	3.40	(0.10)	3.60	0.20	0.10	2.9%
Finance	17.3	15.2	(2.10)	16.30	1.10	16.70	0.40	17.00	0.30	17.80	0.80	2.60	17.1%
Cust Svce	40.6	45.7	5.10	48.2	2.50	46.7	(1.50)	43.9	(2.80)	45.8	1.90	0.10	0.2%
ResPlan&NP		14.4	14.40	17.6	3.20	18.3	0.70	20.0	1.70	22.6	2.60	8.20	56.9%
LawLandReg	4.8	14.8	10.00	17.4	2.60	17.0	(0.40)	17.6	0.60	18.4	0.80	3.60	24.3%
IT & Security		56.5	56.50	61.5	5.00	70.1	8.60	79.0	8.90	85.3	6.30	28.80	51.0%
HR	22.6	25.6	3.00	27.2	1.60	27.0	(0.20)	27.7	0.70	28.9	1.20	3.30	12.9%
Commercial		16.3	16.30	31.9	15.60	35.9	4.00	30.4	(5.50)	27.0	(3.40)	10.70	65.6%
Bus Develop	12.6	3.9	(8.70)	1.1	(2.80)	1.4	0.30	1.5	0.10	1.5	-	(2.40)	(61.5%)
CCS Initiative		2.6	2.60	10.6	8.00	6.3	(4.30)	10.6	4.30	11.1	0.50	8.50	326.9%
Total Core		**563.1**	**-**	**564.8**	**1.70**	**600.4**	**35.60**	**620.2**	**19.80**	**640.7**	**20.50**	**77.60**	**13.8%**
DSM	11.8	19.2	7.40	15.4	(3.80)	14.3	(1.10)	14.6	0.30	14.9	0.30	(4.30)	(22.4%)
PPA-OMA	18.1	22.9	4.80	26.2	3.30	22.2	(4.00)	26.2	4.00	30.5	4.30	7.60	33.2%
Other Exp	8.2	14.5	6.30	11.3	(3.20)	10.8	(0.50)	11.4	0.60	11.7	0.30	(2.80)	(19.3%)
Total Other		**56.6**	**-**	**52.9**	**(3.70)**	**47.3**	**(5.60)**	**52.2**	**4.90**	**57.1**	**4.90**	**0.50**	**0.9%**
Total OM&A		**619.7**	**-**	**617.7**	**(2.0)**	**647.7**	**30.0**	**672.4**	**24.7**	**697.8**	**25.4**	**78.1**	**12.6%**
% Increase		**-**		**(0.3%)**		**4.9%**		**3.8%**		**3.8%**			

2011 figures from Nov 8, 2012 Forkast Consulting 2013 Rate Proposal Application Review (page 69); Act = Actual; Forec = Forecast; Var = Variance; 2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;

Table A1.8 - Depreciation from 2011 to 2016

(in $ millions)	2011 Act	2012 Act	2012 Var	2013 Forec	2013 Var	2014 Forec	2014 Var	2015 Forec	2015 Var	2016 Forec	2016 Var	2012-2016 $Var	2012-2016 %Var
Depreciation													
SaskPower Dep	268.4	289.3	20.9	323.3	34.0	367.5	44.2	399.0	31.5	424.3	25.3	135.0	47%
Asset Retire-Dep Exp	4.3	5.2	0.9	1.4	(3.8)	1.4	0.0	1.4	0.0	1.4	0.0	(3.8)	(73%)
Total SaskPower Dep	**272.7**	**294.5**	**21.8**	**324.7**	**30.2**	**368.9**	**44.2**	**400.4**	**31.5**	**425.7**	**25.3**	**131.2**	**45%**
Capital Lease Amort	17.0	21.3	4.3	41.8	20.5	56.4	14.6	60.4	4.0	64.4	4.0	43.1	202%
Total Depreciation	**289.7**	**315.8**	**26.1**	**366.5**	**50.7**	**425.3**	**58.8**	**460.8**	**35.5**	**490.1**	**29.3**	**174.3**	**55%**

2011 figures from First Round IR # 24; Act = Actual; Forec = Forecast; Var = Variance;
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;

