FORKAST CONSULTING

Independent Review of the SaskPower 2013 Rate Proposal Application

Final Report

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Executive Summary

The Forkast Consulting team of Forrest and Kostelnyk (Forkast) was retained by the Saskatchewan Rate Review Panel to provide an independent review of SaskPower's 2013 General Rate Application, pursuant to the Minister's order issued specific to this review on July 10, 2012. The review commenced immediately upon receipt of the Application in July 2012. Forkast's Final Report was submitted to the Panel on November 8, 2012.

The Application requested an overall system average increase in rates of 4.9%, except for the Power – Contract Rate Class which are dependent on the pricing terms contained within the individual customer contracts. The Application to be effective on January 1, 2013, was estimated to result in a net operating income of $165.9 million, with incremental revenue generated estimated to be $90.8 million. The Mid-Application Update has reduced the forecasted net income to $ 126.1 million.

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 Purchase 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 periodic updates, as provided by SaskPower, in confidence, to the end of August 2012. 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.

Additionally, 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 existing 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 2010 Application.

SaskPower has recently undertaken a review of the Cost of Service methodology which, when finalized, will likely be used in the next general rate application. The Cost of Service Methodology review is expected to be completed early in 2013.

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 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 several interested parties, as well as submissions made by the public at meetings or through various other exchanges.

A detailed list of documents used by Forkast in this review is attached as Appendix 1 to this Report.

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 are detailed in Section 16.

The following is a summary of Forkast's recommendations submitted to the Panel.

1. That the 2013 revenue requirements based on updated load data, including reduced natural gas costs and all other factors submitted in the Application as updated in the Mid Application Update be approved subject to the following:

a) That the revenue requirement be set to allow SaskPower to generate sufficient revenues to earn the 6.4% Rate of Return estimated to produce a 2013 net income of $126.1 million.

b) That the September 2012 Mid-Application forecast cost of Gas of $4.00/GJ be used for purposes of setting 2013 rates for an estimated consumption of 43.6 million GJ. In summary, we recommend that the Panel accept a 2013 F&PP cost of $545.1 million.

c) That the total forecasted costs of $363.0 million for depreciation and amortization expense are considered to be justified and reasonable.

d) That the forecasted total net finance charges for 2013 of $303.3 million be considered justified and reasonable.

e) That the Return on Equity and Overall Rate of Return be accepted at 6.4%.

f) That the Municipal Tax, Corporate and Other Taxes Obligations of $53.5 million are considered to be just and reasonable.

g) That the Other costs of $ 9.0 million be considered just and reasonable.

In reviewing the most recent financial updates provided by SaskPower, we note that the 2013 net income is now expected to be less than the $165.9 million estimated in the original application (currently forecasted to be $126.1 million) and would yield an ROE of 6.4%, less than the Application's target of 8.5 %, if the requested overall average 5.0% is accepted. Under Section E, subsection (iii) of the Terms of Reference the Panel is required to provide SaskPower an opportunity to generate a return on equity of 8.5%.

However, as noted in Section 6.9.1 SaskPower's return on equity over the last three years together with the expected returns in 2012 and 2013, will average in excess of 9.0%, which is greater than the target of 8.5%. On the basis of the foregoing, we are satisfied with the current Mid-Application's forecasted ROE of 6.4%. While this rate is less than the target specified in the Terms of Reference, it is our opinion that it meets the spirit of the target in that for the five year period ending in 2013 the overall return is or is expected to be greater than the specified target of 8.5%.

As evidenced in SaskPower’s Application, due diligence has been undertaken to vet out efficiencies and cost effectiveness in the Corporation and to mitigate the anticipated progression of increases in future operating costs, given, the projected economic growth of the province and the need for additional and refurbished infrastructure to accommodate the increased energy demands. We consider that the various initiatives have demonstrated a serious and fundamental commitment by all managers within the Corporation to formulate, implement and track effective and measureable cost control, productivity and efficiency targets for all program components.

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

We find that SaskPower’s approach on fuel dispatch is reasonable, certainly acceptable within industry norms, and conclude their system operation from a fuel dispatch perspective is appropriate and should be continued.

We are of the view that SaskPower’s methodology of forecasting numbers of customers’ results is reasonable account estimates, considering Saskatchewan’s projected economic performance relative to the rest of Canada, and most recently in light of the economic uncertainty, nationally and internationally. The methodology has been reviewed by an external consultant who has agreed with SaskPower’s forecasting process, with some “fine tuning” recommendations which have been incorporated by SaskPower in this Application. As well, our analysis of variances between forecast and actual accounts suggests an acceptable degree of forecasting account accuracy, especially in this unsettled economic climate.

We consider that the 2013 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. We also consider that the overall impact of the updates provided by SaskPower will have no impact on the methodology and Class allocation results relative to the Application, albeit the accrual allocation of dollars will differ.

Going forward, we recognize the significant capital program and the pressures these investments in infrastructure will put on the revenue requirements to fund the depreciation and interest costs alone. This coupled with other increased cost pressures suggests there will be significant upward pressure of consumer’s rates for the foreseeable future.

TABLE OF CONTENTS

1.0 INTRODUCTION 10

1.1 Terms of Reference 10

1.2 Changes in Terms of Reference 11

1.3 Conduct of Review 12

2.0 SASKPOWER 2013 GENERAL RATE APPLICATION 14

2.1 Background, Governance and Historical Rate Changes 14

2.2 Application Financial Requirements and Impacts 15

2.3 September Mid-Application Update 20

3.0 LOAD FORECASTS AND DEMAND SIDE MANAGEMENT 23

3.1 2013 Load Forecasts 23
- 3.1.1 General Methodology 23
- 3.1.2 Economic Indicators and Forecasts 25
- 3.1.3 Annual Energy and Peak Load Forecast Methodology 26
- 3.1.4 Projected Annual and Peak Day Requirements 30
- 3.1.5 High-Low Scenarios 31
- 3.1.6 SaskPower Energy Sales History and 2013 Forecast 32
- 3.1.7 Current Resource Use Strategy 32
- 3.1.8 Far North Resources Supply Plan 36
- 3.1.9 40 Year Resource Supply Plan 38
- 3.1.10 Observations 41

3.2 Demand Side Management 42
- 3.2.1 Programs 42
- 3.2.2 Observations 44

4.0 INTERNATIONAL FINANCIAL REPORTING STANDARDS 45

4.1 Transition from Canadian GAAP 45

4.2 Observations 48

5.0 2013 APPLICATION REVENUES 49

5.1 Revenue Forecasts....................49

5.2 Domestic Sales....................51

5.3 Export Revenue....................51

5.4 Electricity Trading....................51

5.5 Ancillary Revenue....................52

5.6 Observations....................52

6.0 EXPENDITURE FORECASTS....................53
6.0.1 Operating Expenditure Summary....................53
6.1.1 Fuel & Purchase Power (F&PP) & Electricity Trading Costs....................55
6.1.2 Observations....................58
6.2.1 Operating, Maintenance & Administration (OM&A) Costs....................62
6.2.2 Demand Side Management....................70
6.2.3 New Operating Initiatives....................72
6.2.4 Observations....................74
6.3.1 Efficiency and Effectiveness....................75
6.3.2 Observations....................80
6.4.1 Depreciation and Amortization....................82
6.4.2 Observations....................85
6.5.1 Finance Charges....................86
6.5.2 Observations....................88
6.6.1 Debt Obligations....................88
6.6.2 Observations....................91
6.7.1 Foreign Exchange....................92
6.7.2 Observations....................92
6.8.1 Capital Program Operating Expenses and Capital Structure....................92
6.8.2 Observations....................94
6.9.1 Return on Equity, Rate Base and Overall Rate of Return....................94
6.9.2 Observations....................97
6.10.1 Municipal, Corporate and Other Tax Obligations....................98
6.10.2 Observations....................100
6.11.1 NorthPoint Energy Solutions....................100
6.11.2 Observations....................102
6.12.1 Affiliated Company Transactions....................102
6.12.2 Observations....................103
6.13.1 Other Costs....................103
6.13.2 Observations....................106
6.14.1 Future Financial Outlook....................106
6.14.2 Observations....................108

7.0 SYSTEM OPERATIONS 111

7.1 System Description 111

7.2 System Generation Capacity and Purchased Power 111

7.3 System Dispatch Rules 113

7.4 Observations 114

8.0 SASKPOWER HISTORIC AND 2013 CAPITAL PROGRAM 116

8.1 Purpose and Capital Budgeting 116

8.2 Infrastructure Capital Spending 118

8.3 New Generation Expenditures 118

8.4 Planned Maintenance, Life Extensions and Shutdowns 119

8.5 Observations 119

9.0 ENVIRONMENTAL AND SUSTAINABILITY REPORT 121

9.1 Highlights 121

9.2 Observations 122

10.0 COST OF SERVICE 123

10.1 Introduction 123

10.2 COSS – General Purpose and Principles 124

10.3 Demand Charges 125

10.4 Energy Charge 126

10.5 Basic Monthly Charge 126

10.6 2013 Cost of Service Study 126

10.6.1 Functionalization 126

10.6.2 Classification 127

10.6.3 Allocation 129

10.7 2013 COSS Results and Updates 130

10.8 Observations 137

11.0 RATE DESIGN 142

11.1 Rate Design General 142

11.2 Revenue to Revenue Requirement Ratios (R/RR) 143

11.3 Meeting Revenue Requirement 145

11.4 Maximum Customer Increases 147

11.5 Rate Design Observations 147

12.0 HISTORICAL RATE COMPARISON SUMMARY 150

12.1 Other Jurisdiction's Rates 150

12.2 Historical Rate Changes 154

12.3 Observations 155

13.0 SENSITIVITY POTENTIAL IMPACTS 156

13.1 Discussion 156

13.2 Observations 157

14.0 CONFIDENTIALITY AND TRANSPARENCY 158

15.0 PUBLIC AND STAKEHOLDER SUBMISSIONS 160

15.1 Consumer Association of Saskatchewan (CASK) 160

15.2 City of Saskatoon - Saskatoon Light and Power (SL&P) 161

15.3 Greater Saskatoon Chamber of Commerce 162

15.4 City of Swift Current - Light and Power 162

15.5 Paper Excellence 163

15.6 Canadian Association of Petroleum Producers (CAPP) 164

15.7 Saskatchewan Industrial Energy Consumers Association (SIECA) 165

15.8 Saskatchewan Mining Association (SMA) 166

15.9 Public Participation 167

16.0 RECOMMENDATIONS AND COMMENTARY 168

17.0 ACKNOWLEDGMENTS....................174

APPENDIX 1 DOCUMENTS PROVIDED DURING THE REVIEW 175

1.0 Introduction

1.1 Terms of Reference

On July 10, 2012 the Minister responsible for Saskatchewan's Crown Investments Corporation released the Terms of Reference for SaskPower's 2013 Rate Application to the Saskatchewan Rate Review Panel. The Panel, a Ministerial Advisory Committee, was appointed by the Minister on January 1, 2010 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, 2013. It should be 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, 2010. Specifically with respect to this Application, the Panel is to provide an opinion of the fairness and reasonableness of SaskPower's 2013 proposed rate change 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 the proposed 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 delivery cost of service for 2013, 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 delivery cost of service.

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

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

i. the current rate structure, with the final rate change to be applied uniformly to all customer classes (except the Power - Contract Rate class) and all components (basic charge, energy charge and demand charge) of the rate;
ii. the budgeted capital allocation, the rate base and established corporate policies;
iii. the proposed 2013 Return on Equity target of 8.5%;
iv. the existing service levels;
v. any existing supply contracts; and
vi. 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 fulfilling its mandate and the terms of reference.

SaskPower is to provide the Panel with a mid-application review update once SaskPower's 2013 Business Plan has been completed, which is targeted for September 2012.

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

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 provide SaskPower with factual information as well as the consultant's observations.

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 D), 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 electricity rate change request to the Minister of Crown Investments and the Minister responsible for SaskPower no later than Monday, November 19, 2012. 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 for the Panel’s review of SaskPower’s 2013 Rate Application were revised from those issued for SaskPower’s last (2010) Rate Adjustment Application review.

The 2010 terms asked the Panel to consider the rationale and proposed methodology associated with introducing a fuel cost variance account (FCVA) as a mechanism to track and potentially settle up any differences between forecasted fuel costs and actual fuel costs. This matter is not included for the current review, as the matter of a FCVA is currently being reviewed by an external consultant retained by SaskPower, and a report is expected to be prepared in the fall of 2012.

The 2012 terms also did not require an impact assessment of rate redesign as a consequence of undertaking cost of service methodology adjustments. This Application directs the Panel to consider, as a given, a uniform rate increase for all customer classes as discussed below. As well, the cost of service methodology remains unchanged from that used in the 2010 review. Currently the Cost of Service Methodology is being examined by an external consultant retained by SaskPower, the report of which is expected to be prepared in the fall of 2012.

Additions to the current terms of reference that were not part of the 2010 terms included:

- SaskPower to provide the Panel with its application package immediately and any supplementary information as may be required.
- SaskPower to provide the Panel with a mid-application review update once it's 2013 Business Plan was completed.
- The Panel to provide SaskPower the opportunity to make a presentation to it and to the public as they considered appropriate.
- The Panel to provide SaskPower the opportunity and reasonable time to review the technical consultant's preliminary report including observations prior to its finalization.

The current terms also directed that the final rate increase of 5.0% was to be applied uniformly 4.9% to all customer classes (except the Power - Contract Rate class where a 6.1% rate increase was to be applied) and for all rate components (basic charge, energy charge and demand charge) of the rate. Lastly, the Return on Equity target was increased from 7.4% in 2010 (which was specifically reduced in that year from the longer term ROE of 8.5%) back to 8.5% for 2013. All other terms remained unchanged from 2010.

1.3 Conduct of Review

In order to complete this review 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 138 information requests (IRs) in the first round, 55 in the second round, and 7 supplemental information requests related to the Mid-Application update on its own and/or on the Panel's behalf. 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 comments submitted by corporations and individuals at the public hearings, by phone or electronically and these 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.

The main activities conducted by Forkast as part of its independent review were as follows:

- Carried out a comprehensive review of SaskPower's 2013 Rate Application.
- Participated in SaskPower's Application overview presentation to the Panel on July 19, 2012.
- Met with the Panel on July 19, 2012 to discuss process schedules, preliminary impressions, issues and potential concerns.
- Developed and submitted 138 first round Information Requests for SaskPower on July 26, 2012.
- Reviewed responses to first round Information Requests received on August 17, 2012.
- Met with SaskPower Executive and staff as well as the Panel Chair on September 10 and 11, 2012 to review SaskPower's responses to the first round of questions and receive additional information.
- Received Mid-Application update on September 14, 2012 and started the update review.
- Developed and submitted 55 second round Information Requests for SaskPower on September 14, 2012.
- Attended a meeting with the Panel, Stakeholders and the Public on September 19, 2012 at which SaskPower made a presentation and responded to questions.
- Met with the Panel on September 20, 2012 to discuss impressions, issues and potential concerns.
- Submitted supplemental information requests relative to Mid-Application update on September 21, 2012.
- Reviewed and analyzed responses to second round Information Requests received on September 21, 2012.
- Attended a presentation by SaskPower respecting the AMI project status in Regina on October 17, 2012.
- Met with the Panel in Regina to discuss the Application, Application update and initial observations on October 17, 2012.
- Participated in a conference call with the Panel to discuss IRs and final positions October 28th, 2012.
- Prepared and submitted an abridged Draft Report to SaskPower to review for factual accuracy and correct data interpretation on October 31, 2012.
- Submitted Draft Report to Panel on November 2, 2012.
- Participated in a conference with the Panel to review Draft Report on November 7, 2012.
- The Final Forkast Report was submitted to the Panel on November 8, 2012.

2.0 SaskPower 2013 General Rate Application

2.1 Background, Governance and Historical Rate Changes

SaskPower 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 some eighty years since it first commenced its operation in 1929. That 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 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. 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 provide electricity reliably and safely. 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. In turn, the SaskPower Board is responsible to the Board of Directors of the Crown holding company, Crown Investments Corporation of Saskatchewan (CIC). The CIC Board is composed of Cabinet ministers and is also appointed by the Government of Saskatchewan. The CIC Board is responsible to Cabinet.

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 over 490,000 customers in 2013. This is an increase of approximately 17,000 customers from 2010. SaskPower's customers are dispersed over approximately 651,000 square kilometers. SaskPower manages over $6.3 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. The transmission grid is made up over of 12,576 km of power lines and 55 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 139,390 km of power lines, 186 distribution centres and approximately 155,000 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 3,513 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 Red Lily and SunBridge Wind Power Facilities, Spy Hill Generation Station, the Meridian and Cory Cogeneration stations and NRGreen heat recovery facilities at Kerrobert, Loreburn, Estlin and Alameda. At the end of 2011, SaskPower's total available generation and purchase power available capacity was 4,094 MW including 581 MW of purchase power.

SaskPower continues to expand its generation facilities to support its growing customer base. Expansions to facilities such as the Boundary Dam Power Station Unit # 3 with its Carbon Capture and Storage (CCS) facility, the Queen Elizabeth Power Station and its three new natural gas turbines and six steam generations will support power generation in an environmentally responsible way. Additionally, SaskPower expands its transmission and distribution facilities as necessary to attach new customers and rehabilitates aged facilities, 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 on August 1, 2010 when a system average increase of 4.5% was implemented.

2.2 Application Financial Requirements and Impacts

Should the application for a 5.0% overall system average increase, consisting of a 6.1% increase for the Power - Contract Rate Class and a 4.9% increase for all other customer classes be implemented, the additional 2013 revenue generated would be $90.8 million, resulting in a forecasted return on equity of 8.5%. This was revised in the application update as discussed later, so that the projected ROE for 2013 is now forecasted to be 6.4% and revenue to be generated by the rate application is forecasted to be $ 89.2 million.

For each of the customer classes with a majority of all accounts (474,503 of 495,031 total accounts or 95.9% of total) the breakdown on an average rate increase in dollars per month in 2013 would be:

- $4 per month for an urban residential (300,684 accounts – 60.7%) and $6 per month for a rural residential customer (55,835 accounts – 11.3%);
- $10 per month for a farm customer (62,245 accounts – 12.6%); and
- $25 per month for a commercial customer (55,739 accounts – 11.3%).

These increases exclude municipal surcharges and taxes.

SaskPower's original application estimated that without the requested increase in rates, the 2013 net income would be $74 million and the return on equity would be reduced to 3.9%. The Mid-Application update and revised forecasts now suggest that the return on equity without the proposed rate increase would result in net income of $36.9 million and a ROE of 1.9%.

In its original Application, SaskPower requested a 5.0% overall system rate increase to be effective on January 1, 2013, that would have raised revenues by $90.8 resulting in a net income of $165.9 million for all of 2013. The Mid-Application Update revised (with the proposed rate increase) the incremental 2013 revenue to $2,015.2 million with a net income of $126.1 million, as shown on the table below.

Table 2.1 - SaskPower Consolidated Income Statement for 2010 to 2013

SaskPower Consolidated Statement of Income (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Revenue												
Saskatchewan	1,605.0	1,575.0	(30.0)	1,678.8	1,666.8	(12.0)	1,683.9	1,697.8	13.9	1,913.8	1,874.1	(39.7)
Export	28.0	12.0	(16.0)	23.0	40.3	17.3	27.3	23.7	(3.6)	22.2	27.5	5.3
Net Sales from Trading	18.0	1.0	(17.0)	5.3	13.9	8.6	15.8	17.0	1.2	11.5	12.0	0.5
Other	112.0	163.0	51.0	108.0	116.6	8.6	112.1	109.2	(2.9)	101.4	101.6	0.2
Total Revenue	**1,763.0**	**1,751.0**	**(12.0)**	**1,815.1**	**1,837.6**	**22.5**	**1,839.1**	**1,847.7**	**8.6**	**2,048.9**	**2,015.2**	**(33.7)**
Expense												
Fuel	559.0	511.0	(48.0)	484.3	485.4	1.1	502.8	494.5	(8.3)	563.1	545.1	(18.0)
OM&A	611.0	641.0	30.0	563.5	575.1	11.6	582.3	603.3	21.0	627.0	615.2	(11.8)
Depreciation	271.0	258.0	(13.0)	297.5	289.7	(7.8)	321.2	321.2	0.0	354.2	363.0	8.8
Finance Charges	150.0	139.0	(11.0)	202.5	197.5	(5.0)	215.5	202.1	(13.4)	273.7	303.3	29.6
Taxes	46.0	42.0	(4.0)	45.3	43.4	(1.9)	48.0	47.5	(0.5)	56.0	53.5	(2.5)
Other	0.0	0.0	0.0	6.2	7.7	1.5	9.6	13.2	3.6	9.0	9.0	0.0
Total Expense	**1,637.0**	**1,591.0**	**(46.0)**	**1,599.3**	**1,598.8**	**(0.5)**	**1,679.4**	**1,681.8**	**2.4**	**1,883.0**	**1,889.1**	**6.1**
Operating Income	**126.0**	**179.0**	**53.0**	**215.8**	**238.8**	**23.0**	**159.7**	**165.9**	**6.2**	**165.9**	**126.1**	**(39.8)**
Unrealized Market Value Adjustment	0.0	19.0	19.0	25.4	9.3	(16.1)	(31.5)	12.2	43.7	0.0	0.0	0.0
Net Income	**126.0**	**160.0**	**34.0**	**241.2**	**248.1**	**6.9**	**128.2**	**178.1**	**49.9**	**165.9**	**126.1**	**(39.8)**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

The following table shows SaskPower's 2010 and 2011 estimated and actual revenues, as well as 2012 and 2013 Application and Mid-Application revenues.

Table 2.2 - SaskPower Consolidated Revenues for 2010 to 2013

SaskPower Consolidated Revenues (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Saskatchewan Sales												
Residential	n/a	382.0	n/a	400.9	407.3	6.4	388.3	395.5	7.2	403.0	409.2	6.2
Farm	n/a	141.0	n/a	145.3	144.9	(0.4)	142.3	137.5	(4.8)	143.4	148.5	5.1
Commercial	n/a	339.0	n/a	356.3	355.5	(0.8)	351.0	355.0	4.0	352.4	354.9	2.5
Oilfields	n/a	234.0	n/a	249.4	241.6	(7.8)	265.6	271.5	5.9	281.6	291.0	9.4
Power Customers	n/a	404.0	n/a	449.1	440.3	(8.8)	459.2	461.3	2.1	563.5	503.3	(60.2)
Reseller	n/a	75.0	n/a	77.6	77.2	(0.4)	77.6	77.1	(0.5)	79.1	78.0	(1.1)
Sales Before Rate Increase	**n/a**	**1,575.0**	**n/a**	**1,678.8**	**1,666.8**	**(12.0)**	**1,684.0**	**1,697.9**	**13.9**	**1,823.0**	**1,784.9**	**(38.1)**
Revenue Rate Increase Lift	n/a	0.0	n/a	0.0	0.0	0.0	0.0	0.0	0.0	90.8	89.2	(1.6)
Total Saskatchewan Sales	**1,605.0**	**1,575.0**	**(30.0)**	**1,678.8**	**1,666.8**	**(12.0)**	**1,684.0**	**1,697.9**	**13.9**	**1,913.8**	**1,874.1**	**(39.7)**
SaskPower Export	28.0	12.0	(16.0)	23.0	40.3	17.3	27.4	23.7	(3.7)	22.2	27.5	5.3
Total SaskPower Sales	**1,633.0**	**1,587.0**	**(46.0)**	**1,701.8**	**1,707.1**	**5.3**	**1,711.4**	**1,721.6**	**10.2**	**1,936.0**	**1,901.6**	**(34.4)**
Net Sales from Trading	18.0	1.0	(17.0)	5.3	13.9	8.6	15.8	17.0	1.2	11.5	12.0	0.5
Other Revenue												
Gas & Elect Inspection	n/a	n/a	n/a	13.2	14.2	1.0	14.4	14.4	0.0	14.7	14.7	0.0
Customer Connects	n/a	n/a	n/a	47.9	55.6	7.7	49.9	47.1	(2.8)	41.8	41.8	0.0
Miscellaneous Revenue	n/a	n/a	n/a	37.8	35.7	(2.1)	39.6	38.4	(1.2)	37.5	37.0	(0.5)
Cory & MRM Equity Invest	n/a	n/a	n/a	9.1	11.1	2.0	8.2	9.2	1.0	7.4	8.1	0.7
Total Other Revenue	**112.0**	**163.0**	**51.0**	**108.0**	**116.6**	**8.6**	**112.0**	**109.1**	**(2.9)**	**101.4**	**101.6**	**0.2**
Total Revenue	**1,763.0**	**1,751.0**	**(12.0)**	**1,815.1**	**1,837.6**	**22.5**	**1,839.2**	**1,847.7**	**8.5**	**2,048.9**	**2,015.2**	**(33.7)**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

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 2010 to 2011, as well as projections for 2012 and 2013.

Table 2.3 - SaskPower Consolidated Expenses for 2010 to 2013

SaskPower Expenses (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Expense												
Fuel	559.0	511.0	(48.0)	484.3	485.4	1.1	502.8	494.5	(8.3)	563.1	545.1	(18.0)
OM&A	611.0	641.0	30.0	563.5	575.1	11.6	582.3	603.3	21.0	627.0	615.2	(11.8)
Depreciation	271.0	258.0	(13.0)	297.5	289.7	(7.8)	321.2	321.2	0.0	354.2	363.0	8.8
Finance Charges	150.0	139.0	(11.0)	202.5	197.5	(5.0)	215.5	202.1	(13.4)	273.7	303.3	29.6
Taxes	46.0	42.0	(4.0)	45.3	43.4	(1.9)	48.0	47.5	(0.5)	56.0	53.5	(2.5)
Other	0.0	0.0	0.0	6.2	7.7	1.5	9.6	13.2	3.6	9.0	9.0	0.0
Total Expense	**1,637.0**	**1,591.0**	**(46.0)**	**1,599.3**	**1,598.8**	**(0.5)**	**1,679.4**	**1,681.8**	**2.4**	**1,883.0**	**1,889.1**	**6.1**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

The impact of the proposed overall system average increase of 5.0% on each customer class and the change in Revenue to Revenue Requirement (R/RR) ratios is illustrated below:

Table 2.4 - 2013 Rate Changes & R/RR Ratios (Original Application)

Year 2013 Rate Change & R/RR Ratios
5.0% General Rate Increase Rate With No Rebalancing Maintenance

Class of Service	2013 R/RR Ratio (Existing Rates)	2013 Rate Change	2013 R/RR Ratio (Revised Rates)
Urban Residential	0.96	4.9%	0.96
Rural Residential	0.95	4.9%	0.95
Total Residential	**0.96**	**4.9%**	**0.96**
Farms	0.96	4.9%	0.96
Urban Commercial	0.99	4.9%	0.99
Rural Commercial	0.97	4.9%	0.96
Total Commercial	**0.98**	**4.9%**	**0.98**
Power - Published Rates	1.03	4.9%	1.04
Power - Contract Rates	0.98	6.1%	1.00
Total Power	**1.02**	**5.1%**	**1.03**
Oilfields	1.05	4.9%	1.05
Streetlights	1.00	4.9%	0.99
Reseller	1.02	4.9%	1.03
Total (System)	**1.00**	**5.0%**	**1.00**

Table 2.5 - 2013 Rate Changes & R/RR Ratios (Updated Application)

Year 2013 Rate Change & R/RR Ratios
5.0% General Rate Increase With No Rebalancing Maintenance

Class of Service	2013 R/RR Ratio (Existing Rates)	2013 Rate Change	2013 R/RR Ratio (Revised Rates)
Urban Residential	0.97	4.9%	0.97
Rural Residential	0.97	4.9%	0.96
Total Residential	**0.97**	**4.9%**	**0.97**
Farms	0.97	4.9%	0.97
Urban Commercial	0.98	4.9%	0.98
Rural Commercial	1.01	4.9%	1.00
Total Commercial	**0.99**	**4.9%**	**0.98**
Power - Published Rates	1.02	4.9%	1.03
Power - Contract Rates	0.97	6.3%	0.99
Total Power	**1.01**	**5.2%**	**1.02**
Oilfields	1.05	4.9%	1.05
Streetlights	1.01	4.9%	1.00
Reseller	1.00	4.9%	1.01
Total (System)	**1.00**	**5.0%**	**1.00**

2.3 September Mid-Application Update

On September 14, 2012 SaskPower provided an update to the original Application based on June 30, 2012 forecasts. Updated figures were provided for Net Income, Revenues, Net Fuel and Purchased Power, Operations, Maintenance and Administration (OM&A) Expenses, Depreciation, Finance Charges, Taxes, Gains and Unrealized Market Value Adjustments.

The updated forecasts indicate that the net income will be $126.1 million rather than the $165.9 million originally forecast, a decrease of $39.8 million. However, SaskPower has not requested any change to the originally proposed 5.0% overall system average increase. The newly forecasted financial position, in conjunction with the 5.0% rate increase, would result in a ROE of 6.4%, rather than the ROE target and original forecast of 8.5%. Without the rate increase proposed for January 1, 2013, the forecasted ROE would be reduced to 1.9% with a net income of $36.9 million.

The economic assumptions used in the Mid-Application update were:

Inflation rate:	2.0%
Short-term borrowing rate:	1.2%
Long-term interest rate:	3.4%
Wages and salaries increase:	2.0%
Hedged SaskPower natural gas price:	$4.00/GJ

2012 Revenue & Expense Variances

Revenues

- Total forecasted revenues for 2012 increased from $1,839.1 million to $1,847.7 million, an overall increase of $8.6 million.
- Saskatchewan sales were up $13.9 million due to higher projected sales from residential ($7.2 million), commercial ($4.0 million) and oilfields ($5.9 million), resulting from improved second quarter performance. Revenue from power customers also increased by $2.1 million, mainly attributable to higher demand from the potash sector. These favourable variances were offset by lower sales to farm ($4.8 million) and reseller ($0.5 million) customers.
- Export revenues dropped $3.7 million and net sales from trading grew $1.2 million.
- Other revenue went down by $2.9 million due to lower customer connect revenues.

Expenses

- Fuel and Purchased Power costs were revised down from $502.8 million to $494.5 million, an overall decline of $8.3 million due to:
    - $12.8 million unfavourable price variance, due entirely to the price of natural gas/GWh increasing from $38.66 to $41.36.
    - $2.8 million favourable volume variance, due to total generation declining.
    - $18.3 million favourable mix variance, due to increased hydro volumes of 580 GWh offsetting reduced gas volumes of 505 GWh.
- OM&A costs were revised up from $582.3 million to $603.3 million, an overall increase of $21 million, the majority of which was due to damage caused by storm and high wind activity. The total cost associated with this activity was $15 million.
- Depreciation remained unchanged.

- Finance charges decreased from $215.5 million to $202.1 million, an overall decline of $13.4 million.
- Taxes went down from $48.0 million to $47.5 million, an overall decline of $0.5 million.
- Other expenses went up from $9.6 million to $13.2 million, an overall increase of $3.6 million.

2013 Revenue & Expense Variances

Revenues

- Total forecasted revenues for 2013 declined from $2,048.9 million to $2,015.2 million, an overall decrease of $33.7 million.
- Saskatchewan sales were down $39.7 million due primarily to lower projected sales in power customers ($60.2 million). Reseller revenue was also reduced by $1.1 million. These unfavourable variances were offset by increased sales to residential ($6.2 million), farm ($5.1 million), commercial ($2.5 million) and oilfields ($9.4 million).
- Export revenues are expected to increase by $5.3 million while net sales from trading are expected to increase by $0.5 million due to increased optimism of Alberta sales.

Expenses

- Total forecasted expenses for 2013 increased from $1,883.0 million to $1,889.1 million, an overall increase of $6.1 million.
- Fuel and Purchased Power costs were revised down from $563.1 million to $545.1 million, an overall decline of $18.0 million due to:
    - $5.1 million unfavourable price variance due to higher costs for natural gas ($0.68/GWh), hydro ($0.38/GWh) and wind/other ($4.44/GWh), which were partially offset by lower prices for coal ($0.23/GWh) and imports ($8.41/GWh).
    - $16.2 million favourable volume variance due to total generation (primarily from natural gas sources) declining.
    - $6.8 million favourable mix variance due to hydro generation increasing from 13.7% to 14.2% and gas generation dropping from 32.2% to 30.7%.
- OM&A expenses were down $11.8 million, due to pension expense being reclassified as part of finance charges.
- Depreciation expense was up $8.8 million due solely to increased capital lease amortization relating to the North Battleford Energy Center (NBEC).
- Finance charges were up $29.6 million, due primarily to higher interest costs on capital leases due to NBEC ($27.9 million) and the re-allocation of pension expense ($11.8 million). Lower interest on long-term debt ($10.1 million) partially offset this increase.
- Taxes went down $2.5 million.

R/RR Ratio Variances

There are two financial changes which impacted R/RR ratios:

1. Increased generation and transmission costs which decreased the R/RR ratios for large Power and Reseller customers and increased the R/RR ratios for all other customers.

2. Increased demand related costs which decreased the R/RR ratios for Residential, Farm, Commercial and Reseller customers, which have low coincident peak load factors, and

increased the R/RR ratios for Power and Oilfield customers, which have high coincident peak load factors.

3.0 Load Forecasts and Demand Side Management

3.1 2013 Load Forecasts

3.1.1 General Methodology

SaskPower establishes its rates on a prospective basis by forecasting customer demand and then estimating required costs to meet that demand or load. Forecasting provides SaskPower with the basis for determining demand expectations. Forecasting begins in January of each year and takes into account a number of factors such as:

- Information provided by industrial customers;
- Economic variables from the provincial economic model (i.e. GDP, population, households, and commercial data) provide the primary input to the forecasting models;
- Weather normalization to determine historic energy requirements and peak demands under normal weather conditions;
- Residential and commercial end-use data; and
- Historical load data.

There are many variables that can affect load forecasting. The most significant are those obtained from key accounts. Key accounts are considered to be large-scale industrial and commercial customers. Their forecast information is vital as industrial 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. The most recent forecast does not assume a significant change.

SaskPower conducts an external review of its load forecasting methodology approximately every five years. An external review of SaskPower's methodology, as recommended in the previous Panel Report, was completed in October 2010 by Itron Inc., an industry leader in load forecasting software and a regular provider of load forecasting workshops. Itron verified SaskPower’s methodology using their own forecasting expertise as well as an in depth industry survey. The industry survey reviewed load forecasting processes for 3 Canadian and 6 U.S. Companies. Itron provided the following recommendations for enhancements to SaskPower’s methodology:

> 1) Use three years of data in SaskPower's weather normalization models and revise the heating degree day (HDD) and cooling degree day (CDD) variables to a base of 10 degrees Celsius instead of 18 degrees Celsius.
>
> This work was completed and incorporated into the 2012 and 2013 forecasts. In addition, SaskPower was also able to undertake weather normalization on a class by class basis using customer class load shapes developed from Saskatchewan load research. This advancement provides a more accurate distribution of the weather normalization for the total system back to the individual customer classes.
>
> 2) Update SaskPower's residential end use models with the 2010 residential end use survey data provided by the Demand Side Management department. This work was completed and incorporated into the 2012 forecast.

3) Add an employment component to the commercial GDP drivers used to determine the energy growth rate for the commercial class.

This recommendation was not implemented, as SaskPower believes the employment component is already included in the commercial drivers used to develop the commercial load forecast.

4) Use industry forecasts, if available, as a check on customer supplied forecasts for the Power class.

This recommendation was modified and implemented. SaskPower has access to only one industry forecast applicable to the Power class, which is for potash production and not suitable for long term planning needs. The modification to this recommendation was for SaskPower to meet with Energy & Resources staff at least once per year to review its assumptions on the in service date of expansions at existing potash mines and potential Greenfield mines. SaskPower's assumptions regarding northern mining customers are also reviewed at these meetings.

The load data in the application for 2011 is actual data. The load data for the 2012 forecast is a combination of 2 or 3 months of actual data and the remaining months of normalized data. The load data for the 2013 forecast is weather normalized.

The 2011 Q2 DSM adjusted forecast was used for the original load estimates for 2012 and 2013, as well as the cost of service modeling for 2013. The estimates and model were updated in September using SaskPower's recently completed 2012 Q2 DSM adjusted forecast. It should also be noted that the first 3 months of 2012 were unusually warm and loads were down in some classes due to the reduction in heating loads. Also, the 2012 data includes adjustments to the Power Class as of the end of March 2012. An example of such an adjustment is for the potash market 2013 load forecast reduction from the first quarter of 2012 and delays to other anticipated expansion projects.

SaskPower continues to define normal weather as the average daily weather conditions as calculated from the most recent 30 year period, unchanged from previous years. The 30 year period was specifically addressed in the 2010 review of SaskPower's load forecasting methodology. Itron recommended that SaskPower continue with the 30 year average based on consistency with common industry practice. The weather normalization survey which was done in conjunction with the methodology review showed 47% of respondents use at least 30 years of history from which to compute normal weather.

Major inputs into the forecasting methodology include the Corporate and Financial Services economic forecast and normalized weather. The economic forecast supplies information related to population, household growth, and GDP growth rates for residential, commercial and farm classes. SaskPower and the Ministry of Finance use the same economic model for forecasting growth, including customer class forecasts to ensure consistency and to help facilitate a common approach. As weather has a significant impact on SaskPower's operations, historical daily averages of weather conditions for the past thirty years are assumed throughout the forecast horizon.

Additionally, in response to a previous Panel recommendation, adopted by the Minister, SaskPower has conducted internal load research by installing real time meters on a random basis for its Residential, Farm, Commercial and Oilfield Customer Classes. Results of this research are currently being evaluated and SaskPower may incorporate the results into the next Rate Application.

3.1.2 Economic Indicators and Forecasts

The Conference Board of Canada has published its Provincial Outlook Winter 2012 Economic Forecast. This report examines the economic outlook of the provinces in terms of GDP, industry output, and labour market conditions.

Economic Indicators

The volatile global economic environment continues to generate much uncertainty when it comes to Canada's near-term forecast. While the US economy continues to expand and create jobs, the ongoing sovereign debt problems in Europe threaten to disrupt global economic activity and hamper Canada's trade flows.

Canadian government spending restraints will stifle domestic demand in 2012. A decline in public infrastructure investment is expected to remove approximately $4.6 billion from real GDP in 2012. However, strong resource prices, a relatively stable domestic economy, low financing rates, and an elevated Canadian dollar should help convince businesses to continue boosting capital investment in 2012 despite the volatile external environment. Overall, the challenges facing households, government, and business suggest a weaker performance by Canada's domestic economy this year. Real GDP growth is anticipated to fall to 2.1% in 2012 while growth of 2.9% is expected in 2013 with the help of a strong US performance.

Stronger economic fundamentals and a fast-expanding mining sector have made Western Canada a destination of choice. The flood of migration to the Prairie Provinces and BC, influenced by strong commodity prices, has tipped the population balance. Despite this, labour shortages are resurfacing and could impact near-term growth. Regardless, the economic outlook for Western Canada remains very positive. Real GDP growth is forecasted to be a full percentage point stronger than the rest of the country this year and next. Ontario and Quebec are expected to experience soft economic growth in 2012 while Atlantic Canada is facing modest near-term economic prospects.

Economic Outlook - Saskatchewan

The boost recently provided to Saskatchewan's economy by booming potash production will be interrupted. The uncertain global economic outlook will temporarily weaken that demand. Real GDP growth in the province is expected to be 2.6% in 2012, half of the 5.2% reported in 2011. A rebound in potash mining and a healthy domestic economy should produce a 3.5% gain in real GDP next year.

Saskatchewan continues to perform well despite the backdrop of a global slowdown and stabilizing commodity prices. The province runs a balanced budget, which means that public sector budget cuts will not weigh down bottom-line growth as much as in other provinces. Saskatchewan's sources of growth are wide spread, with the goods sector continuing to outperform the service sector. This trend is expected to go on during the forecast period.

Although the agriculture, construction, and utilities sectors will record moderate growth this year, they should pickup in 2013. Housing starts will be down, but still remain elevated. Mining and manufacturing will be some of the best performers in 2012 and again in 2013. Mining, specifically, continues to grow at a strong pace as driven by the mineral fuels sector. Also, strong non-residential business investment is expected to continue over the near term. This should result in productivity gains and stronger economic prospects in the future.