Table A1.9 - Finance Charges from 2011 to 2016

(in $ millions)	2011 Act	2012 Act	2012 Var	2013 Forec	2013 Var	2014 Forec	2014 Var	2015 Forec	2015 Var	2016 Forec	2016 Var	2012-2016 $Var	2012-2016 %Var
Finance Charges													
Borrowing Interest	233.6	243.9	10.3	328.2	84.3	399.9	71.7	431.0	31.1	457.1	26.1	213.2	87%
Interest Capitalized	(11.7)	(29.6)	(17.9)	(46.0)	(16.4)	(22.8)	23.2	(21.3)	1.5	(10.6)	10.7	19.0	(64%)
Debt Retire Fund	(24.8)	(22.4)	2.4	(23.4)	(1.0)	(9.4)	14.0	(9.3)	0.1	(10.2)	(0.9)	12.2	(54%)
Other Int & Charge	0.4	11.1	10.7	13.5	2.4	15.6	2.1	15.9	0.3	16.2	0.3	5.1	46%
Total Finance Exp	**197.5**	**203.0**		**272.3**		**383.3**		**416.3**		**452.5**		**249.5**	

2011 figures from Nov 8, 2012 Forkast Consulting 2013 Rate Proposal Application Review (page 87); Act = Actual; Forec = Forecast; Var = Variance;
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;

Table A1.10 - Taxes from 2011 to 2016

(in $ millions)	2011	2012		2013		2014		2015		2016		2012-2016	
	Act	Act	Var	Forec	Var	Forec	Var	Forec	Var	Forec	Var	$Var	%Var
Taxes													
Corporate Capital Tax	23.0	26.9	3.9	31.7	4.8	34.5	2.8	37.4	2.9	38.6	1.2	11.7	43%
Grants in Lieu	20.0	20.8	0.8	21.2	0.4	22.5	1.3	23.9	1.4	25.3	1.4	4.5	22%
Total Taxes	**43.0**	**47.7**	**4.7**	**52.9**	**5.2**	**57.0**	**4.1**	**61.3**	**4.3**	**63.9**	**2.6**	**16.2**	**34%**

2011 figures from SPC Annual Report (MFR Tab1, page 84);
2013 figures based on Jul 2013 forecast (Jan to Jul actual, Aug to Dec forecast); 2014 to 2016 figures based on 2014 Business Plan;
Act = Actual; Forec = Forecast; Var = Variance;

SaskPower
2014, 2015, 2016
Rate Application

Mid-Application Update

February 2014

SaskPower
Powering the future

1.0 Overview

In October 2013, SaskPower submitted a rate application requesting a system average rate increase of 5.5% in 2014, 5% in 2015 and 5% in 2016. A regular element of the rate application process includes a review of the underlying assumptions presented in the initial rate application. The original rate application forecasted a return on equity (ROE) of 1.3% in 2014, 2.0% in 2015 and 1.9% in 2016. The initial submission was based on SaskPower's 2014 Business Plan with a forecast effective July 2013. This mid-application update compares the initial rate application submission to the most recent financial forecast, effective January 2014.

Operating income

The original rate application forecasted an operating income of $26.9 million in 2014 and an ROE of 1.3%. The mid-application update forecasts operating income of $66.0 million in 2014 and an ROE of 2.9%. The improved forecast results are due to a $4.4 million improvement in revenue and a $34.7 million reduction in expense.

Revenue and load

SaskPower's revenue in 2014 is expected to increase $4.4 million above the original rate application forecast. This is driven largely by an updated load forecast, which results in a $14.8 million improvement in Saskatchewan energy sales. The load forecast in the update is based on the 2013 Q4 Load Forecast adjusted for January actuals. Overall, the load in 2014 is expected to decline slightly, but will be more than offset by a change in the revenue mix. Consumption in the residential and consumer classes are expected to increase while being offset by a decline in the power class segment. The improvement in Saskatchewan sales revenue is partially offset by a $3.4 million decline in exports and a $7.0 million reduction in other revenue.

Expense

Expenses are expected to decline $34.7 million in 2014 compared to the forecast in the original rate application. The main reason for the decline in expense is due to an expected $69.2 million reduction in depreciation and finance expenses. The primary driver for this reduction has been a delay in the commissioning of the Integrated Carbon Capture and Storage (ICCS) facility at Boundary Dam #3. The original rate application assumed that the ICCS facility would be fully operational by January 1, 2014. However, the revised forecast anticipates delays with both the power station island and the carbon capture facility. The impact of these delays is that there will be a decrease in both depreciation expense and finance charges, as these costs do not hit the income statement until the facility is operational. There has also been a change in the estimated pension expense for 2014 which is contributing to the reduction in finance expense.

These reductions in expense are partially offset by a forecasted $35 million increase in fuel and purchased power expense in 2014. This is due largely to a forecasted increase in the price of natural gas. The original application assumed a market price of $3.29 / GJ in 2014. The latest forecast, which is based on the forward price of natural gas at the end of January, assumes a forward price of $4.08 / GJ.

Conclusion

The net impact of these changes is SaskPower's operating income for 2014 is forecasted to improve from $26.9 million in the initial submission to $66.0 million in this mid-application update. SaskPower's revised ROE forecast for 2014 is now 2.9% compared to the original ROE forecast of 1.3%, still well below the Crown Investment Corporation (CIC)-approved long-term target of 8.5%. As the impact of the new information does not cause SaskPower to exceed its long-term ROE target, SaskPower recommends that the rate increase request be approved as requested in the initial submission.

2.0 Financial Requirements Update

The following section provides a comparison between the initial rate application and the mid-application update forecast. If the SRRP approves the 2014 to 2016 rate application, similar financial updates will be provided for 2015 and 2016.

2.1 FINANCIAL SUMMARY

Consolidated Statement of Income			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Revenue			
Saskatchewan Electricity Sales	$1,979.8	$1,994.6	$14.8
Export	27.5	24.1	(3.4)
Net Sales from Electricity Trading	7.2	7.2	0.0
Other	129.6	122.6	(7.0)
Total Revenue	**2,144.1**	**2,148.5**	**4.4**
Expense			
Fuel and Purchased Power	587.4	622.0	34.6
Operating, Maintenance & Administration	647.7	647.7	0.0
Depreciation and Amortization	425.3	399.3	(26.0)
Finance Charges	383.3	340.1	(43.2)
Taxes	57.0	57.0	0.0
Other	16.5	16.5	0.0
Total Expense	**2,117.2**	**2,082.5**	**(34.7)**
Operating Income	**$26.9**	**$66.0**	**$39.1**
Return on Equity (Operating Income)	**1.3%**	**2.9%**	**1.6%**

Operating income is forecasted to be $66.0 million, an increase of $39.1 million from the original submission. This results in an improvement in SaskPower's forecasted ROE from 1.3% to 2.9%.

The anticipated changes in SaskPower's revenues and expenses are explained in detail in the following sections.

2.2 REVENUE

SaskPower revenue is expected to increase $4.4 million from the initial submission. This is due to a $14.8 million increase in Saskatchewan sales partially offset by a $3.4 million reduction in exports and a $7.0 million reduction in other revenue.

2.2.1 Saskatchewan Customer Revenues

SaskPower Revenues			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Total Saskatchewan Sales	$1,979.8	$1,994.6	$14.8
SaskPower Exports	27.5	24.1	(3.4)
Net Sales From Trading	7.2	7.2	0.0
Total Other Revenue	129.6	122.6	**(7.0)**
Total Revenue	**$2,144.1**	**$2,148.5**	**$4.4**

Saskatchewan Sales Volume (Load Forecast)			
	2014 Forecast		
(in GWh)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Saskatchewan Sales			
Residential	3,013.5	3,129.4	115.9
Farm	1,305.3	1,291.8	(13.5)
Commercial	3,609.2	3,690.0	80.8
Oilfield	3,685.7	3,682.9	(2.8)
Power	8,233.6	8,017.1	(216.5)
Reseller	1,264.1	1,267.6	3.5
Total Saskatchewan Sales	**21,111.4**	**21,078.9**	**(32.5)**

Saskatchewan sales are expected to increase $14.8 million despite a slight decline in load. The revised load forecast is based on the 2013 Q4 forecast, adjusted for January 2014 actuals. This forecast anticipates a 32.5 GWh decline in total load. The power customer class forecast decreased by 216.5 GWh, primarily in the potash sector. This decrease is largely offset by forecasted increases in residential sales of 115.9 GWh due to a slightly higher household forecast and per customer usage, and commercial sales of 80.8 GWh due to an increase in the commercial GDP drivers.