Labour markets will remain tight, with the unemployment rate averaging 4.6% this year. This should help boost real personal disposable income growth by 1.4% this year with a stronger performance expected next year for income gains. Income growth and a strong goods sector will lead to higher demand for services. However, services provided by the public sector will continue to lag as the provincial government remains committed to fiscal restraint.

3.1.3 Annual Energy and Peak Load Forecast Methodology

On January 18, 2012, a new peak load record of 3,265 megawatts (MW) was experienced by SaskPower. The previous record was established on December 14, 2009 at 3,231 MW. In 2011 a new all-time record for energy consumption in a single day of 69,456 MWh was set. Saskatchewan electricity sales volumes were 19,226 GWh in 2011, up 608 GWh or 3% compared to 2010. This rise in sales volumes was driven by the residential and major key account customer classes, which showed a combined increase of 513 GWh or 5% from the previous year. These milestones illustrate the importance for SaskPower to revitalize and reinforce its electrical system. Current peak load estimates for 2012 and 2013 are 3,591 MW and 3,695 MW, representing estimated peak load increases of 10% and 2.9% respectively. In those years energy consumption is expected to increase by 5.8% to 22,488 GWh in 2012 and by a further 3.3% to 23,238 GWh in 2013.

The following table indicates the actual electrical generation by source for the 24 hour period coincident with the peak day load requirements from 2005 to 2011.

Table 3.1 - Peak Day Generation by Fuel Source for 2005 to 2011

		Daily Generation in MWh by Fuel Source					
Year	Peak Date	Hydro	Coal	Gas	Import	Wind & Other	System Req.
2005	2005-01-13	10,239	37,061	15,018	400	74	62,791
2006	2006-11-29	9,523	32,645	17,136	1,257	2,700	63,260
2007	2007-02-01	10,690	37,373	13,212	76	3,741	65,092
2008	2008-12-15	10,435	35,872	16,224	3,943	2,001	68,475
2009	2009-12-14	8,692	38,928	15,618	2,319	3,119	68,675
2010	2010-12-12	8,556	39,626	12,449	2,604	3,213	66,447
2011	2011-01-12	9,999	39,105	16,420	800	3,132	69,456

The following table illustrates the actual and estimated annual fuel mix type by percentage for 2005 to 2013 inclusive.

Table 3.2 - Annual Fuel Mix Type for 2005 to 2013

Year	Hydro	Coal	Gas	Import	Wind & Other
2005	22.3%	56.0%	15.8%	5.5%	0.5%
2006	20.5%	56.3%	18.0%	2.3%	2.9%
2007	21.4%	56.7%	17.2%	1.5%	3.2%
2008	19.7%	55.7%	18.6%	2.9%	3.2%
2009	14.9%	62.0%	17.3%	2.2%	3.6%
2010	18.6%	58.0%	17.7%	2.5%	3.2%
2011	21.4%	53.8%	18.7%	2.3%	3.8%
2012	18.7%	53.0%	21.5%	3.0%	3.8%
2013	13.7%	49.1%	32.2%	1.4%	3.6%

Load growth over the next decade is expected to increase by 2.9% per year in system energy requirements. This would include all Saskatchewan sales, corporate energy use, and line losses. Also, an increase of 2.2% per year over that same period of time is expected for the system peak load (the highest level of demand placed on the system at any one time). This is in contrast with the 2001 to 2011 period where system energy requirements increased by an average of 1.8% 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. As noted above, SaskPower has incorporated 3 of the 4 Itron recommendations respecting load forecasting and weather normalization.

Power Accounts – Large Commercial or Industrial Customers

The Power account load forecasting is an aggregation of individual accounts for each customer. The approach to estimating loads for these accounts depends on and varies with the type of industry, as well as the data available for that industry and that customer. Methods or factors include energy forecasts supplied by SaskPower's Key Account Managers in consultation with the customer, consideration of production estimates, energy intensity (demand) levels, planned expansions, and planned maintenance schedules. By extrapolation of individual forecasts, the results include a base load and expansion load as necessary. Potash, Pipeline, Steel, Chemical, Refinery and Northern Mining industries are included in the Power Class. Pursuant to an Itron recommendation, SaskPower now meets with Energy & Resources staff at least once per year to review its assumptions on the in service date of expansions at existing potash mines and potential Greenfield mines. SaskPower's assumptions regarding northern mining customers are also reviewed at these meetings.

The Power Class typically has the largest variances each year. This is primarily due to market fluctuations (Potash & Natural Gas Prices) and individual customer planning - production interruptions / delays / cancellations.

Oilfield Accounts – Customers in individual oil and gas production, pumping and processing (6 Regions: Estevan Medium; Swift Current Medium; Kindersley Heavy; Lloydminster Heavy; Kindersley Light; and Estevan Light)

Oilfield customer production and the resulting energy requirements are heavily influenced by world markets and provincial royalty structures, which are prepared on an individual basis. Econometric, extrapolation and statistical regression methods are used to determine future load needs. The number of operating wells indicates customer numbers, while oil production and growth statistics provided by the Ministry of Energy & Resources, water production and energy intensity levels are used to determine energy needs. Other factors include capacity, available resources, and economic viability. Forecasts are validated by analyses of the correlation between price and production, comparisons of oil reserves to estimated production, and forecasted sales to historical usage from the Ministry and CAPP.

Commercial Accounts – Non-residential and Non-farm Customers not in any other category

Econometric, end use, extrapolation, and statistical regression methods are also used for these accounts. Customer growth is estimated by regression analysis on the GDP. Historical sales are separated into seven specific code categories and economic variables are used to estimate growth in each category. SaskPower's forecasts are weather normalized, and assume that the current customer base and market share will be maintained. Forecasts are validated by historical comparisons of weather normalized actual results to forecasts, as well as an annual analysis of economic variables.

Residential Accounts – Customers occupying residential premises, apartments, resort cottages, and domestic outbuildings (except those served by municipal utilities in Saskatoon and Swift Current)

As with the Commercial Accounts, econometric, end use, extrapolation and statistical regression methods are used for estimating loads for the residential class. The number of customers is determined by the household projections using economic forecast factors for population growth and residents per household. Households are split into apartments and single family units. Average use per customer is calculated based on household type, 24 end use market conditions and efficiency standards. Factors include appliance use and consider average hours of use, efficiency, penetration, and saturation rates obtained from outside agencies. Forecasts are validated by comparing historic actual energy use to forecast energy sales. SaskPower has updated its residential end use models to incorporate residential end use survey data provided by the Demand Side Management department, commencing with the 2012 forecast.

Farm Accounts – Customers with normal farm household and agricultural use and irrigation energy loads

The methodology used to forecast the requirements for the Farm Accounts is the same as that employed to forecast Residential Accounts energy requirements.

Reseller Account – Customers whose energy requirements are purchased in bulk from SaskPower and distributed by municipal utilities in Saskatoon and Swift Current, within specific defined franchise areas

SaskPower requests and receives individual load forecasts from its two reseller customers as they are believed to be in the best position to estimate load growth given their franchise constraints. These load forecasts come with a DSM component factored in from the reseller customers, and is reviewed by SaskPower, based on previous data and historical growth rates. The data for these two customers is combined into a single Reseller Class.

Corporate Use – SaskPower energy needs for fuel supply and all other electric system internal use. Extrapolation of existing data is used to estimate internal energy use, while coal mine consumption is calculated from production estimates provided internally.

System Losses and Unaccounted for Energy – Transmission and Distribution Systems

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 SPC Loss program are used to predict system losses resulting in annual sales forecasts. Transmission losses use the SPC Loss computer program, while distribution and unmetered losses use a 3 year historic average predictor.

Grid losses are minimized by the Grid Control Centre using a Supervisory Control and Data Acquisition (SCADA) tool that monitors voltages at key stations around the system. System studies show that closely monitoring and controlling these voltages captures most of the loss reduction on the system. Basically, operating the system voltages at the upper limits reduces system losses. As of the end of the second quarter of 2012, SaskPower saved approximately 3,654 MWh of energy due to losses for an estimated value of $183,000.

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

Energy forecasts are determined by extrapolating historical use per customer and number of northern customers. Energy requirements are provided by the Kinoosao diesel plant and import power from Manitoba Hydro.

Projected changes in load growth for each customer class are detailed in this section of the report.

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. 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. Traditionally, SaskPower's peak load has occurred during the winter heating season from November to February.

However, SaskPower's peak forecasts consistently assume that the potential peak will occur just prior to Christmas. Historical and sales forecast data is used to develop load patterns for all Power and Oilfield Accounts during the peak period. These forecasts include the customer's anticipated changes in operations during the peak period, including production or expansion.

Peak loads for all other customer classes are estimated using historic class loads at the time of system peak and assume normalized weather using a rolling 30 year average. In determining degree day deficiency, SaskPower has incorporated an Itron recommendation to use three years of data in the weather normalization models and to revise the heating degree day (HDD) and cooling degree day (CDD) variables to a base of 10 degrees Celsius instead of 18 degrees Celsius.

3.1.4 Projected Annual and Peak Day Requirements

SaskPower's energy requirement projections (in GWh) on a class-by-class basis are shown on the following table, from 2012 to 2022 as found in the 2013 Business Plan load forecast:

Table 3.3 - 2013 Business Plan Projected Energy Requirements by Customer Class - GWh

Customer Class	2012 Energy Requirements	2022 Energy Requirements	Change	Average Annual Change	2012 % of Total Sales	2022 % of Total Sales
Power	7,751.8	13,726.5	5,974.7	7.01%	38.9%	50.4%
Oilfields	3,307.1	3,845.5	538.4	1.48%	16.6%	14.1%
Commercial	3,477.6	3,620.7	143.1	0.37%	17.5%	13.3%
Residential	2,897.9	3,428.3	530.4	1.66%	14.5%	12.6%
Farm	1,227.0	1,296.3	69.3	0.51%	6.2%	4.8%
Reseller	1,256.3	1,299.2	42.9	0.31%	6.3%	4.8%
Saskatchewan Total Sales	**19,917.7**	**27,216.5**	**7,298.8**	**3.33%**	**100.0%**	**100.0%**
SaskPower Export	357.4	417.0	59.6	1.52%		
SaskPower Total Sales	**20,275.1**	**27,633.5**	**7,358.4**	**3.30%**		

The Load Forecast assumes that the off grid energy requirements for 2013, supplied by Diesel Generation and Manitoba Hydro Imports, will remain relatively stable at 29.2 GWh for 2012 and continue to remain at that level over the next decade.

The 2013 Load Forecast uses customer growth as one tool for estimating load. The following table shows the projected customers by class and indicates the relative proportions of each class to total, for 2012 and 2013.

Table 3.4 - Customer Account Projections for 2012 & 2013

Customer Class	2012	% of Total	2013	% of Total
Power	122	0.03%	123	0.02%
Oilfields	14,898	3.12%	17,081	3.45%
Commercial	54,681	11.45%	55,739	11.26%
Residential	343,280	71.86%	356,519	72.03%
Farm	61,802	12.94%	62,245	12.57%
Reseller	3	0.00%	3	0.00%
Streetlights	2,906	0.60%	3,321	0.67%
Total Sales	**477,692**	**100.00%**	**495,031**	**100.0%**

SaskPower's 2013 customer base forecasts almost 496,000 accounts, including streetlight accounts. This forecast is an increase of approximately 25,700 customers over the 3 years from 2010. Customers are placed into a variety of classes based on size and load factors. Key customer classes and number of accounts projected for 2013 are:

Table 3.5 - Customer Accounts for 2012 & 2013

Class of Service	2012 Forecasted Number of Accounts (2012BP)	2013 Forecasted Number of Accounts (2013BP)
Urban Residential	289,447	300,684
Rural Residential	53,833	55,835
Total Residential	**343,280**	**356,519**
Farms	61,802	62,245
Urban Commercial	42,148	42,963
Rural Commercial	12,533	12,777
Total Commercial	**54,681**	**55,739**
Power - Published Rates	109	110
Power - Contract Rates	13	13
Total Power	**122**	**123**
Oilfields	14,898	17,081
Streetlights	2,906	3,321
Reseller	2	2
Total (System)	**477,692**	**495,031**

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.

3.1.5 High-Low Scenarios

Because uncertainty exists with long term load forecasts, SaskPower develops, in addition to the most likely scenario, a low case and a high case scenario developed by computer models which results in a 90% confidence level. The major factors leading to uncertainty are changes in the economic climate, as discussed above, and weather variability. The 2012 Economic Forecast was the major driver in developing the most likely scenario which also assumed average weather and median hydraulic conditions, resulting in a 2013 estimated energy requirement of 23,951 GWh and a peak load of 3,735 MW. Based on the second quarter 2012 load forecast, the DSM adjusted high forecast scenario total energy requirement and potential peak are 1,848 GWh and 287 MW higher respectively than the most likely scenario. Alternatively the low forecast scenario indicates energy and peak requirements to be 1,891 GWh and 294 MW lower than the most likely case, with 2022 forecast being 4,550 GWh and 680 MW lower. The current long range 2022 forecast is for DSM adjusted energy needs to be 29,020 GWh and the peak load to be 4,434 MW.

The following table shows the impact on SaskPower's annual energy and peak load for average weather and what these amounts would be for the warmest and coldest years on record using 2011 consumption and peak load data.

Table 3.6 - Impacts of Warmest and Coldest Recorded Weather on 2011 Load

	2011 Actual	2011 Normal Weather	2011 with 1987 (Warmest) Weather	2011 with 1996 (Coldest) Weather
Energy (GWh)	21,120	21,048	20,892	21,365
Peak (MW)	3,195	3,179	3,114	3,236

Notes:

- All peaks are winter peaks.
- 1987 was the warmest year (highest mean temperature for the year) over the period 1982 to 2011.
- 1996 was the coldest year (lowest mean temperature for the year) over the period 1982 to 2011.
- In December 1996 the very cold weather did not occur until the Christmas week. Had this weather arrived a week or two earlier, the peak load would have been much higher.

3.1.6 SaskPower Energy Sales History and 2013 Forecast

Table 3.3 illustrates projected energy requirements, based on the provincial economic outlook and other factors used for load forecasting methodology.

3.1.7 Current Resource Use Strategy

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. If required to meet additional load, based on economic considerations, Off-Peak imports, additional Meridian and Cory generation and On-Peak imports are used, based on availability and economics.

SaskPower operates three coal-fired power stations, seven hydroelectric stations, six natural gas stations, and two wind facilities. These generate a combined 3,513 megawatts (MW) of electricity. SaskPower also purchases power from the Red Lily Wind Power Facility, SunBridge Wind Power Facility, 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 was 4,094 MW at the end of 2011. The following table illustrates the total annual energy actually generated by fuel mix type in GWh for 2010 and 2011 as well as the forecasts for 2012 and 2013.

Table 3.7 - Annual Fuel Source Generation Mix for 2010 to 2013

SaskPower Fuel - Generation (in GWh)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Supply Source												
SaskPower Gas	4,177	3,682	(495)	2,221	1,194	(1,027)	2,033	1,640	(393)	2,753	2,319	(434)
Gas (PPA)	Included in Above	Included in Above	Included in Above	2,689	2,838	149	3,221	3,109	(112)	5,033	4,881	(152)
Coal - Net of Internal Use	12,083	12,038	(45)	12,316	11,614	(702)	11,875	11,694	(181)	11,867	11,777	(90)
Imports	1,052	518	(534)	984	502	(482)	657	651	(6)	327	288	(39)
Hydro	3,302	3,866	564	3,282	4,641	1,359	3,556	4,136	580	3,321	3,327	6
EPP, Wind, Other	748	655	(93)	809	824	15	845	833	(12)	878	891	13
Gross Volume Supplied	**21,362**	**20,759**	**(603)**	**22,301**	**21,612**	**(689)**	**22,186**	**22,063**	**(123)**	**24,177**	**23,483**	**(694)**
Less: Line Losses	(1,767)	(1,897)	(130)	(1,820)	(1,936)	(116)	(1,875)	(1,788)	87	(1,786)	(1,785)	1
Total Generation & Purchased Power	**19,595**	**18,862**	**(733)**	**20,481**	**19,676**	**(805)**	**20,311**	**20,275**	**(36)**	**22,391**	**21,698**	**(693)**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

The following table illustrates the current total capacity available by fuel type, at the end of 2011.

Table 3.8 - Fuel Source Mix (by Percentage & in MW)

Fuel Type	Percent	Net MW
Coal	41.2%	1,686
Natural Gas	19.9%	813
Hydro	20.8%	853
Purchased Power - Other	14.2%	581
Wind	3.9%	161
Total Generation	100.0%	4,094

SPC owned – 3,513 MW & 581 MW PPA

Hydro Generation

SaskPower's seven hydroelectric sites have a peak capacity of 853 MW and under normal flow Conditions, with all 26 units being operated can generate 3,298 GWh. Maximum flow conditions can result in generation capacity near 4,600 GWh.

Hydro capacity factors (maximum annual output relative to installed capacity) vary widely from year to year, as well as for plants on the Churchill River System (generally near 85%) and the Saskatchewan River system (from 35% to 50%) because of varying flow conditions and operating considerations. On an overall basis hydro capacity factors have ranged from a low of 32% to a high of 61%.

For several years ending in 2007 Hydro generation output has increased annually because, on an overall basis, flows were greater than previously determined median flows. This trend reversed in 2008 when flows decreased to below median and further decreased in 2009 to more than 10% below median. In 2011 hydro generation was up over 1,300 GWh from median but is expected to return to nearer to normal flows in 2012. SaskPower's original application is based on median flows for 2013.

Coal Generation

As the cheapest thermal firm energy source, coal generation output has been constant in volume and displayed little price volatility, with price increases being relatively predictable. SaskPower's Resource Supply Plan included an assessment of future expenditures for plants related to coal fired generation, and will be influenced by the results of the ICCS project at Boundary Dam.

Coal currently provides the majority of Saskatchewan's electricity. Transformative Carbon Capture and Storage (CCS) technologies may provide SaskPower with cost-competitive options for transitioning its aging and emissions-intensive coal plants into a modern low-carbon fleet. The refurbished Boundary Dam unit #3 will supply 110 MW of capacity, offset by the retirement of the 66 MW Boundary Dam unit #1, scheduled for 2013.

Natural Gas

With the current anticipated load growth, primarily in the industrial sector and environmental concerns related to coal-fired generation, SaskPower is actively pursuing construction of additional gas fired generation. In 2010 gas generation accounted for approximately 18% of total output while in 2012 it is expected to generate about 22% of total annual requirements and 32.2% in 2013. This is predicated on median hydraulic flows and estimated 2013 import electricity prices. SaskPower added the 141 MW Yellowhead Power station in 2010 and expects to have additional natural gas generation from the North Battleford Energy Centre in 2013 under a PPA. As well gas fired generation under PPAs is expected to increase from 2,838 GWh in 2011 to 5,033 GWh 2013.

As natural gas forms a greater percentage of fuel mix, and is primarily the short to medium term fuel choice to satisfy load growth, SaskPower's price management policy and annual plans will become increasingly important to control price volatility and to ensure that reasonable prices can be obtained on an annual basis. In this regard SaskPower (through NorthPoint) has amended its policy so as to allow for hedging volumes 10 years into the future, up from the previous 5 year time frame. Considerable discussion in this regard is presented elsewhere in various sections of this Report. Because natural gas is the highest cost of the major fuel sources, optimal use of hydro and coal continues to be critical.

Wind Generation

SaskPower now owns wind Farms at Cypress and Centennial. As well, it purchases power from Sunbridge from an IPP, and 26 MW of wind from the Red Lily project. All the facilities can produce about 650 GWh annually at a capacity factor of about 40%. By its nature, wind power is variable and must be backed up by other sources. It is not a firm source of supply and cannot command firm domestic or export prices.

Saskatchewan wind capacity factors have remained consistent since 2010 with some small annual fluctuations. Since 2010, one new wind power project has been added to the SaskPower electric system. Specifically, the 26 MW Red Lily Wind Power Project was added in 2011.

Environmentally Preferred Power & Independent Purchased Power

SaskEnergy has numerous EPP/IPP arrangements in place for the purchase of power, utilizing various fuel sources – (natural gas, wind, heat recovery and biomass) all of which contain confidentiality clauses, and specific financial data. Further arrangements are expected to be entered into in the future, likely by way of RFPs, as SaskPower attempts to introduce additional "green" power sources. In 2011, total generation sourced from these arrangements was approximately 2,838 GWh and is expected to be 5,920 GWh in 2013.

Imports and Exports

SaskPower purchases electricity from North American suppliers at various times when it is economic (that is, when purchase price is less than SaskPower's marginal generation costs) to do so. Purchase decisions are made on a 24 hour, 365 day a year basis. Prices differ for Off-

Peak and On-Peak purchase and are dictated by the market place. The ability to import or export power is constrained by size of inter-ties with other markets, as well as transmission congestion and OATT entitlements outside of Saskatchewan. SaskPower's Development Plan does not consider Export Power as a planning criterion, but SaskPower will export power if and when excess is available and export market prices are advantageous.

SaskPower has interconnections at the Manitoba, Alberta, and North Dakota borders. This gives them the capability to import or export electricity to meet higher internal demand or take advantage of export market opportunities. Under normal system conditions, the import capability is up to 150 MW from Manitoba, 75 MW from Alberta, and 90 MW from North Dakota. The export capability is up to 50 MW to Manitoba, 153 MW to Alberta, and 150 MW to North Dakota. These interconnection capabilities vary with system conditions, including generation and load level. SaskPower is required to compete with others for access to these interconnections. The Open Access Transmission Tariff (OATT) enables competitors to schedule access to SaskPower's transmission system, allowing them to transport power through Saskatchewan or sell to SaskPower's wholesale (Reseller) customers.

3.1.8 Far North Resources Supply Plan

SaskPower filed a Far North Resource Supply Plan with Forkast in confidence, as part of this Application. SaskPower's Far North Supply Strategy was prepared in 2011.

The energy demand is projected to increase significantly and that the current facilities will not be able to supply the forecasted northern industrial demand as well as other energy needs. The 2011 peak load was 75 MW, comprised of 30 MW for the residential sector and 45 MW industrial high loads. The high load demand is primarily from the northern mining industry which makes up over 80% of this demand. The forecast anticipates that the majority of the future requirements will result from new mining operations and expansions to existing facilities.

By 2020, the peak demand is projected to be 132 MW with an energy requirement of 895 GWh. This is a 76% increase over the 2011 peak load requirement.

Based on the projected growth timeline in these far north, SaskPower's options to successfully supply the forecasted demand are constrained. Considerations that SaskPower has factored in when determining their strategy are:

- Timing of supply needs vs. load forecast;
- Hydrological changes;
- Construction time periods and durations for new transmission lines and power stations;
- Ability to supply energy with diesel generation; and
- Ability and liability of future generation projects.

As a result, a three stage plan has been developed: Short, Medium and Long-Term, all of which have pros and cons as discussed in greater detail below.

The short term plan, from 2011 to 2015, is to invest in a transmission line upgrade which will facilitate purchase agreements and transmission of power from either the South Wheeling System or Manitoba Hydro to meet the anticipated energy demand.

The medium term plan, 2016 - 2023, is to develop generation stations at either Elizabeth Falls or Whitesand Dam. In addition to this SaskPower will continue to explore and invest in research and development for other small hydro generation projects, biomass and diesel generated power.

The long term plan, from 2024 onward, will be to consider the development costs of additional power stations and transmission lines.

In the short term, SaskPower anticipates there will be limited resources to meet the projected loads. To meet the demand projected for 2014, SaskPower will need to increase capacity or reinforce the transmission and/or install leased diesel generators. Although diesel generation is expensive and the cost of fuel in future years is difficult if not impossible, to reasonably anticipate, it will still fulfill meeting the load requirements and allow for more time to upgrade/reinforce the existing transmission lines.

SaskPower intends to address this by developing additional or enhancing existing generation facilities. SaskPower indicates that an optimistic timeline for the in-service date of these facilities will be no earlier than 2016. This may not meet the 2014 demand projections and SaskPower also notes that due to contractual negotiations and in other processes that is on-going with third parties, there may be an anticipated delay to the in-service date of 2017 or 2018.

The long term plan is to develop additional power generation facilities to ensure a continual ability to meet the forecasted growth of the Far North System. The report focused on hydro projects as its long term solution in conjunction with third parties that have expressed interest in development of these projects as a partner.

As well, SaskPower has taken initiative to address its immediate concerns of being able to supply the required volumes of power generation in the short term and is currently working with other parties to establish and determine whether they will be able to support SaskPower's growing demand for electricity. In conjunction with establishing generation capabilities, SaskPower is conducting studies on transmission interconnections to determine the cost of supply and firm energy capacities.

The 2013 forecast determined that energy demand would be able to be supported by SaskPower’s power generation and transmission facilities, while by 2016 the system is forecasted to require a minimum of an additional 32 MW of peak demand and 80 GWh of energy.

Estimated Costs of initiatives

The upgrade to the capacity of the transmission lines in 2011 was estimated to be $122 million, with an in-service date of late 2013 or early 2014. The upgrade will allow SaskPower to utilize the full capacity of the Island Falls power generation facility or alternatively facilitate the ability to provide distribution from other purchased sources of power.

As noted earlier, the majority of the demand in the Far North is a result of the forecast for the expansion and development of the mining industry, predominately around uranium mining. The option of using diesel fuel powered generators is available and this will defer the need for the upgraded transmission lines in the short term if funding is still tied up on current projects. However, it was identified in the report that the cost of fuel continues to increase and the ability to forecast the future costs of operating these generators is only estimated based on current trends. Current trends indicate that the fuel charge alone for 1 MW of diesel supplied fuel would be in the range of $270. Estimated total cost of operation for 1 MW is between $300 - 500 currently. Further generators required to produce 1 MW were each the size of a full semi-truck load. Thus, to produce 50 MWh of power would require 50 semi-load size generators. The sheer size of the units combined with the remoteness of the areas where these units would be required is another consideration that will affect SaskPower's decision forward. The 2016 economic analysis indicates that to meet the demand requirements, 22 MW of diesel generation would be required.

Deferral of the transmission line upgrade by supplementing the energy demand with diesel units provides the opportunity to allow the transmission line reasonable completion and in-service start date for Elizabeth Fall power generation in 2016. Under this option, the generators would be already installed and operational, guaranteeing the ability to produce the necessary power (although very expensive) to meet demand. This would provide a contingency plan in the event that construction or negotiations cause lengthy delays in the Elizabeth fall project.

3.1.9 40 Year Resource Supply Plan

In 2011 SaskPower conducted an extensive evaluation of system resource needs to meet forecasted growth over the next 40 years, including upgrades and new transmission lines. As well, SaskPower recognized that some power generation facilities are nearing their estimated useful life end and are thus exploring opportunities and costs to extend the operating life for these units. Understanding how each of these aspects impacts the base load and peaking requirements in future years is necessary for SaskPower to determine their short, medium and long term strategies and plans to meet their customer supply.

SaskPower has thus developed three term supply plans as follows:

- Short Term - Years 2011 - 2015
- Medium Term - Years 2017 - 2024
- Long Term – Years 2022 - 2034

Incremental Short Term capacity requirements are over 1,066 MW. The projected load growth during this period is 659 MW and 407 MW from retirement and refurbishment of current in service facilities. Due to SaskPower's diverse portfolio of power generation supply utilizing natural gas, coal, hydro and wind, over the short term SaskPower has indicated that they will be able to meet the supply reliability. The diversity of the portfolio has multiple initiatives to ensure this short term is successfully supplied such as:

- DSM in savings related to efficiency, conservation and load management.
- Simple cycle natural gas turbines will provide flexibility in the short term, as well as meet peak supply generation demands for short term, high power demand requirements.
- Engage independent power producers in power generation utilizing biomass and wind. Options available include wind generation, Import contracts from neighboring utilities, and Biomass.
- Upgrade the existing transmission lines' voltage capability and add new lines to the supply grid.

- Secure short term import contracts with neighboring provincial utilities for additional supply by 2015.

In the event that projected loads materialize sooner than expected, SaskPower has developed a contingency plan for the short term demand, as detailed below.

- Meet requirements to 2015 using import power purchase agreements such as spot market purchases and, as a fallback position, curtailment contracts.
- Customer services will work to firm up customer demands or push out in-service start dates with large volume key account users. They will also continue to develop and improve DSM initiatives (i.e. Demand Response products for short term supply).
- Engage in discussion with neighboring utilities to firm up purchases for 2015. Currently a memorandum of understanding has been signed and a terms sheet is in process.
- Initiate discussion with electric power generators to determine the volumes and years of available power to enter into purchase power agreements.
- Determine whether the K+S development is a go or no go and proceed as necessary.
- Explore co-generation options for mine sites.
- Develop biomass projects at several sites.
- Delay issuing of CCGT RFP while continuing to optimize the site selection for the project which has an estimated in-service date of 2017 or 2018.
- If all of the above opportunities do not materialize to the point of being able to satisfy energy demand, SaskPower will prepare the SCGT site and solicit private developers to ensure target load is met.

The overall objective is to create and maintain a sustainable energy supply that balances the economic, environmental and social requirements. SaskPower acknowledges that the plan to achieve this requires continuous system planning and diligent monitoring to ensure a comprehensive plan that satisfies all stakeholders.

Two primary factors need to be considered to ensure success:
1.) the need to retire or life extend current power generation facilities and
2.) need to forecast and monitor the growing demand for electricity in Saskatchewan and plan appropriately.

The majority of SaskPower generating units are near their end life cycles. They are between 30-50 years old and need infrastructure revitalization to continue to stay in-service and meeting federal regulations.

Over the last 10 years the demand growth for electricity has been on average 1.1% per year. The next ten years are forecasted to grow on an average of 2.5% per year which is primarily due to large industry and commercial developments.

A major threat in the future to successfully meeting energy requirements is the impact of environmental regulation, which has already implemented a reduction on the use of coal fire power generation facilities. Although a substantial portion of SaskPower's generating capability, the diversity of their required energy supply portfolio will allow SaskPower to depend and explore opportunities using Gas, Hydro, Wind and Power Purchase Agreements in lieu of Coal Fire generation.

The minimum amount of electricity power delivered to meet requirements or base load will be supported going forward with DSM initiatives to reduce the consumption and improve the system and usage efficiency. Some of the DSM initiatives of interest include coal (if permissible), hydro and co-generation facilities.

There are many short term initiatives that SaskPower is aware of and currently researching for best fit and implementation. These include:

- DSM - Residential & Commercial Geothermal / Renewable Loan Program / Rebate Program
- Customer Side Renewable Energy Generation
- Net Metering Program
- Small Power Producer Programs
- Residential Energy Star Loan / Lighting / EnerGuide for homes / Efficient Appliances
- Commercial Lighting / HVAC / Hi efficiency furnace & boiler / Plug Load Program
- Energy performance contracting / Demand Response products / Energy Info Services
- Green Power / SaskPower Facilities and Industrial Demand Response Programs

The medium term plan will focus on increasing SaskPower's supply capabilities. Specifically the focus has been indicated on the natural gas generation facilities.

SaskPower is exploring co-generation options in the medium to long term. Simultaneous electricity and steam production using a single fuel source and combustion gas turbines will use the exhaust from each of the various processes to help generate power in the in plant process. SaskPower is working with various Potash mining companies to secure co-generation. An option being explored is to have the mines generate their required power demand and sell the surplus power to SaskPower to be transmitted to the power grid as necessary.

Other options for power mentioned briefly above are explained in detail below:

SCC - Simple Cycle Combustion turbines are gas fired generation which uses natural gas and other light hydrocarbon fuel to power turbines connected to generators. This is effective in supporting peak capacity requirements.

CCGT - Combined Cycle Gas Turbine consists of one or more combustion turbines and hot exhaust gases from turbines produce steam which can be used to facilitate further electrical generation.

Wind Power - SaskPower has 3 initiatives on the go; Red Lily in-service as of 2011 (26 MW), a RFP for a facility to produce 175 MW with a submission deadline of September 2011 & decision by 2012 and finally Green Options Partner Program which will develop three 10 MW wind farms.

Imported Power - Available from Alberta, Manitoba and North Dakota will be negotiated as needed for small or short term requirements. Purchase Power Agreements will be required for longer term planning and large volume procurement. SaskPower has indicated that this option is of great importance to providing power to meet the demand requirement for its Far North Supply Strategy.

GOPP - Their focus will be to attract interest from various parties to generate up to 50 MW of environmentally preferred power per year. Project sizes can be either 100 KW to 10 MW. Currently there is no capacity credit attributed to these projects as SaskPower is of the opinion they need to be review once implemented to determine the value and cost of operation.

Biomass - SaskPower has been in discussion with the forestry industry to develop 2 projects; the execution of this plan would be over a 10 year period.

Hydro - SaskPower is working with third parties to develop additional power generation facilities. Due to delays, SaskPower is considering taking a more active role in the planning and development of this project.

Environmentally Preferred Power (EPP) - Extend existing NRGreen Projects.

3.1.10 Observations

Subsequent to a request by the Panel in 2010, SaskPower engaged Itron Inc. to review its Load Forecasting Methodology. We note Itron found that; overall, SaskPower's existing methodology was satisfactory and conformed, in all significant areas, with industry norms. We further note that SaskPower incorporated three of four recommendations submitted by Itron as discussed above. The recommendation not adopted by SaskPower was to add an employment component to the commercial GDP drivers used to determine the energy growth rate for the commercial class. SaskPower believes this employment component is already included in the commercial drivers used to develop the commercial load forecast.

SaskPower's forecasts have historically been fairly accurate, given the uncertainty with projecting the industrial requirements, as these are primarily driven by individual production and expansion plans. We note that SaskPower continues to use 30 year's data in defining normal weather and do not assess any greater than average weights to the most recent years. SaskPower uses a 12 year estimation period (1997 to 2008) in their models to estimate hourly net energy as a function of weather variables, calendar conditions and time trend. This results in 288 models each containing different weather slopes. The models contain a composite of HDD, lagged HDD, wind chill, and wind speed variables to capture heating load impacts and composite CDD, Lagged CDD and Humidity Variables to capture cooling load impacts. We also note that 47% of the utilities canvassed by Itron use at least 30 years of weather data.

While the use of at least 30 years of average weather data appears to be the industry norm as evaluated by Itron, it is not clear if there is any greater weight given to the most recent years weather to recognize the apparent trend to warmer than normal temperatures. Such weighting has recently been introduced by SaskEnergy and results in an adjustment factor to define normal weather. We would suggest that SaskPower review this matter to determine if adopting a similar approach would materially impact the weather normalization process results.

SaskPower faces significant challenges to supply future expected load growth. This is largely driven by its Power Customers, primarily in the mining and Oilfield sector. It is also further complicated by the fact that many of SaskPower's generation plants are near, or indeed, beyond their expected useful life. Over the past decade and perhaps even earlier, SaskPower did not carry out a proactive maintenance program, rather expending funds on reactive type maintenance. Thus future supply plans are of increasing importance as necessary refurbishment and expansion of generation and transmission facilities will be major drivers for future incremental revenue requirements, naturally offset somewhat be increased revenues generated by related incremental sales.

It is encouraging that SaskPower has assessed its future needs over the next 40 years, for the first time looking beyond the usual 10 year plan. As well, SaskPower has conducted extensive analyses of its northern requirements. There is expected to be a fundamental shift in the nature of future growth in that, unlike in the recent past where demand has been from the southern portions of the province, the industrial growth will largely be in the north. Future supply plans have considered possible alternatives for each of the short, medium and long term plans. These plans are dynamic in that all potential alternatives will require further review and finalization, as future requirements, related to growth, environment and economics' change.

As shown on Table 3.2, the proportion of natural gas used for generation has gradually increased since 2005. Natural gas accounted for 15.8% of all generation fuels used in 2005 and this increased to 20.7% by 2011. Natural gas is projected to account for 21.5% of generation fuel in 2012 and significantly increase to 32.2% in 2013. SaskPower is anticipating significant increases in energy requirements for the Power Class in 2012 and 2013. Natural gas appears to be the only practical fuel source able to meet this incremental load in the short term. Currently, the variable cost of natural gas generation ($32.98/MWh) is considerably higher than that of the two other main fuels: coal ($20.43/MWh) and hydro ($4.36/MWh). Hydro flows are always maximized within operating constraints, and coal is utilized to maximum capacity within operating constraints. Thus future F&PP costs will be higher, not only because of increased load, but also because of a higher future blended unit cost of all generation fuels.

3.2 Demand Side Management

3.2.1 Programs

Due to increasing SaskPower and public requirements for energy and capacity savings partially offset load growth, the provincial government's green strategy, and growing expectations are driving SaskPower to be more aggressive in DSM programming. In SaskPower's view, Demand Side Management (DSM) differs from energy conservation and energy efficiency programs. DSM programs include those activities intended to alter the consumption pattern of customers demand in order to manage costs for both the utility and the end user. By working closely with customers to reduce or adjust their electricity consumption patterns, overall demand for power can be modified. On the other hand, energy conservation and energy efficiency more appropriately describe the consumers' initiatives to reduce consumption, leading to lower costs and lesser environmental impacts. SaskPower's efforts encompass all such programs, initiatives, and activities.

However, for an electric utility DSM initiative plays an important role in the Corporation's overall integrated resource plan. These should be evaluated utilizing the same underlying criteria and the same economic approach as used with alternative resource options.

An example of an electrical energy efficiency initiative is the promotion of the installation of lighting technologies that use less energy than conventional technologies and provide comparable lighting levels. Load management initiatives are designed to modify customer demand for energy at particular times or shift demand from one time period to another.

SaskPower benefits from all of these types of DSM programs because they allow them to delay the addition of new higher cost generation. They cannot replace existing generation or eliminate the need for refurbishment or replacement of existing generation. DSM can benefit customers as it affords them the opportunity to somewhat mitigate increased energy costs by taking action to reduce energy usage.

SaskPower's initial long term goal is to deliver 100 MW of cost efficient savings to the generation supply plan by 2017. In addition, demand response, an initiative undertaken targeting industrial customers, is forecast to provide a capacity reduction of 85 MW available to be utilized by SaskPower when needed to protect the reliability of the overall system. The short term goal is to achieve 100 MW of energy savings and 120 MW of capacity savings, while SaskPower's longer term goal is to achieve 300 MW of energy savings.

Savings are projected to be achieved through market transformation by using a variety of portfolio of programs involving all market segments. However to accomplish this, SaskPower will require additional funding to generate increased interest in the DSM program portfolio, This increased interest will be necessary if the target requirements of the Integrated Supply Plan are to be met. This target is exclusive of demand response incentive programs for large industrial customers.

SaskPower's initiatives include energy efficiency, energy conservation and DSM programs, which are intended to deliver the following specific benefits:

1. They provide a cost effective source of generation supply by delivering low cost energy and capacity savings. These low cost demand side savings are used to partially offset current and future energy and capacity requirements that would otherwise have to be met with higher cost supply alternatives. In this way, DSM programs can yield lower short-term fuel costs and/or lower long-term capital costs by deferring the need for some electric system investments.

2. They stimulate the adoption of economic energy efficient end-use and small scale customer renewable energy technologies which contribute to the market transformation for these technologies in a way that reduces total long term energy costs.

3. They reduce SaskPower's overall environmental footprint in a cost effective manner.

4. They enhance customer awareness and give customers (residential, commercial, and industrial) an opportunity to play a role in reducing energy usage and the negative environmental impacts of energy production and distribution.

5. They provide a validation to all stakeholders that SaskPower is optimizing energy costs to the greatest degree possible.

6. They support government energy and environmental plans and policies.

When analyzing the type of initiatives and programs to implement, SaskPower focuses on investments in all customer class segments including residential, commercial and industrial in order to capture cost effective energy savings. A 2013 total annual energy savings of 47,000 MWh is forecasted while a 44,000 MWh energy saving was forecast for 2012. The proposed 2013 program expenditure which was originally forecast to be $26.1 million and is now estimated $20.0 million represents an increase of approximately $19.0 million from the 2012 forecast. The costs are allocated to the commercial and industrial and residential sectors with approximately a third allocated to the residential component. The actual cost of Demand Side Management in 2011 was $11.8 million.