Despite the decrease in load, revenues are expected to increase as a result of the anticipated change in the sales mix that will see an increase in consumption by the residential and commercial classes offset by a reduction in sales to the power customer segment.

2.2.2 Export Revenue

Export Revenue			
	2014 Forecast		
	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
SaskPower Exports *(in $ millions)*	$27.5	$24.1	($3.4)
SaskPower Exports *(in GWh)*	486.3	346.7	(139.6)
SaskPower Exports *(in $/MWh)*	$56.5	$69.5	$13.0

Export revenue for 2014 is expected to decrease by $3.4 million, or 12.4% compared to the original rate application. This is the result of a 139.6 GWh or 28.7% reduction in export volumes from the initial submission. Since the initial submission, a 90-day Saskatchewan-to-Alberta tie line outage that was originally scheduled for 2013 has been deferred to March 2014. This deferral significantly reduces SaskPower's export capabilities in 2014. In terms of export revenue, the impact of the 90-day tie line outage is somewhat mitigated, as March to May is historically a period of relatively low export prices for SaskPower.

2.2.3 Net Sales from Electricity Trading

Net Sales From Electricity Trading			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Net Sales From Electricity Trading	**$7.2**	**$7.2**	**$0.0**

The net sales from electricity trading forecast remains unchanged.

2.2.4 Other Revenue

Other Revenue			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Gas and Electrical Inspections	$18.7	$18.7	$0.0
Customer Connects	50.0	50.0	0.0
CO_2 Sales	17.5	10.5	(7.0)
CO_2 Test Facility Revenue	4.3	4.3	0.0
MRM Equity Investment	1.1	1.1	0.0
Miscellaneous Revenue	38.0	38.0	0.0
Total Other Revenue	**$129.6**	**$122.6**	**($7.0)**

SaskPower is forecasting a $7 million decrease in other revenue due to the delay in the completion of the ICCS facility, which will reduce the amount of CO_2 available for sale in 2014.

2. 3 EXPENSE

SaskPower Expenses			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Expense			
Fuel and Purchased Power	$587.4	$622.0	$34.6
Operating, Maintenance & Administration	647.7	647.7	0.0
Depreciation and Amortization	425.3	399.3	(26.0)
Finance Charges	383.3	340.1	(43.2)
Taxes	57.0	57.0	0.0
Other	16.5	16.5	0.0
Total Expense	**$2,117.2**	**$2,082.5**	**($34.7)**

Expenses are anticipated to be $34.7 million or 1.6% lower than forecasted in the initial submission. This is due to a reduction in depreciation and finance charges partially offset by an increase in fuel and purchased power expense.

2.3.1 Fuel and Purchased Power

Net Fuel and Purchased Power Expense			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Fuel Expense			
Gas	$255.2	$292.0	$36.8
Coal	264.9	242.0	(22.9)
Wind	10.3	11.2	0.9
Hydro	18.0	17.5	(0.5)
Imports	8.9	28.4	19.5
Other	30.1	30.9	0.8
Total Fuel and Purchased Power Expense	**$587.4**	**$622.0**	**$34.6**

Net Fuel and Purchased Power Volumes			
	2014 Forecast		
(in GWhs)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Fuel Expense			
Gas	7,163	7,003	(160)
Coal	11,610	11,224	(386)
Wind	674	702	28
Hydro	3,645	3,556	(89)
Imports	156	652	496
Other	262	248	(14)
Gross Volumes Supplied	**23,510**	**23,385**	**(125)**

Fuel and purchased power expense is expected to increase by $34.6 million from the original rate application forecast. This is primarily due to an expected increase in natural gas prices from the initial submission. The original application assumed a market price of $3.29 / GJ in 2014. The latest forecast, which is based on the forward price of natural gas at the end of January 2014, assumes a forward price of $4.08 / GJ. The net impact from the increase in natural gas prices is a $36.8 million increase in fuel costs. Coal costs are expected to decrease $22.9 million in 2014 as a result of a forecasted 386 GWh reduction in generation due to an expected reduction in coal unit availability. Because of the increase in natural gas prices and lower forecast coal generation, SaskPower is expecting a larger reliance on imports, which are forecasted to increase by 496 GWhs and $19.5 million from the initial submission.

2.3.2 Operating, Maintenance and Administration (OM&A)

SaskPower Operating, Maintenance & Administration			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Power Production	$182.4	$189.8	$7.4
Transmission & Distribution	131.6	133.3	1.7
Operation Other	43.5	34.2	(9.3)
Subtotal Operations	**357.5**	**357.3**	**(0.2)**
President/Board	3.5	12.5	9.0
Finance	16.7	15.7	(1.0)
Customer Services	46.7	38.5	(8.2)
Resource Planning & NorthPoint	18.3	15.5	(2.8)
Law, Land, Regulatory Affairs	17.0	18.5	1.5
Information Technology & Security	70.1	70.2	0.1
Human Resources	27.0	28.6	1.6
Commercial	35.9	35.2	(0.7)
Business Development	1.4	1.4	0.0
Carbon Capture & Storage Initiatives	6.3	6.3	0.0
Total Core Costs	**600.4**	**599.7**	**(0.7)**
Demand Side Mangement	14.3	14.4	0.1
PPA-OM&A	22.2	20.0	(2.2)
Other Expense	10.8	13.6	2.8
Total Other Costs	**47.3**	**48.0**	**0.7**
Total OM&A	**$647.7**	**$647.7**	**$0.0**

Although OM&A costs have moved between business units, total OM&A is forecasted to remain unchanged.

2.3.3 Capital-Related Expenses

Finance Charges

Finance Charges			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Finance Charges			
Interest on Borrowings	$399.9	$391.6	($8.3)
Interest Capitalized	(22.8)	(42.8)	(20.0)
Debt Retirement Fund Earnings	(9.4)	(18.1)	(8.7)
Other Interest and Charges	15.6	9.4	(6.2)
Total Finance Charges	**$383.3**	**$340.1**	**($43.2)**

Finance charges are forecasted to decrease by $43.2 million from the initial submission. Interest on borrowings is expected to decrease by $8.3 million. Although total borrowings are expected to remain largely unchanged from the original submission, timing differences between the borrowing schedule in the initial submission and the mid-application update will result in a decrease in interest on borrowing costs for 2014.

Interest capitalized is forecast to increase by $20 million due largely to an anticipated delay in the commissioning of the ICCS facility. Until an asset goes into service, any interest paid during the asset's construction is considered a capital cost, not an expense. Interest capitalized represents the interest paid on capital projects under construction and is deducted from the total finance charges paid by SaskPower. Therefore, a deferral in the commissioning date of the ICCS facility increases the amount of interest capitalized in 2014, which reduces SaskPower's finance charges.

Debt retirement fund earnings are forecast to increase by $8.7M due to an ongoing trend of strong earnings from the funds. Other interest and charges are expected to decline by $6.2 million due to a reduction in the Corporation's pension expense as a result of an increase in interest rates. SaskPower's pension expense is calculated by an independent actuary based on assumptions regarding future plan earnings and plan obligations. Changes in interest rates have a material impact on the pension expense calculation.

Depreciation and Amortization

Depreciation			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Depreciation			
SaskPower Depreciation	$367.5	$341.5	($26.0)
Asset Retirement Asset - Depn Expense	1.4	1.4	0.0
Total SaskPower Depreciation	**368.9**	**342.9**	**(26.0)**
Capital Lease Amortization	56.4	56.4	0.0
Total Depreciation	**$425.3**	**$399.3**	**($26.0)**

The depreciation expense forecast has decreased by $26.0 million largely due to the anticipated delay in commissioning the ICCS facility. Depreciation expense does not begin until the facility is commissioned. Therefore, a delay in the commissioning date reduces the amount of depreciation expense recorded in 2014.