The OM&A costs of DSM are expected to be offset by the energy savings that occur because of the ongoing nature of the program initiatives. SaskPower confirms that the program savings are calculated using an appropriate end-use load factor to estimate the amount of energy savings at the customer site. For 2011 the total accumulated demand savings was 38 MW the target for that year. For 2013 50 MW of accumulated demand savings are targeted.

Most of the programs identified for 2013 are already in place, such as the residential and commercial lighting program, energy efficient technology programs for computers, electronics, car plugs, an industrial energy efficient program and the Refrigerator/Freezer Recycling program.

Industry standards for measurement of specific programs are used to evaluate the program's economic value. SaskPower uses four basic tests; the Total Resource Test (TRC), the Rate Impact Measure (RIM) test, the Utility Cost Test and the Participant Cost Test. SaskPower's base requirement for program acceptability is that a TRC and a RIM test showing a ratio greater than 1.0. In other words, the present value of the benefits counted on a specific program under the test must exceed the present value cost, so that the benefit ratio is greater than one. We can confirm that all current DSM programs surpass that base requirement.

Any benefits derived from DSM programs are reflected in reductions to base load, its profile and the subsequent revenue forecasts contained in the Business Plan. These reductions then result in savings in other budgeted cost items such as fuel and purchased power which are reflected in the cost of service.

3.2.2 Observations

SaskPower's DSM programs have been structured to encourage reduction of energy consumption for residential, commercial and industrial users in the form of energy efficient appliances and lighting, self-generated power (such as geothermal systems) and other load shifting DSM programs. Through low interest loans, technical assistance, advice and education campaigns, SaskPower is also developing other programs for commercial and industrial customers, as well as expanding the residential program. Across Canada these types of programs are being implemented or developed by other electric utilities for the benefit of consumers and the utility.

SaskPower's initiative in this area is reasonable as expected greater demand is materially enhancing the targeted energy savings expected in the future.

4.0 International Financial Reporting Standards

4.1 Transition from Canadian GAAP

Canadian Generally Accepted Accounting Principles (GAAP) has been replaced with the International Financial Reporting Standards (IFRS) for all publically accountable corporations or entities. SaskPower adopted IFRS effective January 1, 2011, and for 2010 tracked financial data under both GAAP and IFRS accounting principles and reporting standards.

The 2011 Annual Report is the first prepared in accordance with IFRS 1, *First-Time Adoption of IFRS*, respecting financial position, income and cash flows. IFRS requires that comparative financial information be provided for the initial period, which for SaskPower is from January 1, 2010 (Transition Date) to December 31, 2010. SaskPower selected the following options as provided by IFRS:

i). Elected to measure certain land and building assets at fair value at the transition date. This fair value becomes the deemed cost which is subject to subsequent amortization (IFRS 1).

ii). IFRS 1 provided the option of determining whether an arrangement contains a lease, and SaskPower determined that it was not required to reassess arrangements which were previously evaluated under Canadian GAPP.

iii). IFRS 1 provided the option of retrospectively applying the corridor approach respecting employee benefits for recognition of actuarial gains and losses or recognizing all cumulative actuarial gains and losses deferred under Canadian GAAP in opening retained earnings at the Transition Date. SaskPower chose to recognize all cumulative actuarial gains and losses that existed at its Transition Date in opening retained earnings for all its defined benefit pension plans, as well as disclosing amounts required by IAS 19, paragraph 120A(p), as these are determined for each accounting period prospectively from the Transition Date.

iv). SaskPower has elected not to comply with the requirements for changes to liabilities that occurred prior to the Transition Date, an option allowed by IFRS 1, with respect to decommissioning, restoration and similar liabilities.

v). IFRIC 18 allows for transitional provisions for transfer of assets from customers and a first time adopter may designate any date before the Transition Date and apply it to all transfers of assets from customers received after July 1, 2009. SaskPower has elected to apply IFRIC 18 retrospectively. On the Transition Date all unamortized customer contribution balances were recognized in opening retained earnings.

The following is a summary of the reconciliations between Canadian GAAP and IFRS as at January 1, 2010 and December 31, 2010.

Table 4.1 - 2010 Equity Reconciliation (x $ million)

Reconciliation of Equity:	**Jan.1/2010**	**Dec. 31/2010**
Total Equity under Canadian GAAP	**$1,632**	**$1,792**
IFRS Adjustments to Equity:		
Recognition of customer contributions	$322	$350
Recognition of actuarial gains/losses on employee benefit plans	(185)	(137)
Recognition of finance lease obligations	(153)	(167)
Recognition of property, plant, equipment	(116)	(138)
Restatement of land and building assets to fair value at transition	57	56
Restatement of provisions	(7)	(8)
Recognition of onerous contracts and subleases	(1)	0
Recognition of compensated absences	(1)	(1)
Restatement of associated and joint venture interests	9	11
Total Equity under IFRS	**$1,557**	**$1,758**

Table 4.2 - 2010 Consolidated Financial Statement Reconciliation

Reconciliation of Consolidated Statement of Financials				
(x $ millions)	**1-Jan-10**		**31-Dec-10**	
	Canadian GAAP	IFRS	Canadian GAAP	IFRS
Assets				
Current Assets	361	370	372	377
Property, Plant & Equipment	4,258	4,653	4,535	4,923
Total Assets	4,948	5,376	5,268	5,699
Liabilities & Equity				
Current Liabilities	574	580	495	502
Total Liabilities	3,316	3,819	3,476	3,941
Total Equity	1,632	1,557	1,792	1,758
Total Liabilities & Equity	4,948	5,376	5,268	5,699

Table 4.3 - 2010 Consolidated Income Statement for CGAAP and IFRS

Consolidated Statement of Income Year Ending Dec 31, 2010		
(x $ millions)	**Canadian GAAP**	**IFRS**
Revenue	1,751	1,691
Expenses	1,591	1,468
Net income	160	204
Total comprehensive income	160	201
Adjustments to reconcile net income to cash provided by operating activities		
Depreciation & amortization	258	266
Finance charges		192
Other losses (gains)		9
Unrealized market value adjustments	19	19
Debt retirement fund earnings	(17)	
Defined benefit pension plan contributions	(27)	(27)
Defined benefit pension plan expenses	53	7
Other benefit plans		(3)
Share of profit from equity accounted investees	(6)	(10)
Environmental remediation expenditures	(3)	(3)
Allowance for obsolescence	(4)	(4)
Other		
Net change in non-cash working capital	8	6
Interest paid		(219)
Cash provided by operating activities	441	437
Cash used in investing activities	(518)	(516)
Decrease in cash before financing activities	(77)	(79)
Cash provided by financing activities	74	77
(Decrease) increase in cash	(3)	(2)
Bank indebtedness, beginning of year	(2)	(5)
Bank indebtedness, end of year	(5)	(7)

4.2 Observations

SaskPower is not considered to be a rate regulated utility under IFRS. As a result, regulatory assets and liabilities cannot be recorded on the balance sheet, but rather must be recognized immediately on the income statement. The adoption of IFRS was mandated by CIC and was adopted by SaskPower's Board of Directors effective January 1, 2011. The 2011 year-end financial statements were reported pursuant to IFRS 1: First-Time Adoption of IFRS. SaskPower reported adjusted financial statement amounts previously in accordance with Canadian GAAP, resulting in a decrease in equity under IFRS from $1,792 million to $1,758 million as at January 1, 2010 and from $1,632 to $1,557 million as at December 31, 2010.

Thus, SaskPower's equity position was worsened by $34 million relative to Canadian GAAP on the Transition Date of January 1, 2010. In 2010 IFRS accounted for a further decrease in equity of $41 million, resulting in a total decrease in equity of $75 million relative to Canadian GAAP on January 1, 2011.

On the Transition Date of January 1, 2010, SaskPower's IFRS estimates all reflected conditions in effect at that time under Canadian GAAP, satisfying the IFRS mandatory exception related to significant estimates. As noted above, SaskPower elected specific courses of action for the five IFRS optional exceptions permitted, resulting in the above mentioned changes in financial position of SaskPower.

Where the change to IFRS has impacted specific aspects of SaskPower's operations, these are further discussed in sections of this report dealing with property, plant and equipment (including decommissioning liabilities), leases, employee benefits and customer contributions in Sections 6, 8 and 10.

All future financial statements will be compiled pursuant to IFRS requirements. While it is expected that future accounting changes related to IFRS may be required or refined, SaskPower together with its external auditor continue to monitor future developments or specific requirements that may change the reporting requirements.

5.0 2013 Application Revenues

5.1 Revenue Forecasts

A key principle underlying any rate application is that SaskPower should have rates that provide a reasonable opportunity of recovering prudently incurred costs for providing electrical services to all its customers. In the original Application, SaskPower requested a rate sufficient to generate the target return on equity (ROE) of 8.5% as approved by its shareholder. In the update SaskPower did not request an additional rate increase to the 5.0% system average increase, even though its September projections are for decreased net income. The requested overall rate increase is now expected to generate an ROE of 6.4% and a net income of $126.1 million.

In its Application SaskPower stated it required additional incremental revenues in 2013 to enable it to:

- Ensure revenues reflect the actual cost of providing service;
- Invest in capital improvements to the generation, transmission and distribution facilities to ensure safe, reliable service for the future;
- Invest long-term in new and refurbished infrastructure to support the customer's growing demands for electricity; and
- Provide for increased operating, maintenance and administration costs.

On August 1, 2010 SaskPower increased their rates by a system average 4.5% which generated incremental revenues in 2010, 2011 and 2012. On a go-forward basis, the requested 5.0% increase on January 1, 2013 was forecasted to generate $89.2 million increase in revenue.

The following table summarizes the consolidated revenues from 2010 to 2013:

Table 5.1 - SaskPower Consolidated Revenues for 2010 to 2013

SaskPower Consolidated Revenues (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Saskatchewan Sales												
Residential	n/a	382.0	n/a	400.9	407.3	6.4	388.3	395.5	7.2	403.0	409.2	6.2
Farm	n/a	141.0	n/a	145.3	144.9	(0.4)	142.3	137.5	(4.8)	143.4	148.5	5.1
Commercial	n/a	339.0	n/a	356.3	355.5	(0.8)	351.0	355.0	4.0	352.4	354.9	2.5
Oilfields	n/a	234.0	n/a	249.4	241.6	(7.8)	265.6	271.5	5.9	281.6	291.0	9.4
Power Customers	n/a	404.0	n/a	449.1	440.3	(8.8)	459.2	461.3	2.1	563.5	503.3	(60.2)
Reseller	n/a	75.0	n/a	77.6	77.2	(0.4)	77.6	77.1	(0.5)	79.1	78.0	(1.1)
Sales Before Rate Increase	**n/a**	**1,575.0**	**n/a**	**1,678.8**	**1,666.8**	**(12.0)**	**1,684.0**	**1,697.9**	**13.9**	**1,823.0**	**1,784.9**	**(38.1)**
Revenue Rate Increase Lift	n/a	0.0	n/a	0.0	0.0	0.0	0.0	0.0	0.0	90.8	89.2	(1.6)
Total Saskatchewan Sales	**1,605.0**	**1,575.0**	**(30.0)**	**1,678.8**	**1,666.8**	**(12.0)**	**1,684.0**	**1,697.9**	**13.9**	**1,913.8**	**1,874.1**	**(39.7)**
SaskPower Export	28.0	12.0	(16.0)	23.0	40.3	17.3	27.4	23.7	(3.7)	22.2	27.5	5.3
Total SaskPower Sales	**1,633.0**	**1,587.0**	**(46.0)**	**1,701.8**	**1,707.1**	**5.3**	**1,711.4**	**1,721.6**	**10.2**	**1,936.0**	**1,901.6**	**(34.4)**
Net Sales from Trading	18.0	1.0	(17.0)	5.3	13.9	8.6	15.8	17.0	1.2	11.5	12.0	0.5
Other Revenue												
Gas & Elect Inspection	n/a	n/a	n/a	13.2	14.2	1.0	14.4	14.4	0.0	14.7	14.7	0.0
Customer Connects	n/a	n/a	n/a	47.9	55.6	7.7	49.9	47.1	(2.8)	41.8	41.8	0.0
Miscellaneous Revenue	n/a	n/a	n/a	37.8	35.7	(2.1)	39.6	38.4	(1.2)	37.5	37.0	(0.5)
Cory & MRM Equity Invest	n/a	n/a	n/a	9.1	11.1	2.0	8.2	9.2	1.0	7.4	8.1	0.7
Total Other Revenue	**112.0**	**163.0**	**51.0**	**108.0**	**116.6**	**8.6**	**112.0**	**109.1**	**(2.9)**	**101.4**	**101.6**	**0.2**
Total Revenue	**1,763.0**	**1,751.0**	**(12.0)**	**1,815.1**	**1,837.6**	**22.5**	**1,839.2**	**1,847.7**	**8.5**	**2,048.9**	**2,015.2**	**(33.7)**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

5.2 Domestic Sales

In the original application Saskatchewan sales were expected to increase from $1.75 billion in 2012 to a forecast of approximately $1.91 billion in 2013. The updated forecasts provided in September of 2012 now suggest 2012 Saskatchewan sales to be $1.7 billion, a reduction of approximately $50.0 million, and 2013 Saskatchewan sales to be $1.87 billion, approximately $39.7 million less than originally forecasted.

5.3 Export Revenue

Export revenues from the sale of electricity produced by SaskPower to external markets, are now forecast to be $27.5 million in 2013, $5.0 million more than originally anticipated. The amount of revenue is dependent on the company's physical ability to export the power and the prevailing price in external markets. Currently the export market, especially the Alberta market, is more robust than was the case two years ago and is the primary reason for the anticipated increased revenue.

While SaskPower ensures that domestic needs are always met, the sale of power into neighbouring jurisdictions allows temporary surplus generating capacity to be marketed for 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 and price of electricity in SaskPower’s external markets which is primarily the Alberta market and the mid-continental area of the United States.

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 approximately 600 MW gross, at Saskatchewan’s east, south and western borders.

SaskPower’s OATT revenue from external customers has increased annually to just under $1.0 million in 2011 from $600,000 realized when it was first implemented in 2006. NorthPoint is a major user of OATT in Saskatchewan so as to move its exports to markets external to Saskatchewan. NorthPoint costs relative to OATT are netted against revenues generated from export sales to produce the actual or forecasted net income from exports.

5.4 Electricity Trading

Trading revenue consisting of revenue from electricity and natural gas bought in external markets and sold to other external markets is expected to be $12 million in 2013, slightly less than the actual result of $13.9 million in 2011. This trading is done by SaskPower’s subsidiary, NorthPoint, and is considered a growth opportunity for the Corporation. To get a true indication of the profit from trading, the trading revenue needs to be compared with the trading cost. The net trading revenue forecast for 2012 is $17.0 million which is an increase of $3.1 million from

2011. The net profit from trading fluctuates depending on market opportunities available and their financial attractiveness of counterparty arrangements or transactions to NorthPoint.

5.5 Ancillary Revenue

Ancillary revenues (identified in Table 5.1 as “Other Revenue”) include gas and electrical inspection permit fees, meter reading fees, late payment charges, custom work charges and other non-energy related charges. Historically, this account has generally increased slowly reflecting inflation, but also has experienced volatility. In 2009 and 2010 large increases in ancillary revenues were associated with the Integrated Clean Coal Sequestration (ICCS) project. Funding provided by the federal government accounted for $28.2 million in 2009 and $66 million in 2010 and no further revenues from this source are anticipated in 2012 or 2013. Ancillary revenue was $116.6 million in 2011; the updated forecast for 2012 is $109.1 million and $101.6 million in 2013.

5.6 Observations

Saskatchewan sales were down $39.7 million due primarily to $60.2 million lower projected sales in the power customer class. SaskPower recognized the trend in actual power customer revenues falling significantly short of budgeted revenues over the last number of years and worked directly with the large customers in revising their estimates for 2013. In addition to power customers, reseller revenue was also reduced by $1.1 million to reflect the expected load. These unfavourable variances were offset by forecasted increased sales to residential ($6.2 million), farm ($5.1 million), commercial ($2.5 million) and oilfields ($9.4 million).

Since the required demand by the Power Customer Class is over 40% of the total domestic demand it is extremely important, not just for the power customers but all customers, that the forecast accurately reflect the future requirements. Without appropriate load forecasts a number of domino-like issues could create operational, demand, service and reliability issues. However, SaskPower is limited as they have to rely on information provided by their large customers. 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.

Unfortunately globe economics play a significant role in determining future load demands for the Power Customer Class so all involved must be very sensitive to the environment and trends.

As export and trading revenue rely on the future marketplace, SaskPower capitalizes where possible in generating positive revenue but will be dependent on the demand and price of markets external to Saskatchewan.

Other additional revenue is forecasted to be $101.6 million, approximately $8 million less than the 2012 current forecast. The main decrease in revenue is forecast to occur in the Customer Connects category. From our vantage point, it is expected that this category will generate more than the forecast but the overall impact on the net operating income will be marginal given the final return on equity is now expected to be significantly less than the target 8.5%.

We find SaskPower’s forecast for total revenue of $2.015 billion from all sources to be reasonably quantified and justified.

6.0 Expenditure Forecasts

6.0.1 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 2010, 2011, and forecasts for 2012 and 2013 which are further detailed in the following sub-sections. The total net income for SaskPower's 2013 estimate in the Mid Application update is $126.1 million.

Table 6.1 - SaskPower Consolidated Expenses for 2010 to 2013

SaskPower Expenses (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Expense												
Fuel	559.0	511.0	(48.0)	484.3	485.4	1.1	502.8	494.5	(8.3)	563.1	545.1	(18.0)
OM&A	611.0	641.0	30.0	563.5	575.1	11.6	582.3	603.3	21.0	627.0	615.2	(11.8)
Depreciation	271.0	258.0	(13.0)	297.5	289.7	(7.8)	321.2	321.2	0.0	354.2	363.0	8.8
Finance Charges	150.0	139.0	(11.0)	202.5	197.5	(5.0)	215.5	202.1	(13.4)	273.7	303.3	29.6
Taxes	46.0	42.0	(4.0)	45.3	43.4	(1.9)	48.0	47.5	(0.5)	56.0	53.5	(2.5)
Other	0.0	0.0	0.0	6.2	7.7	1.5	9.6	13.2	3.6	9.0	9.0	0.0
Total Expense	**1,637.0**	**1,591.0**	**(46.0)**	**1,599.3**	**1,598.8**	**(0.5)**	**1,679.4**	**1,681.8**	**2.4**	**1,883.0**	**1,889.1**	**6.1**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

6.1.1 Fuel & Purchase Power (F&PP) & Electricity Trading Costs

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

In addition to SaskPower's fuel costs for its own generation, F&PP include costs for purchased power obtained through power purchase agreements (PPAs). For 2013 these include natural gas facilities at Meridian and Cory Cogeneration Stations, Spy Hill Generation Station and the North Battleford Energy Centre. Also F&PP costs include purchased power from various Environmentally Preferred Power projects with Independent Power Producers (IPPs) located in Saskatchewan, including SunBridge and Red Lily Wind Power Facilities, Prince Albert Pulp Inc. (Biomass), NRGreen Heat Recovery facilities at Kerrobert, Estlin, Loreburn and Alameda, and from various 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 takes advantage of such opportunities, and sells energy to export customers. The profit made on those export sale opportunities helps to reduce the upward pressure on rates for domestic customers.

It is important to note that a number of external factors can significantly impact the F&PP costs year over year. These 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.

For example in 2011 hydro generated over 1,300 GWh greater than normal median river flow conditions, while 2012 saw a reduction in these flows, currently expected to result in increased use of natural gas fired generation by approximately 839 GWh. In 2011, SaskPower was able to supply 53.8% of the annual load through the effective operation of its coal generation fleet, representing 49.4% of the generation expense, while hydro units generated 21.5% of the load, representing 4.5% of F&PP costs. Natural gas fired units (including PPAs), on the other hand, generated 18.6% of the load and represented 34.8% of F&PP costs.

SaskPower confirms that it continues to manage 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. SaskPower focuses on the economic dispatch of generating units, meaning that the lowest incremental fuel costs are brought on stream first, hydro and coal having the lowest economic cost. However, a number of factors are taken into account when decisions are made to dispatch generation units, including 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.

Coal and hydro generation costs have remained relatively constant over the last decade. Since coal generation is fully utilized to the extent plants are operational and not down for planned maintenance, and hydro generation, although variable is also fully utilized to the extent water flows allow in any year, additional annual required load must be generated by higher cost fuels, unless additional coal or hydro plants are put into service. In addition to its own facilities, SaskPower purchases power under various PPAs, listed above, as well as utilizing import power when economically feasible. SaskPower indicates that power purchase decisions are made in economic order, that is, least cost unit is generally put into operation first and shut down last.

2013 F&PP Outlook

Hydraulic flows somewhat less than those experienced in 2012 are expected in 2013. As well, the commissioning of Spy Hill generation in late 2011, the Boundary Dam project and the North Battleford natural gas fired plant expected in 2013 (required to meet the bulk of the expected increase in energy requirements of 2,000 GWh), coupled with an expected decrease in imported energy will lead to greater use of higher priced natural gas fired facilities.

It should be noted that future F&PP costs have the potential to increase significantly due to SaskPower's ever increasing reliance on gas-fired generation plants. The use of natural gas as a generation fuel source is likely to comprise a greater portion of SaskPower's fuel mix as it is the most reasonable and economic short-term solution to meet the significant increase in demand for electricity expected in the very near future. Coal and hydro generation units require a much longer time frame to become operational than do gas fired units. SaskPower must forecast the future costs of all fuel commodities, but natural gas prices display much greater volatility and uncertainty than coal or hydro costs. The 2013 forecast methodology is generally consistent with industry standards for pricing the natural gas commodity.

In the original Application 2011 net F&PP costs were estimated at $448.4 million and were forecast to increase to $502.8 million for 2012 and $563.1 million in 2013. The updated Application projects 2012 costs to be $446.7 million and $546.2 million in 2013. F&PP include the mark to market costs flowing from SaskPower's natural gas hedging program. The final settlement related to the 2011 hedging program resulted in gas costs being $31.9 million greater than the total 2011 gas cost of $152.6 million, representing approximately 21%.

The original 2012 Application forecasted gas costs of $160.3 million, including some forecast settlement amounts which had not yet been finalized. The 2012 settlements likely will result in similar hedging program settlement results as experienced in 2011. The 2013 natural gas costs were forecast to be $256.7 million and revised to $243.1 million. Settlements for these will not be known until after 2013 year end and for purposes of the estimates these have not been included in gas costs.

The table shown below illustrates the historical and actual results and estimates of the 2010 to 2013 load requirements by fuel source.

Table 6.2 – F&PP Costs for 2010 to 2013

SaskPower Fuel - Costs (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Supply Source												
SaskPower Gas	277.0	230.0	(47.0)	76.5	65.2	(11.3)	87.2	73.3	(13.9)	121.1	107.5	(13.6)
Gas (PPA)	Included in Above	Included in Above	Included in Above	97.2	89.6	(7.6)	73.1	75.3	2.2	135.6	135.9	0.3
Coal - Net of Internal Use	200.3	212.0	11.7	215.2	219.4	4.2	226.8	223.3	(3.5)	242.4	237.9	(4.5)
Imports	53.9	20.0	(33.9)	16.4	24.4	8.0	29.2	28.9	(0.3)	19.1	14.4	(4.7)
Hydro	13.0	16.0	3.0	20.1	20.0	(0.1)	15.4	18.1	2.7	14.5	15.8	1.3
EPP, Wind, Other	14.8	14.0	(0.8)	24.8	26.0	1.2	28.3	27.8	(0.5)	30.3	34.7	4.4
Gross Volume Supplied	**559.0**	**492.0**	**(67.0)**	**450.2**	**444.6**	**(5.6)**	**460.0**	**446.7**	**(13.3)**	**563.1**	**546.2**	**(16.9)**
Realized NG Management & Inventory Optimization	0.0	19.0	19.0	34.1	40.8	6.7	42.8	47.8	5.0	0.0	(1.1)	(1.1)
Total Generation & Purchased Power	**559.0**	**511.0**	**(48.0)**	**484.3**	**485.4**	**1.1**	**502.8**	**494.5**	**(8.3)**	**563.1**	**545.1**	**(18.0)**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

Natural Gas Costs

SaskPower expects gas generation to significantly increase in 2013, primarily due to increased load and lower than currently projected flow conditions. These projections rely on median estimated hydraulic flow data.

The SaskPower Board has approved policies (NorthPoint Risk Management Manual) which staff must follow in undertaking natural gas management and hedging strategies. The manual has been updated since 2009 to revise and/or amend certain administrative changes, procedures and policies related to credit and liquidity risk. Approval was granted to allow NorthPoint, on behalf of SaskPower, to extend its hedging program from 5 years out to a 10 year horizon. This change was implemented in April of 2012, and SaskPower has hedged volumes in varying amounts until 2022. The hedged volume targets are 55% in the initial year, decreasing by 5% per year, so that the 10 year out (2022) target is 10% of volumes.

As of June 2012 SaskPower completed 51% of 2013 volumes (36% physical hedges -24.3 million GJs, and 15% financial hedges – 20.0 million GJs), but the mark to market benefit or loss will not be able to be determined until all hedges have settled. It is expected that the remaining 4% of volumes will be hedged by the end of 2012. The average cost (per GJ) of financial hedged volumes in 2011 and 2012 was $7.02 and $5.84 respectively. On June 12, 2012 the 2013 cost was expected to be $3.88 and to increase to $4.37 for 2014, then increasing gradually until 2019 with larger increases from 2019 ($4.78) to 2022 ($5.93).

Physical hedged volume costs for 2011 and 2012 were $6.05 and $5.83 respectively and forecast to be $4.42 in 2014. Projected future costs generally track the cost of financial hedged volumes. SaskPower maintains annual contracts for storage gas services for up to 6.0 million GJ. Annually purchases natural gas for injection into storage. SaskPower takes care to ensure that overrun penalties from pipelines are not incurred to supply the approximated 300,000 GJ peak day natural gas requirement. The opening inventory for gas in storage as of January 1, 2012 was 4.8 million GJ and had an average weighted cost of $4.02/GJ (approximately $19 million). In 2011 the average monthly AECO price was $3.48/GJ and AECO spot prices ranged from $2.37 to $4.65/GJ.

The SaskPower unit price of gas in the 2013 Application was $4.54/GJ which changed to $4.00/GJ in the Mid-Application Update.

6.1.2 Observations

Next to OM&A, F&PP costs are the largest expense for SaskPower. Because of the nature and generation mix of SaskPower assets, operational practices are to maximize the use of low cost generation units first and then to use progressively higher cost generation units and purchase power contracts as required meeting the 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 expense 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 their commodity supply needs. Both the market price and volumes can significantly impact the financial forecasts. The policies reviewed suggest that appropriate controls are in place, with proper reporting for approved risk management instruments, and strategies to be employed, and that the policy is being followed in 2012.

The following tables show the historical and forecast generation mix by fuel type volumes and costs from 2009 to 2013.

Table 6.3 - Generation Mix (x $ million)

Class	2009	2010	2011	2012	2013	2013 Updated
Coal	$194.00	$212.00	$219.4	$223.3	$242.4	$237.9
Gas	$266.00	$230.00	$154.8	$148.6	$256.7	$241.4
Hydro	$ 11.00	$ 16.00	$20.0	$18.1	$14.5	$15.8
Imports	$ 19.00	$ 20.00	$24.4	$28.9	$19.1	$14.4
EPP/Wind/Other	$ 19.00	$ 14.00	$26.0	$27.8	$30.3	$34.7
Total Fuel & Purchased Power	**$509.00**	**$ 492.00**	**$444.6**	**$446.7**	**$563.1**	**$546.2**

Table 6.4 - Generation Mix (GWh)

Class	2009	2010	2011	2012	2013*
Coal	12,317	12,038	11,614	11,694	11,777
Gas	3,432	3,683	4,032	4,749	7,200
Hydro	2,962	3,866	4,641	4,136	3,327
Imports	440	518	502	652	288
Wind**	714	656	683	683	675
EPP - Other	n/a	n/a	140	151	173
Total Fuel & Purchased Power	**19,865**	**20,759**	**21,611**	**22,063**	**23,483**

*Based on the 2013 Business Plan
** Combined Wind/Other for 2009 and 2010

The unit costs for the various fuel types from 2009 to 2013 are shown in the following table.

Table 6.5 – Generation Mix ($/MWh)

Class	2009	2010	2011	2012	2013
Coal	$15.72	$17.63	$18.89	$19.09	$20.43
Gas	$77.77*	$49.86	$48.51	$41.36	$32.98
Hydro	$3.88	$4.09	$4.30	$4.37	$4.36
Imports	$57.05	$39.21	$48.56	$44.30	$58.47
EPP	$73.88	$76.25	$77.78	$78.93	$80.86
Wind/Other	$4.66	$4.54	$22.26	$23.44	$25.11

*Includes O&M and Capital costs for gas based PPA. Change to IFRS removed these costs

The foregoing table illustrates that since 2009 the market driven costs (with hedging impacts) for natural gas have steadily declined and are forecast to be less in 2013 than the cost expected in 2012, while cost of coal, hydro and EPP costs show a consistent year over year increase. Imports show a significant degree of variability from year to year.

From 2005 to 2011, SaskPower's hedging transactions resulted in total settlement costs of $182 million greater than market for that period. Total natural gas costs in the same period were approximately $1,119.3 million. Thus the cost of the hedging program represents approximately 16% of total gas costs.

In two of the seven years the program reduced costs by a total of about $13.8 million. The largest impact was in 2009 ($75.3 million 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 the 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 because of new retrieval techniques. Thus gas prices were at almost record lows in 2010, 2011 and into early 2012. It is our view that gas prices are unlikely to remain at similar levels in the near future and 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 and equates to just less than 2% of overall revenue requirement. This is a significant amount given the anticipated increase in natural gas consumption for 2013 and in future years. Hedging future volumes at defined prices dampens the impact and volatility of rising gas prices.

The following Table 6.6 illustrates the components of SaskPower's forecast gas costs as submitted in the original application and in the Mid Application Update (final). The difference between the following table and the SaskPower unit price of gas in the 2013 Application which was $4.54/GJ and changed to $4.00/GJ in the Mid-Application Update is attributable to the impact of the forward price hedging activities.

Table 6.6 - Natural Gas Costs for 2013

	Application 2013	Update 2013
AECO C	$2.89/GJ	$2.89/GJ
Transportation Charges*	$ 0.22/GJ	$ 0.22/GJ
SaskPower Price	$3.62/GJ	$3.53/GJ
SaskPower Hedged Price	$ 4.54/GJ	$ 4.00/GJ
Natural Gas WACOG	$3.61/GJ	$ 3.53/GJ

Forecasting hydraulic generation represents another major risk in the F&PP. SaskPower's 2013 preliminary Business Plan estimated 2013 median hydraulic flows to generate approximately 3,321 GWh. SaskPower provided a Mid–Application Update in September and median flow conditions remained unchanged.

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 latest revision forecasts 2013 F&PP costs to decrease to $545.1 million. In the original Application these costs were estimated to be $563.1 million.

2013 net costs for coal generation are forecasted to be $242.4 million. Coal is now expected to generate 11,867 GWh, approximately the same as is projected for 2012 (11,857 GWh), but with operating costs increasing by about 7% to $242.4 million from $226.4 million in 2012.

SaskPower uses a capacity factor of approximately 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. SaskPower estimates that an additional 200 MW of wind generation could be added with manageable operational impacts and costs. SaskPower is currently assessing the implication of increasing wind power generation and is developing a future wind power strategy.

If the load forecasts and hydraulic conditions that SaskPower has estimated for 2013 materialize, it is expected that imported power will be less than required in 2012 to meet this demand. Given the current market is external to Saskatchewan, it is expected that since market prices in those markets have softened, the prices for imported electricity will also decrease somewhat. Overall, it is expected that F&PP costs will be less than forecasted in the Rate Application. This is mainly due to the lower cost of natural gas and the forecasted cost of imported electricity. However, with the significant softening in the current market of prices associated with natural gas futures, and with 53% of natural gas prices hedged earlier this year, SaskPower may now find it off side modestly with current market conditions.

6.2.1 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, international and local inflationary factors.

Actual OM&A totaled $575.1 million in 2011 including $11.8 million required to fund the Demand Side Management Program (DSM). The Rate Application forecast for 2012 was $582.3 million and $627.0 million was forecasted for 2013 which was approximately 5.5% higher than 2012 original forecast. DSM Program costs for each of 2012 and 2013 were included in the foregoing, with $20.2 million and $26.1 million allocated respectively. The mid applications update forecasts total OM&A expenditure for 2012 of $603.3 million and 2013 of $615.2 million. Also, DSM costs have been reduced to $20.0 million for 2013 and to $19.0 million for 2012.

Over half of the expense increase in OM&A for 2012 was related to the summer storm which hit mid Saskatchewan in late June, necessitating expenditures of just under $15 million to restore service.

The Mid Application Update to the Application revised the OM&A forecast downward from the original forecast of $627.0 million to $615.2 million made up of revised budget projections related to Demand Side Management, Insurance and Pension allocations. While there are offsetting increases and decreases in costs, the reduction is primarily due to a $11.8 million decrease in pension expense. OM&A expense is forecasted to increase $28.2 million in 2012 over the actual 2011 expense of $575.1 million. For 2013, the Mid Application Update now forecasts OM&A total costs to be $615.2 million, approximately $12 million less than the original Application.

Labour costs comprise a large component of OM&A expenses, and the FTEs are managed to help minimize OM&A costs while still supporting significant investments in infrastructure that require additional employees in areas where large-scale building and maintenance projects are underway. In 2011 a new five-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.

The full-time equivalent employees (FTEs) measure gauges SaskPower's progress in remaining aligned with the new five-year Workforce Plan. A FTE position is defined as an employee who works 1,800 hours per year and includes permanent, part-time, and temporary but now excludes overtime hours. SaskPower's 2011 year end compliment was 3,290 FTE, below the original target of 3,330 FTEs. SaskPower's five-year Workforce Plan calls for an employee peak of 3,477 FTE in 2012 before falling to 3,200 by 2016.

SaskPower advises that the initial increase is required to provide resources to implement cost savings initiatives; train staff to fill in for expected retirements; facilitate knowledge transfer; improve service levels; and address infrastructure and service growth. Beyond 2012, SaskPower anticipates continuing reductions as a result of: attrition; improved planned maintenance activities that will reduce overtime; the retirement of Boundary Dam Power Station Units #1 and #2; and the efficiency gains resulting from the implementation of the SDR and Business Renewal Programs.

This category of expense is influenced by the number of employees, wage, and benefit changes, that primarily flow from negotiated collective bargaining agreements, inflation increases for goods and services purchased; new assets acquired which must be maintained, 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 new collective agreements with the employees' unions, as the current ones are scheduled to expire at the end of 2012.

SaskPower in the past had defined its total FTE positions as being, in addition to approximately 2,675 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, as are overtime costs. However a decision was made by the Executive in 2012 to exclude overtime FTE's costs from the FTE calculation for the following reasons:

- The intent of measuring FTE's is to track the actual number of employees working at SaskPower at any one time. Overtime FTE's are employees who are already counted as either a permanent, part-time or temporary FTE and because of either planned or unplanned circumstances, are required to work overtime.
- Overtime FTE's are quite often storm and outage related and costs are therefore uncontrollable in nature. Having this volatility included in the total FTE count does not properly reflect the workforce plan of SaskPower.
- 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 employees by year, customers and customer/ employee ratios:

Table 6.7 - SaskPower FTE & Customer Comparison for 2007 to 2012

	Actual					Forecast
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
SaskPower FTEs	2,744	2,801	2,947	3,018	3,000	3,225
# of Customers	451,713	460,006	467,329	473,007	481,985	486,926
Customer/SP FTEs	165	164	159	157	161	151

2013 forecasts FTEs at 3,352, customers at 495,031 with a resulting customer/ FTEs at 148.

Please note the FTE numbers for 2007 to 2011 are based on year end actual FTE levels and include permanent, part-time, and temporary FTE's. For 2012, the numbers are based on SaskPower year-end target and again, are comprised of permanent, part-time and temporary FTE's. It is expected that by 2016 this ratio will improve significantly.

The following table shows the actual results for 2010 and 2011 together with the 2012 and 2013 proposed FTE's by Business Unit.

Table 6.8 - SaskPower FTE's by Business Unit for 2010 to 2013

	Actual		Forecast	
	2010	**2011**	**2012**	**2013**
President's Office	3	3	16	16
HR, Safety, & Corporate Comm	117	123	163	184
Corporate & Fin Services	158	134	87	87
Corporate Infor & Tech	87	99	148	165
Customer Services	436	444	436	456
PERA & NorthPoint	109	89	108	112
Power Production	916	869	953	959
T&D	1,145	1,185	1,184	1,234
Clean Coal	13	14	13	14
LLRA	34	33	35	39
Supply Chain	-	-	75	79
Business Development	-	7	7	7
	3,018	3,000	3,225	3,352

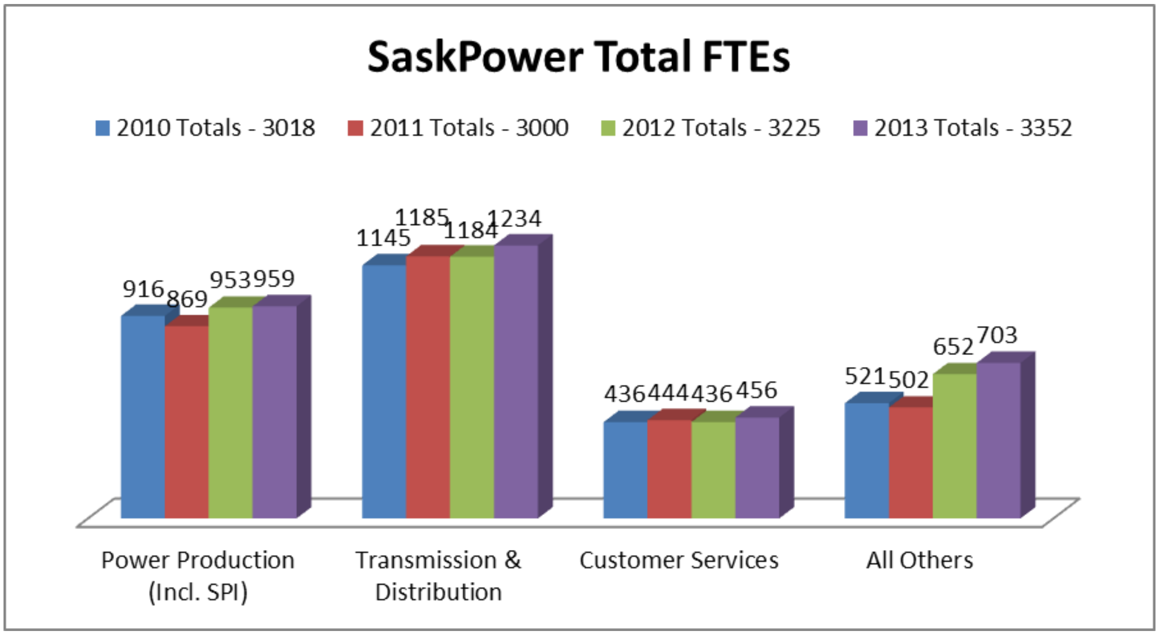
The foregoing table does not include part-time and temporary employees, which are expected to be 239 for each of 2012 and 2013.

The following is a summary of material changes to SaskPower's organizational chart since 2010:

- 2 new business units were created:
  - Business Development which was formed by transferring employees from NorthPoint, Finance, PERA and Power Production; and
  - Supply Chain which was formed by transferring purchasing and Corporate Services from Finance.
- Stakeholder Relations and Aboriginal Relations were transferred from Corporate Relations to Strategic Relations-President's Office.
- Fleet Services was transferred from Corporate & Financial Services to Transmission and Distribution.
- Planning, Environment & Regulatory Affairs and North Point were merged under one VP/President.
- Safety and Corporate Relations were merged with Human Resources.
- Workplace Learning and Performance was transferred from Transmission and Distribution to Human Resources.
- SDR measurement group and Pricing and Energy Forecasting were transferred from Customer Service to Finance.

The following graph represents actual permanent, temporary and part-time FTE's for 2010 and 2011 and budgeted FTE's for 2012 and 2013. It should be noted that overtime FTE's have not been included in these totals.

Graph 6.1 - SaskPower Total FTE's for 2010 to 2013



The following table illustrates OM&A cost per customers (actual) for 2009, 2010 and 2011 with the forecasts for 2012 and 2013. The OM&A forecast for 2013 has been revised downward from $627 million to $615 million which will reduce the OM&A per customer to approximately $1,242.

Table 6.9 - OM&A Cost per Customer for 2009 to 2013

	Actual			Forecast	
	2009	**2010**	**2011**	**2012**	**2013**
OM&A Cost (millions)	$ 495	$ 513	$ 575	$ 603	$ 627
# of Customers	467,329	473,007	481,985	486,926	492,887
OM&A Cost per Customer	$ 1,059	$ 1,085	$ 1,193	$ 1,238	$ 1,272

Please note the 2009 OM&A was based on Canadian GAAP, 2010 to 2013 is based on IFRS.

Below is a detailed breakdown of OM&A costs for the period 2009 to 2013:

Table 6.10 - OM&A Cost Breakdown for 2009 to 2013

OM & A Costs ($ millions)	Actual 2010	Actual 2011	Budget 2012	Forecast 2013 *
Wages & Benefits				
Salaries & Wages	$ 262	$ 274	$ 286	$ 300
Benefits	51	54	62	66
Pension Expense	7	(1)	(5)	-
Labour Credits	(36)	(35)	(33)	(35)
Allocated Labour	(10)	(11)	(13)	(13)
Sub-total Wages & Benefits	**274**	**281**	**297**	**318**
External Services	**252**	**214**	**186**	**194**
Materials & Supplies	**32**	**36**	**33**	**35**
Other Administration				
Administration	20	27	23	24
Travel	15	16	17	17
Vehicles	11	13	12	12
Insurance	5	5	5	5
Property	6	6	6	7
Tools & Equipment	3	3	2	3
Other	5	5	1	-
Sub-total Other Administration	**65**	**75**	**66**	**68**
ICCS Grants	**(110)**	**(31)**	**-**	**-**
Total OM&A	**$ 513**	**$ 575**	**$ 582**	**$ 615**

*Note – the 2013 Forecast numbers have been estimated by Finance based on the submissions received from each of the business units. Detailed budgets will be finalized in mid-December and the allocation between the various categories may vary from those noted in the table above. The total OM&A budget of $615 million however will not change.

As noted above, wages and benefit costs are impacted by two specific ingredients. The first is the number of FTE positions in the organization, and secondly 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 benefits 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 and these are capitalized to be retired over the life expectancy (in years) of the specific asset.

The following table details the actual OM&A expenses capitalized for 2010, 2011 and projected for 2012 & 2013 by labour, and interest. It provides a historical and current forecast on both labour and overhead charges together with capitalized interest.

External contract and consulting services costs peaked in 2010 at $252 million, approximately 50% of total OM&A in that year. A portion of that amount (roughly a third) was attributed to the ICCS Boundary Dam costs. All ICCS costs were recovered from other levels of government and are shown in SaskPower's "Other Revenue" category on the financial statements. The actual

External Services costs in 2011 were $214 million or approximately 37% of the total OM&A costs for that year. For 2012 contact services are forecasted to be around $202 million, 33% of total OM&A.

Actual Material and supply costs were $32 million in 2010 and $36 million in 2011. They are forecast to decrease to $33 million in 2012; they make up approximately 6% of total OM&A expense. Other administrative expenses are decreasing annually and for 2012 are expected to be $1.0 million, down from $ 5.0 million in 2010.

Table 6.11 - Capitalized Labour and Interest for 2010 to 2013 (x $ million)

($ millions)	Actual 2010	Actual 2011	Budget 2012	Forecast 2013 *
Allocated Labour Costs	$ 10	$ 11	$ 13	$ 13
Labour Costs Capitalized	36	35	33	35
Interest Capitalized	15	12	22	45
Total	$ 61	$ 58	$ 68	$ 93

*Note – the 2013 Forecast numbers have been estimated by Finance based on the submissions received from each of the business units. Detailed budgets will be finalized in mid-December and the amount allocated to Labour may vary from those noted in the table above. The total OM&A budget of $615 million however will not change.

On a historical basis, in 2004 the expenditures for wages, salaries and benefits for SaskPower employed labour accounted for 52% of the total OM&A budget. In 2008 this category was forecast to be $227 million, approximately 53% of OM&A expenses. In 2009 the actual cost was $274 million or 52% of the total OM&A expense and for 2012 this number is forecasted to decrease to 51%. The revised updated forecast suggests that wages and benefits category of expenses will be approximately 52% of the total OM&A for 2013.

When comparing the individual business units' year over year increases shown in the table above, it is important to note that a number of changes have been made to SaskPower's organizational structure between 2011 and 2013 and which have impacted the actual and forecasted numbers and as such may not be directly comparable.

Total OM&A is now expected to increase from $603.3 million in 2012 to $615.2 million in 2013, an increase of $11.9 million which is mainly related to the new Asset Management Program and Nuclear Feasibility Study initiative. From the original submission, the pension expense was reassigned to finance expense and that cost increase is primarily due to both the performance of the plan's assets and to changes in the actuarial assumptions used to calculate the liabilities of the plan. The Disability Income Plan (DIP) Premium Increase of $1.6 million forecasted for 2013 was based on an actuarial valuation of both the Group Life Insurance Program and Disability Income Plan and SaskPower's contribution rates to this plan were increased. This increase became effective in 2012 and is included in the 2012 forecast. Because it was not anticipated in last year's Business Plan, it is shown separately as a new item in the 2013 Business Plan.

Also included in OM&A are increased funding for initiatives such as researching nuclear power ($6.4 million), Asset Management ($3.0 million) and training for the new Clean Coal power station ($4.7 million) and Enterprise Learning ($1.1 million). Funding is also included for new information and technology initiatives such as SAP software upgrades, licensing, Business Intelligence, and the expansion of the procurement department. These initiatives alone are expected to generate long term annual saving of $40.0 million a year. Overall the Business Renewal Initiative in 2013 is expected to generate $220 million savings as compared to the 2009 Business Plan baseline.

The last SaskPower Application outlined a number of factors which have contributed to rising SaskPower employed labour costs over the past five years. Briefly these factors as outlined in that Application 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.

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 drive new cost savings through improved, refocused and reengineered processes while still providing a reliable, safe, secure electrical service.

At present 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 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 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 for 2011 and the forecast for 2012 (both based on the application and update) and 2013 (application and update) with the original 2012 figures based on March 31, 2012 forecast:

SaskPower 2013 Mid Application Update has revised the foregoing schedule as shown below:

Table 6.12 - SaskPower OM&A for 2010 to 2013

SaskPower OM&A (millions)	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
President Office	1.7	1.6	(0.1)	1.2	1.2	0.0	2.7	2.9	0.2	2.8	2.8	0.0
Power Production	184.0	173.6	(10.4)	192.5	183.0	(9.5)	187.7	187.7	0.0	183.6	183.6	0.0
Transmission&Distribution	131.6	123.3	(8.3)	152.0	165.1	13.1	159.5	174.5	15.0	162.7	163.5	0.8
Finance	18.2	17.8	(0.4)	21.7	17.3	(4.4)	13.5	12.9	(0.6)	14.2	14.2	0.0
Customer Service	39.7	38.1	(1.6)	37.6	40.6	3.0	40.0	41.6	1.6	42.0	42.0	0.0
Planning, Environment & Regulatory Affairs	17.5	10.2	(7.3)	17.3	10.8	(6.5)	11.4	11.4	0.0	12.0	12.0	0.0
Law, Land, Regulatory	5.1	5.5	0.4	4.9	4.8	(0.1)	4.3	4.3	0.0	4.5	4.5	0.0
CI&T	36.9	41.9	5.0	47.3	48.7	1.4	56.8	58.4	1.6	57.9	62.7	4.8
Human Resources	24.9	22.4	(2.5)	14.7	22.6	7.9	27.3	28.7	1.4	28.7	28.7	0.0
Business Development	0.0	0.0	0.0	9.6	12.6	3.0	2.8	5.3	2.5	2.9	3.5	0.6
Shand Greenhouse	0.9	0.6	(0.3)	0.9	0.7	(0.2)	0.7	0.7	0.0	0.7	0.7	0.0
NorthPoint Energy	9.9	8.3	(1.6)	9.0	8.4	(0.6)	6.4	6.4	0.0	6.7	6.7	0.0
Supply Chain	0.0	0.0	0.0	0.0	0.0	0.0	7.3	7.3	0.0	8.5	8.3	(0.2)
ICCS	67.2	111.1	43.9	1.1	2.2	1.1	2.4	3.2	0.8	7.6	4.7	(2.9)
SDR	16.7	12.3	(4.4)	14.2	11.0	(3.2)	8.5	9.1	0.6	8.9	8.9	0.0
DIP Premium Increase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	1.6	0.0
Asset Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0
Wage&Benefit Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0
Total Operation Costs	**488.0**	**566.7**	**78.7**	**524.0**	**528.9**	**4.9**	**531.3**	**554.4**	**23.1**	**545.3**	**554.4**	**9.1**
Other												
Nuclear Initiative	0.0	0.0	0.0	0.0	0.0	0.0	1.5	1.5	0.0	6.4	6.4	0.0
Insurance Expense	6.4	4.8	(1.6)	5.9	5.0	(0.9)	5.3	5.3	0.0	7.6	5.6	(2.0)
Pension Expense	46.9	53.3	6.4	(1.2)	(1.2)	0.0	(4.5)	(4.5)	0.0	11.8	0.0	(11.8)
Bad Debt Expense	2.2	1.9	(0.3)	1.8	2.5	0.7	2.7	2.7	0.0	2.3	2.3	0.0
Human Resource Program	3.1	1.5	(1.7)	1.4	1.8	0.4	2.3	2.5	0.2	2.5	2.5	0.0
Other Expense	4.2	2.5	(1.7)	(8.7)	8.2	16.9	0.0	0.0	0.0	0.0	0.0	0.0
PPA OM&A	8.5	7.9	(0.6)	19.4	18.1	(1.3)	23.5	22.4	(1.1)	25.0	24.0	(1.0)
Total Other Costs	**44.0**	**71.9**	**27.9**	**18.6**	**34.4**	**15.8**	**30.8**	**29.9**	**(0.9)**	**55.6**	**40.8**	**(14.8)**
Demand Side Mgmt	12.3	8.8	(3.5)	20.9	11.8	(9.1)	20.2	19.0	(1.2)	26.1	20.0	(6.1)
Total OM&A	**611.0**	**641.3**	**30.3**	**563.5**	**575.1**	**11.6**	**582.3**	**603.3**	**21.0**	**627.0**	**615.2**	**(11.8)**

2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast; CGAAP for 2010 - 2011 & 2012 IFRS

Another cost component of OM&A expense is the credit card program providing 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 is forecasted to be $421,500 in 2012 and 2013 forecasted costs are expected to be in excess of $1.5 million, due to usage that has increased substantially.

However SaskPower considers this expense a cost of doing business. Somewhat offsetting this increased cost (notionally) is bad debt expense which is forecasted to decrease to $2.3 million, down from a forecast of $2.7 million for 2012 and significantly down from $3.4 million in 2009. Whether there is a direct correlation between these two issues is yet to be factually determined, but it is expected there is a financial relationship.

Notwithstanding, SaskPower is examining new arrangements and contracts with credit card providers with a view to lowering the cost of this service. As well SaskPower is investigating means to provide other electronic opportunities for customers to pay for services through web-based protocols, as customers appear to want the convenience to exercise other options.

6.2.2 Demand Side Management

The following table illustrates SaskPower's existing and currently proposed DSM Programs discussed in Section 3.2.1, as well as SaskPower's projected investment in 2012 and 2013 together with the estimated energy savings.

The estimated investment includes marketing, consultant costs, and administration and incentive costs.

Table 6.13 - DSM Portfolio for 2012 & 2013

DSM PORTFOLIO					
Program	**Status**	**2012 Estimate Investment (000s)**	**Estimated Annual Energy Savings MWh**	**2013 Estimated Investment (000s)**	**Estimated Annual Energy Savings MWh**
Residential Programs					
Refrigerator/Freezer Recycling Program	On Going	2,100	8,500	2,100	8,500
Retail Customer Track Program	On Going	750	3,800	750	3,800
Light Exchanges	On Going	1,500	5,000	2,000	6,300
Block Heater Timer	On Going	2,500	12,000	200	500
EnerGuide For Houses Program	On Going	50	400	50	400
HVAC Program	On Going	130	400	155	400
Geothermal & Self-Generated Renewable Power Loan & Rebate	On Going	190	600	190	600
Commercial Programs					
Lighting Incentive	On Going	800	2,300	800	2,300
Energy Efficient Lighting For Small Business	On Going	1,000	1,800	1,000	1,800
HVAC/Boiler	On Going	160	700	200	700
Energy Performance Contracting	On Going	30	2,400	50	2,400
Municipal Ice Rink	On Going	135	0	400	2,000
Municipal Seasonal Lighting Program	On Going	135	400	200	600
Parking Lot Controller	On Going	450	3,900	450	3,900
Geothermal Rebate	On Going	25	500	25	500
Industrial					
Demand Response*	On Going	6,000	0	6,000	0
Energy Optimization	On Going	1,000	0	3,000	9,000
Renewable					
Net Metering	On Going	1,100	800	1,100	800
Small Producers	On Going	175	1,800	180	2,500

Numbers are estimates and subject to change.
*Demand Response programs are not operated to achieve energy savings but are used for system reliability purposes.

SaskPower forecasts DSM energy savings based on participation estimates, targeted technology, and industry experience and market data. They also consider the potential market, 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 applied to specific services.

As noted in the following table while the Demand Response is not operated to achieve energy savings it does provide a significant value to SaskPower and at a fraction of the cost to implement this system reliability program for the benefit of all customers whether they be Residential, Commercial or Industrial customers.

Table 6.14 - Demand Response Cost for 2009 to 2011

		2010	2011	
	2009	DR1	DR1	DR2
Number of Contracts	0	1	2	1
Capacity – MW	0	60	86	20
Total Events Called	0	4	3	0
Approximate Value To SaskPower	0	3.7 M	$8.1 M	TBD
Approximate Cost To SaskPower	0	$1.9M	$2.8M	$1.3M

In 2011, DR2 was in the pilot stage. While in the first season of operation there were no opportunities identified where the curtailable load provided an economic trading opportunity. However the potential for considerable return from this product exists but the suitability of customers relative to trading opportunities need to be developed expanding the full potential for this program.

The costs for DSM are estimated to be $20.0 million for 2013. 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 2011, total accumulated demand savings was 38 MW, on target for the year. For 2013 accumulated demand savings are targeted at 50 MW, on track to achieve 100 MW of savings by 2017.

In the updated September application, SPC has reduced the 2013 budget for Demand Side Management from the original of $27.0 million to $20.0 million although the energy savings are still targeted at the 50 MW goal for 2013.

6.2.3 New Operating Initiatives

In 2010 SaskPower commenced a number of new OM&A initiatives costing approximately $20.8 million, excluding the Integrated Carbon Capture and Sequestration (ICCS). These initiatives were summarized in our 2010 report but were mainly in the transmission and distribution areas for managing internal and external customer expectations. Other initiatives were in the areas of Finance and Enterprise Risk Management to support the Internal Project Control and assistance on the IFRS project.

Service Delivery Renewal initiative was to support the multi-phase, multi-year project that is expected to result in significant business process improvements and benefits for serving customers. The objective is to contribute a substantial increase in overall customer satisfaction through implementation of improved business processes and the supporting technology infrastructure. Additionally economic growth which was driving increased demand for services also needed additional human and financial support, both internal and external.

As noted in the 2010 report SaskPower in cooperation with the Government of Canada, has undertaken a number of initiatives at Boundary Dam for the ICCS Demonstration Project. With the success of this project the Boundary Dam ICCS demonstration project has resulted in a decision to proceed with $1.2 billion government-industry Partnership between the Government of Canada, Government of Saskatchewan and SaskPower to retrofit a coal-fired generation unit with carbon capture and enhanced oil recovery operation, resulting in low-emission electricity and carbon dioxide for oil extraction. This technological advance will renew the existing generation fleet and transform the aging Unit 3 at this facility to a long term producer of 115 MW of clean base load electricity. This project is scheduled to be completed in the later part of 2013.

Aside from the above ICCS project, the main initiative budgeted for 2013 is the Nuclear Initiative wherein SaskPower is examining all its options of the meeting the corporations long-term resource generation needs, or a portion thereof, through this initiative.

The business renewal initiative is forecast to generate $220 million in savings through avoided costs in 2013 (including finance cost savings) as compared to the base year 2009. As part of our due diligence the significance of the accumulated forecasted savings were delineated in the current and future years.

When originally established in 2010, the Business Renewal Office reported to Corporate Planning within the Corporate and Financial Services support function. The Business Renewal Office was staffed with 3 FTEs redeployed from other areas for 2011 and 2012. Going forward the responsibility for implementation of the efficiency projects will rest with the individual Business Units involved. Implementation costs have been prioritized and initiatives are included in the 2013 Business Plan where resources are available.

Responsibility for monitoring and reporting progress for the various initiatives is being shifted to the Performance Measurement and Benefits Realization department, transferred from the Service Delivery Renewal project office to Finance Department. The mandate of the Business Renewal Office was to review all aspects of SaskPower's expenses (including Fuel, Capital, Finance Charges, and OM&A) and make recommendations on initiatives that could provide savings. The actual costs for the Business Renewal Office in 2011 were $3.4 million. The budget for 2012 is $0.6 million and it is forecast that the actual result will be near the budget. The plan is to proceed with the initiatives as resources can be found to incorporate them into the 2013 and future Business Plans. Included in the 2013 budget is $3.0 million to be used to proceed with the business process of the initiative within the board category of "Asset Management".

Asset management was one of the areas where SaskPower was advised to refocus its processes with a view to generate significant future cost savings relative to the operation and management of their fleet of Transmission, Distribution and Power Production Assets. Strategic Asset Management business models are being deployed by leading utilities around the globe and the concept is gaining support by informed management, as well as regulatory and compliance standards boards. This new thrust is a risk based asset management and reengineering process which provides the foundation for improved business performance at the same time managing the utilities financial and operational risk (management) profile.

In finite terms, the bottom line for effective Risk Based asset management is the ability to understand and manage the right balance among risk, cost and performance. This will be a significant challenge for the leadership of SaskPower.

It is expected that it will take considerable effort to fully deploy the new process but significant financial savings are expected to accrue as this initiative moves from a “plan” to implementation.

6.2.4 Observations

As highlighted in the foregoing summary of SaskPower’s 2013 June Rate Application and September Mid Application Update, total actual expenditures were $575.1 million in 2011 including OM&A, other operating and DSM costs. For the current 2012 calendar year the Mid Application Updates forecasts expenditures to be $603.3 million. From the due diligence we have undertaken through interrogatories and investigations we are satisfied that this forecast is a reasonable expectation. This number is approximately $21 million greater than the forecast included in the original Rate Application. The recent 2012 summer storm that passed through central Saskatchewan caused significant material and supply costs as well as requiring a significant human resources effort to restore power to a very large group of SaskPower customers.

While the final costs of this event are still being tabulated, it is expected that approximately two-thirds or $14 million of the $21 million in additional expenditures, can be attributed to the 2012 storm activities. The balance of the budget overruns thus far is attributable to Boundary Dam Unit 6 emergency outage and Boundary Dam Unit 4 outage in addition to a number of less significant cost overruns. We have been assured that every effort is being taken within the organization, at the direction of the SaskPower’s President, to minimize budget overruns and we are reasonably confident that the final OM&A total is likely to be slightly less than the current forecast for 2012 of $603.3 million.

While the original Application had forecasted OM&A to be $627 million in 2013, the Mid Application Update reduced the budget forecast to $615.2 million. Total operating costs were increased by $9.1 million. $6 million were associated with proceeding with the Asset Management Program earlier than had been previously planned, wage and benefit adjustments and other less significant downward operating budget adjustments mainly associated with a decrease of $11.8 million cost in pension expense and Demand Side Management. DSM was reduced from the original $26.1 million to the current estimate of $20.0 million or approximately 25% less. However, the reduced budget of $20.0 million is slightly greater than 2012 budget allocation, so the expectation remains that the annual energy savings of 47,000 MWh for 2013 will be achieved, notwithstanding the reductions in the budget.

The nuclear feasibility study and initiative remains in the OM&A updated forecasts in the amount of $6.4 million.

We are extremely pleased to see that additional funds are being allocated to allow for the earlier implementation of the recommended Asset Management project initiative, as we consider this to be a major driver for future financial savings in the Generation, Transmission and Distribution expenditures. As noted earlier, Asset Management was one of the areas where SaskPower was advised by its external consultant to refocus its processes with an objective to achieving lower costs relative to the operation and management of their fleet of Transmission, Distribution and Power Production Assets. This refocused thrust is a risk based asset management process which provides the foundation for improved business performance at the same time manage the utilities financial and operational risk profile. We see the $3.0 million allocation as an investment to garner significant cost saving for the future benefit of all ratepayers.

With respect to the staffing, SaskPower is planning on adding 127 new staff in 2013, bringing the staff complement to 3,352 FTE's from the current 2012 total of 3,225. While this represents an increase of just less than 4%, the additional resources are to be focused in the Power Production, Transmission & Distribution, Service Delivery Renewal, Customer Information & Technology, and Human Resources units in the corporation. It appears the majority of the new additions are associated with undertaking the large capital program, improving customer service and accelerating customer additions, and with the new business renewal project, all of which are a fundamental requirement and investment to deliver a safe, cost efficient, reliable electric service.

We are comforted by the fact that the staff resource plan for 2014/2015 forecasts the staff compliment at the end of 2015 to be less than the current 2012 allocation of 3,225 FTE's which should improve the matrices in that future planning time period. In 2013 matrices such as customers per employees appear to be regressing negatively with this application, albeit very modestly and OM&A cost per customer are expected to increase to $1,242 up from the forecast for 2012 of $1,238, less than a 0.4% increase, a significant improvement over the annual increases that occurred over the period 2009 to 2012.

All of the foregoing activities suggest that SaskPower is taking the Panel's productivity/efficiency recommendations very seriously. We laud them for the efforts they are embarking on to drive efficiencies in their organization. While some of the recommended efficiency projects are still in the research or design phase and others are in the implementation phase. SaskPower is measuring the results of each of these initiatives to ensure forecasted outcomes are realized. SaskPower has used 2009 as the benchmark for base data to compare the actual costs, the forecasted future costs and the actual cost savings generated. As each of these projects become fully operational, only then will the actual results or annual financial benefits realized, fully quantified and the cost savings determined. However, it is important to remember that these initiatives are being undertaken to reduce the level of expected cost increases in the future, but it will not eliminate those costs entirely.

This Application where the total OM&A costs are forecasted to increase by $12 million over 2012 current forecasted results or approximately 2%, confirms, in our view, that SaskPower is making significant strides to operate more efficiently, especially in light of the fact that materials and other external costs in general have all faced upward cost pressures, and the significant increase forecast for the 2013 capital program. Even removing the cost related to the summer storm from the 2012 cost base, the 2013 forecasted costs suggest cost containment measures are producing positive financial results.

6.3.1 Efficiency and Effectiveness

SaskPower has developed a key strategic initiative priority to improve its efficiency and effectiveness throughout all aspects of its business. The 2010 rate application had incorporated savings of $18 million resulting from this initiative in that year. While these savings were incorporated into the OM&A expense category, the expectation was that the savings would be found in all areas of SaskPower operations. The program's aim is to save $2 billion, and/or realize cost increase avoidance of this amount over a 10-year period forecast.

In its last Report, the Panel recommended and the Minister directed SaskPower to "*…achieve annual productivity savings of 2% in its OM&A expenses.*" SaskPower's 2010 OM&A budget (net of ICCS) was $553M, and a 2% savings would amount to approximately $11 million. SaskPower's actual total OM&A expenses for 2010 were $22 million under budget at $531million) approximately 4% less than originally budgeted for that year.

The majority of these savings were in salaries and wages. The new President and CEO was appointed in August 2010 and immediately implemented a temporary freeze on creating new positions and on filling any employee vacancies. In the second quarter report of 2010 SaskPower was forecasting Salaries and Wages to be $240 million. At the end of 2010, Salaries and Wages were reduced to $227million, a savings of approximately $13 million from the July forecast. The net benefit of the reduced salaries and wages produced an additional $3 million in savings related to avoided employee benefit costs for a total cost saving of approximately $16 million.

For the longer term, SaskPower has initiated a Business Renewal process designed to achieve additional and significant savings relative to a business-as-usual perspective, measured using2009 as the base year to compare results gained from this new Business Renewal initiative. This is a long-term effort with significant focus on asset management (cradle-to-grave), materials management (inventory and warehousing), and procurement. In 2010 External resources were secured to examine all areas of SaskPower's business and identify areas of savings. This work was to be completed in first half of 2010. A second phase of the program was to introduce the changes in operations or systems needed to deliver these savings.

As expected both phases took longer than originally contemplated to complete reflecting the complexity of the organization, the robust economy which requires increased effort to service new and growing customers, and "to do it right" requires an investment of time, financial and human resources, some of which apparently still need to be acquired.

Progress will be measured by the addition of several new matrices to supplement existing ones, in the balanced scorecard that monitors asset productivity and spending efficiency in addition to the current labour productivity and thermal utility rate comparisons. SaskPower will continue to monitor and report on the results of the corporate productivity and efficiency program.

The Business Renewal Program has achieved significant benefits in a wide variety of areas at SaskPower. Some of the initiatives and their forecasted savings for 2013 include:

Finance Charges/Capital Structure - SaskPower has achieved savings in market opportunities with lower interest rates by shifting more of the borrowing to the short term and by replacing equity with lower cost debt in the capital structure. While these measures require a higher level of risk since short term rates are more volatile and debt must be supported by profitable assets to maintain a good credit rating, there are currently significant savings to be secured. There is risk to this process, but considered to be prudent in the current market. Forecasted savings are to be $140 million in 2013.

Procurement - is a focus on strategic sourcing and realizing better value from SaskPower's suppliers, with a long term goal of saving $40 million per year. For example, the first area in which savings were identified is transformer procurement with a forecast of savings of $4.7 million over the next five years. Additionally, an RFP process for light duty fleet vehicles was issued and it is forecast that there will be an additional $0.6 million in savings in this area over the same time period.

Reduce Power Plant Outage Duration and Frequency - Power Production is forecasting a reduction in costs in 2013 by $4 million in OM&A and $22.9 million in fuel by extending the annual outage cycle for power plants from 12 months to 24 months and by reducing the maintenance outages by 7 days. It is noted that this is an ambitious plan that works to optimize the maintenance schedule while still achieving the plant availability and avoiding forced outages.

Information Technology - SaskPower is producing cost savings in information technology through a number of initiatives such as implementing a sourcing strategy, enhancing project management practices, reducing the number of printers, outsourcing the service desk, introducing IP telephony and automated test tools for software upgrades. This is part of an ongoing effort to apply new technology to the business challenges of the utility industry and to improve efficiency. IT initiatives are forecast to save an estimated $9 million in 2013.

Office Space Utilization - SaskPower is working to reduce office costs by standardizing office designs, reducing the workspace areas, and putting more employees (including professional and supervisory staff) into cubicles rather than offices with the resulting savings of about $0.7 million per year.

Business Renewal initiatives or process reengineering are inherently long-term for organizations as complex and widely dispersed as SaskPower which is at the early stages of implementation with significant work plans under development. SaskPower has stated that it is important to recognize that Business Renewal 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.

Ongoing efforts in the Service Delivery Renewal (SDR) project which started in 2009 are also projected to continue delivering savings over the longer term.

SaskPower has many other initiatives underway to improve customer service through the SDR project. Through SDR, SaskPower reports it is improving internal processes and information systems to increase efficiency and effectiveness, and to ensure employees are provided with the tools needed to do their best work.

During 2011, SaskPower's replaced the more than 25-year-old billing system, which had become increasingly difficult to maintain because of the vintage of the system. The new technologically advanced Customer Relationship and Billing System will provide 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.

The implementation of the new system allows for the introduction of additional SDR initiatives, such as Advanced Metering Infrastructure (AMI). 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.

Through AMI, customers will have access to more timely information about their power consumption, with monthly bills being based on actual usage. AMI testing is currently underway in several Saskatchewan communities. A full provincial rollout is expected to be complete by the end of 2014, with AMI estimated to generate $470 million in savings over a 20-year period.

SaskPower has also streamlined the process to connect new customers to the system and have significantly reduced the service delivery time. SaskPower is working to eliminate the construction backlog in this area and are achieving improvements in on-time service delivery. In addition to improving service, a labour efficiency gain of approximately $17 million per year is forecasted.

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%. Savings of $8.9 million are forecast for 2013.

Overall, the SDR program is on target to deliver planned accumulated benefits of approximately $400 million by 2020 and it is the forward looking plan 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.

SDR is transforming 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 and less frustrated, by removing barriers that create inefficiencies in the work they perform. When SDR is fully implemented, decisions about serving customers will be made from a service business perspective and a customer's point of view. Employees will be appropriately supported by having the right tools and information they need to do their jobs.

The following projects have already been completed as part of SDR:

- **Telephony:** a web browser-based service routes customer calls through an interactive voice response system, improving service levels.
- **New Connect process**: by implementing a consistent process, the average time to provide a customer quote for new service has decreased by nearly half.
- **Customer relationship and billing system:** the new system provides a comprehensive view of customer information, can be adapted to changing business requirements, and can manage complex billing and rate structures.
- **Phase 1 of Field Worker project:** 525 laptop computers were installed in field worker trucks with mobile mapping software and automatic vehicle locators.
- Business process end to end documentation is complete for the Calculate and Collect Revenue, Deliver Products and Services, and Maintain Electrical System Reliability corporate business processes.

The following projects are part of SDR's 2012 business plan:

- **Phase 2 of Field Worker Project** (aka Schedule and Dispatch): Using centralized scheduling and dispatch functionality in two provincial locations, connected with laptop computers in service trucks, the goal is to optimize resources for prioritizing work, minimize travel, and shorten power outage durations.
- **Advanced Metering Infrastructure:** the province-wide project to install 500,000 electronic meters at residential and business locations, combined with a communication network and a meter data management system.

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. In 2012 a RFP will be prepared to secure a vendor for the long-term OMS solution simultaneously while an interim solution will be implemented to streamline the existing trouble call system, allowing for the corporate mainframe computer to be taken out of service by year-end.

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 December 2010 with a budget of $189.5 million. SDR is on budget for completion mid-2015.

Table 6.15 - SDR Financials for 2009 to 2015

SDR Financials, June 2012		OM&A	Capital	Total
Actual	2009	7,972,253	9,857,158	$ 17,829,411
	2010	12,284,220	15,486,528	$ 27,770,748
	2011	10,973,536	23,215,410	$ 34,188,946
	2012	3,907,513	12,041,552	$ 15,949,066
	Total	$ 35,137,522	$ 60,600,649	$ 95,738,171
Forecast	2012	4,506,887	24,217,259	$ 28,724,145
	2013	6,703,248	69,548,025	$ 76,251,273
	2014	10,147,575	82,360,643	$ 92,508,218
	2015	1,455,711	1,130,784	$ 2,586,495
	Total	$ 22,813,421	$ 177,256,711	$ 200,070,131
Program	Total	$ 57,950,943	$ 237,857,359	$ 295,808,302

As of December 2011, an annual benefit of $22.7 million was realized from continuous improvement and initiatives related to SDR program activities which is an improvement from the SDR Business Case benefits forecast of $21.1 million. Because SDR is measuring business processes, SaskPower was able to capture the impact of process changes (from SDR projects) in Transmission & Distribution and Customer Services. Improvement initiatives were built on the foundation of standardized business processes and performance metrics developed in SDR.

SaskPower uses the OM&A expense, as a percentage of revenue, as one method to illustrate the utilities operational efficiency. A lower ratio suggests that the operations are more efficient.

This indicator is somewhat sensitive as it is perceived to be a component that is wholly under management control. Other cost categories, such as F&PP or Depreciation, are considered to be less controllable. SaskPower's OM&A expense to annual revenue ratio has generally been in the 26% to 28% range (excluding pension expense adjustments) in the recent past and is 30.5% (excluding pension expense) in this application.

Over the longer term, SaskPower is seeking to reduce OM&A expenses to approximately 20% of revenue (excluding pension adjustments) through steady annual improvements that will put SaskPower in a position comparable to its peers in the electricity industry. The 20% target reflects the savings from initiatives such as SDR and the business renewal initiatives which are expected to eclipse the 2% per annum productivity gain recommended by the Panel.

SaskPower uses Thermal Utilities Rate Comparisons to other utilities as a measure the relative position of its rate structure against other thermal utility peers through an average of the rates paid per customer class, with an objective of keeping rates comparable to the national average. This benchmark is appropriate given SaskPower's large operating area, relatively small population base and ongoing requirement to deal with growth and infrastructure investments.

SaskPower's historical results have been positive, especially for large use customers with average rates at approximately 80% of those charged by industry peers. Although this advantage is eroding as new investment comes on line, peer utilities may face similar upward cost pressures. Detailed rate comparisons are discussed in another section of this report.

6.3.2 Observations

In their report to the Minister related to SaskPower's 2010 rate change 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. As the Panel and SaskPower both further noted, the utility was experiencing and would continue to experience increased capital, as well as operations, maintenance and administration costs. SaskPower had stated and has again confirmed that this phase is expected to continue for the next decade.

SaskPower previously had stated publicly that significant steps to operate the utility business efficiently, as well as to prudently manage and reduce costs were undertaken. However, the Panel challenged them to seek further productivity improvements from within the OM&A expenditure areas. In response, SaskPower initiated the Business Renewal Program in 2010, a major new initiative to vet out cost savings which is now proceeding into its second 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.

In 2010 SaskPower, with the assistance of independent consultants (KPMG, UMS, and Deloitte) undertook a collaborative major review and evaluation of all of SaskPower's 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 midst of implementing the various initiatives recommended by the consultants, identifying a number of savings or cost reduction opportunities which are defined as reductions in operating costs and other expenditures relative to those that likely would have occurred had these initiatives not been pursued or realized.

As part of the review, the Consultants were privy to substantial confidential information which demonstrated the breadth of the reviews, benchmarks considered and processes established including critical path analyses and established end targets. The three reports contained numerous initial broad recommendations for consideration, each of which will require further priority evaluations and the establishment of workflow teams to validate the recommendations and develop focused implementation plans. All of the numerous recommendations are in various stages of progress, and each requires time to accomplish the goal or target together with human and financial resources.

The key initiatives that will drive savings include:

- Redesigning the procurement process;
- Improving asset management processes;
- Improving start-up success rates;
- Revising inventory replenishment practices; and
- Improving plant staff productivity.

In addition to a review of on-line operating departments, the analyses reviewed SaskPower's support functions; financial, human resource, information technology, corporate services, corporate relations and safety areas which represent a significant component of the organization. These support business units 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.

Commencing in 2012 the Business Renewal Program is projected to realize the benefits of some of the initiatives designed to cut costs and/or improve efficiency, pursuant to established performance targets and measures. The benefits expected in 2012 will be quantifiable and transparently demonstrate the savings target of $ 12.3 million for the current year.

For 2013 the savings from these business renewal activities are forecasted to be $220 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 none the less a significant amount.

As highlighted in the Efficiency and Effectiveness subsection above the forecasted savings for 2013 is approximately $220 million. The cost savings initiatives in procurement, the reduction in power plant outage duration and frequency, information technology initiatives and office space utilization are real and significant. The reduction in finance costs and capital structure are also savings but we would suggest that these are just good current business practices which many utilities now employ which effectively result in significant cost savings for the corporation but we would not classify them as operation, maintenance and administration savings.

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 vital role to ensure and perhaps to advocate doe further advances or progression as the renewal or re-engineering continues.

It is important for the Panel, the public and SaskPower's customers to recognize and understand that successful Business Renewal initiatives will reduce, but not eliminate, the need for future rate increases, as rates are driven not only be operating costs, but also by the substantial, albeit prudent, investments in infrastructure renewal and growth required to maintain a safe and reliable electrical system as noted elsewhere in this report.

Typically in business, "business process reengineering" or 'business renewal' is the primary tool in which large organizations utilize to become more efficient, and to modernize and transform operations and processes that directly affect performance and customer satisfaction. Academics suggest the two cornerstones of any large organization are people and processes. Revamping these two basic elements can have dramatic effects on cash flow, service delivery and customer satisfaction. SaskPower's leadership along with its Board decision to re-examine these elements and other cost reduction initiatives with outside independent assistance, are to be congratulated. Success is not guaranteed, but with the leadership taking a wholesome approach and providing the general direction and specific focus should auger well for the organization as a whole and their end use consumers. The initiatives are intended to provide improved customer service at a lower future cost than otherwise would have been the case.

As SaskPower moves these initiatives forward it is expected at the outset that additional financial and human resources to ensure processes are reconfigured may be required. As results are achieved with appropriate streamlined processes in place cost reductions will be realized. The efficiencies and/or savings will not be realized immediately and it may be years before final results are fully known, materialized and quantified. It can be expected that the progress made by SaskPower on this Business Renewal Project will be examined in subsequent rate applications and annual reports. SaskPower should expect to report on the progress made on all the specific initiatives, benchmarks improved with specific end targets; and the financial and other benefits materialized together with a detailed financial quantification of the savings generated.

6.4.1 Depreciation and Amortization

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 experience, future expectations, and comparison of results to other Canadian Utilities.

The depreciation policy and study is reviewed annually and studied thoroughly approximately 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.

SRRP 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 it did and filed it with SaskPower in February 2011.

SaskPower's current internal policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. Gannett Fleming refers to this as the Average Group Life – Whole Life procedure. Gannett Fleming report confirms this is a widely used method for calculation of depreciation rates and has been accepted as a reasonable method in a number of regulatory jurisdictions throughout North America. Gannett Fleming confirmed the average service life using the following factors:

- Review of the physical plant based on site tours of typical facilities, and through conversations with management and operating staff;
- Review of the current capitalization and retirement policies;
- Review of the upcoming projects and outlooks;
- ASL estimates from previous SaskPower studies;
- ASL estimates from other peer electric generation, transmission and distribution utilities;
- And finally the professional judgment of Gannett Fleming.

It is noted that 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 forecasted annual depreciation rates and amortization costs by major plant categories from 2009 to current 2013 forecast.

Table 6.16 - Depreciation and Amortization for 2009 to 2013

Depreciation Rates and Amortization Costs						
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
Natural 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
Cogeneration	3.3%					4,962
Wind	2%-6.67%	13,213	13,915	13,220	13,168	12,722
Leased	4.0%	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 Contribuition Amortization						(13,675)
Asset Retirement Expense		5,215	4,269	4,269	2,750	1,201
Total Other Dep Exp		5,215	4,269	4,269	2,750	(12,474)
Total Dep Exp		354,100	321,247	289,699	266,180	228,518

The estimated impact of the 2010 Depreciation Study on the 2011 depreciation rates was as follows:

Table 6.17 - 2011 Depreciation Comparison

			(in millions)
Asset Group	**Estimated 2011 Dep'n Using Revised Rates**	**Estimated 2011 Dep'n At Current Rates**	**Variance**
Generation	$ 144.4	$ 136.2	$ 8.2
Transmission	21.20	21.80	(0.60)
Duistribution	68.50	68.50	-
Mining	0.90	0.90	-
Other Assets	36.80	36.20	0.60
Total	271.80	263.60	8.20

It should be noted that the Corporation would have increased its depreciation rates by approximately $9.5 million in 2011 under its existing methodology which calls for annual reviews of depreciation expense for appropriateness. This increase in depreciation expense would have occurred due to the decision to retire a significant portion of BD#3 in 2013; the decision to retire existing mechanical meters in 2014 as a result of AMI; and a decision to capitalize scheduled overhauls on new gas turbines.