Taxes

Taxes			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Taxes			
Corporate Capital Tax	$34.5	$34.0	($0.5)
Grants in Lieu	22.5	23.0	0.5
Total Taxes	**$57.0**	**$57.0**	**$0.0**

The net tax expense forecast remains unchanged, as the moderate decrease in the forecasted corporate capital tax expense is expected to be offset by an equal increase in grants-in-lieu of taxes.

Other Expense

Other			
	2014 Forecast		
(in $ millions)	Initial Submission (July 31, 2013)	Mid-Application Update (Jan 31, 2014)	Variance
Total Other Expense	**$16.5**	**$16.5**	**$0.0**

Other expenses are largely made up of gains or losses on asset disposals and retirements. The other expense forecast remains unchanged.

Capital

SaskPower's capital forecast remains unchanged at $1.2 billion for 2014.

3.0 Mid-Application Update Summary

The net impact of the updated forecast is that SaskPower's operating income for 2014 is expected to improve from $26.9 million in the initial rate application submission to $66.0 in this mid-application update. SaskPower's revised ROE forecast for 2014 is now 2.9%, compared to the original ROE forecast of 1.3%. As the forecasted ROE remains well below the CIC-approved long-term target of 8.5%, SaskPower continues to recommend that the rate increase be approved as requested in the initial submission.

Appendix 3 - Information Request Index

SaskPower 2014, 2015, 2016 Rate Application - IR Reference Table				
Category	**Consultant Round 1**	**Consultant Round 2**	**SIECA Round 1**	**SIECA Round 2**
Application & Annual Report	**IR # 1-33**			
Rev & Exp Data & Source	1, 4, 11a	39		1
Economic Forecast Data & Source	2a, 2b	1	48	
Rate Changes & Impact	3, 4, 5, 8, 12, 124		37, 38, 41	
ROE & Operating Income	6, 7, 8, 12, 32	2a, 2b, 2c		
Interest Coverage Ratio (ICR)	10			
Employee Productivity Indicator	11b			
AB/BC Tie Line & Markets, MATL	14b,14c,14e,14f,16,188,197	4, 5		
Electricity Trading	15	4	49	
Other Revenue (incl Misc)	17, 119	6		
BD ICCS CO2 Sales & Costs	18a, 18b, 125	7a, 7b	25	16
Shand CCTF (Hitachi/SPC)	19	8		
Finance Expense & Charges	22			
Foreign Currency	23			
Plant In Svce & Prop Plan Equip	27			
Working Capital	28	9		
Tax Expense	29			
Provincial Payments incl Dividends	30, 31, 32, 89, 94, 199	10		
Other Expenses	33	15		
Business Plan	**IR # 34-39**			
Plan Coverage Dates	34			
Workforce Plan & Org Structure	38, 39	13	26	
OM&A	**IR # 40-53**		**IR # 26-35**	
OM&A / Revenue Comparison	11a			
OM&A Costs	35, 36, 42, 45, 50	11a, 11b, 14a, 14b	29	12
New Initiatives Impacting OM&A	36, 51	16		
FTE's	37, 38, 41	12b, 13, 19	27	
OM&A / Customer Comparison	40	14b		
Number of Customers	40, 41	3a, 14b	15	
Labour, OH, Interest Capitalized	43			
Pension Plan	44			
OM&A Increase Explanation	46a, 46b, 47			
Labour Agreement Expiration	48			
Gas & Electrical Inspections	49	17		
Credit Card Program	52			
Benchmarking			28	
Debt & Equity	**IR # 54-59**			
Debt / Equity Ratio	9, 32, 58, 59, 127		19	
Debt (S-T, L-T, Leases) Amounts	20, 21			
Debt (S-T, L-T) Policy & Limits	54, 56, 57			
Borrowing Limits & Credit Capacity	54, 55a, 55b, 56			
Debt Savings	59			
BR & SDR	**IR # 60-72**			
BR Program List & Savings	53, 62, 71	18a, 18b		
Procurement Process	60a, 60b			
Customer Connect Process	60a, 61			
AMI Program	63	18c	20	
Field Worker Technology	64, 65			
Line Locates	66, 67	19, 20		
IT&S Sourcing	68			
Disaster Recovery	69			
SDR Costs	70	21	15	