The impact of the external consultant's review was a reduction in depreciation expense of approximately $1.3 million. As a general rule of thumb, for every $ 100 million in capital expenditures, SaskPower will see its depreciation expense increase by approximately $ 3 million.

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 and the current forecast for 2012 is $ 321.1 million. The Rate Application forecast for 2013 was $ 354.1 million as noted in the foregoing table but this amount has been increased to $ 363.0 million in the Updated September Application. The results represent a year over year forecasted increase of $ 41.9 million or 13% increase.

6.4.2 Observations

Depreciation and Amortization expenses are forecasted to increase from the original application forecast of $ 354.2 million to $ 363 million in the Mid Application Update. The following table highlights the change in forecast:

Table 6.18 - Depreciation for 2010 to 2013

SaskPower Depreciation (x $ millions)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Depreciation												
SaskPower Depreciation	265.9	249.5	(16.4)	280.1	268.4	(11.7)	298.4	295.6	(2.8)	313.9	314.0	0.1
Asset Retirement; Asset - Depreciation Expense	5.1	8.4	3.3	1.2	4.3	3.1	1.4	4.3	2.9	1.4	1.4	0.0
Total SaskPower Depreciation	**271.00**	**257.9**	**(13.1)**	**281.3**	**272.7**	**(8.6)**	**299.8**	**299.9**	**0.1**	**315.3**	**315.4**	**0.1**
Capital Lease Amortization	0.0	0.0	0.0	16.0	17.0	1.0	21.4	21.3	(0.1)	38.9	47.6	8.7
Total Depreciation	**271.0**	**258.0**	**(13.0)**	**297.3**	**289.7**	**(7.6)**	**321.2**	**321.2**	**0.0**	**354.2**	**363.0**	**8.8**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

As you will note from the table above, the additional $ 8.8 million in the updated forecast was mainly attributable to an increase in capital lease amortization. However, comparing the actual depreciation and amortization expenses of 2011 of $ 289.7 million, this category of expenses has increased over that period by $ 73.3 million which is one of the major drivers of increased revenue requirement. It is important to note, that this category of expense increase results from the capital investment made in the generation, transmission, distribution system and other capital undertakings including the service delivery renewal program during the past couple of years. With the substantial capital program currently underway it is expected that this category of expenses will continue to increase in like amounts during this decade of reinvestment by SaskPower.

Since SaskPower depreciation study was examined by Gannett Fleming which confirmed the methodology used to calculate depreciation rates and average service life of their assets as being appropriate, and since Gannett Fleming/SaskPower approach is consistent to methodologies used by other utilities we find the above forecast to be reasonable.

6.5.1 Finance Charges

Finance charges increased from $192 million in 2010 to $197 million in 2011. They are currently forecasted to increase to $202 million in 2012. All stated were under IFRS.

For 2011, with the overall debt levels increasing to $3.16 Billion, gross interest cost were $222.4 million with $11.7 million in interest attributed to construction that year. Offsetting interest income is $ 0.1 million together with debt Retirement Fund Earnings (Sinking Funds) of $ 24.7million produced net finance costs of $197.5 million.

SaskPower has recently been using more short term financing options rather than long term secured debt arrangements. According to SaskPower's calculations, this had lowered the estimated 2011 finance costs associated with new capital projects by approximately $5.9 million and is expected to grow in benefit as the size of the annual capital program has significantly increased to in excess of $ 1 billion. During 2011 short term advances were in excess of $ 250 million and carried an average interest rate of less than 1%, significantly less than current standard interest rate between 4% and 5%.

The makeup of Finance Charges for the years 2010 to 2013 are forecasted as follows:

Table 6.19 - Finance Charges for 2010 to 2013

SaskPower Finance Charges (x $ millions)								
	2010	2011	2012			2013		
	Actual	Actual	Initial	Final	Variance	Initial	Final	Variance
Finance Expense								
Long-Term Debt Interest	173.0	173.0	174.7	173.5	(1.2)	191.6	181.5	(10.1)
Finance Lease Interest	0.0	54.2	67.9	67.9	0.0	122.7	150.6	27.9
Short-Term Debt Interest	1.0	1.4	4.6	5.5	0.9	11.9	15.4	3.5
Accretion	0.0	5.0	5.2	5.3	0.1	5.5	4.7	(0.8)
Interest Capitalized	(15.0)	(11.7)	(21.5)	(28.0)	(6.5)	(44.8)	(45.9)	(1.1)
Other Interest & Charges	0.0	0.4	2.6	0.6	(2.0)	7.4	20.8	13.4
Total Finance Expense	**159.0**	**222.3**	**233.5**	**224.8**	**(8.7)**	**294.3**	**327.1**	**32.8**
Fixed Income								
Debt Retirement Fund	(20.0)	(24.7)	(17.6)	(22.5)	(4.9)	(19.8)	(19.9)	(0.1)
Interest Income	0.0	(0.1)	(0.4)	(0.2)	0.2	(0.8)	(3.9)	(3.1)
Total Fixed Income	**(20.0)**	**(24.8)**	**(18.0)**	**(22.7)**	**(4.7)**	**(20.6)**	**(23.8)**	**(3.2)**
Total Finance Charges	**139.0**	**197.5**	**215.5**	**202.1**	**(13.4)**	**273.7**	**303.3**	**29.6**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;								

Three of the major drivers of the Finance Charges 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.

Finance charges were $197.5 million in 2011, up approximately $ 6 million from 2010 half of which was as a result of commissioning Spy Hill Generating Station with the balance resulting from the decrease in interest capitalized during that year.

Gross interest expense changes with the gross debt balance and the interest rate charged. Interest during construction changes with the capital program as interest is charged to the capital projects while they are being built. Finance charges have been held relatively constant over the past few years as a result of the efficiencies of the short term financing program but with the major capital undertakings debt financing costs are expected from the actual net finance charges of $197.5 million in 2011 to $303.3 million forecasted (Mid Application Update) for end of 2013 up from $273.7 million forecasted in the June Rate Application. The main driver for this increase in forecasted interest costs is attributable to a finance lease coming into production earlier than anticipated in the June Application.

The overall financing costs reflect capital spending and this forecasted trend is expected to increase as debt levels increase, particularly when aging infrastructure must be 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.

6.5.2 Observations

As noted in the above examination of the Finance Charges expense forecast for 2013, there are three main drivers for finance expense. First is the amount of debt, secondly the interest charges on the debt and lastly, the amount of interest or finance costs on the debt that is capitalized.

Interest charges that occur during the acquisition and construction phase can be capitalized but as soon as the project (investment) is operational and used, those carrying charges are rolled into the asset as a fixed investment cost and amortized over the life of the asset.

SaskPower's Mid Application Update increased the Finance Charge forecast by $29.6 million to $303.3 million. SaskPower has confirmed the increase in finance charges is as a result of $18 million increase in the capital lease amortization as a result of North Battleford Energy Centre being commissioned earlier than originally forecasted. The balance of the finance charges increase, approximately $12 million, was the reclassification of pension expense from the OM&A cost category to finance charges.

The current forecast for this category of expense for 2012 is $202.1 million. With the current forecast for 2013 now $303.3 million, the year over year increase in finance charges is $101.2 million. This is a very significant increase notwithstanding the corporation's decision to carry a high amount of debt in short term financial instruments on which interest rates are significantly less. While interest on long term debt (as one specific category) has remained relatively stable, the increase in interest on finance leases has grown significantly.

From the information secured SaskPower has not issued any new long term debt since September 2010. All recent capital investment projects have been undertaken with short term financial instruments. At the end of 2013, should current arrangements prevail, SaskPower could be holding near to half of their debt in short term instruments which in itself, carries a risk profile. It is expected that SaskPower's Board needs to satisfy itself that this risk profile 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 interest coverage ratio is forecast to be 1.1 in 2013, it is expected to increase to between 1.3 and 1.4 in the next few years.

6.6.1 Debt Obligations

As a result of the current period of significant capital reinvestment in infrastructure and new generation required to meet the growing load demand on the entire system, SaskPower has approved a new Capital structure target range consisting of 60% - 75% debt during this period of high reinvestment.

Debt is a measure of SaskPower's financial leverage within the capital structure. A high number indicates that a high percentage of debt has been used, rather than equity, to finance operations and capital. SaskPower has maintained a long-term debt target of 60% for the last ten years. 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 each of the next five years are expected to average over $1 billion annually. This will lead to debt ratio results that exceed the 60% long term target, with a target of 75% in the medium term. In the long term, SaskPower plans to work towards reducing the debt ratio again to the 60% range.

The Capital requirements of SaskPower for infrastructure and capital programs averaged slightly less than $300 million in 2007, increasing to $422 million in 2008. However, in 2009 SaskPower budgeted for a significant capital program totalling $954 million. The 2009 actual program included $381 million invested in Infrastructure and Capital projects and $260 million in new generation projects. The total spent on capital in that year was $641 million, some $313 million less than forecasted.

SaskPower indicates this trend will continue and further, will increase over the next few years. Increasing capital expenditures impose the need to undertake borrowings which add to the long-term debt to fund these projects.

SaskPower's long-term debt has grown from $2.449 billion at the end of fiscal year 2005 to total net debt at the end of 2011 at $3.16 billion. With the size of the capital expenditures planned in 2012 and 2013, total debt is expected to be $ 5.18 billion at the end of 2013. This growth in outstanding debt drives the forecasted increases in the finance charges and depreciation expense of the Corporation.

Table 6.20 - Long-Term Debt for 2009 to 2013

Long Term Debt ($ millions)	2009	2010	2011	2012*	2013*
SaskPower Debt	2,472	2,672	2672	2,672	2,575
SPI Non-Recourse	0	0	0	0	0
Debt	0	0	0	200	850
Unamortized Debt Premium	21	36	35	34	33
Total Gross Debt	**2,493**	**2,708**	**2,707**	**2,906**	**3,458**
Short Term Advances	272	159	251	667	883
Total Debt	**2,765**	**2.867**	**2,958**	**3,573**	**4,341**
Lease Obligations	413	412	555	552	1,248
Remove DRF's	246	291	353	389	406
Long Term Debt	**2,932**	**2988**	**3,160**	**3,736**	**5,183**

* Both 2012 and 2013 are forecasted numbers.

As outlined above under the heading Lease Obligations, the Corporation has a number of Contractual Power Purchase Agreements (PPAs), which must be financially satisfied over the term of the contracts and as such are under IFRS proprietary contracts which 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 2011 annual report. There have been no changes to the long-term debt levels since December 31, 2011.

Table 6.21 - Long-Term Debt Outstanding (x $ million)

Date of Issue	Date of Maturity	Effective Interest Rate (%)	Coupon Rate (%)	Par Value	Unamortized Premium (Discount)	Outstanding Amount
July 20, 1993	July 15, 2013	8.63	7.81	$ 97	$ -	$ 97
December 20, 1990	December 15, 2020	11.23	9.97	129	(1)	128
February 4, 1992	February 4, 2022	9.27	9.60	240	6	246
July 21, 1992	July 15, 2022	10.06	8.94	256	(1)	255
May 30, 1995	May 30, 2025	8.82	8.75	100	(1)	99
August 8, 2001	September 5, 2031	6.49	6.40	200	(2)	198
January 15, 2003	September 5, 2031	5.91	6.40	100	6	106
May 12, 2003	September 5, 2033	5.90	5.80	100	(1)	99
January 14, 2004	September 5, 2033	5.68	5.80	200	3	203
October 5, 2004	September 5, 2035	5.50	5.60	200	3	203
February 15, 2005	March 5, 2037	5.09	5.00	150	(2)	148
May 6, 2005	March 5, 2037	5.07	5.00	150	(1)	149
February 24, 2006	March 5, 2037	4.71	5.00	100	4	104
March 6, 2007	June 1, 2040	4.49	4.75	100	4	104
April 2, 2008	June 1, 2040	4.67	4.75	250	3	253
December 19, 2008	June 1, 2040	4.71	4.71	100	-	100
September 8, 2010	June 1, 2040	4.27	4.75	200	15	215
				$ 2,672	**$ 35**	**$ 2,707**

In 2010, with debt levels rising to just under $3 billion (including short-term borrowing), gross interest was approximately $222.4 million with a slightly lower interest rate averaging around 6%. The average interest rates are declining as older debt is retired as noted in the above table. Because of the significant increase in planned capital expenditures planned for 2012 and 2013, interest during construction for 2010 grew from $15.1 million to the $ 44.8 million forecast for 2013. The overall net of these two items and the adjustments for income on debt retirement funds and foreign exchange the current forecast for end of 2013 is $303.3 million. This is $105.8 million greater than the 2010 actual amount of $197.5 million.

The 2010 and 2011 debt equity ratio was constant at 63% debt versus 37% equity. For 2012 the debt ratio is expected to increase to 66.4% increasing further in 2013 to 71.7% debt and 28.3 % equity.

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 1.1% in 2013, with current future forecasts remaining in the 1.4% to 1.6% range. Since 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.

While no dividend was declared in 2011, in the first quarter of 2012, Crown Investment Corporation, declared a special dividend of $ 120 million based on the 2011 financial results to be paid quarterly this year. Going forward with this application the financial forecasts do not anticipate future dividend payments during this capital extensive planning cycle.

It should be noted that as a general rule, for every $ 100 million in capital expenditures undertaken add $ 7 million of additional costs to SaskPower between the depreciation costs associated with the new investment together with interest costs on the debt. Therefore undertaking a $ 1 billion capital program would add annually $ 70-80 million in expenses that needs to be funded.

6.6.2 Observations

As noted in the above section SaskPower's long term debt grew from $2.449 billion end of 2005 to $3.16 billion at the yearend 2011. SaskPower's debt is now forecasted to be $5.18 billion year end 2013.

If that forecast materializes, in the period 2005-2013 SaskPower's debt will have more than doubled. This outstanding debt is the main driver of the finance charges of the corporation. While the debt to equity ratio is expected to be 71.3% debt and 28.7% equity, this ratio is not uncommon for integrated electric utilities. Indeed, SaskPower's ratio is stronger than many other Crown owned utilities even at that ratio, notwithstanding the significant reinvestments currently being undertaken.

It is important to note that under IFRS SaskPower must record all contractual Power Purchase Agreement 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 Table 6.20 lease obligations in 2013 are forecasted to total $ 1.248 billion.

SaskPower has the 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 only one issue matures (par value of $97,000) in 2013, $750,000 higher interest bearing securities will remain to be discharged in the 2020/2025 time period. While the debt ratio has been increasing in the last couple of year, it is considered reasonable, especially in the time of major (high cost) capital projects to be undertaken. It is expected that once the period of intensive capital expenditures has been completed, the debt ratio will slowly return to the lower end of SaskPower, approved target. While the interest coverage ratio forecast has been reduced for 2013, the future trending has this ratio moving upwards closer to 1.3 or 1.4.

While there is significant saving to be gained using short term financial instruments to fund significant capital projects as demonstrated by SaskPower in the finance charge section, there is also an offsetting risk element in the event interest rates move upwards and 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.

6.7.1 Foreign Exchange

As of December 31, 2009, SaskPower had no foreign currency exposure in either debt outstanding or outstanding capital market activities.

However, on the trading side the 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.

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. SaskPower is assuming the exchange rate for 2012 and 2013 to be at par.

6.7.2 Observations

As SaskPower has no significant exposure to foreign change costs, no further comments or observations are being made.

6.8.1 Capital Program Operating Expenses and Capital Structure

Actual capital spending was $422 million in 2008, $641 million in 2009, $538 million in 2010 and $625 million in 2011. SaskPower is forecasting to spend $998 million in 2012 and $1.15 billion in 2013. It is expected that SaskPower capital program/spending will continue being significant through the balance of this decade as it continues to experience a period of high capital reinvestment due to ongoing investments in existing infrastructure and new generating, transmission and distribution assets.

Actual and forecast capital expenditures from 2010 to 2013 are as follows:

Table 6.22 - Capital Expenditures for 2010 to 2013

Capital Expenditure ($ millions)	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Infrastructure & Capital Programs	389.1	437.1	482.7	659.8
SaskPower New Generation	148.9	187.9	515.3	490.2
Total SaskPower Consolidated	538.0	625.0	998.0	1,150.0

Capital spending was $279.8 million in 2007 and 2008 with the actual results being $421.9 million.

The forecast for 2009 capital expenditures was $954.2 million but only $ 641 million materialized. Details of the 2013 Capital Program are specifically discussed in Section 8.0 of this Report.

The effect of capital expenditures on future rates depends on a number of factors. These include the anticipated and actual capital construction costs, current and future dividend policy, cash flows required, interest and financing costs, and in SaskPower's view, the approval of the increase sought in this Application. The capital investments undertaken today will flow through to future year's income statements in the form of increased amounts of return, depreciation, and financing expenses. Those increased costs will result in an upward impact on future rate increases to cover those expected costs and to provide a reasonable return. Capital spending of $100 million translates to an approximate 0.5% increase in rates.

Since capital spending is not within the purview of the Panels Terms of Reference no further comments are being made.

The percent debt to equity ratio is a test used by lenders to determine the financial wellness of a corporation. This measure of debt expressed as a percentage of the total corporate financing structure reflects whether a corporation has a prudent level of debt. Another measure used by lenders is the interest coverage ratio.

Notwithstanding the growth in debt as a ratio to equity, SaskPower still has one of the stronger utility balance sheets relative to other utilities in Canada.

Table 6.23 - Debt Equity Ratio for 2009 to 2012

	2009	2010	2011	2012
Debt to Equity Ratio	62.4%	63.0%	63.0%	66.4%

Primarily, as result of the substantial capital program forecast for 2009, the debt equity ratio was less than the forecast of 64/36 at 62.4/37.6, due to projects coming in under budget and projects still in the construction phase. While the growing debt should be a concern to ratepayers, the capital spending is, from SaskPower's view, required and prudent to upgrade the current infrastructure of the Corporation to ensure it can deliver a safe and reliable product. Also from a ratepayer's perspective, it is currently less onerous to finance projects with debt than with the current cost of equity as debt cost about half the cost of rate of return on equity which target is 8.5%. The current debt/equity forecast for SaskPower in 2013 is 71.3%.

SaskPower's debt equity ratio target as directed by the Crown Invest Corporation of the Province of Saskatchewan is now in a target range of 60-75% with the balance being equity in the 40% to 25% range. In the future it is expected that SaskPower's ratio will remain above that target for a period in the future. However, the long term plan is to return the ratio to the lower end of the target range.

6.8.2 Observations

The majority of the increased revenue requirement in this application results from the investment made by SaskPower through its capital program. If you specifically review the Finance Charges and Depreciation and Amortization sections you will note revenue requirement has been increased by $143 million for 2013 mainly as a result of the Capital Program investments in prior years which have now been completed and operational.

While the Capital Program and Capital Structure is outside the purview of the Panel the impact of specifically the capital program, on rates, can be significant. It is expended this trend will continue for a few more years until the capital program returns to more normal levels.

The target range on the capital structure has been repositioned to reflect the significant capital program. The current capital structure has a debt to equity range of 60% to 75% with the equity ranges correspondingly at 40% to 25%, not out of the norm for provincially crown owned utilities.

6.9.1 Return on Equity, Rate Base and Overall Rate of Return

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 discharge their obligation to serve and meet its debt obligations.

According to the Application and the long-term business plan, the long-term return on equity target is 8.5%. If this application is approved as submitted, and if the forecasts materialize, the forecasted revenues are not expected to deliver a return on equity as mandated by the shareholder. As a result of the Mid Application update the requested increase in rates will only generate, if forecasts materialize, a 6.4% return on equity. Without the rate increase proposed, the rate of return would be approximately 1.9%. The 2012 forecast is now expected to generate an ROE of 8.9% for the current year.

Table 6.24 - ROE for 2009 to 2013

	2009	2010	2011	2012*	2013*
Return on Equity	6. 5%	13.4%	13.3%	7.6%	8.5%

*Application Forecast

Without the revenue to be generated by the proposed rate increase of 5.0 % (an additional $89.2 million) the rate of return would be reduced to approximately 1.9% based on the Mid Application Update forecasts.

The following table reflects all recent changes to the ROE for Canadian Utilities as approved by their specific regulator.

Table 6.25 - ROE Changes

Awarded ROE Summary	Date	Awarded ROE
British Columbia		
BC Hydro	2009	11.75%
Fortis BC	2010	9.50%
Pacific Northern Gas Ltd.	2010	10.15%
Terasen Gas Inc.	2010	9.50%
Alberta		
AUC	2011-1012	8.75%
Ontario		
Ontario Generic	2012	9.75%
Nova Scotia		
Nova Scotia Power Inc.	2011	9.32%
Newfoundland		
Newfoundland Power Inc.	2011	8.32%

The following table provides the continuity schedule showing the Gross and Net Plant, Depreciation, plant additions and plant retirements since 2009:

Table 6.26 - Plant in Service

Plant in Service Continuity Schedule ($000)					
	Jun-12	**2011**	**2010 IFRS**	**2010 GAAP**	**2009**
Plant in Service Beginning of Year	9,050,608	8,518,060	8,003,126	7,858,120	7,361,395
Additions	244,107	572,830	568,662	596,209	543,570
Removals	(14,116)	(40,282)	(53,728)	(53,728)	(46,845)
Plant in Service End of Year	9,280,599	9,050,608	8,518,060	8,400,601	7,858,120
Accum Deprn Beginning of Year	(4,098,199)	(3,845,928)	(3,628,402)	(3,563,432)	(3,365,521)
Depreciation Provision	(152,473)	(285,430)	(263,430)	(257,976)	(240,992)
Accum Deprn on Retired Assets	10,567	33,159	45,904	45,904	43,081
Accum Depn End of Year	(4,240,105)	(4,098,199)	(3,845,928)	(3,775,504)	(3,563,432)
Net Plant in Service	**5,040,494**	**4,952,409**	**4,672,132**	**4,625,097**	**4,294,688**
Customer Contributions				(367,302)	(340,374)
*Other Property Plant & Equip	617,698	434,383	251,126	277,240	304,567
Total Property Plant & Equipment	5,658,192	5,386,792	4,923,258	4,535,035	4,258,881

*Other Property Plant & Equip includes: asset retirement assets and construction in progress.

As shown on the above table, Rate Base consists of Net Plant (Plant in service, less accumulated depreciation and amortization of past customer contributions, including reconstruction charges*),* plus Working Capital Allowance (WCA), inventory carrying costs and other miscellaneous finance charges. Accumulated depreciation is comprised of prior year balances plus annual depreciation expense for assets newly put into service as well as an allowance for retired assets. Customer contributions and reconstruction charges are under IFRS and now taken into revenue as compared to GAAP where customer contributions were amortized over the useful life of the asset.

The following table indicates Actual Working Capital for 2009, 2010, 2011 and Projected Working Capital (for 2012 and 2013:

Table 6.27 - Working Capital for 2009 to 2013

	Actuals			Forecasted	
	2009	2010	2011	2012(2010Base)	2013(2010Base)
Working Capital	$70,267,175	$85,416,800	$77,316,927	$78,843,792	$85,375,000

Working Capital is calculated by taking 12.5% of the total of OM&A and Taxes. Please note that 2009 and 2010 actual are based on GAAP accounting while 2011 actual results and 2012 and 2013 forecasted are based on IFRS accounting.

As highlighted in the Rate Application, SaskPower reviews and compares all of its financial targets, particularly the ROE, relative to its peers across Canada, relevant regulatory decisions, and market expectations. In addition, business risk (uncertainty in a firm's operation) and financial risk (the amount of debt used to finance the firm's investments) unique to SaskPower influence these targets. In SaskPower's opinion, business and financial risk has increased in recent years due to:

- An increased reliance on natural gas for the generation of electricity. The cost of natural gas is more volatile than the cost of coal notwithstanding the current market prices
- An aging coal fleet which may be more susceptible to outages. While the risk is partially mitigated by increased maintenance and upgrades, the capital expenditures incurred result in greater financial risk and a requirement for higher returns and cash flows.
- The potential impact of increased environmental regulations on coal-fired generation plants

6.9.2 Observations

In reviewing rates of returns for other utilities both in Canada and the United States, the targeted forecast of 8.5% for SaskPower as determined by Crown Investments Corporation is a reasonable target. As noted from the table provided in the above section SaskPower's target of 8.5% is lower as compared to all but one of the electric based utilities mentioned and compared. Only Newfoundland Power Inc. utility is less.

The revised Mid Application Update has resulted in SaskPower proceeding with a proposed system average increase of 5% that will only deliver a return on equity of 6.4% for 2013, approximately 2 % less than the Business Plan target of 8.5%. SaskPower indicated that, based on this updated application revenue and expense forecast for 2013, the required rate increase to allow SaskPower to earn an 8.5% ROE in 2013 would have to be 7.5 % or approximately $ 55 million in additional revenue.

Rate base in June 2012 was $5,658,192,000 up from $5,386,792,000 at the end of 2011. Year end 2012 cannot be determined until the full year has expired.

The forecasted overall rate of return is projected to be less than the proposed Return of Equity target specified in the Minister's Terms of Reference. While the Panel under the Terms of Reference section D is obligated to advise the Minister that the current request will not meet the specified target.

6.10.1 Municipal, Corporate and Other Tax Obligations

Taxes and other costs for 2011 were $43.4 million. This is an increase of approximately $1.6 million more than the actual in 2010. The Tax obligation increased to $35 million in 2008 and is forecasted to be $ 47.5 in 2012, an increase of $12.5 million in 5 years.

Table 6.28 - Tax Obligation

SaskPower Taxes (x $ million)												
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Taxes												
Corporate Capital Tax	26.0	23.0	(3.0)	31.0	22.5	(8.5)	28.2	27.0	(1.2)	34.5	31.8	(2.7)
Grants In Lieu	19.0	19.0	0.0	20.0	20.4	0.4	19.6	20.1	0.5	21.0	21.2	0.2
Misc Tax Expense	1.0	0.0	(1.0)	1.0	0.5	(0.5)	0.2	0.4	0.2	0.5	0.5	0.0
Total Taxes	**46.0**	**42.0**	**(4.0)**	**52.0**	**43.4**	**(8.6)**	**48.0**	**47.5**	**(0.5)**	**56.0**	**53.5**	**(2.5)**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

While more investments or capital is required by SaskPower, there is expected a complementary increase in capital taxes, as invested capital drives the tax formula. However, as noted above, the overall capital tax expense category increased from $18.7 million in 2009 to the current forecast for 2013 of $31.8 million. Corporate capital taxes are calculated on the paid portion of corporate capital, which is driven by increased capital spending and borrowing. So there is an expectation that this category of expense will significantly increase as these capital investments are put into service.

Grant-in-lieu of taxes (similar to municipal property taxes) is paid to 13 communities based on the land and buildings in those communities. A municipal surcharge is also added to consumer's obligations and the money collected is on electrical revenues received from customers in those communities transferred directly to the municipalities.

6.10.2 Observations

The Mid Application Update reduced the forecasted Municipal, Corporate and Other Tax Obligations from the Application forecast of $56 million to $53.5 million. This reduction was mainly attributable to the reduced forecast for the Corporate Capital Tax. Corporate capital taxes are calculated on the paid portion of corporate capital, which is driven by increased capital spending and borrowing. Since these are calculated on the paid portion of the corporations capital which is driven by the capital spending and the progress made on specific projects or investments, the downward adjustments of approximately $2.5 million reflects that fact that the original forecast has not materialized both in the amount and expected time frame. The adjustments are appropriate and reasonable.

However, there is an expectation that this category of expense will significantly increase as investments are made and these capital investments are put into service.

6.11.1 NorthPoint Energy Solutions

NorthPoint is 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 as 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 of the formation of the subsidiary, 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 which are intended to deliver positive gross margins to SaskPower's financial resources 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.

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

NorthPoint has a new service agreement with SaskPower where it provides electricity export and import 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.

However, effective January 1, 2012 SaskPower and NorthPoint have terminated the transfer price agreement related to generation and load management services, electricity export and import functions related to the generation assets of SaskPower, and management of SaskPower`s natural gas supplies for its natural gas-fired power plants. In addition it provides SaskPower with the skills to manage its purchased power agreements. While these activities are still performed all of the costs and benefits are now, for 2012, recorded in SaskPower`s utilities financial records. While there is no change in the consolidated financial statements of the Corporation, the costs will now be 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. At year-end 2009, NorthPoint had 55 full time employees. For clarification, these FTE's were included in the SaskPower 2010 and 2011 FTE OM&A costs.

NorthPoint's activities as of March 2010 were reorganized into three distinct groupings; Front office (people who transact) 26 FTE's (4.5 with the gas management portfolio and 21.5 with the electricity portfolio), Middle office 9 FTE's dedicated to SaskPower services (people who analyze, control, set rules and report on transactional risk), and 6 FTE's in the Back office who settle and report on the financial and credit position of the company, in accordance with SaskPower's Risk Management Policy and Procedures requirements. The remaining FTEs were in the Executive and other Support services.

As a result of the reorganization there has been a reduction in their staff complement from 50 to 39 with the actual OM&A for NorthPoint Energy Solutions for 2011 was $8.4 million and a reduction in 2012 which is forecasted to be $6.4 million and $6.7 million for 2013.

Since 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 economically calls for the 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.

The Generation and Load Management Services unit also provides Import and Export Management Services and also works closely with other departments of SaskPower to review and investigate power system planning and operational processes that can be enhanced to increase efficiency and decrease SaskPower's costs.

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.

From the Rate Application SaskPower had forecast net sales from electricity trading for 2012 to be $15.8 million and $11.5 million for 2013. However, SaskPower`s aggregated unrealized market value adjustments were forecast to be negative $ 31.5 million for the current year. The unrealized market adjustments net for both electricity trading and natural gas trading are currently forecasted to be positive between $ 2-3 million.

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 requirements for natural gas, power contract management, and the potential for implementing market-based emission mitigation solutions.

During the period 2007 to 2011 NorthPoint has been able to generate a profit from trading activities totalling $ 49 million. In 2011, NorthPoint reported net income before unrealized market adjustments of $ 14 million and with unrealized market adjustments of $ 7 million had a net income of $ 21 million compared to a negative $ 2 million in 2010 after unrealized market adjustments.

NorthPoint on December 31, 2011 recorded a dividend payable to SaskPower in the amount of $18,877,000 as a current liability.

6.11.2 Observations

Both SaskPower and SaskEnergy including NorthPoint continue to work jointly to pursue structural efficiencies or other economies related to the gas procurement processes using all of their infrastructures to generate value and or savings for their ratepayers. NorthPoint confirmed that it will continue to work together with its parent 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.

As NorthPoint is not subject to the purview of the Saskatchewan Rate Review Panel other than for the cost effectiveness of the services provided no observations or recommendations are being made relative to this subsidiary.

6.12.1 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.

SaskPower International 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. As a result of this transition, 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 was built under SaskPower International but is now owned and operated within SaskPower`s generation fleet. This power plant began commercial operation on March 15, 2006.

Additionally, 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 operation of Centennial and the fly-ash business are carried out by SaskPower directly.

6.12.2 Observations

With SaskPower as NorthPoint's main business focus, giving attention to 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 needs of the utility. That coupled with the financial relationship between SaskPower and NorthPoint, wherein NorthPoint provides a dividend to SaskPower, from which the ratepayers benefit, the strict rules of affiliate transaction's is significantly mooted as compared to more robust utility-affiliate transaction needed by other organizations that have regulated and non-regulated operations wherein costs can be moved from one corporation to another to the benefit of perhaps one at the cost to the other.

We are satisfied that appropriate recognition has been given to this matter and formal agreements are in place to ensure each transaction is appropriately recorded.

As result of the change in structure made early to 2009 with respect to SPI International the needs to observe transactions are very limited both in nature and content. Shand Greenhouse operates a greenhouse to supply tree seedlings for the purpose of reforestation. The Shand Greenhouse has an agreement with SaskPower, whereby it operates the greenhouse and in turn SaskPower funds the greenhouse corporation for the costs incurred.

As a result of the foregoing we are satisfied measures are in place to ensure costs are tracked and allocated appropriately.

6.13.1 Other Costs

SaskPower has an "Other Expense Category "for expense items such Asset Disposal costs, Asset Retirements costs, Foreign Exchange and Environmental Expense. In 2011 the actual costs for this category was $7.7 million and forecasted to be $13.2 million in 2012. For 2013 the forecasted costs for these expenses is $9.0 million of which $8.0 million is forecasted for Asset Disposal costs.

The following table summarizes the Other Expense Category.

Table 6.29 - Other Expenses for 2010 to 2013

SaskPower Other Expenses (x $ million)											
	2010			2011			2012			2013		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Initial	Final	Variance	Initial	Final	Variance
Other Expenses												
Asset Disposals					2.9		8.0	7.0	(1.0)	8.0	8.0	0.0
Asset Retirements					1.9		1.6	6.2	4.6	1.0	1.0	0.0
Foreign Exchange					(0.1)		0.0	0.0	0.0	0.0	0.0	0.0
Environmental Expense					3.0		0.0	0.0	0.0	0.0	0.0	0.0
Total Expense	**0.0**	**0.0**	**0.0**	**6.2**	**7.7**	**1.5**	**9.6**	**13.2**	**3.6**	**9.0**	**9.0**	**0.0**
2012 Initial Submission Forecast based on March 31 Forecast; 2012 Final Submission Forecast based on June 30 Forecast;												

SaskPower had requested that no dividend payment be paid in both 2009 and 2010 in light of its future significant capital requirements. The Minister at that time confirmed that SaskPower would not be required to pay a dividend in 2010.

However, in the first quarter of 2012, it was determined that SaskPower would pay a special dividend of $ 120 million to Crown Investment Corporation as result of higher than expected net income generated in 2011. This special dividend will be paid in quarterly installments starting March of 2012.

What is not clear, however is what the government policy on dividends going forward is in the past the decision on whether or not a dividend was payable, was reviewed annually. Should SaskPower be relieved of a dividend obligation, it would permit a greater proportion of SaskPower's capital investments to be self-financed out of cash flow, hence reducing borrowing requirements and the associated interest expense. However, with SaskPowers 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.

Water rental charges for 2010 were $4.07430/MWh and $ 4.27802 for 2011, relative to 2008 and 2009 fees of $3.5477/MWh and $3.84006/MWh respectively. For 2012 the water rental fees is $ 4.47053/MWh and for 2013, it is forecasted to be $ 4.69406/MWh. Water rental fees paid to the Province are a function of the use of water in SaskPower hydraulic generation facilities. Water rental payments have averaged between $15 and $20 million annually over the past few years.

Also included in the fuel and purchased power expense category are the royalties paid for coal. Coal royalties paid were $22.9 million in 2010 and $22.4 million for 2011. Coal royalties are expected to grow to $25.3 million in 2012 and 26.2 million in 2013.

Lastly, the Power Corporation Superannuation Board retained an independent actuary to perform an actuarial evaluation of the assets and liabilities of the Power Corporation Superannuation Plan as at December 31, 2011. The December 31, 2010 evaluation of the accrued financial position of the plan showed a deficit of $ 146,809,000 with the results of the current (December 31, 2011) evaluation disclosing a deficit of $ 261,831,000 or an increase in excess of $ 115 million. The independent report disclosed that the increased deficit was mainly associated with lower than expected investment income coupled with a change in actuarial assumptions.

For the year ending on December 31, 2011, $143 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., While we have no further information available on the impact of the amended version of IAS 19 on SaskPower`s financial statements, it is expected by year end 2012 it will be so recognized.

6.13.2 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 forecast of $ 13.2 million in 2012. The actual costs in 2011 were $ 7.7 million.

Dividends, Water Rental Fees, Coal Royalties and Pension Costs are all obligations of SaskPower which impact the corporation's annual revenue requirement but on which they have no control as to the amount. 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.

Likewise, water rates and coal royalties and the requirement for a dividend are determined elsewhere. SaskPower is obligated to fund those costs and they are recognized as other costs that need to be forecasted and discharged.

6.14.1 Future Financial Outlook

In its last Application SaskPower projected load growth from 2010 to 2019 to increase at significantly greater rates than experienced in the recent past. Total system energy requirements were expected to increase by an average of 3.1% per annum and system peak loads by 2.4% per annum. This growth compared to 1997 to 2007 average system increases of 1.6% per annum and the system peak load of 0.7% per annum. The recent economic activity in Saskatchewan resulted in increased demand for electric energy which saw the 2011 system peak grow by 8.3% and energy consumption by approximately 4%.

Within the current planning horizon of the next 10 years, SaskPower projects annual energy requirements to increase by an average of 2.5% 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 2.1% per year over this timer period. While the expected annual system average growth is expected to be 2.5%, the Power Class growth is forecast at 5.3%. Additionally, the growth in Power Class energy requirement is expected to be greater in the short term (7.9%) from 2012 to 2017.

Residential sales on the other hand in the past 10 years (2000-2010) for the grid residential class increased by 537.2 GWh representing a 2.1% average growth rate over that period. DSM adjusted grid residential energy sales is expected to grow from 2,880.8 GWh in 2011 to 3,505.9 GWh in 2021 a total growth of 425.1 GWh which equates to an annual growth rate of 1.4% .

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 Plan. Capital expenditures are expected to average near $1 billion over 10 years, as more fully discussed in Section 8.0. 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 further 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 million per year. Given the current capital budget is in excess of a billion $, this impact alone would require an annual increase in rates of about 4.4%.

As discussed in Section 8.0, the only realistic short term approach to meeting the immediate increase in load expected in 2013, or 2014, at the latest is to 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 per GWh basis. OM&A costs would be expected to increase due to increased infrastructure maintenance requirements and customer service costs, which should be somewhat off-set by efficiencies and productivity improvements flowing from the Business Renewal initiatives.

The expected growth requiring additional capital and operating costs will increase the financial needs 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 products that are extremely competitive, not only nationally but also globally and are sensitive to global price pressures. This, combined with the need to preserve company confidentiality, makes it difficult for any projected expansion plans to remain firm as circumstances change, often several time per year. This 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 sales income and other risks, such as that respecting fuel purchasing requirements and costs. As a greater portion of generation fuel is 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.

The current forecasts have seen a 4.2% 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. This has resulted in delays of a number of major projects and which it is difficult to speculate on when these projects may be restarted. This in turn impacted the Mid Application Update forecasts provided by SaskPower by approximately a $60 million decrease in revenue from what was originally forecasted.

In the recent forecast for 2013 SaskPower used a 2% inflation rate, 1.2% short term borrowing rate, together with long term interest rates of 3.4% as compared to the 2010 forecast, wherein SaskPower used a 2% inflation rate and a 5.7% long-term interest rate as basic assumptions. Additionally the forecast for natural gas cost has been reduced to $ 4.00 a GJ compared to overall unit cost of $5.19/GJ, finally used in 2010.

The following table demonstrates the projected growth in revenue and expenses from 2010 to 2013. Forecasting in the current environment is challenging, but 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 economy from 2012 onwards of both Saskatchewan and Alberta.

Table 6.30 - Total Capital Requirements (x $ million)

Description	2010	2011	2012	2013
Revenue	$1,691	$1,837	$1,847	$2,015
Expenses	$1,468	$1,598	$1,682	$1,889
Net Income	$204	$248	$165.9	$126
OM & A Expense	$513	$575	$603	$615
Past & 2013 Rate Increase	4.50%	0.0%	0.0%	5.0%
Sales (GWh)	18,682	19,675	20,275	21,698
ROE	13.4%	13.2%	8.8%	6.4%
Net Debt	$2,995	$3,166	$3,646	$4,341
Average Equity	$1,758	$1,864	$1,921	$2,047
Debt Ratio	63.0%	63.0%	66.4%	71.3%
Dividends Expected to be Declared	$0	$0	$120	$0
Capital Generation	$568	$624.5	$515	$490
Other	$309	$276	$483	$660
Total Capital Requirements	**$568**	**$624.5**	**$998**	**$1,150**

* Application

6.14.2 Observations

With current 2012 projections expected to be reasonably accurate, we note that revenue increased by approximately 9.6% over the 2 years from 2010 to 2012 while the system average increase for Saskatchewan ratepayers was 4.5% (implemented on August 1, 2010), generating incremental revenue from $1.69 billion to $1.85 billion. Expenses for the period 2010 to 2012 increased from $.1.47 billion to $1.68 billion or approximately a 2 year increase of 14.6%.

The data in the Mid-Application update indicates that 2013 revenues and expenses are annually forecasted to increase approximately 9.1% and 12.4% respectively over 2012. The corresponding load growth over the 2 years to 2010 & 2011 was 21.5% and the 2013 load is forecast to be 7% greater than it was in 2012. Net income is forecasted to be $126 million in 2013 generating a return on equity of approximately 6.4%, over 2% less than the ROE target of 8.5%.

Going forward we received 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 included as part of the financial assumptions. With the significant capital required by the corporation, relief from the need to pay dividends will eliminate some financial stress the overall need however will remain substantial. With this growth in cost and electricity demand, 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.

This expected net growth in expenses is partially offset by the growth in additional sales but the remainder would be required from future rate increases. Major cost categories, including F&PP which amounted to $484.4 million in 2011, are expected to be $494.5 million in 2012 and $545.4 million in 2013, and thereafter increasing in similar future percentage increases. The increase is attributable to a significant increase in the volume for natural gas fired generation units to meet the expected demand as well as anticipated market price increases, offset somewhat by increase efficiencies of gas fired generation units. The current price for natural gas is near the $4.00/GJ range compared to the $5.19/GJ which as forecast for 2010. Within the future planning window, natural gas prices are expected to increase.

In addition, increased interest costs associated with the new debt required for the 2011, 2012, and 2013 capital program as well as the subsequent depreciation and amortization costs flowing from the expanded capital program could see the 2014 revenue requirement being significantly greater than that requested in this Application which for these two expenses categories alone the forecast is in excess of $140 million. The possible rate increases required, beyond 2013, 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 together with the benefits of SaskPower's efficiency programs.

Planning for new generation is a very significant and increasingly complex undertaking. Uncertainties with respect to viability of clean coal generation, future hydro facilities and the probability of future growth concentration in the far north, as opposed to the traditional load growth in the south of Saskatchewan, and the requirement for significant transmission infrastructure expansions and/or upgrades lead to these complexities. As noted from the above table, if these planned capital needs are undertaken, the debt ratio of SaskPower could increase from the 2010 ratio of 63.8% to over 71% by the end of 2013. The Corporation's interest coverage ratios are forecasted to deteriorate from 2.0 in 2011 to 1.1 in 2013 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 ambitious capital program plans, but will certainly remain within the range of other electric utilities.

To September 2012, SaskPower has spent approximately $415 million for the Boundary Dam unit 3 ICCS project. The total budget is approximately $1.238 billion, of which $140 million is being funded by a federal government grant. The overall project is currently on time and budget, and is expected to be completed in late spring of 2014. The remaining funds will be expended during 2013 and 2014 and comprise a significant portion of the capital program, which is expected to peak during these years at amounts in excess of $1 billion per year. Incremental revenues are expected from CO2, flyash and sulphur sales and will partially offset operating costs of the carbon capture facilities. The Boundary Dam project will demonstrate the economic viability of longer term coal fired generation, which could be of significant benefit to SaskPower as coal is abundant in Saskatchewan, and is a relatively cheap fuel source.

SaskPower continues to face significant financial challenges in the near and long-term. The current aging infrastructure costs more to operate, requires a higher standard of maintenance, and higher capital spending. These costs will start to erode the debt equity and interest coverage ratios of SaskPower drawing it more in line with industry norms. This, coupled with the increased capital demands for new generation, and future CO2, as well as other emission mitigation costs, will negatively affect the Corporation's financial flexibility and its subsequent ability to withstand future demands and negative results. This will be further magnified as subsequent new generation is installed to replace older generation assets that are at, near, or even beyond the end of their useful life.

SaskPower has recognized that it has not been operating to optimum efficiency. During the last two years 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 but more needs to be done. In order for these initiatives to be successful will take time, upfront financial support and strong commitment by the leadership and the organization as a whole. SaskPower`s Business Renewal Program wherein efficiencies are to be generated by changing the culture and processes of an organization. With a corporation as large as SaskPower, reengineering will not come easy and be without challenges. We are however pleased with the process and the focus of the organization with respect to the Business Renewal Program thus far.

The success of this program in seeking out cost savings, streamlining customer services and operating more efficiently will be the final determent of future rate increases. The magnitude of the future rate increases for SaskPower customers as result of the capital investment already made and in the capital plan coupled with fuel and purchase power to meet new demand will on their own be substantial and the success of the business renewal efficiency initiatives could keep the average percentage increases going forward in the future in the ball park of what customers are facing today. But as described in Section 13, there are elements and risk outside the control of SaskPower which could negatively impact future rates further.

Additionally, since SaskPower's debt is ultimately reported on the consolidated financial statement of the province, consideration must be given to ensure results from those decisions do not adversely affect its taxpayers.

7.0 System Operations

7.1 System Description

SaskPower serves a geographic area of approximately 651,000 square kilometers (km). In 2011, SaskPower reported employing over 2,720 employees, resulting in 3,000 full-time equivalent positions, which is expected to increase to 3,225 in 2012 and then gradually reduce to about 3,200 by 2016. Its generation fleet is fuelled by coal, hydroelectric, natural gas, and wind. Additionally, it purchases electricity through other power, generation, and cogeneration sources as well as through heat recovery projects and imports from other electric utilities outside Saskatchewan.

SaskPower purchases power from Saskatchewan Independent Power Producers (IPPs) through Purchase Power Agreements (PPAs). These PPAs apply to Red Lily and SunBridge Wind Power, Spy Hill Generation, Meridian and Cory Cogeneration, and NRGreen Heat Recovery in Kerrobert, Loreburn, Estlin, and Alameda. At 2011 year end SaskPower's total available generation capacity, excluding imports was 4,094 MW (3,513 MW by SaskPower generating units and 581 MW through PPAs).

SaskPower's transmission assets include 12,576 km of power lines (12,404 km in 2009) and 55 high voltage switching stations located across Saskatchewan (56 in 2009). SaskPower's transmission system also has interconnections with systems in Manitoba, Alberta, and North Dakota. SaskPower's distribution assets include 139,390 km of power lines (145,169 km in 2009) and 186 low voltage substations in Saskatchewan (184 in 2009).

SaskPower manages more than $6.3 billion in assets to generate and supply electricity to its customers (which was valued at approximately $4.9 billion at the end of 2009). SaskPower services more than 486,000 accounts (which were approximately 457,000 in 2009). Several customers have multiple accounts due to a business structure while farm infrastructures result in multiple meters.

7.2 System Generation Capacity and Purchased Power

The system map below shows the location of the related generating facilities as well as SaskPower's major transmission lines and interconnects. The total generation capacity owned or contracted by SaskPower by fuel source as of December 31, 2011 was:

Table 7.1 - Total Generation Capacity for 2009 & 2011

	2011 MW	2011 %	2009 MW	2009 %
Coal	1,686	41.2%	1,682	43.8%
Hydroelectric	853	20.8%	854	22.2%
Natural Gas	813	19.9%	663	17.3%
Wind	161	3.9%	172	4.5%
Total Owned	**3,513**	**85.8%**	**3,371**	**87.8%**
Total Contracted (PPAs)	**581**	**14.2%**	**469**	**12.2%**
Total Available Capacity	**4,094**	**100.0%**	**3,840**	**100.0%**

SaskPower system map

As of December 31, 2011

AVAILABLE GENERATION (net capacity)

HYDROELECTRIC

1. Athabasca Hydroelectric System - 23 MW
   - Wellington (5 MW)
   - Waterloo (8 MW)
   - Charlot River (10 MW)
2. Island Falls Hydroelectric Station - 101 MW
4. Nipawin Hydroelectric Station - 255 MW
5. E.B. Campbell Hydroelectric Station - 288 MW
13. Coteau Creek Hydroelectric Station - 186 MW

NATURAL GAS

3. Meadow Lake Power Station - 44 MW
7. Yellowhead Power Station - 138 MW
9. Ermine Power Station - 92 MW
10. Landis Power Station - 79 MW
12. Queen Elizabeth Power Station - 430 MW
15. Success Power Station - 30 MW

WIND

16. Cypress Wind Power Facility - 11 MW
18. Centennial Wind Power Facility - 150 MW

COAL

20. Poplar River Power Station - 582 MW
21. Boundary Dam Power Station - 828 MW
23. Shand Power Station - 276 MW

INDEPENDENT POWER PRODUCERS

6. Meridian Cogeneration Station - 210 MW
8. NRGreen Kerrobert Heat Recovery Facility - 5 MW
11. Cory Cogeneration Station - 228 MW
14. NRGreen Loreburn Heat Recovery Facility - 5 MW
17. SunBridge Wind Power Facility - 11 MW
19. NRGreen Estlin Heat Recovery Facility - 5 MW
22. NRGreen Alameda Heat Recovery Facility - 5 MW
24. Red Lily Wind Power Facility - 26 MW
25. Spy Hill Generating Station - 86 MW

TRANSMISSION

- 230 kV
- 138 kV/115kV/110kV
- Switching station
- Interconnection

7366/Jan2012

7.3 System Dispatch Rules

SaskPower continues to use its multiple fuel source options for dispatching fuel sources. SaskPower prioritizes its dispatching based on incremental costs of production, dispatching least cost fuel sources first and highest cost units last. This is done in conjunction with optimizing its fleet generation and costs considering factors and criteria which include: 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, wind, and coal-based generation units first. 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 must take into consideration SaskPower's physical and contractual constraints, energy and demand growth, market prices, and new generation units being put into service. SaskPower has contractual take-or-pay obligations related to the Meridian and Cory Co-Generation which currently approximates to 2,300 GWh/year. The new North Battleford Energy Centre will have a "must run" (take or pay) obligation of 1,800 GWh/year, commencing in 2013.

The next hierarchy is Hydro and Coal generation which can produce up to 3,302 GWh/year hydro – normal flow (while the maximum capacity is 4,600 GWh/year for high flow) and coal at 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.

Table 7.2 illustrates SaskPower's owned and purchased annual volumes from 2009 to 2013.

Table 7.2 - Generation and Purchased Power Volume (in GWh)

Class	2009	2010	2011	2012	2013*
Coal	12,317	12,038	11,614	11,694	11,777
Gas	3,432	3,683	4,032	4,749	7,200
Hydro	2,962	3,866	4,641	4,136	3,327
Imports	440	518	502	652	288
Wind/Other	714	656	823	834	848
Total Fuel & Purchased Power	**19,865**	**20,759**	**21,611**	**22,063**	**24,177**

The following table shows the actual results (2009-2011), 2012 estimated and 2013 projected fuels costs by fuel type, as per the original Application.

Table 7.3 - Annual Fuel Costs (x $ million)

Class	2009	2010	2011	2012	2013	2013 Updated
Coal	$194.00	$212.00	$219.4	$223.3	$242.4	$237.9
Gas	$266.00	$230.00	$154.8	$148.6	$256.7	$241.4
Hydro	$ 11.00	$ 16.00	$20.0	$18.1	$14.5	$15.8
Imports	$19.00	$20.00	$24.4	$28.9	$19.1	$14.4
EPP/Wind/Other	$ 19.00	$ 14.00	$26.0	$27.8	$30.3	$34.7
Total Fuel & Purchased Power	**$509.00**	**$492.00**	**$444.6**	**$446.7**	**$563.1**	**$546.2**

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 7.4 - Actual 2009 to 2011, Estimated 2012 and Projected 2013 Fuel Costs per Delivered MWh - ($/MWh)

Class	2009	2010	2011	2012	2013
Coal	$15.72	$17.63	$18.89	$19.09	$20.43
Gas	$77.77*	$49.86	$48.51	$41.36	$32.98
Hydro	$3.88	$4.09	$4.30	$4.37	$4.36
Imports	$57.05	$39.21	$48.56	$44.30	$58.47
EPP	$73.88	$76.25	$77.78	$78.93	$80.86
Wind/Other	$4.66	$4.54	$22.56	$23.44	$25.11

*Includes O&M and Capital costs for gas based PPA. Change to IFRS removed these costs.

The unit cost of delivered fuel is used to determine the order of utilizing generation facilities by fuel type, from least to most costly. All else being equal the order continues to be hydro, coal, imports, wind, cogeneration, EPP/IPP and natural gas. Oil or imports are used to supply non-grid energy, which is independent of other fuel types.

7.4 Observations

SaskPower's priority for dispatching generation units remains unchanged and its objective continues to be ensuring system integrity, safety and reliability. System integrity, safety and reliability can take precedence over decisions based purely on economic considerations at certain times. Also overriding economic dispatch of units, in terms of dispatching lowest fuel units first, are take or pay obligations with respect to SaskPower's PPA Terms and Conditions. Once these priorities and contract obligations have been satisfied, the order of dispatch by fuel source then is from least costly to most costly, notably hydro, coal, wind to the extent possible in the real time sense and natural gas. The use of import power is determined by electric demand and market price.

The daily operation of SaskPower's electrical system is complex and dynamic and can change at any minute throughout every day of the year. Operations are controlled through the many data gathering and analyses programs, systems and procedures at SaskPower's Central Operations Control Office, as well as those of NorthPoint. This system operation, in order to meet the energy and demand requirements of its widely dispersed customers, coping with unplanned outages related to severe weather, at times highly volatile electricity and natural gas prices, is critical and requires a dedicated and continuous effort. It is our view that SaskPower operates its system in an effective and efficient manner.

8.0 SaskPower Historic and 2013 Capital Program

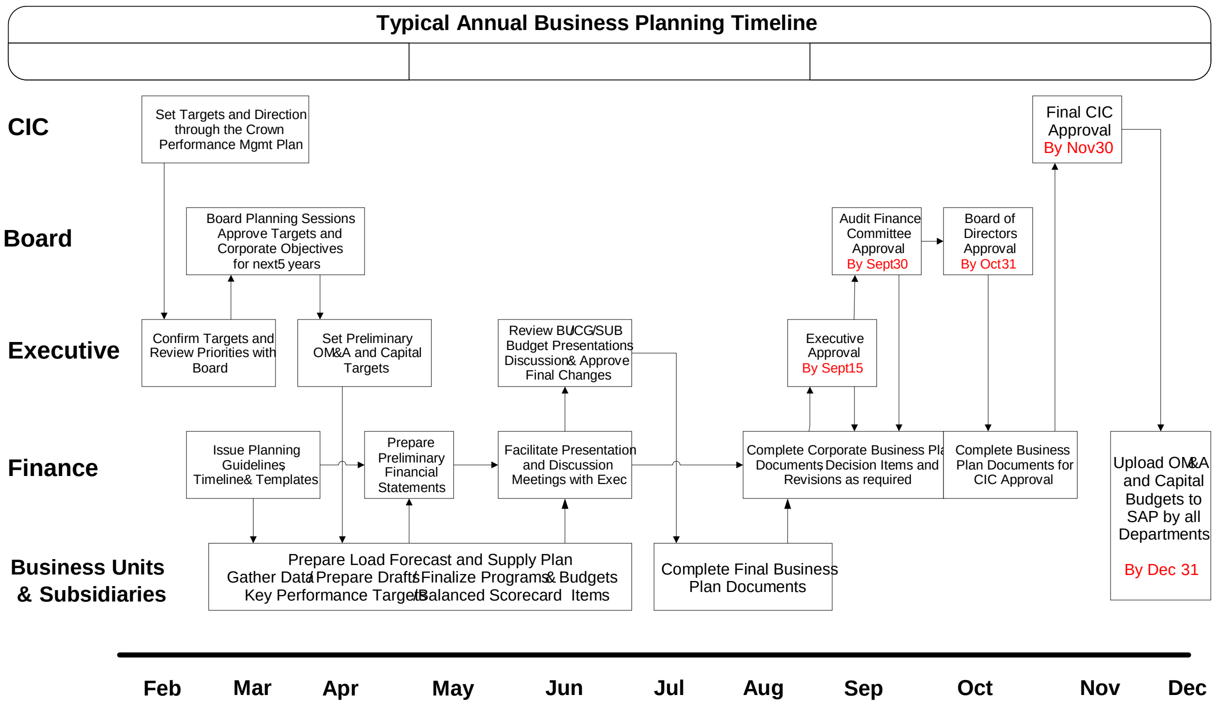
8.1 Purpose and Capital Budgeting

SaskPower constructs additional generation and transmission assets to meet growing demands for energy, and also refurbishes and upgrades existing facilities for purposes of capacity, reliability service improvement, and environmental mitigation under its Capital Program. Annual capital expenditures are the most significant component of any increase in rate base for SaskPower. 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 2010 Application.

Preliminary budgets are revised as required, as is the organization's spending plan. The major functional areas are Generation, Transmission & Distribution, Customer Service, and Other. The annual business plan is reviewed and approved by both SaskPower's Executive and 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 approvals are shown in the chart on the next page.

Chart 8.1 - Capital Expenditure Approval Process



For each capital project, detailed financial analyses identifying the cost and benefits, as well as costs and benefits of alternatives are conducted. Additionally, 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 are also provided. Each project must meet or exceed SaskPower's cost of capital requirements and have positive net present values before the project is entertained and 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. That is, if the capital program in year 1 is justified and approved at $1.0 billion and year 2 also at $1.0 billion, and the first year expenditure is $900 million, the year 2 program is not automatically approved at $1.1 billion. Rather, the year 2 must be justified and approved in its entirety, and budgetary limits may eliminate some year 2 projects included in the original year 2 estimates. Generally, for every $100 million in capital expenditures, SaskPower's depreciation expense will increase by $3 million and finance charges by $4 million at current interest rates. Additionally, the amount of ROE incremental revenue requirement would also increase by the allowed ROE rate, in this case 8.5% (reduced to 6.4% in the Mid-Application Update), of the capital expenditure. With an allowed ROE 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.

As an illustration, SaskPower's actual and forecasted capital program from 2010 to 2013 is approximately $3.34 billion. This would translate into a revenue requirement for depreciation and finance charges of $234 million greater on December 31, 2013 than there were on December 31, 2009. SaskPower's 2013 Capital expenditures, estimated to be $1.45 billion in the 2012 Business Plan were reduced to $1.15 billion in the 2013 Business Plan, while the 2012 capital expenditures are now projected to be $998.0 million.

The actual results for 2010 and 2011, and budgets for the 2012 and 2013 Capital Expenditures are as follows:

Table 8.1 - Capital Program Business Unit for 2010 to 2013 (x $ million)

Capital Expenditure	2010 Actual	2011 Actual	2012 Budget	2013 Budget
Total Infrastructure and Capital Programs	$389.1	$437.1	$482.7	$659.8
Total New Generation	$148.9	$187.9	$515.3	$490.2
Total Capital Expenditure	$538.0	$625.0	$998.0	$1,150.0

8.2 Infrastructure Capital Spending

SaskPower has detailed the substantial and continuing investments in capital assets required to provide cost-effective services to its customers. Over the past few years, SaskPower has undertaken a concerted plan to add assets and upgrade facilities to increase capacity, maintain and enhance reliability, improve services and mitigate environmental impact. 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.

As noted in the above table, SaskPower's infrastructure and capital programs, including new generation increased from the actual 2010 capital expenditure of $538 million to a projected $998 million in 2012 (budgeted at $1,150 million in the original application).

The 2012 Infrastructure and Capital Program expenditures now forecast to be $483 million. Included are major expenditures for Power Production ($135 million), Transmission and Distribution and PERA business unit ($300 million), Customer Information & Technology ($34 million), Customer Service ($3 million), SDR ($35 million), Supply chain ($33 million), and a contingency allowance ($57 million). The contingency allowance (a deduction from the program) is to account for expected customer connections that do not materialize as well as weather and other factors that could impact the ability to complete the entire program.

Power production expenditures are for generation plant renewals. Transmission and Distribution and PERA projects include transmission and distribution customer connects, infrastructure capacity increases and sustainment. Customer Information and Technology, Customer Service and Supply Chain budgets incorporate a number of smaller initiatives, mostly identified in the Business Renewal Plan.

8.3 New Generation Expenditures

SaskPower's current generation capacity is being taxed and is approaching its available capacity. Significant additional load requirements are forecast for the industrial sector, primarily for mining and Oilfield customers for 2013. In 2009 SaskPower's available capacity was 3,840 MW, and the 2009 peak load was 3,233 MW. A new record peak of 3,265 MW was experienced on January 18, 2012 and the single day consumption record of 69,456 was set in 2011. Available generation capacity in 2012 is expected to be 4,014 MW. Allowing for the requirement for system reliability reserves and other reoccurring factors, the peak load very nearly reached total available generation capacity. Accordingly, more emphasis is being given to construction of new generation and new or upgraded transmission facilities to convey the power to markets. The new supply options consisting of more natural gas fired facilities have a higher marginal cost (including expenses such as fuel, financing costs, and depreciation) than existing heritage generation, resulting in overall higher costs to SaskPower and the ratepayer.

Capital investment in 2012 for new generation was $515 million and was originally estimated to be $490 million for 2013, but is now also expected to be $515 million. The major 2013 Capital expenditures are as originally estimated, which were approximately $335 million for Boundary Dam Unit #3 refurbishment, repowering of Queen Elizabeth unit #3 estimated to be $34 million, completion of the Carbon Capture Test Facility for $114 million, and $7 million for new generation related interconnections.

SaskPower expects to commission the North Battleford Energy Centre, under a PPA in April 2013. For accounting purposes the PPA will be treated as a capital lease and recorded on the balance sheet as an asset and a corresponding liability upon commissioning.

8.4 Planned Maintenance, Life Extensions and Shutdowns

Included in SaskPower's annual maintenance expenditures are those related to its planned maintenance program and for rehabilitation of generation facilities, as well as miscellaneous projects on the Transmission and Distribution system. This program is intended to extend the life, refurbish, and end/or replace components of coal, hydraulic or natural gas generation facilities. It is integrated into SaskPower's overall supply dispatch protocols to ensure security of supply, with adequate reserves throughout the year on a continuous basis. The nature, amount and length of time required to complete each of the program components varies from year to year.

Overhauls for 2013 are planned for SaskPower owned facilities respecting hydro (10 projects - multiple locations), coal (4 - Boundary Dam and Shand), and gas facilities (39 - various locations, primarily Queen Elizabeth and Yellowhead). The most significant outage will be for Boundary Dam Unit #3, in excess of 5 months, related to the ICCS project, while other outages are expected to last for as little as 1 day.

One of SaskPower's Business Renewal Program's potential benefits was the "Reduce Power Plant Outage Duration and Frequency" initiative. SaskPower anticipates this initiative to have a two-fold benefit through the extension of the annual outage cycle from 12 to 24 months and by the reduction of the maintenance outages by 7 days. Forecast OM&A savings for 2013 are $4 million and fuel savings related to the maintenance outage reduction of $22.9 million.

8.5 Observations

SaskPower experienced a record peak in 2011 of 3,265 MW and the electric delivery system, most notably its generation facilities, are operating at almost capacity considering potential plant outages and reserve requirements necessary to meet NERC and industry standards. SaskPower expects to expend in excess of $5.7 billion for Infrastructure and Capital Programs between 2012 and 2022, while new generation is expected for an additional $4.1 million, for a total anticipated expenditure of $9.8 billion. We note that total capital expenditures are expected to be near $1 billion for 2013 and 2014, remaining at that level until 2021 and somewhat decreasing thereafter.

Although it is anticipated that the 2012 capital program cost will be near the original estimates, we note that ROE and other capital program related expenses are embedded in rates based on projected budgets. If these embedded expenses are reduced, the consumer ends up paying for costs that have either not yet been incurred or are not used in the period for which their payment has commenced. Because capital project costs are not included in Rate Base until they are actually put into use, the 2013 Capital Program should, but for financing costs, have little impact on 2013 rates. However, rates are expected to increase in 2014.

We note SaskPower has stated that for every $100 million of capital cost that contributes to Rate Base, a 0.5% rate increase, on an overall basis, is expected to occur. Thus, for an expenditure of about $1 billion, rates on an overall basis will likely require a 40% to 50% increase over the next decade for this item alone.

With respect to SaskPower's Planned Maintenance Program, we laud SaskPower for taking the initiative in reviewing the entire scope of the corporation to identify areas for possible production and/or efficiency improvements resulting either in cost savings or future avoided costs. The 2013 savings estimated for this aspect of SaskPower's operations alone are almost $27 million. The estimated cost reductions are calculated to be $800,000 per outage on average, based on reduced outage planning costs, mobilization and demobilization costs, labour and overtime costs and replacement energy costs. If the savings materialize to this degree they would represent a 2.5% savings on the 2013 OM&A.

As the Minister's Order requires the Panel to consider the Capital Program as given, no further comment will be made on this matter.

9.0 Environmental and Sustainability Report

9.1 Highlights

The most recent SaskPower Sustainability Report was issued for 2011. SaskPower continues to support its growing customer base through new facility construction which will support Saskatchewan's economic growth while maintaining an environmentally conscious approach. Boundary Dam Station Unit # 3 is in process of installing a carbon capture and storage (CCS) facility which will play a crucial role in Saskatchewan meeting Federal and Provincial Greenhouse Gas reduction targets and reducing its carbon footprint. This project is expected to reduce CO2 emissions by 90% or 1 million tons per year by 2014 when it is operating at its full capacity.

Captured CO2 will be used in enhanced oil recovery and any residual CO2 will be stored in deep saline aquifers. The CCS facility will capture almost 100% of sulphur dioxide emissions which is intended to be used in production of sulphuric acid. SaskPower is currently in the process of negotiating agreement(s) relative to the sale of the CO2 by-product, once the plant commences operation.

As a province that is heavily reliant on fossil fuel 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 place significant emphasis on reducing greenhouse gas as well as other emissions. It has added 20 new environmentally preferred power projects totalling 50 megawatts (MW) from independent power producers through the Green Options Partners Program (GOPP).

Environmental regulation is a mandatory part of doing business. Emission mitigation, site assessments and environmental studies account for a significant part of their need 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. The Federal Environment Minister has recently announced the long awaited regulations to curtail emissions from coal fired generation plants. These regulations will come into force on July 1, 2015.

Some changes that SaskPower had requested have been included in the official version of the regulation. 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 increased from 375 to 420 tonnes of CO2 per Gigawatt hour net produced (t/GWh).

The final regulation provides SaskPower with additional but limited time for proving out the viability of CCS technology, allowing SaskPower to delay a decision on BD Units 4 & 5 until mid-2019. On the converse, current constraints within the regulation do not allow SaskPower to receive credit for early adoption of CCS with respect to BD Unit 3.

The regulation will limit the useful life for Power Resource Plants Service Units 1 and 2 to 46 years and 48 years respectively. Generation units that do not comply with the performance standard, when required to do so, must shut down.

SaskPower is working closely with the Provincial Ministry of Environment to ensure a Saskatchewan/Federal Equivalency Agreement appropriately recognizes SaskPower's efforts to reduce CO2 emissions. The Saskatchewan Greenhouse Gas Regulations and the Saskatchewan/Federal Equivalency Agreement are both expected to be finalized by mid-2013 and implemented in 2014.

SaskPower will work closely with the Provincial Ministry of Environment and other provincial ministries in finalizing the provincial greenhouse gas regulations and in development of a Provincial/Federal Equivalency Agreement in order to achieve a sustainable supply of electricity for its customers while minimizing rate increases.

In the recent past SaskPower has built simple cycle natural gas turbines to generate electricity for new load growth which emit 50% less carbon than coal generators. SaskPower, in cooperation with large customers have installed new waste heat recovery units as part of its Environmentally Preferred Power Program. This initiative as well as additions to its Wind Power facility, efficiency and conservation initiatives, and its net metering program encourages development of green power by specific customers. It somewhat limits the demand placed on SaskPower's electricity generation capacity and reliance on traditional coal generation plants which are less costly operationally, but significantly less environmentally friendly.

SaskPower has also signed a Memorandum of Understanding with First Nations Power Authority to collaborate and cooperatively look at power generation projects in Saskatchewan.

SaskPower through its subsidiary Shand Greenhouse reached a distribution mark of 500,000 seedlings annually and are engaging seedling planting partnerships, which in the long term assist in reducing SaskPower's carbon foot print.

As part of SaskPower's report, historical and current statistics are provided on the Environmental Commitment and Responsibility Program (ECRP). Because of SaskPower's heavy reliance on its traditional coal generation capacity, they continue to work diligently via research in clean coal technology projects, coupled with current investments into plant upgrades. This is intended to minimize the current and future emission impacts of those plants.

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.

In addition to the foregoing, SaskPower will be completing the ICCS generation project at Boundary Dam during the next calendar year which is on time and on budget at this point. We expect further information on this matter will be reported on in the future.

9.2 Observations

SaskPower appears to be taking its environmental and sustainability role seriously. Significant effort has been placed on this initiative in the last few years and is now generating positive results. They have set environmental, economic and social targets, for which they monitor the results and publicly report on the target and actual results. While some results are less than the target or goal, significant progress has been made and it is expected they will guide SaskPower's future direction on their environmental, economic and social agenda.

10.0 Cost of Service

10.1 Introduction

Once an annual revenue requirement has been determined, a cost of service study (COSS) is conducted to ensure that each customer class pays its share of the overall revenue requirement in a fair, reasonable and economically efficient manner, recognizing historic rates, customer class development, and the utility's cost drivers. Thus, the assignment and allocation of costs to various customer classes is forward looking on a prospective or forecasted cost basis. SaskPower confirms that there have been no methodological changes to the cost of service or to the classification and allocation factors since the 2010 Application.

In a report submitted in the fall of 2008, the Panel completed an extensive review of SaskPower's existing COSS undertaken by Foster and Associates. The review included substantial stakeholder involvement, and concluded that review by making a number of recommendations on the methodology employed coupled with other considerations to the Minister.

SaskPower has retained the services of an external consultant to review its COSS methodology as had been previously recommended by the Panel. This review is currently underway and a report in this regard is expected to be completed by the end of 2012.

SaskPower's COSS is described as being all of the utility's operating expenses plus its reasonable return investment ("rate base") devoted to the service of the rate paying public. SaskPower states that parties concerned with a COSS include:

1. The Saskatchewan Rate Review Panel who are responsible for assuring that SaskPower only includes the costs and returns which are related to its core businesses as well as insuring that the methodologies applied are fair and reasonable through the use of a third party consultant.
2. SaskPower Management including the executive and board of directors are responsible ensuring SaskPower achieves its financial targets. The COSS is used to ensure that the rates developed are accurate and support this objective.
3. Customers are provided with COSS documentation to substantiate the cost of providing service to them and the amount of the cost that is recovered through the rates they pay.

The 2013 test embedded COSS methodology incorporates a six step process to determine the rates for each customer class. These steps are:

1. Identifying all accounting costs to be allocated to customer classes.
2. Functionalize all costs between generation, transmission, distribution and customer services.
3. Classify each set of functionalized costs into demand, energy and customer components.
4. Allocate the functional classified costs amongst the customer classes.
5. Compare the allocated costs and revenues collected from the customer classes to determine the revenue to cost ratios.
6. Calculate ideal rates for each customer class.

10.2 COSS – General Purpose and Principles

The purpose of the COSS is to analyze the components of the utility costs and assign them to the various customer classes. The study or analysis then compares the assigned costs of the Utility to the forecasted revenue expected by the various customer classes. The resulting financial relationship from each customer class and sub-class of the assigned costs for that class, and the revenue expected is the resultant cost revenue to revenue relationship (R/RR). A customer class whose revenues are equal to the assigned costs would have a R/RR of one.

Once the revenue requirement of a utility is determined through a process traditionally called Phase one (1) process of the Utilities Rate Application, the attention is then turned to Phase two (2) process called Cost of Service and Rate Design.

Bonbright, a noted author on Utility Regulation, states in his published books that valuable criteria for a desirable rate structure should include:

- Effectiveness in yielding the Utilities total revenue requirement, under the fair return standard, without socially undesirable expansion of rate base or socially undesirable level of product quality or safety.
- Revenue stability and predictability with a minimum of unexpected changes seriously adverse to the utility company.
- Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to the ratepayers, and with a sense of historical continuity.
- Static efficiency of the use of rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use.
- Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision.
- Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity.
- Avoidance of undue discrimination in rate relationships.
- Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.
- The related, practical attributes of simplicity, certainty, convenience of payment, economy of collection, ease of understanding, public acceptability, and feasibility of application.
- Freedom from controversies as to proper interpretation.

As discussed, SaskPower uses a six step process for its COSS. The first step is the identification of all applicable accounting costs. Once these are identified the following three step process is conducted:

- Functionalization of the costs according to functions (services) performed by the Utility. For an electric utility, the major functions by which costs are assigned are generation, transmission and distribution, and Customer Service.
- Classification of each function's costs is related to the system design or specific operating characteristics, which caused those costs to be made or incurred. In the case of electric utilities, costs are generally classified as one of the following:

  - Demand related costs – allocated among the customer classes on the basis of demand imposed on the system during peak hours, and the capacity of facilities required to service the demand of customers.
  - Energy related costs – allocated among the customer classes on the basis of energy which the system must supply to service the customers.
  - Customer related costs – allocated among the customer classes on the basis of the number of customers, or weighted average, or costs per customer.
- Allocation of each functionalized and classified cost component to specific customer classes based on each class's contribution to the specific cost driver selected.

Once costs have been allocated to the appropriate customer class's revenues at existing rates are established to determine the revenue shortfall (or sufficiency) in each rate class. This yields a revenue to revenue requirement (R/RR) ratio. The last step is the determination of customer class rates designed so as to yield R/RR ratios that fall within the accepted range. The current policy for the R/RR range for SaskPower is 0.95 to 1.05.

The judgments that are made regarding cost of services issues, while reflecting the underlying nature of the utility system's operation, customer characteristics, and planning process, should not be considered final, and never to be considered in future rate applications. It is for this reason that there is a need to file an annual COSS for each change in a rate application.

In conclusion, judgments are made throughout the COSS process. Arbitrary classifications or allocations should ideally be minimized. Although many methods are available to the cost analyst, they are not all equally appropriate to all systems. It is the application of the cost analyst's knowledge of the system, its customers, and the application of sound judgment, reflecting cost causation criteria that will result in a good cost of service study. The regulators role and, in this matter, the Panel's task, is to test the reasonableness of the judgments made to ensure that the filed COSS, when used as a primary criterion to design rates, will provide the appropriate price signals to the utility's customers, and effect the desired customer behaviour.

SaskPower's fully embedded COSS for this Application uses the existing methodology last reviewed in 2009. There have been no significant changes in the COSS methodology since that time. SaskPower's COSS functionalizes SaskPower into four main areas: Generation, Transmission, Distribution and Customer Service. These functional areas are further split into sub-functions to accommodate SaskPower's rate structure and design. Functionalized costs are then classified into Energy (amount consumed), Demand (costs to meet peak demand load) and Customer related costs (fixed costs). Functionally classified costs are then allocated to each customer class based on relative consumptions including line losses for the Energy Charge, relative demand levels based on the system winter coincident peak (1CP) currently the single coincident peak methodology, and uses the weighted number of customers for the Basic Monthly Charge.

10.3 Demand Charges

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 that do not vary with a customer's consumption, but which are incurred to meet the customer's capacity requirements. These costs are usually incurred to put in place generation capacity and to transmit and deliver 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. However, as discussed in the Rate Design Section of this Report, SaskPower 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 that includes a Demand Charge.

10.4 Energy Charge

SaskPower considers F&PP, a portion of fixed costs and OM&A together with certain other variable administrative costs to be energy related and recoverable on a per unit consumption basis.

This approach is especially important for utilities, such as SaskPower, that proportionally have high fuel and power purchase costs.

10.5 Basic Monthly Charge

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 that are included in the basic charge include Rate Base items (onsite plant and certain general plant items) metering, billing, corporate support services and other direct services. Ideally, all fixed costs should be recovered by the Basic Monthly Charges. However, as discussed later in this Section, SaskPower, like most other Canadian utilities, recovers some portion of fixed costs through the variable energy rate in most customer classes.

10.6 2013 Cost of Service Study

10.6.1 Functionalization

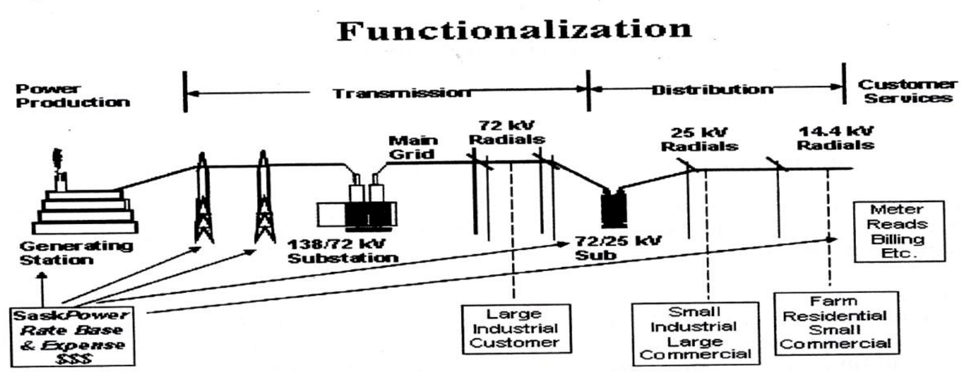
All of SaskPower's rate base costs and operating expenses are assigned to one of four functions (Generation, Transmission, Distribution and Customer Services), as shown in the table below. Functionalized costs are further disaggregated into sub-functions to recognize unique customer features for purposes of rate design.

Table 10.1 - 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 Marketing & Key Accounts
Supplementary Reserve		Services Customer	
Planning Reserve		Rural Laterals	
Reactive Supply		Meters	
Grants in-lieu of Taxes		Streetlights	
Interruptible Adjustment			

The following Diagram illustrates the above functionalization of costs:

Figure 1: Functionalization Schematic



10.6.2 Classification

All functionalized costs are classified as being Demand, Energy and/or Customer related, as follows:

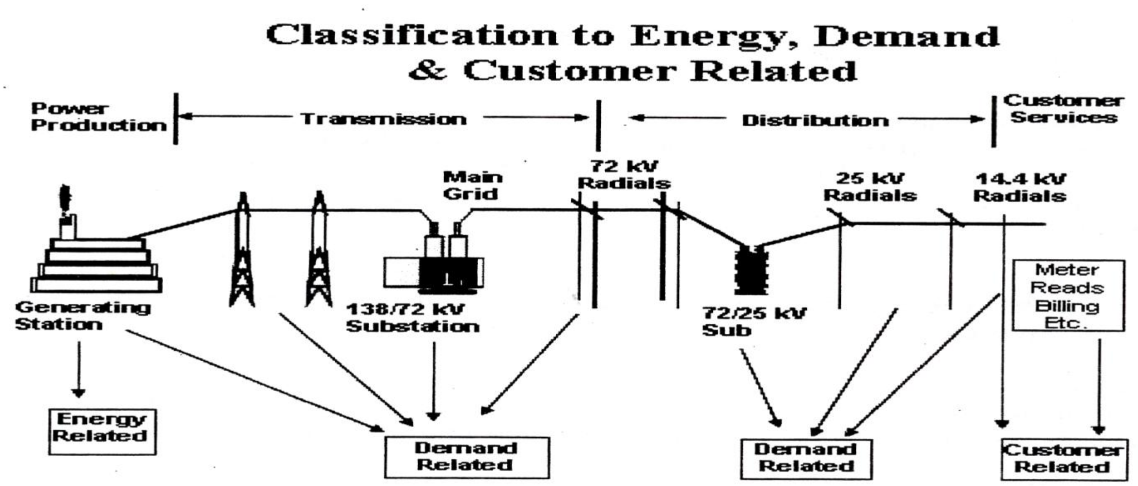
- Demand related costs vary with the KW demand placed on the system and include the demand component of generation, transmission and distribution systems.
- Energy related costs vary with the energy provided and consumed (KWh) which include fuel and other variable generation costs.
- Customer costs relate to the number of customers served and include customer billing, meter reading, Customer Service and capital costs (rate base) for meters and services.