F&PP	IR # 73-79		IR # 26-35	
Generation Mix (added & deleted)	73		21, 23a	12
Fuel Mix Volume & Cost	74	22a, 22b	23a, 30	12, 20d
Fuel Mix Unit Price	74, 75, 76		23a	12
Import & Export (Rev Exp Volume)	77, 100	22a, 22b		
Take or Pay Obligations	78			
Net Metering Programs	79	23a, 23b		
Natural Gas	**IR # 80-86**			
Volume & Cost	74, 84	22a, 22b, 26	23a, 23b	
Unit Pricing	74, 75, 76, 81, 85	26, 39	23a, 23b, 31	
Risk Management	80			
Purchasing (incl TEP)	81, 82, 86	22c, 24, 25, 27		
Hedging	81, 83a, 84	27	33, 34	
Storage	83a, 83b	25	31	
Heat Rate			32	
Coal	**IR # 87-92**			
Volume & Cost	74, 88	22a, 22b	23a	
Unit Price	74, 75, 76		23a	
Supply Contracts	87	28		
Heat Values & Sources	88, 90			17
Royalties	89			
Future Viability	91			
Flood Impact	92			
Hydro	**IR # 93-99**			
Volume & Cost	74, 95	22a, 22b	23a	
Unit Price	74, 75, 76		23a	
Flow Conditions (incl Weather)	93, 95, 96, 97, 98, 133			
Water Rental Fees	94			
FNPA Agreement	99			
Export Power	**IR # 100-102**			
Export Revenue & Volume	14a, 77, 100, 101		49	
Electricity Pricing	14d			
Impact on Domestic Planning	102, 197			
Wind	**IR # 103-105**			
Generation (added & or deleted)	73, 103		23a	9, 10
Volume & Cost	74, 105	22a, 22b	23a	10
Unit Pricing	74, 75, 76, 103		23a	
Benefits	103	29b	12, 13	9, 10
Capacity Factors/System Planning	104, 105	29a, 29b, 30	13	
Challenges			14	8
Planned Maintenance	**IR # 106-110**			
Operating/Capital Projects & Costs	106, 110	11a, 32		
Outages	106, 107, 189			21
Savings	107	31		
Asset Management	108, 110	18b, 32		
Maintenance Criteria	109			
Capital	**IR # 111-128**		**IR # 15-20**	
Finance Charges & Taxes	22,29,112b,112c,118,124			
Depreciation & Asset Retirement	24,26,112b&c,113,118,124			
BD Unit Retirements	25, 114, 125, 203		11	
Planning	111, 127			
Projects & Costs	111, 112a, 118, 124	12a, 33, 35a, 35b	15	
Non-Grid Customers	115			
Policy	116, 120, 122	16	18	
Customer Connect Rev & Exp	13, 117	3a, 3b	15, 16, 17	11
Customer Contributions	119, 120, 121	34		
Transmission Interties	123			