The classification is summarized in the following Table**:**

Table 10.2 - 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	Fixed/Variable by Plant Type	Fixed/Variable by Plant Type	Fixed/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%

Figure 2: Classification Schematic



10.6.3 Allocation

SaskPower allocates all of the functionally classified costs into one of the rate codes in each of its nine customer classes as well as the Reseller Class:

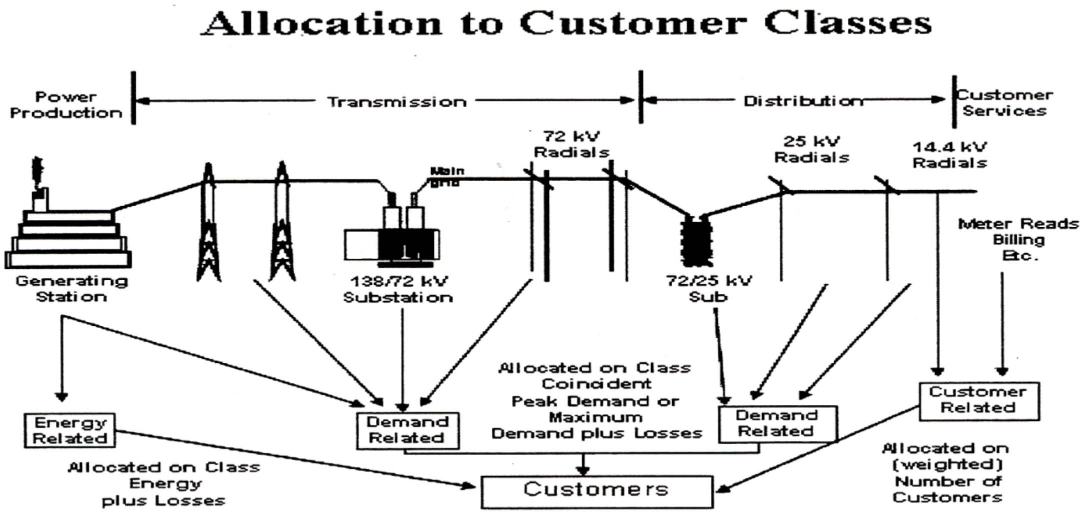
- Urban Residential
- Urban Commercial
- Power Published
- Rural Residential
- Rural Commercial
- Power Contract Rates
- Power Published Rates
- Farms
- Oilfields
- Streetlights
- Resellers

The following table depicts the method for customer class allocation of functionally classified costs:

Table 10.3 - 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 – 1 CP
Generation –Energy – RB & Expenses	Pro-rata class energy consumed + estimated losses
Transmission –Demand – All	Pro-rata class contribution to peak load – 1 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 – 1 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

Figure 3: Allocation Schematic



Currently SaskPower does not have its own load research data for a number of customer classes. In 2010 SaskPower expects to have sufficient data to compile its own load shape for Residential, Farm, Commercial, Oilfield and Streetlight classes. SaskPower currently uses load profiles borrowed from an Alberta utility (ATCO Electric) gathered and based on 1996 to 1998 data in order to develop their own class load profiles, adjusting them with specific information when available from their own system. Pending the result of the load research, SaskPower extrapolates this data to the entire class in proportion to the class billing determinants.

The Power Class load patterns are determined by analyzing hourly meter readings from actual customer's interval metered sites.

Loss of electrical energy (line losses) and demand on various segments of the system are determined by a loss analysis study done by SaskPower's Network Planning department for transmission losses. Distribution losses are determined and apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

10.7 2013 COSS Results and Updates

The following table summarizes the functionally classified rate base and revenue requirement by major financial account for the 2013 test year embedded COSS:

Table 10.4 - Functionalization of Financial Account Details for 2013

Summary of the Functionalization of Financial Account Details
2013 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Rate Base									
Plant In Service (Schedule 1.1)	11,147.5	6,269.7	56.2%	1,458.3	13.1%	3,326.3	29.8%	93.2	0.8%
Accumulated Depreciation (Schedule 1.2)	(4,788.4)	(2,782.6)	58.1%	(536.3)	11.2%	(1,426.9)	29.8%	(42.6)	0.9%
Allowance For Working Capital	76.9	42.8	55.7%	6.9	8.9%	17.1	22.2%	10.2	13.2%
Inventories (Schedule 1.3)	157.2	77.8	49.5%	21.6	13.8%	57.3	36.5%	0.4	0.3%
Other Assets (Schedule 1.3)	9.1	7.1	77.8%	0.4	4.4%	1.0	11.1%	0.6	6.7%
Total Rate Base	**6,602.3**	**3,614.8**	**54.7%**	**951.0**	**14.4%**	**1,974.8**	**29.9%**	**61.8**	**0.9%**
Revenue Requirement									
Fuel Expense SaskPower Units	366.2	366.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchased Power & Import	178.9	178.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Export & Net Electricity Trading Revenue (Credit)	(39.5)	(39.5)	100.0%	-	0.0%	-	0.0%	-	0.0%
Operating,Maintenance & Administration (Schedule 1	615.2	333.1	54.1%	55.0	8.9%	139.0	22.6%	88.0	14.3%
Depreciation & Depletion (Schedule 1.5)	372.0	216.9	58.3%	34.5	9.3%	112.6	30.3%	8.1	2.2%
Corporate Capital Tax	31.8	17.4	54.8%	4.6	14.5%	9.5	29.9%	0.3	0.8%
Grants in Lieu of Taxes	21.2	21.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	87.1%	0.0	0.7%	0.0	1.6%	0.1	10.5%
Other Income (Credit) (Schedule 1.6)	(93.5)	(16.8)	18.0%	(13.1)	14.0%	(40.0)	42.7%	(23.6)	25.2%
Return on Rate Base @ 6.38%	421.4	230.7	54.7%	60.7	14.4%	126.0	29.9%	3.9	0.9%
Total Revenue Requirement	**1,874.1**	**1,308.5**	**69.8%**	**141.7**	**7.6%**	**347.2**	**18.5%**	**76.8**	**4.1%**

The following table shows the results of the classification of the 2013 functionalized costs into Demand, Energy and Customer Related components:

Table 10.5 - Classified Revenue Requirement for 2013

Summary of Classified Revenue Requirement by Customer Class
2013 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Demand Related		Energy Related		Customer Related	
		($)	(%)	($)	(%)	($)	(%)
Urban Residential	**347.6**	**184.3**	53.0%	**95.1**	27.4%	**68.2**	19.6%
Rural Residential	**96.0**	**53.4**	55.6%	**22.1**	23.0%	**20.5**	21.3%
Farms	**161.4**	**95.4**	59.1%	**46.1**	28.6%	**19.9**	12.3%
Urban Commercial	**268.8**	**148.7**	55.3%	**99.3**	36.9%	**20.8**	7.7%
Rural Commercial	**93.3**	**55.4**	59.4%	**30.2**	32.4%	**7.7**	8.2%
Power - Published Rates	**418.5**	**191.6**	45.8%	**221.6**	52.9%	**5.3**	1.3%
Power - Contract Rates	**100.0**	**47.8**	47.8%	**51.3**	51.3%	**1.0**	1.0%
Oilfields	**290.9**	**152.7**	52.5%	**121.2**	41.7%	**17.0**	5.8%
Streetlights	**16.4**	**4.8**	29.6%	**2.1**	12.9%	**9.4**	57.5%
Reseller	**81.1**	**40.1**	49.5%	**40.7**	50.2%	**0.3**	0.4%
Total	**1,874.1**	**974.3**	**52.0%**	**729.7**	**38.9%**	**170.1**	**9.1%**

The customer specific data used to allocate the 2013 COSS functionally classified costs to the various customer classes is shown in the following table:

Table 10.6 - Customer Cost Allocation Data for 2013:

Customer Data for Cost Allocation
2013 Test Embedded Cost of Service Study

Customer Class	Energy Sales GWH	NCP Demand KW	CP Demand KW	NCP Load Factor [1]	CP Load Factor [2]
Urban Residential	2,373	2,176,281	516,779	12.45%	52.43%
Rural Residential	638	584,677	138,837	12.45%	52.43%
Farms	1,331	550,006	258,627	27.62%	58.73%
Urban Commercial	2,577	809,420	439,962	36.34%	66.86%
Rural Commercial	877	297,968	156,102	33.60%	64.13%
Power - Published Rates	6,868	1,135,977	886,237	69.02%	88.47%
Power - Contract Rates	1,601	350,566	226,446	52.13%	80.70%
Oilfields	846	125,190	94,959	77.14%	101.69%
Streetlights	60	14,648	14,467	47.12%	47.71%
Reseller	1,275	244,189	204,688	59.60%	71.10%
Total	**18,446**	**6,288,923**	**2,937,105**	**33.48%**	**71.69%**

1 - NCP Load Factor is calculated as follows: (Energy Sales*1,000,000) / (NCP Demand * 8,760)
2 - CP Load Factor is calculated as follows: (Energy Sales*1,000,000) / (CP Demand * 8,760)

The following table shows the prospective 2013 COSS results for Basic, Energy and Demand Related costs, relative to the 2012 projected results.

Table 10.7 - Basic, Energy and Demand Cost Changes - $

2013 COSS Impact on Basic, Energy and Demand Costs by Class				
	2012 Results	**2013 Prospective**	**Change**	**% Change**
Residential				
Basic	$79,816,033	$89,008,055	$9,192,022	11.5%
Energy	325,367,532	329,870,121	4,502,589	1.4%
Total	**405,183,565**	**418,878,176**	**13,694,611**	**3.4%**
Farm				
Basic	18,215,747	20,076,158	1,860,411	10.2%
Energy	45,416,461	44,422,754	(993,707)	(2.2)%
Demand	83,226,242	84,236,877	1,010,635	1.2%
Total	**146,858,450**	**148,735,789**	**1,877,339**	**1.3%**
Commercial				
Basic	35,172,666	38,017,515	2,844,849	8.1%
Energy	132,315,734	130,260,068	(2,055,666)	(1.6)%
Demand	187,665,288	189,237,338	1,572,050	0.8%
Total	**355,153,688**	**357,514,921**	**2,361,233**	**0.7%**
Power				
Basic	5,471,855	6,838,453	1,366,958	25.0%
Energy	285,586,083	309,364,099	23,778,016	8.3%
Demand	211,808,902	235,774,538	23,965,636	11.3%
Total	**502,866,840**	**551,977,090**	**49,110,250**	**9.8%**
Oilfields				
Basic	14,519,170	15,814,415	1,295,245	8.9%
Energy	114,774,259	116,987,128	2,212,869	1.9%
Demand	129,683,634	135,678,292	5,994,658	4.6%
Total	**258,977,063**	**268,479,835**	**9,502,772**	**3.7%**
Reseller				
Basic	262,115	325,594	63,479	24.2%
Energy	41,906,205	41,229,116	(677,089)	(1.6)%
Demand	35,906,254	35,928,890	22,636	0.1%
Total	**78,074,574**	**77,483,600**	**(590,974)**	**(0.8)%**
Grand Total	**$1,747,114,180**	**$1,823,069,411**	**$75,955,231**	**4.3%**

Customer class allocation factors from the 2013 COSS are shown in the following three tables:

Table 10.8 - 2013 Allocation Factors by Customer Class (Transmission)

Allocation Factors by Customer Class
TRANSMISSION Related Costs
2013 Test Embedded Cost of Service Study

Customer Class	Main Grid	138 kv Lines Radials	138/72 kv Substations	72 kv Lines Radials
	Demand	Demand	Demand	Demand
Urban Residential	16.2%	12.0%	20.7%	20.7%
Rural Residential	4.3%	3.2%	5.5%	5.5%
Farms	8.1%	6.0%	10.3%	10.3%
Urban Commercial	13.8%	10.2%	17.6%	17.6%
Rural Commercial	4.9%	3.5%	6.3%	6.3%
Power - Published Rates	24.9%	33.4%	20.6%	20.6%
Power - Contract Rates	7.6%	16.4%	1.7%	1.7%
Oilfields	13.9%	12.0%	16.4%	16.4%
Streetlights	0.5%	0.3%	0.6%	0.6%
Reseller	5.9%	3.0%	0.4%	0.4%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: All allocation factors based on Coincident Peak (1 CP) & losses.

Table 10.9 - Allocation Factors by Customer Class (Distribution)

Allocation Factors by Customer Class
DISTRIBUTION Related Costs
2013 Test Embedded Cost of Service Study

Customer Class	Area Substations [1]	Distribution Mains [1]	Urban Laterals [1]	Urban Laterals [2]	Rural Laterals [1]	Rural Laterals [3]	Transformers [4]	Transformers [5]	Services [6]	Unamortized Customer Contributions [7]	Amortization Customer Contributions [7]	Meters [8]	Streetlights [9]
	Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Urban Residential	26.3%	26.4%	53.3%	84.0%	0.0%	0.0%	45.2%	59.2%	18.9%	0.0%	16.6%	19.5%	0.0%
Rural Residential	7.0%	7.0%	0.0%	0.0%	15.5%	37.1%	12.1%	11.0%	11.3%	0.0%	16.7%	3.6%	0.0%
Farms	13.1%	13.1%	0.0%	0.0%	28.8%	41.4%	11.3%	12.2%	2.1%	0.0%	16.9%	4.6%	0.0%
Urban Commercial	22.3%	22.4%	45.3%	12.0%	0.0%	0.0%	15.9%	8.4%	26.1%	0.0%	12.5%	30.5%	0.0%
Rural Commercial	7.3%	7.3%	0.0%	0.0%	16.1%	8.5%	5.5%	2.5%	12.0%	0.0%	14.4%	12.4%	0.0%
Power - Published Rates	2.5%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.0%	0.0%
Power - Contract Rates	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%	0.0%
Oilfields	20.5%	20.5%	0.0%	0.0%	39.5%	11.4%	9.7%	3.4%	29.7%	0.0%	22.8%	12.2%	0.0%
Streetlights	0.7%	0.7%	1.4%	4.0%	0.1%	1.6%	0.3%	3.3%	0.0%	0.0%	0.0%	0.0%	100.0%
Reseller	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**0.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (1CP) & losses.
[2] Based on the number of urban customers in each customer class. Urban streetlights are based on 6 lights per circuit.
[3] Based on the number of rural customers in each customer class. Rural streetlights are based on 3 lights per circuit.
[4] Based on Non Coincident Peak (NCP) & losses.
[5] Based on the number of customers with transformer related equipment in each customer class. Streetlights are based on 6(urban) & 3(rural) lights per circuit.
[6] Based on the number of customers in each customer class supplied through services weighted by installed cost of a service.
[7] Based on customer contributions in each customer class.
[8] Based on the new capital cost of meters and instrument transformers multiplied by the number of customers in the customer class.
[9] Direct to the streetlight class.

Table 10.10 - Allocation Factors by Customer Class (Customer Service)

Allocation Factors by Customer Class CUSTOMER SERVICE Related Costs 2013 Test Embedded Cost of Service Study						
Customer Class	**Metering Services**	**Meter Reading**	**Billing & Customer Accounts**	**Customer Collections**	**Customer Service**	**Marketing**
	Customer	**Customer**	**Customer**	**Customer**	**Customer**	**Customer**
Urban Residential	16.7%	62.9%	41.3%	71.7%	58.1%	10.5%
Rural Residential	3.1%	9.6%	7.7%	13.3%	10.7%	3.9%
Farms	3.9%	13.0%	10.1%	8.0%	13.7%	7.8%
Urban Commercial	21.0%	7.3%	12.3%	4.7%	8.6%	13.0%
Rural Commercial	6.6%	2.3%	3.7%	1.3%	2.5%	2.9%
Power - Published Rates	19.6%	0.0%	5.9%	0.0%	0.9%	29.0%
Power - Contract Rates	3.5%	0.0%	1.0%	0.0%	0.2%	5.1%
Oilfields	24.9%	4.9%	16.7%	1.0%	4.5%	25.5%
Streetlights	0.0%	0.0%	1.0%	0.0%	0.9%	1.2%
Reseller	0.7%	0.0%	0.2%	0.0%	0.0%	1.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: All allocation factors based on the department responsible's estimate of labour time spent on each customer class.

10.8 Observations

SaskPower's 2013 COSS study that ultimately allocates each component of rate base and expense to each customer class does not contain any methodological changes from that used in the 2010 Application. Amounts charged to specific functions and sub-functions have changed by virtue of overall and differing amounts of changes in expenditures, both capital and operating, while classification and allocation factors will also change because of load and use pattern changes for various customer classes.

As can be seen on the following tables, there have been few material methodological changes in this Application from the 2011 COSS results. Where changes in costs to various customer classes differ, these are related to pro-rata changes flowing from different categories of capital programs being installed that are reflected in varying amounts and percentages of ROE in revenue requirement. Similarly changes in fuel mix ratios, as well as reduced export revenues also have impacted all customer classes.

The following tables indicate the changes in the functionally allocated costs from the 2009 Application.

The following table shows the changes in the functionally allocated costs from 2011 to 2013.

Table 10.11 - 2013 COSS Relative to 2011 COSS (x $ million)

Function and Classification	2011					2013				
Major Account	Total $	% Gen.	% Trans.	% Dist.	% Cust.	Total $	% Gen.	% Trans.	% Dist.	% Cust.
Total Rate Base	**5,239.1**	**53.7**	**12.3**	**33.0**	**1.1**	**6,602.3**	**54.7**	**14.4**	**29.9**	**0.9**
Fuel Expense – SPC	345.6	100.0	0.0	0.0	0.0	366.2	100.0	0.0	0.0	0.0
Purchased Power/Import	139.8	100.0	0.0	0.0	0.0	178.9	100.0	0.0	0.0	0.0
Export/Net Trading	(54.2)	100.0	0.0	0.0	0.0	(39.5)	100.0	0.0	0.0	0.0
OM&A	575.1	52.8	9.2	23.3	14.8	615.2	54.1	8.9	22.6	14.3
Depreciation	302.5	56.3	10.2	32.0	1.5	372.0	58.3	9.3	30.3	2.2
Corporate Tax	22.4	53.8	12.3	33.2	0.7	31.8	54.8	14.5	29.9	0.8
Grants-in-Lieu	20.4	100.0	0.0	0.0	0.0	21.2	100.0	0.0	0.0	0.0
Misc. Tax	0.5	85.8	0.7	1.6	11.8	0.5	87.1	0.7	1.6	10.5
Other Income	(105.5)	16.3	21.4	40.5	21.8	(93.5)	18.0	14.0	42.7	25.2
Return on Rate @ 8.02% for 2011 & 6.38% for 2013	420.0	53.7	12.3	33.0	1.1	421.4	54.7	14.4	29.9	0.9
Total Revenue Requirement	**1666.8**	**68.8**	**6.9**	**20.0**	**4.3**	**1,874.1**	**69.8**	**7.6**	**18.5**	**4.1**

The table below compares the 2011 and 2013 classification factors of functional costs into Demand, Energy and Customer components for each customer class.

Table 10.12 - Functionalized Revenue Requirement by Customer Class

Summary of Functionalized Revenue Requirement by Customer Class						
Customer Class	Demand		Energy		Customer	
	2011	2013	2011	2013	2011	2013
Urban Residential	52.8%	53.0%	27.9%	27.4%	19.3%	19.6%
Rural Residential	53.1%	55.6%	22.8%	23.0%	24.2%	21.3%
Farms	63.0%	59.1%	26.2%	28.6%	10.8%	12.3%
Urban Commercial	54.2%	55.3%	38.5%	36.9%	7.4%	7.7%
Rural Commercial	58.1%	59.4%	34.7%	32.4%	7.2%	8.2%
Power - Published Rates	44.5%	45.8%	54.3%	52.9%	1.2%	1.3%
Power - Contract Rates	51.3%	47.8%	47.9%	51.3%	0.8%	1.0%
Oilfields	55.1%	52.5%	39.1%	41.7%	5.8%	5.8%
Streetlights	27.7%	29.6%	10.6%	12.9%	61.7%	57.5%
Reseller	50.6%	49.5%	49.1%	50.2%	0.3%	0.4%
Total	**52.5%**	**52.0%**	**38.1%**	**38.9%**	**9.4%**	**9.1%**

The comparison of the allocation of functionally classified revenue requirement to each customer class for 2011 and 2013 is shown in the table below, expressed in $ millions.

Table 10.13 - Customer Class Revenue Requirement (x $ million)

Revenue Requirement by Customer Class					
Customer Class	**2011 $**	**2011 % of Total**	**2013 $**	**2013 % of Total**	**2011 to 2013 % Increase**
Urban Residential	323.1	19.4%	347.6	18.6%	(0.8)%
Rural Residential	94.5	5.7%	96.0	5.1%	(0.6)%
Farms	164.0	9.8%	161.4	8.6%	(1.2)%
Urban Commercial	242.4	14.6%	268.8	14.4%	(0.2)%
Rural Commercial	82.2	4.9%	93.3	5.0%	0.1%
Power - Published Rates	332.3	19.9%	418.5	22.3%	2.4%
Power - Contract Rates	90.7	5.4%	100.0	5.3%	(0.1)%
Oilfields	242.5	14.6%	290.9	15.5%	0.9%
Streetlights	16.1	1.0%	16.4	0.9%	(0.1)%
Reseller	77.7	4.7%	81.1	4.3%	(0.4)%
Total	**1,665.4**	**100%**	**1,874.1**	**100%**	

The following four tables track the variances between the 2011 and 2013 COSS customer class specific data for Energy Sales, NCP Demand Factors, CP Demand Factors, and Load Factors.

Table 10.14 - Customer Class Cost Allocation (Energy Sales)

Customer Cost Allocation Data - Energy Sales					
Customer Class	**2011 GWh**	**2011 % of Total**	**2013 GWh**	**2013 % of Total**	**2011 to 2013 % Increase**
Urban Residential	2,356	12.2%	2,373	12.9%	0.7%
Rural Residential	650	3.4%	638	3.4%	0.0%
Farms	1,298	6.8%	1,331	7.2%	0.4%
Urban Commercial	2,529	13.1%	2,577	14.0%	0.9%
Rural Commercial	867	4.5%	877	4.8%	0.3%
Power - Published Rates	5,890	30.6%	6,868	37.2%	6.6%
Power - Contract Rates	1,429	7.4%	1,601	8.7%	1.3%
Oilfields	2,901	15.1%	846	4.6%	(10.5)%
Streetlights	51	0.3%	60	0.3%	0.0%
Reseller	1,261	6.6%	1,275	6.9%	0.3%
Total	**19,232**	**100%**	**18,446**	**100%**	

Table 10.15 - Customer Class Cost Allocation (NCP Demand)

Customer Cost Allocation Data - NCP Demand					
Customer Class	**2011 KW**	**2011 % of Total**	**2013 KW**	**2013 % of Total**	**2011 to 2013 % Increase**
Urban Residential	2,160,382	31.8%	2,176,281	34.6%	2.8%
Rural Residential	595,825	8.8%	584,677	9.3%	0.5%
Farms	772,424	11.4%	550,006	8.7%	(2.7)%
Urban Commercial	851,380	12.5%	809,420	12.9%	0.4%
Rural Commercial	312,476	4.6%	297,968	4.7%	0.1%
Power - Published Rates	998,534	14.7%	1,135,977	18.1%	3.4%
Power - Contract Rates	348,020	5.1%	350,566	5.6%	0.5%
Oilfields	495,698	7.3%	125,190	2.0%	(5.3)%
Streetlights	12,452	0.2%	14,648	0.2%	0.0%
Reseller	242,059	3.6%	244,189	3.9%	0.3%
Total	**6,789,251**	**100%**	**6,288,923**	**100%**	

Table 10.16 - Customer Class Cost Allocation (CP Demand)

Customer Cost Allocation Data - CP Demand					
Customer Class	**2011 KW**	**2011 % of Total**	**2013 KW**	**2013 % of Total**	**2011 to 2013 % Increase**
Urban Residential	439,059	15.9%	516,779	17.6%	1.7%
Rural Residential	121,091	4.4%	138,837	4.7%	0.3%
Farms	257,987	9.3%	258,627	8.8%	(0.5)%
Urban Commercial	355,656	12.9%	439,962	15.0%	2.1%
Rural Commercial	124,388	4.5%	156,102	5.3%	0.8%
Power - Published Rates	669,431	24.2%	886,237	30.2%	6.0%
Power - Contract Rates	219,365	7.9%	226,446	7.7%	(0.2)%
Oilfields	366,164	13.2%	94,959	3.2%	(10.0)%
Streetlights	12,298	0.5%	14,467	0.5%	0.0%
Reseller	197,603	7.2%	204,688	7.0%	(0.2)
Total	**2,763,043**	**100%**	**2,937,105**	**100%**	

Table 10.17 - Customer Class Cost Allocation (Load Factors)

Cost Allocation Customer Data - Load Factors						
Customer Class	2011* NCP %	2013** NCP %	Change	2011* CP %	2013** CP %	Change
Urban Res	12.45%	12.45%	0.0%	61.26%	52.43%	(8.83)%
Rural Res	12.45%	12.45%	0.0%	61.26%	52.43%	(8.83)%
Farms	19.19%	27.62%	8.43%	57.45%	58.73%	1.28%
Urban Comm.	33.91%	36.34%	2.43%	81.17%	66.86%	(14.31)%
Rural Comm.	31.68%	33.60%	1.92%	79.58%	64.13%	(15.45)%
Power – P	67.33%	69.02%	1.69%	100.43%	88.47%	(11.96)%
Power – C	46.87%	52.13%	5.26%	74.36%	80.70%	6.34%
Oilfields	66.80%	77.14%	10.34%	90.44%	101.69%	11.25%
Streetlights	47.12%	47.12%	0.0%	47.71%	47.71%	0.0%
Reseller	59.45%	59.60%	0.15%	72.83%	71.10%	(1.73)%
Total	**32.34%**	**33.48%**	**1.14%**	**79.46%**	**71.69%**	**(7.77)%**

*it should be noted that the 2011 CP/NCP load factors are based on SaskPower's actual load research results, while the numbers used for the 2013 rate app are based on ATCO's load research (excluding Resellers and Power class customers) – That's why there is such a discrepancy between some years (i.e., Urban Commercial)

It is our view that the 2013 COSS was carried out in a manner consistent with that previously used. SaskPower retained the services of an external consultant to review the existing COS methodology. The consultant has now prepared a preliminary draft report and this was presented to Stakeholders, including the Panel on October 16, 2012. The review covers all aspects of cost allocation. Input from stakeholders is encouraged and tentatively scheduled to be submitted by December 7, 2012. The consultant's final report is due by January 31, 2013.

Subsequent to its finalization SaskPower will review the consultant's report and assess the recommendations and determine which of them can be proceeded with prior to filing of the next application, and which must be postponed. The assessment will include an approximation of the impact of those recommendations to be implemented prior to the next rate application.

11.0 Rate Design

11.1 Rate Design General

SaskPower considers the following to be the primary objectives for its rate design:

- Meeting Revenue Requirement
- Fairness and Equity
- Economic Efficiency – i.e. pricing power close to marginal cost of supply
- Conservation of Resources
- Simplicity and Administrative Ease
- Stability and Gradualism

SaskPower historically, in common with many utilities, has had a legacy rate structure that included significant cross-subsidies, benefiting various rate classes at the expense of others. An increasingly competitive market structure has required the reduction and/or elimination of these cross-subsidies in order to send appropriate price signals to the market and consumers. Influencing this trend has been an increasing unwillingness by various customer classes to continue to subsidize other rate classes. This unwillingness is driven by a sense of equity and a desire to reflect proper costs. In 2002, the Panel accepted the standard industry revenue to revenue requirement ratio (R/RR) range of 0.95 to 1.05 and recognized at the time that SaskPower needed to undertake significant rate rebalancing to ensure that all of SaskPower's customer classes fell within that range.

Each of SaskPower's customer classes consists of one or more rate codes that outline the specific price paid by a group of customers with similar characteristics. Characteristics include location (Urban or Rural), size, supply voltage level, and type of load being supplied. SaskPower currently has over 60 rate codes, unchanged from 2010. Customer size is measured as the maximum customer demand, expressed in KW. Load factor is the ratio of annual energy to maximum demand multiplied by 8,760 hours.

SaskPower's Residential, Small Farm and Small Commercial customers have simple energy meters that cannot measure customer's demand levels. Thus, the rate design 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.

SaskPower's Commercial and Farm customers over 50 KVa demand and all Power customers have meters that measure energy consumed in KWh and maximum monthly demand in KVa. The rate structure for these customers consist of energy, demand and basic monthly charges, which 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 C-P Allocation method for a Demand Adjustment Mechanism to each customer within each class.

The following example illustrates this methodology:

Table 11.1 - Demand Adjustment Rate Mechanism Example

R/RR Ratio vs. Load Factor for a Typical 138kV Power Customer - Cost of Service Rate Design				
Load Factor	**40%**	**60%**	**80%**	**90%**
Customer Maximum Demand (KVa)	16,807	16,807	16,807	16,807
Customer Maximum Demand (KW)	16,000	16,000	16,000	16,000
Annual Energy Consumption (KWh)	56,064,000	84,096,000	112,128,000	126,144,000
Customer Coincident Peak Demand	8,800	11,200	13,600	14,800
Customer Annual Demand Billing (KVa)	161,748	175,059	188,370	195,025
Revenue Requirement Calculation	**$3,607,600**	**$5,016,514**	**$6,424,976**	**$7,129,207**
Total Revenue Requirement (cents/KWh)	6.43	5.97	5.73	5.65
Revenue Calculation				
Basic Monthly Charge ($/month)	**$6,257**	**$6,257**	**$6,257**	**$6,257**
Annual Customer Revenue	$ $ 75,079	$75,079	$75,079	$75,079
Energy Rate (cents/KWh)	4.805	4.805	4.805	4.805
Annual Energy Revenue	$2,693,698	$4,040,547	$5,387,396	$6,060,820
Demand Rate ($/KVa/month)	5.335	5.335	5.335	5.335
Annual Demand Revenue	$862,897	$933,908	$1,004,920	$1,040,425
Total Revenue	**$3,631,673**	**$5,049,534**	**$6,467,394**	**$7,176,325**
Total Revenue (cents/KWh)	6.48	6.00	5.77	5.69
R/RR Ratio	**1.01**	**1.01**	**1.01**	**1.01**

11.2 Revenue to Revenue Requirement Ratios (R/RR)

As mentioned above, an 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 a R/RR of 1.01. An R/RR of 1.00 indicates that class revenues equal class revenue requirement, and that class neither subsidizes nor receives subsidies from other classes.

SaskPower's previous and current Applications comply with this standard. The 2010 Application requested rates that would result in an R/RR ratio of 0.98 to 1.02 whereas the current 2013 Application ratios are forecasted to be 0.96 to 1.05.

In this application in addition to the Residential Class, the Farm, some Commercial and Power Contract classes also are below an R/RR of 1.00, while the other classes fall within an R/RR range of 1.00 to 1.05.

This results because the requested incremental revenue is generated by an equal percentage increase (4.9% or 6.1%) while none of the increased costs are increasing at an equal percent.

The cost of service model described in Section 10.0 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 indicates that the revenues exactly match the costs of providing the service, or to put it simply that customer is paying the amount that it costs SaskPower to provide them with the service. An R/RR below 1.00 indicates that a customer class is being subsidized by others within the system while an R/RR ratio above 1.00 indicates that a customer class is subsidizing other classes. On a system-wide basis, the R/RR must equal 1.00 to enable recovery of the full amount of the revenue requirement.

In the past, SaskPower followed the practice of setting 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 structure between rate applications. Because of equalized across the board increases in this application, the R/RR range has spread so that it is projected to be just within the range of 0.95 to 1.05.

R/RR ratios will change every year because of changes in class revenue and class revenue requirements. Class revenue requirements change because of: the non-uniform escalation of Generation, Transmission, Distribution, and Customer Service costs; changes to class demand at system peak; and changes to COSS. In the original application the range of R/RR ratios is from 0.95 to 1.05. The Mid Application Update shows this range 96.0 to 1.05.

The current Application rate request would result in the R/RR ratio for Residential, Farm, Urban Commercial and Power Contract are forecasted to be slightly below 1.00 and above 1.00 for all other classes. In the previous application, only Farm and Residential classes were below 1.00. This change means that, generally the Farm, Residential and Urban Commercial and Power Contract customers are being subsidized by the Power, Oilfield and Reseller classes. This shift is because, while the revenue has increased equally for all rate classes in this application, costs have not. The R/RR ratio for the Reseller Class was originally calculated to be 1.03, but was changed to 1.01 in the Mid-Application Update. This compares to an R/RR of 1.00 in the 2010 application.

The following table displays the Revenue to Revenue Requirement Ratios and Impacts of the overall system average 5.0% rate increase, based on the mid-application update.

Table 11.2 - 2013 Rate Changes & R/RR Ratios

Year 2013 Rate Changes & R/RR Ratios 5.0% General Rate Increase Rate with No Rebalancing Maintenance				
Class of Service	**2013 Rate Change (Application)**	**2013 R/RR Ratios (Application)**	**2013 Rate Change (Mid-App)**	**2013 R/RR Ratios (Mid-App)**
Urban Residential	4.9%	0.96	4.9%	0.97
Rural Residential	4.9%	0.95	4.9%	0.96
Total Residential	**4.9%**	**0.96**	**4.9%**	**0.97**
Farms	4.9%	0.96	4.9%	0.97
Urban Commercial	4.9%	0.99	4.9%	0.98
Rural Commercial	4.9%	0.96	4.9%	1.00
Total Commercial	**4.9%**	**0.98**	**4.9%**	**0.98**
Power - Published Rates	4.9%	1.04	4.9%	1.03
Power - Contract Rates	6.1%	1.00	6.3%	0.99
Total Power	**5.1%**	**1.03**	**5.2%**	**1.02**
Oilfields	4.9%	1.05	4.9%	1.05
Streetlights	4.9%	0.99	4.9%	1.00
Reseller	4.9%	1.03	4.9%	1.01
Total	**5.0%**	**1.00**	**5.0%**	**1.00**

The impacts of the changes to the R/RR ratios from the initial application to the updated application are summarized in the following table:

Table 11.3 - R/RR Ratio Change Summary

Financial Change	Power	Oil	Residential & Farm	Commercial	Resellers
Increase in G & T costs	Reduced R/RR ratio	Minimal impact	Increased R/RR ratio	Increased R/RR ratio	Reduced R/RR ratio
Increase in demand related costs	Increased R/RR ratio	Increased R/RR ratio	Reduced R/RR ratio	Reduced R/RR ratio	Reduced R/RR ratio
Overall Impact	Slightly Reduced R/RR ratio	Minimal Change	Slightly Increased R/RR ratio	Minimal Change	Reduced R/RR ratio

11.3 Meeting Revenue Requirement

Obviously the prime objective of a rate design is for the various rate structures and rates to generate sufficient revenue that, on an overall basis, equals the revenue requirement, a component of which is return on rate base, for the equivalent period. The incremental revenue for 2013 as per the Mid-Application Update is an estimated $89 million, with a net income of $126 million, which would result in an ROE of 6.4%. SaskPower's long term target return is 8.5%.

As previously discussed, all functional costs are classified as being energy, demand or customer related. The following table shows the prospective 2013 revenue results for Basic, Energy and Demand, relative to the 2012 projected results.

Table 11.4 - Basic, Energy and Demand Revenue Changes - $

2013 Impact on Basic, Energy and Demand Revenues by Class				
	2012 Results	**2013 Prospective**	**Change**	**% Change**
Residential				
Basic	$84,944,331	$86,213,727	$1,269,396	1.5%
Energy	312,238,643	316,789,697	4,551,054	1.5%
Total	**397,182,974**	**403,003,424**	**5,820,450**	**1.5%**
Farm				
Basic	21,265,195	21,247,638	(17,558)	(0.1)%
Energy	118,800,515	119,346,416	545,901	0.5%
Demand	2,768,567	2,774,902	6,335	0.2%
Total	**142,834,277**	**143,368,956**	**534,678**	**0.4%**
Commercial				
Basic	18,061,957	18,199,658	137,701	0.8%
Energy	285,915,448	286,719,856	804,408	0.3%
Demand	47,507,319	47,483,618	(23,701)	0.0%
Total	**351,484,724**	**352,403,132**	**918,408**	**0.3%**
Power				
Basic	6,216,072	6,252,072	36,000	0.6%
Energy	414,352,988	459,261,571	44,908,583	10.8%
Demand	86,725,964	98,021,003	11,295,039	13.0%
Total	**507,295,024**	**563,534,647**	**56,239,622**	**11.1%**
Oilfields				
Basic	10,793,305	11,365,753	572,448	5.3%
Energy	184,638,680	193,059,735	8,421,054	4.6%
Demand	74,455,415	77,191,735	2,736,321	3.7%
Total	**269,887,400**	**281,617,223**	**11,729,823**	**4.3%**
Reseller				
Basic	282,240	282,240	0	0.0%
Energy	41,768,941	42,149,568	380,626	0.9%
Demand	36,378,599	36,710,222	331,623	0.9%
Total	**78,429,780**	**79,142,030**	**712,250**	**0.9%**
Grand Total	**$1,747,114,180**	**$1,823,069,412**	**$75,955,232**	**4.3%**

SaskPower attempts to design the basic monthly charge for each customer class as close to the ideal rate as possible, which would recover 100% of the required Customer revenue without exceeding the 15% rate cap. The following table illustrates the percentage of customer revenue recovered for applicable rate classes by the BMC:

Table 11.5 - Revenue from Customer Classes

Description	2013 # of customers	2013 Total Customer Revenue	2013 Proposed Customer Revenue BMC	2013 BMC as a % of Total Revenue
Residential	348,409	$403,003,424	$86,213,727	21.4%
Farm	61,751	143,368,956	21,247,638	14.8%
Commercial	55,105	352,403,132	18,199,658	5.2%
Power	125	563,534,647	6,252,072	1.1%
Oilfields	15,715	281,617,223	11,365,753	4.0%
Reseller	3	79,142,030	282,240	0.4%
Total	**481,108**	**$1,823,069,412**	**143,561,088**	**7.9%**

11.4 Maximum Customer Increases

This application requests an equal percentage increase for all rate components for all customer classes. The increase proposed is an average of 6.1% for the Power – Contract Rates Class and 4.9% for all other customer classes. Accordingly all customers other than the Power - Contract Rate class will see an increase of 4.9%. Customers in the Power – Contract Rate class will see an average 6.1% increase, but individual customers will see varying increases pursuit to the escalation clauses in their energy supply agreements.

11.5 Rate Design Observations

For this review, the Minister's Terms of Reference stipulated that the Panel was to take, as a given, "...the current rate structure, with final rate change to be applied uniformly to all customer classes (except the Power-Contract Rate class) and all components (basic charge, energy charge and demand charge) of the rate". Accordingly, SaskPower has not altered the rate structure for any of its customer classes that were utilized in the 2010 Rate Application. Customer classes having a two part rate (BMC and Energy Rate) remains unchanged as do those classes with a three part rate (BMC, Energy and Demand Rates). In the Mid-Application update, the range of R/RR is 0.96 (Rural Residential) to 1.05 (Oilfields), with the Reseller at 1.01 and Streetlight Class and Rural Commercial at 1.00.

We understand that the rationale for imposing a uniform across the board rate increase for customer classes, with the only variance amongst classes being in the amount of the increase for the Power-Commercial Class, was to avoid varying rate changes that would be driven by 2013 COSS. It was SaskPower's expectation that the new COSS could well result in rates moving in the opposite direction. This would have the potential negative consequence of some rates having significant increases in the next application driven not only by increased capital and operating costs, but also by a change in COSS. It is expected that future rates will reflect expected future revenue requirements by class.

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. It is our understanding that the COSS review by the external consultant may contain recommendations in this regard.