BD ICCS	125	8	24	13, 14, 15
Program Deferral	126			
Small Modular Nuclear Reactors	128			
Load Forecasts / Growth	**IR # 129-143**		**IR # 1-9**	
Load Forecast Variances	126, 131, 132, 136		2, 3	8
Itron Recommendations	129			
Load Forecast Data & Sources	130,131,135,136,137,138		1,2,4,5,8a,8c,9	5, 6, 7
Weather	133, 134, 143	37	3, 8b	
Peak Loads/Capacity/Consump	139, 140, 141, 143	36, 37	6,7,22,23a,39,40	19, 20a, 20c
DSM Adjusted Load Forecasts	142			
DSM	**IR # 144-150**			
Savings	11d,144, 145, 147	38	43	
Costs	144, 145	11c		
Portfolio	145	38		
Program Discontinuation	146			
Cost / Benefit Testing	148			
Demand Response Program	149		43,44,45,46,47	20b
Municipal Turbine Program	150			
Sustainability / Environmental	**IR # 151-153**		**IR # 10-14**	
CO2 Emissions	11c, 151		10	
CEA Report	152			
PCB's	153		10	
Regulations			10	
Sensitivity Analysis & FCVA	**IR # 154-162**			
Capital Impact on Depr & Finance	118			
Various Impact on Net Income	154a, 156	39		
2012 Summer Storm Impact	154b			
Positive/Negative Change Impacts	155, 156			
FCVA (RFP - Submissions - Cost)	157			
FCVA Findings/Recommendations	158, 159		35	
SaskEnergy GCVA Comparison	160, 161			
Risk Mitigation (Annual Reviews)	162	40a,40b,40c,40d,40e		
Fuel Cost Impact on Rate Increase			37	
COSS	**IR # 163-180**		**IR # 36-47**	
2013 COSS results / impact	163, 166, 169		42	2, 3, 15, 16
Winter-Summer Peak impact	163, 164, 169		40	
Internal Load Research Study	165, 169	41	1, 2, 4	4
Methodology	167, 168, 172	42, 44	36	
Elenchus Study - Cost Review	170	42		
Time of Use Rates	171	43a, 43b		
Customer Class Changes	173			
Rate Codes	174, 175			
R/RR Ratio Range	176, 177		42	
Streetlight R/RR	178a, 178b			
BMC, Energy & Demand Charges	179, 180	45	36	
System Operations / Generation	**IR # 181-191**		**IR # 21-25**	
Generation Capacity (add & del)	73, 181, 183		21	
New Transmission Lines & Losses	182, 191			
Fuel Source Dispatch	184, 185		14	
Peak & Annual Load Fuel Mix	186			
Tazi Twe Hydro Project	187, 196			
NERC Compliance	72, 190		5	
Resource Supply Plans	**IR # 192-204**			
Methodology	192			
10, 20 & 40 Year Supply Plans	193, 194	46		
Far North Resource Plan	195	46		
CCGT	197			

Key Account Generation Facilities	198			
Water Security Agency Funding	199			
Carbon Tax	200	47		
Grid Losses	201, 202			
Contingency Plans & Reserves	204			18, 20e
Miscellaneous	**IR # 205-208**		**IR # 48-50**	
Donation Policy	205			
Advertising Policy	206, 208a			
Sponsorship Policy	206, 208f	48		
Business Development Unit	207, 208g			
Safety & Awareness	208b			
Energy Efficiency	208c			
Customer Services	208d			
Professional Dues / Membership	208e			

Four additional IRs were submitted to SaskPower subsequent to the review of the Mid-Application Update. These IRs related to:

- Impacts on 2015 and 2016 ROE resulting from revised load forecast and ICCS change;
- Details of natural gas cost changes;
- Coal fired generation capacity reduction; and
- Revised finance charges and depreciation expense.

Appendix 4 - Capital Project Analysis Sheet

SASKPOWER

CAPITAL PROJECT SUBMISSION FOR THE 10-YEAR PLAN

For Project 1M> in 2014/and or 10M> in 10 Years

BUSINESS UNIT	**Operations**	**BU's PROJECT ID:**	**0**
		SAP Project ID#	D352

Budget year 2014 | **Ten-year Plan 2014-2023**

Project Title	**Substation - Fleet Street - 138kV-25kV - Expansion**
Plant (PPBU)	
Location/Region	
Project to be Completed in (Year)	**2014**
Prepared by	[redacted]
Date prepared (dd/mm/yy)	**29/10/2013**

Requested Capital (IDC included)	**$ Thousand**
2013 & Prior	**8,896.4**
2014	**1,400.0**
2015-2023	**0.0**
Total 2014-23 Cost	**1,400.0**
2023 and Later	**0.0**
Total Project Cost	**10,296.4**

Please enter budget cost in column H

in $ thousand

Asset type	Transmission
Sustaining vs New	New
Annual Project	No
Project Risk Analysis Completed?	Choose Yes/To be Completed/Not Requried

Project Description:

Description: **Describe what the project is, why it is being proposed, the background and the objective of the project. Please give reference to the relevant Federal, Provincial regulations or standards if available.**

Provides funds to increase the Fleet Street substation transformer capacity. The capacity increase will be achived by the addition of a new Fleet Street 138-25kV substation within the Fleet Street switching station. The proposed 138-25kV Fleet Street substation will be equipped with a new 138-25kV, 30/40/50 MVA transformer and supplied by the Fleet Street switching station 138 kV bus. This CPA covers Substation, Switching Station, Protection, Communications, SCADA and Distribution services costs associated with this project.