Table 11.6 - Customer Rate Design Data (Accounts)

Rate Design Customer Data						
Number of Accounts	2011	2011	2013	2013	2011 to 2013	Change
		% of Total		% of Total		%
Urban Res	279,686	58.3%	300,684	60.7%	20,998	7.5%
Rural Res	66,626	13.9%	55,835	11.3%	(10,791)	(16.2)%
Farms	60,871	12.7%	62,245	12.6%	1,374	2.3%
Urban Comm.	41,910	8.8%	42,963	8.7%	1,053	2.5%
Rural Comm.	12,625	2.6%	12,777	2.6%	152	1.2%
Power – P	83	0.0%	86	0.0%	3	3.6%
Power – C	14	0.0%	14	0.0%	0	0.0%
Oilfields	15,015	3.1%	17,104	3.5%	2,089	13.9%
Streetlights	2,823	0.6%	3,321	0.7%	498	17.6%
Reseller	3	0.0%	3	0.0%	0	0.0%
Total	**479,656**	**100.0%**	**495,031**	**100.0%**	**15,375**	**3.2%**

Table 11.7 - Customer Rate Design Data (Revenues)

Rate Design Customer Data						
Annual Revenues	2011	2011	2013	2013	2011 to 2013	Change
	$	% of Total	$	% of Total	$	%
Urban Res	317,938,026	19.1%	337,217,371	18.0%	19,279,345	6.1%
Rural Res	89,327,401	5.4%	92,094,179	4.9%	2,766,778	3.1%
Farms	144,928,556	8.7%	155,808,363	8.3%	10,879,807	7.5%
Urban Comm.	250,383,072	15.0%	262,563,101	14.0%	12,180,029	4.9%
Rural Comm.	90,254,600	5.4%	93,313,911	5.0%	3,059,311	3.4%
Power – P	354,760,611	21.3%	430,293,011	23.0%	75,532,400	21.3%
Power – C	84,141,276	5.1%	99,110,768	5.3%	14,969,492	17.8%
Oilfields	241,621,603	14.5%	305,314,224	16.3%	63,692,621	26.4%
Streetlights	14,891,994	0.9%	16,453,970	0.9%	1,561,976	10.5%
Reseller	77,130,209	4.6%	81,894,164	4.4%	4,763,955	6.2%
Total	**1,665,377,348**	**100.0%**	**1,874,063,063**	**100.0%**	**208,685,715**	**12.5%**

Table 11.8 - Customer Rate Design Data (Sales)

Rate Design Customer Data						
Annual Sales MWh	2011	2011 % of Total	2013	2013 % of Total	2011 to 2013	Change %
Urban Res	2,356,156	12.2%	2,373,496	11.2%	17,340	0.7%
Rural Res	649,819	3.4%	637,661	3.0%	(12,158)	(1.9)%
Farms	1,298,298	6.8%	1,330,636	6.3%	32,338	2.5%
Urban Comm	2,528,935	13.1%	2,576,641	12.2%	47,706	1.9%
Rural Comm.	867,126	4.5%	876,943	4.2%	9,817	1.1%
Power – P	5,889,700	30.6%	6,868,494	32.5%	978,794	16.6%
Power – C	1,428,950	7.4%	1,600,755	7.6%	171,805	12.0%
Oilfields	2,900,828	15.1%	3,546,267	16.8%	645,439	22.3%
Streetlights	51,400	0.3%	60,464	0.3%	9,064	17.6%
Reseller	1,260,606	6.6%	1,274,898	6.0%	14,292	1.1%
Total	**19,231,817**	**100.0%**	**21,146,254**	**100.0%**	**1,914,437**	**10.0%**

12.0 Historical Rate Comparison Summary

12.1 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 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 threshold 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 SaskPower's last rate application in February 2010, the following rate adjustments have occurred across Canada in other provincial jurisdictions:

BC Hydro

- Rates have increased by 8% effective May 1, 2011;
- Increased 3.91% effective April 1, 2012; and
- An additional 1.44% effective April 1, 2013.

Manitoba Hydro

- Rates have increased by 1.9% in April 2010;
- 2% in April 2011;
- 2% on an interim basis in April of 2012; and
- Manitoba Hydro has applied for additional increases of 2.5% on an interim basis effective September 1, 2012 and 3.5% effective April 1, 2013.

Nova Scotia

- Power rates increased 5.6% on January 1, 2012; and
- Nova Scotia Power has applied for a rate increase of 3% per year for 2013 and 2014.

Newfoundland

- Power rates have increased 7.7% effective July 1, 2011.

The following tables display historical provincial rate changes by provincial utility providers from 2007 to present day, as amended since the 2010 application.

Table 12.1 - Historical Provincial Rate Changes

Canadian Utilities	Between 2011 and 2015		
	Date	%	Comments
BC Hydro, BC	May 1, 2011	10.5	8% increase with a deferral account rate rider of 2.5%
	April 1, 2012	8.91	3.91% increase with a deferral account rate rider of 5%
	April 1, 2013	6.44	1.44% with a deferral account rate rider of 5%
Fortis BC	Jan 1, 2012	4.0	BCUC granted 1.5% interim increase effective Jan 1, 2012
	Jan 1, 2013	6.9	
Manitoba Hydro , MB	Apr 1, 2010	1.9	Final
	Apr 1, 2011	2.0	Final
	Apr 1, 2012	2.0	Interim granted
	Sep 1, 2012	2.5	Interim granted
	Apr 1, 2013	3.5	Applied for
Hydro-Quebec Distribution	April 1, 2012	-0.5	Decrease
Nova Scotia Power, NS	Jan 1, 2012	3.0	Fuel Adjustment Mechanism adjustment
	Jan 1, 2012	5.6	Increase
	2013, 2014	3.0	Applied for 3% in each of 2013 and 2014 as Rate Stabilization Plan
Maritime Electric, PEI	Mar 1, 2011	-14	Rate decrease
Newfoundland Power	July 1, 2011	7.7	Increase
	Mar 1, 2013	6.0	Applied for (with a corresponding increase to Newfoundland and Labrador Hydro's rates)
Northwest Territories Power Corp.	2012-2014	7.0	Applied for increase effective April 1, 2012/2013/2014
	2015	5.0	Applied for

Table 12.2 - BC Rate Changes

Canadian Utilities	Between 2007 and 2015		
	Date	%	Comments
BC Hydro, BC	1-Apr-08	6.56	
	1-Apr-09	2.34	
	1-Apr-10	8.74	
	1-May-11	10.5	8% increase with a deferral account rate rider of 2.5%
	1-Apr-12	8.91	3.91% rate increase with a deferral account rate rider of 5%
	1-Apr-13	6.44	1.44% with a deferral account rate rider of 5%
Fortis BC	1-Jan-07	1.2	
	1-Apr-07	2.1	
	1-Jan-08	4	
	1-Sep-09	4.6	
	1-Jan-10	3.5	
	1-Jan-12	4	BCUC granted 1.5% interim increase effective Jan 1, 2012

The following table summarizes SaskPower's comparative residential rate comparisons with other Canadian Thermal Utilities:

Table 12.3 - SaskPower Rate Comparison

COMPARISON OF ELECTRICITY COSTS
MONTHLY NET RATES - AS OF JANUARY 1, 2012

1.) Hydro Utilities

COMMUNITY	SERVED BY	RESIDENTIAL 675 kW.h/month	SMALL COMMERCIAL SERVICE 5 kW & 1,000 kW.h/month	STANDARD COMMERCIAL SERVICE 215 kW (239 kVa) & 65,000 kW.h/month	72 kV Power 9,500 kW (10,000 kVa) & 4,854,500 kW.h/month
VANCOUVER, BC	BC HYDRO	$49.42	$93.74	$4,535.51	$231,779.49
PRINCE GEORGE, BC	BC HYDRO	$49.42	$93.74	$4,535.51	Not Available
TRAIL, BC	FORTIS BC	$79.99	$101.32	$5,838.24	$290,548.82
BC Average		$59.61	$96.26	$4,969.75	$261,164.15
WINNIPEG, MB	MANITOBA HYDRO	$51.54	$87.85	$4,214.11	$195,069.65
BRANDON, MB	MANITOBA HYDRO	$51.54	$87.85	$4,214.11	$195,069.65
Manitoba Average		$51.54	$87.85	$4,214.11	$195,069.65
MONTREAL, QC	HYDRO-QUEBEC	$48.74	$100.13	$5,788.60	$259,888.65

2.) Thermal Utilities

COMMUNITY	SERVED BY	RESIDENTIAL 675 kW.h/month	SMALL COMMERCIAL SERVICE 5 kW & 1,000 kW.h/month	STANDARD COMMERCIAL SERVICE 215 kW (239 kVa) & 65,000 kW.h/month	72 kV Power 9,500 kW (10,000 kVa) & 4,854,500 kW.h/month
CALGARY, AB	ENMAX (City-Calgary)	$138.57	$205.75	Not Available	Not Available
EDMONTON, AB	EPCOR	$142.47	$208.65	Not Available	Not Available
ST. ALBERT, AB	EPCOR (FortisAlberta)	$150.93	$225.79	Not Available	Not Available
GRANDE PRAIRIE, AB	ATCO (Direct Energy)	$202.15	$262.99	Not Available	Not Available
LLOYDMINISTER, AB	ATCO (Direct Energy)	$202.15	$262.99	Not Available	Not Available
Alberta Average		$167.25	$233.24	Not Available	Not Available
TORONTO, ON	TORONTO HYDRO	$95.28	$125.11	$8,398.98	$580,926.91
OTTAWA, ON	OTTAWA HYDRO	$89.75	$121.32	$7,390.30	$546,221.33
THUNDER BAY, ON	THUNDER BAY HYDRO	$81.01	$121.58	$8,003.70	Not Available
Ontario Average		$88.68	$122.67	$7,930.99	$563,574.12
ST. JOHN, NB	CITY OF ST. JOHN	$76.24	$142.00	$7,346.10	Not Available
MONCTON, NB Standard	NEW BRUNSWICK POWER	$86.22	$141.63	$7,644.13	$353,328.75
New Brunswick Average		$81.23	$141.82	$7,495.12	$353,328.75
HALIFAX, NS	NOVA SCOTIA POWER	$104.81	$151.98	$8,583.48	$454,214.00
CHARLOTTETOWN, PE	MARITIME ELECTRIC	$105.91	$176.37	$8,988.42	$428,534.55
ST. JOHN'S, NF	NFLD LIGHT & POWER	$85.96	$139.85	$7,071.41	$409,882.22

3.) Utility Rate Summary

COMMUNITY	SERVED BY	RESIDENTIAL	SMALL COMMERCIAL SERVICE	STANDARD COMMERCIAL SERVICE	72 kV Power
		675 kW.h/month	5 kW & 1,000 kW.h/month	215 kW (239 kVa) & 65,000 kW.h/month	9,500 kW (10,000 kVa) & 4,854,500 kW.h/month
Hydro Utility Average		$53.30	$94.75	$4,990.82	$238,707.48
Thermal Utility Average		$105.64	$160.99	$8,013.88	$441,906.73
Canadian Utility Average		$88.19	$138.91	$6,880.23	$365,707.01
REGINA, SK	SASKPOWER	$90.90	$125.01	$6,549.80	$292,749.86

4.) SaskPower Comparison

	RESIDENTIAL	SMALL COMMERCIAL SERVICE	STANDARD COMMERCIAL SERVICE	72 kV Power
	675 kW.h/month	5 kW & 1,000 kW.h/month	215 kW (239 kVa) & 65,000 kW.h/month	9,500 kW (10,000 kVa) & 4,854,500 kW.h/month
SaskPower compared to Hydro Utility Average	170.6%	131.9%	131.2%	122.6%
SaskPower compared to Thermal Utility Average	86.0%	77.7%	81.7%	66.2%
SaskPower compared to Canadian Utility Average	103.1%	90.0%	95.2%	80.1%

5.) SaskPower Compared to All Thermal Utilities (All Classes) 77.9%

12.2 Historical Rate Changes

SaskPower's last approved rate increase was 4.5% effective August 1, 2010. SaskPower compares its rates to the average charged nationally, including low-cost hydro jurisdictions, and by other thermal utilities in Canada. SaskPower customers currently pay rates that are on average 8% lower than the Canadian average and 22% lower than the rates of other thermal utilities in Canada. Generally, electrical rates are rising in all jurisdictions across Canada.

The following indicates SaskPower’s rate adjustments since 2001:

April 1, 2001	2.00 %
January 1, 2002	4.54 %
September 1, 2004	5.65 %
January 1, 2006	4.90 %
February 1, 2007	4.20 %
June 1, 2009	8.50 %
August 1, 2010	4.50 %
January 1, 2013 Proposed	5.00 %

SaskPower’s rates from 1999 to 2011 have increased 41.8% on a compounded basis. During this same period the Consumer Price Index (CPI) increased by 35.0%. From 2005 to 2011 rates have increased by 24.0%, while the CPI has increased by 16.6%. 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.

12.3 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. These are shown on the above table. SaskPower rates compare favourably with other provinces (on average 8% lower than the Canadian average and 22% lower than the Canadian thermal average). However, we caution that any comparisons must recognize that each utility has unique characteristics such as generation fuel mix and related hierarchy of costs, customer density, geographic population distribution and potential for export revenues.

13.0 Sensitivity Potential Impacts

13.1 Discussion

As highlighted in Section 2.3.1 of this Report the Mid-Application Update SaskPower's forecasted net income had declined $39.8 million from the original Rate Application submission.

Saskatchewan sales were down $39.7 million due primarily to $60.2 million lower projected sales in the power customer class. SaskPower management noted the trend in actual power customer of revenues falling significantly short of the budget over the last number of years and thus worked directly with the large customers in revising their estimates for 2013. In addition to power customers, reseller revenue was also reduced by $1.1 million to reflect the expected load changes. All these unfavourable variances were offset by forecasted increased sales to residential, farm, commercial and oilfield customers.

Since the demand required by the Power Customer Class is over 40% of the total domestic demand, it is extremely important not only for the power customers and all customers, that the demand forecast accurately reflect the future requirements. Without appropriate load forecasts and the corporations ability to react to these changing circumstances, a number of domino like issues could cause service and reliability issues.

However, SaskPower is somewhat constrained in preparing these forecasts have to rely on information provided by the large customer. It is extremely important for all parties that the exchange of future plans by large customers is as accurate as reasonably possible given the current global economic circumstances.

While a strong economy and job growth are expected for the balance of 2012 and 2013, the Saskatchewan economy is heavily reliant on exports and therefore vulnerable to global downturns and decreased export opportunities.

Adverse global economic conditions experienced during 2011 and 2012 continue to slowly recover. Markets and economic data continue to send somewhat mixed signals as to the level of economic growth expected in 2013. This creates significant issues for SaskPower in forecasting load and customer demand accurately, thereby increasing the risk of financial performance as forecasting revenue and fuel and purchase power costs become more difficult, even problematic. This was clearly demonstrated in the Mid-Application update.

Unfortunately global economic conditions play a significant role in determining future load demands as noted in SaskPower's forecast for the Power customer class. The current global market for potash and other sectors demonstrates that SaskPower's load forecasts need to be very sensitive to that environment and its trends.

To assist the Panel and readers we have examined and prepared a sensitivity analysis on some of the basic cost drivers and assumptions used in the preparation of the current forecasts, planning process and the possible impact of these changes in assumptions on operational results. The following are not strictly correlated. As an example, if water flows are higher than the current median forecast more electricity would be generated by hydraulic means, reducing the need to generate electricity by natural gas, and the savings would be the result of buying less natural gas. In the converse, if hydraulic generation was less than median, more natural gas would be required to generate the electricity which costs more than hydro. Generally coal fired generation is operated at maximum efficient output and cannot be relied on to smooth out variances in hydraulic generation. The table below highlights those financial impacts:

Revenue	Impact on Net Income
1% increase in customer rates	$18.0 million
100 GWh change in power customer consumption	$3.0 million
100 GWh change in residential power consumption	$10.0 million
1% change in ROE	$20.0 million
F&PP	
$1/GJ change in natural gas price assumption	$30.0 million
10% change in hydro assumption	$15.0 million
10% change in coal generation assumption	$40.0 million
Capital	
$100 million change in 2012 capital budget (depreciation)	$4.0 million
$100 million change in 2012 capital budget (finance charges)	$3.0 million

13.2 Observations

Recognizing that the forecasted net income for 2013, as supplied in the Mid-Application update, is $126.1 million, the above impacts can potentially drive 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 the negative changes will decrease the net income. The greatest financial impacts flow from changes in load demand coupled with the resulting and potential market changes in the F&PP costs. During the balance of 2012 and 2013, it is to be expected that the current forecast will not materialize exactly as noted in the Mid-Application and could change significantly if one or more of the foregoing result.

A good example of this was the summer storm of 2012. That storm created havoc with SaskPower's transmission and distribution system and required significant additional labour and material to reinstate power service. While the final costs are still being tabulated, it is expected the overall costs to be in the neighbourhood of $14 to $15 million. SaskPower employees are to be congratulated for their efforts in restoring power in a comparatively short time period but there was an Operation, Maintenance and Administrative cost that was not anticipated or forecasted.

However, we anticipate results will closely mirror the net income forecasted in the update.

14.0 Confidentiality and Transparency

In March of 2010 the Panel adopted confidentiality guidelines which were intended to provide guidance to the Panel and the Crown corporations surrounding the classification, use and disclosure of confidential information supplied by either SaskPower, SaskEnergy and SGI's - AutoFund during the course of an application to review a change in rates.

These guidelines are posted on the Saskatchewan Rate Review Panel's web-site: www.saskratereview.com

Confidential information is defined as that which contains:

1. Commercially sensitive information with a legitimate need for protection from disclosure.
2. Information, the disclosure of which could reasonably be expected to:
    a. Result in financial loss or gain to;
    b. Prejudice the competitive position of; or
    c. Interfere with the contractual obligations of the Crown corporation or a third party.
3. Information, the disclosure of which is prohibited by law, including The Freedom of Information and Protection of Privacy Act (Saskatchewan) (FOIPPA). This shall include, but is not limited to:
    a. Information of a personal or financial nature respecting an identifiable individual or corporation, including financial accounts and all utility account information;
    b. Information that could disclose a confidence of Cabinet; or
    c. Information supplied to the Crown corporation in confidence by a third party.

The guidelines further 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."

The basic and 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.

The current guidelines state – "The initial assessment on whether or not any portion of the material supplied by the Crown corporation to the Panel is Confidential Information will be made by the Crown corporation. The Crown corporation shall make its assessment based on the definition of Confidential Information contained in these Guidelines. The Crown corporation shall mark all Confidential Information as 'Confidential' and submit such to the Panel. All Confidential Information submitted to the Panel must be accompanied by the information, including if applicable, specific references to the relevant exemptions contained in FOIPPA and relevant decisions by the Information and Privacy Commissioner and the courts in Saskatchewan."

If the Panel agree with the Crown corporation's assessment of the material as being confidential information as defined in these Guidelines, then the Panel will not disclose the confidential information to the public, nor will it be included in the Panel's report to the Minister. There is an adjudicative process to follow in the event the Panel disagrees with the Crown corporation's assessment of the confidential nature of the relevant information. No party raised any specific concerns directly with the Panel during the process other than the observations made at the public meeting in Regina.

All parties appear to recognize that disclosure of confidential information could harm the Crown corporation and other third parties and that maintaining the confidentiality of the information is important, necessary and integral to their process to test the merits of a specific application.

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.

In the case of SaskPower confidential information currently assessed in 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.

During the SaskPower review, 29 of the questions posed by the Panel and the consultants fell under the confidential protocol. A few of the foregoing questions had subsets to the original question resulting in 37 individual confidential responses related to the first round, second round and a third supplemental round (related to the September Mid-Application Update) of information requests. In total there were 138 first round, 55 second round and 7 supplemental round information requests submitted to SaskPower on behalf of the Panel. Many of the questions posed and responded to by SaskPower had multiple components related to a specific topic area. All the questions were fully addressed and responded to, albeit some confidentially.

As this issue was raised as an observation at the public meeting, we felt it necessary to examine each question and response to determine whether they fell within the spirit and intention of the confidential guidelines. Of the 37 responses, 29 clearly fell within one of the aforementioned categories. The other 8 were not, in our opinion, material to the application or under active consideration at this time nor of broad public interest. Therefore, we did not see any merit in pursing them further with the Panel nor the adjudicative process.

During the process, as consultants we were fully satisfied that SaskPower supplied the information requested at each juncture whether in meetings or the formal disclosure process.

15.0 Public and Stakeholder Submissions

As part of our examination process we pay close attention to the various submissions forwarded to Saskatchewan Rate Review Panel. We find the submissions of great value in understanding the public's views, observations and concerns relative to SaskPower's Rate Application. We also either attend the public meetings or review the discussion and presentations through the specific transcripts of the proceedings. We are grateful for all public participation. Each is presentation is summarized below:

15.1 Consumer Association of Saskatchewan (CASK)

Ms. Ruth Robinson, a Board Member of the Consumer Association of Saskatchewan (CASK), provided a submission on September 19, 2012 outlining their views on the current SaskPower Rate Application.

CASK stated that the reliability of electrical supply is of the utmost concern and that SaskPower needs to deliver it safely while keeping expenditures at a minimum. CASK also noted:

- Education of consumers to modify use to reduce power consumption and bills is important.
- The proposed rate increase without rate rebalancing still needs to result in each class paying its fair share.
- No rate increase in 2013 would be required if there was no dividend payment.
- Power outages and office closures have impacted / will impact service levels.
- Burying overhead power lines to reduce accidents needs should continue.
- Future generation sources with fewer environmental impacts should continue to be considered and developed.
- The rate review process lead time for hearings has improved.

CASK does not believe an increase is warranted at this time for the following reasons:

- Service to customers is decreasing;
- There are still more savings that can be identified without affecting service;
- The 2013 forecasted net income is substantial even without a rate increase; and
- The dividend issue.

SaskPower Response

SaskPower provided a response on October 11, 2012 to the specific issues raised by the Consumer Association of Saskatchewan.

SaskPower agreed that reliability of electrical supply is of the utmost concern to Saskatchewan consumers. SaskPower stated it was increasing efficiency and effectiveness through the Business Renewal Program and Service Delivery Renewal Projects. SaskPower also noted:

- Education of consumers to modify use is being looked at through DSM, time of use rate studies and installation of smart meters.

- The proposed rate increase without rate rebalancing will still fall between the 0.95 and 1.05 R/RR ratios for each customer class, which is in accordance with industry standards.
- A dividend has not been paid in the past three years, allowing SaskPower to renew infrastructure and meet demand growth. A dividend payment is not expected in 2013.
- Additional revenue is required for maintenance activities as well as the replacement and refurbishment of existing infrastructure.
- The frequency of outages has been consistent with the long-term average.
- Office closures only involve customer service payment facilities and not distribution service facilities, which will remain in place.

15.2 City of Saskatoon - Saskatoon Light and Power (SL&P)

Mr. Jeff Jorgenson, General Manager of Saskatoon Light and Power (SL&P), commented on the current SaskPower Rate Application during the public meeting held in Saskatoon on September 19, 2012.

SL&P stated that they were concerned with any proposed Reseller rate increase higher than a Revenue to Revenue Requirement (R/RR) ratio of 1.00. SL&P also noted:

- SRRP has previously recommended the Reseller R/RR ratio should be set at 1.00.
- The rate application showed an actual Reseller R/RR ratio of 1.02, which would rise to 1.03 after the proposed rate increase.
- The proposed rate increase would result in an overpayment of approximately $2.1 million annually by the City of Saskatoon.
- The Urban Residential (R/RR ratio of 0.96) and Urban Commercial (R/RR ratio of 0.99) classes are more reflective of the City of Saskatoon's customer base.

SL&P concluded that the Reseller R/RR ratio should not exceed 1.00 and actually be even lower.

SaskPower Response

SaskPower provided a response on October 11, 2012 to the specific issues raised by SL&P in their October 3, 2012 submission. SaskPower noted the following:

R/RR ratios change from year to year, even if there are no changes in rates or cost of service methodology. Common causes of fluctuating R/RR ratios are increases or decreases in generation costs and changes in the relative weighting of demand and energy related costs.

SRRP recommendations are followed by SaskPower. R/RR ratios in subsequent years can change (up or down) as the cost of service models are rebuilt with updated customer and financial data. The only way to maintain the ratios exactly as they were at the end of a rate application would be to rebalance rates in each and every year.

A cost of service methodology review is being conducted concurrently with this rate application, but will not be completed in time for the results to be incorporated into it. Instead of conducting a full rate rebalancing exercise, which would have to be reversed in the next rate application, it was decided to implement a flat rate increase in 2013. Rates will still fall between the 0.95 and 1.05 R/RR ratios for each customer class, which is in accordance with industry standards.

15.3 Greater Saskatoon Chamber of Commerce

Mr. Kent Smith-Windsor, Executive Director of the Greater Saskatoon Chamber of Commerce, (The Chamber) commented on the current SaskPower Rate Application during the public meeting held in Saskatoon on September 19, 2012.

The Chamber acknowledged that SaskPower has shown significant progress and value in regards to efforts undertaken on efficiency and effectiveness. The Chamber also noted:

- An across-the-board rate increase actually results in the widening of gaps, which is contrary to SaskPower's suggestion that there is no change and will avoid changes having to be undone after the completion of the cost of service and rate design review.
- SRRP has previously recommended a R/RR ratio of 1.00 for Resellers, which the current rate application shows as being 1.02 and proposes increasing to 1.03.
- The targeted rate of return is not in line with the current market reality, which does not take into consideration SaskPower's unique market position.
- Some one-time expenditure, which should perhaps be extended over a period of time, are currently embedded within operation costs and used to justify the rate increase.
- SaskPower could benefit from a US comparison to Montana or North Dakota, which have very similar attributes to Saskatchewan.
- There may be merit in using actual fuel expenditure reductions, including that from hydroelectric production, to reduce future power rates given that expenses are applied on a one-time basis.

15.4 City of Swift Current - Light and Power

Mr. Mitch Minken, Director of the City of Swift Current - Light & Power, provided a submission to the SRRP on October 2, 2012 outlining their views on the current SaskPower Rate Application.

Swift Current believes that R/RR ratios have become skewed since the last rate increase in 2010 and that rate rebalancing needs to be applied. The City of Swift Current also noted:

- Cross subsidization accounts for 28.6% of the total proposed rate increase for 2013.
- The Swift Current R/RR ratio should be in line with the Urban Residential and Urban Commercial classes, as that is what its customer base is entirely made up of, which would make it 0.98 instead of 1.01.
- There appears to be a problem with the manner in which SaskPower calculates R/RR ratios, as those projected from the 2010 rate increase did not result.
- Despite previous recommendations by the SRRP to set the Reseller R/RR ratio at 1.00, the actual ratio resulting from the 2009 rate increase was 1.01 while the projected 2010 rate application ratio of 1.01 actually resulted in being 1.02.
- Swift Current has been over paying for electricity since 2007, which they calculate to be approximately $450,000 / year or equivalent to a 6% municipal tax increase.

The City of Swift Current concluded its formal presentation by requesting the SRRP recommend the Reseller R/RR ratio be reflective of its actual customer base and that SaskPower be required to maintain actual R/RR ratios as projected in their rate applications. In addition to the above formal presentation, the following comments were also provided:

- Swift Current was disappointed with the lack of R/RR ratio and rate rebalancing questions asked by the SRRP consultants, raising concerns as to whether they were in tune with the issues.
- Swift Current was disappointed with the data presented by SaskPower in the mid-application update, which appears to be inconsistent and contradictory.
- Swift Current questioned SaskPower's claim that increased generation and transmission costs, which decrease R/RR ratios for large power and reseller customers, increased the R/RR ratios for all other customers.
- Swift Current finds it difficult to accept the accuracy of SaskPower's numbers based on the inconsistencies contained in the mid-application update and believes the Reseller R/RR ratio is not correctly shown.
- Swift Current disputes they should be considered equivalent to power class customers and requests they be considered part of the urban residential and commercial classes.

SaskPower Response

SaskPower provided a response on October 11, 2012 to the specific issues raised by the City of Swift Current - Light & Power in their October 2, 2012 submission. The response was the same as that provided to Saskatoon Light & Power. Please refer to the SaskPower Response contained in Section 15.2 of this report for details.

15.5 Paper Excellence

Mr. Dale Paterson, Vice-President of Operations for Paper Excellence, commented on the current SaskPower Rate Application during the public meeting held in Regina on October 2, 2012 and in a written submission dated October 11, 2012.

Paper Excellence acknowledged the work SaskPower has done to bring Prince Albert Pulp on-line and restore power services to Meadow Lake Mechanical Pulp (MLMP) after the storm. Paper Excellence also noted:

- Substantial capital investment has been made at MLMP to upgrade equipment, while maintaining the same employment levels over the last 4 to 5 years.
- Production has increased at MLMP since 2007 from 300,000 tonnes/year to 400,000 tonnes/year, which is expected to increase by another 20% or to 500,000 tonnes/year.
- The proposed rate increase will increase MLMP costs by approximately $1.8 million / annum, taking them from a profitable position to one that is unprofitable.
- MLMP relies on both cost competitive and reliable electricity, reporting that the 17 day outage that occurred in June and July resulted in lost revenue of about $13 million.
- Although there has been no increases in Saskatchewan in the last 3 years, electrical rate increases in the last 10 years has been about 50%.
- Paper Excellence challenged SaskPower to produce the same results as MLMP, in which they decreased labour hours/tonne by about 20%.

- Perhaps the 60 megawatt spinning reserve at Meadow Lake can be expanded to help offset the proposed rate increase.
- Other challenges face Meadow Lake besides power.

MLMP is the largest employer in Meadow Lake, contributing about $1.5 million / year in taxes. They directly employ 160 permanent and 10 part-time employees as well as an additional 250 contractors, truckers, and forestry workers indirectly. Although they are currently surviving, 2 others have not been so fortunate recently (1 in BC and 1 in Quebec). These businesses do not run high profit operations. Margins are tight and not open to much spending.

SaskPower Response

SaskPower provided a response on October 17, 2012 to the specific issues raised by Paper Excellence in their October 11, 2012 submission. SaskPower noted the following:

- Rates over the 10 year period between 2003 and 2012 have increased by more than the previous decade.
- SaskPower is working on increasing efficiency and effectiveness through the Business Renewal Program, which will reduce but not eliminate the upward pressure on rates.
- The current rate increase is required to fund long term investments in the province's electrical system to ensure that the infrastructure is in place to support growing demand and to maintain reliable service.
- SaskPower, like other utilities in North America, is facing a prolonged period of reinvestment in infrastructure as demand increases and infrastructure reaches the end of its useful life.

15.6 Canadian Association of Petroleum Producers (CAPP)

Mr. Dale Hildebrand representing the Canadian Association of Petroleum Producers (CAPP) commented on the current SaskPower Rate Application during the public meeting held in Regina on October 2, 2012. CAPP asked for and received clarification on the following:

- Why was there a very significant rate reduction in revenue from the power group or the power rate cost in the mid-application update?
- How will the cost of service study process roll forward and when will the results of the review be implemented into the rates?
- Why was the power class average increase 6% while it was 4.9% for all others classes?

In addition to the above clarification items, CAPP provided the following comments:

- SaskPower is viewed as a critical supplier to the oilfield industry.
- CAPP remains committed to working closely with SaskPower and providing them with accurate forecast information.
- CAPP's goal in attending and participating in the public meetings is to try to encourage continuous improvement to make both Saskatchewan and the oilfield industry more successful in the future.
- Improvements in the quality of information and data supplied by SaskPower and the quality of the questions being asked by the consultants are encouraging.

- The lack of transparency of the data provided is concerning, especially since there is no other jurisdiction where such a lack of transparency and information exists.
- CAPP is encouraged that SaskPower is looking at the cost of service study review, but is concerned that it is not aligned with the rate application process.
- Capital cost expenditure levels and the impact it will have on future rates is concerning.
- CAPP encourages SaskPower to continue to lower operating costs and promote a culture of cost savings and optimization, which is an area of continuous improvement.
- Plans to upgrade SaskPower's metering and billing systems is of great importance as there are issues and concerns with meter reading accuracy, the timing of the billing system, and how information flows electronically.
- It appears that the mid-application update answers the bulk of CAPP's second round questions and provides a better understanding of revenue and cost increases and decreases.

Overall, CAPP did not oppose the proposed rate increase, which seemed reasonable to them based on the information provided. CAPP encouraged the SRRP to make sure that SaskPower remains healthy and asked that SaskPower continue their efforts to keep costs in line.

SaskPower Response

During the CAPP presentation at the public meeting held in Regina on October 2, 2012, SaskPower provided the following clarifications:

The power class energy sales forecast for 2013 was reduced while the reseller class remained about the same and the other customer classes increased. Reasons for this are that some market conditions, primarily in natural gas pumping, changed and some customer expansion projects were delayed by months and others by years. Also, SaskPower relies on industrial customer forecast information. Extra effort was put in this year to try and better firm up those estimates, which are not always accurate or forthcoming from the industrial customers.

The cost of service consultant completed a draft report for presentation on October 16th in Regina. Questions will be taken during and after the presentation. The consultant will respond in writing to questions asked. Submissions will be invited as well, which will be addressed in the final report. Upon receiving the final report, SaskPower will respond to the recommendations made by the consultant. An impact assessment of the changes to the different customer classes will also be provided. This is expected to occur early in the new year. This process is similar to the one followed the last time this was done about 5 years ago.

The 6% or so increase will be applied to the power contract class (i.e. large industrial customers) while the 4.9% increase will be applied to all power customers on published rates. The 6% is to catch up the power contract class rates. Although the power contract class is tied to published rates, they are not tied directly to them. The power contract class also has other conditions contained within their agreements.

15.7 Saskatchewan Industrial Energy Consumers Association (SIECA)

Mr. Eugene Setka, Chairman of the Saskatchewan Industrial Energy Consumers Association (SIECA), commented on the current SaskPower Rate Application during the public meeting held in Regina on October 2, 2012.

SIECA raised concerns about the manner in which SaskPower responded to questions, suggesting that the number of responses hiding behind the veil of confidentiality has increased and that this type of response undermines the trust and confidence of the stakeholders. SIECA also raised three major issues: Load Forecasting, Fuel Cost Variance, and OM&A.

- In regards to load forecasting, SaskPower continues to overestimate consumption.
- In regards to the fuel cost variance, there has been a consistent pattern of overestimating fuel costs as there has been with load forecasting.
- In regards to OM&A, SIECA recognizes that work is being done to try and bring OM&A costs under control, but cannot find the proposed $200 million cost reduction target.

In addition to the above major issues, SIECA provided the following comments:

- The rate design and fuel cost variance account reviews should be happening in parallel with this rate application.
- If a modest rate increase needs to be put in place, then it should not exceed 2%, which is equivalent to the CPI index for Saskatchewan.
- SIECA feels it is prudent to wait until the cost of service study and fuel cost variance account material is available before any rate increase is awarded.
- SIECA concluded by restating it is time for the veil of confidentiality to be removed.

SaskPower Response

During the SIECA presentation at the public meeting held in Regina on October 2, 2012, SaskPower took exception to the suggestion that it was purposely hiding information, making up numbers, or misleading others. SaskPower will clear up any misunderstanding of information by meeting with the SRRP to ensure all factual information comes out.

15.8 Saskatchewan Mining Association (SMA)

Ms. Pam Schwann, Executive Director of the Saskatchewan Mining Association (SMA), commented on the current SaskPower Rate Application during the public meeting held in Regina on October 2, 2012.

Clarification was provided to SMA on the power contract class rate increase, production and power purchase agreement decreases, and reductions in power class revenue generation. SMA then proceeded to provide the following comments:

- SaskPower needs to make significant investments in infrastructure, particularly with respect to base load power generation and transmission.
- SMA is investing over $50 billion in the next 20 years in expansions and new projects with the expectation that there will be power available to run their operations.
- It is extremely concerning that SaskPower will need to rebuild, replace or acquire over 100% of its existing capacity over the next 20 years.
- Power transmission in northern Saskatchewan is at the brink of where it can go.
- Power losses / outages cost mining operations over $20 million a year.

In conclusion, the Saskatchewan Mining Association indicated they would be making a submission on the specific rate increase itself. However, they mainly wanted to recognize and acknowledge that SaskPower needs to re-invest in the infrastructure, which is absolutely necessary for the growth of the province. Also, dividends should be retained and re-invested into the general revenue.

SaskPower Response

SaskPower provided a response on October 11, 2012 to the specific issues raised by the Saskatchewan Mining Association in their October 4, 2012 submission.

SaskPower agrees that it must make substantial investments in power generation, transmission and distribution infrastructure to support Saskatchewan's growing economy and its customer's growing demand for electricity. Investment is required in new infrastructure as well as in the replacement and refurbishment of existing infrastructure as it reaches the end of its useful life. SaskPower also noted the following:

- A dividend has not been paid in the past three years, allowing SaskPower to renew infrastructure and meet demand growth. A dividend payment is not expected in 2013.
- Projects and operations will continue to be managed for cost-effectiveness through the Business Renewal Program and Service Delivery Renewal Projects.
- The results of the depreciation study review conducted in 2010 have been implemented.
- The cost of service review will not be completed in time for the results to be incorporated into the new rates effective January 1, 2013. As the rate application does not feature a rate design and rebalancing component, it will avoid rate changes being made with this application that will have to be reversed following the cost of service review.
- The proposed rate increase without rate rebalancing will still fall between the 0.95 and 1.05 R/RR ratio for each customer class, which is in accordance with industry standards.

15.9 Public Participation

Mr. Kurt Hein commented on the current SaskPower Rate Application during the public meeting held in Saskatoon on September 19, 2012. Mr. Hein noted the following:

- In his view, Saskatchewan residents are not happy about the proposed rate increase and the province already has one of the highest power rates in Canada.
- Saskatchewan residents should not have to pay the $120 million dividend, which is a mistake of the government and has created the need for the proposed rate increase.
- The timing associated with the undertaking of the QE and Boundary Dam capital projects may not be the best as Stats Canada has reported a population decrease in Saskatchewan over the last six months.

16.0 Recommendations and Commentary

We recommend the following for consideration by the Panel:

1. That the 2013 revenue requirement based on the Mid Application Update approved subject to the following:

   a) The revenue requirement be set to allow SaskPower to generate sufficient revenues to earn the requested 6.4% Rate of Return, to produce a net income for 2013 of $126.1 million.

   b) The forecast cost of Gas of $4.00/GJ be used for purposes of setting 2013 rates for an estimated updated consumption of 43.6million GJ.

   c) The Panel accept a 2013 F&PP cost of $545.1 million.

   d) The Panel accept total OM&A expenses of $615.2 Million.

   e) The Panel accept Amortization and Depreciation expenses of $363.0 million.

   f) The Panel accept net finance charges of $303.0 million.

   g) The Panel accept the Municipal Tax, Corporate and Other Taxes Obligations of $53.5 million and

   h) The Panel accept the Other costs at $ 9.0 million.

2. We recommend that SaskPower continue to formulate, implement and track effective and measureable cost control, productivity and efficiency targets and initiatives for all Business Renewal Programs.

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

4. We recommend that the 2013 prospective COSS be accepted as filed.

5. We recommend that the Panel support greater disclosure on future cost implications and make a similar recommendation to the Minister.

In order to further clarify our recommendations, we offer the following commentary.

- Total OM&A costs which are forecast to increase by $12 million over 2012 currently projected results, or approximately 2%, confirms in our view that SaskPower is making significant strides to operate more efficiently. This is especially meaningful in light of the fact that materials and other external costs in general have all faced upward cost pressures, and the significant increase forecast for the 2013 capital program. After considering the adverse impacts on 2012 OM&A of approximately $15 million from 2012 cost base, the 2013 forecasted OM&A cost still suggests that cost containment measures are producing positive financial results.

- While the use of at least 30 years of average weather data appear to be the industry norm as evaluated by Itron, it is not clear if there is any greater weight given to the most recent years weather to recognize the apparent trend to warmer than normal temperatures. Such weighting has recently been introduced by SaskEnergy and results in an adjustment factor to define normal weather. We would suggest that SaskPower review this matter to determine if adopting a similar approach would materially impact the weather normalization process results.

- We find that SaskPower's approach on fuel dispatch is reasonable, certainly acceptable within industry norms, and conclude their system operation from a fuel dispatch point of view is appropriate and should be continued.

- As recommended in our 2010 Report, we continue to urge that a robust level of due diligence be continued to vet out efficiencies and cost effectiveness in the Corporation and to mitigate the projected increases in future operating costs over the next decade. We are pleased with the efforts led by the President and his executive to undertake the systematic review, with the assistance of third parties of all operational processes within SaskPower, with the objective of driving efficiencies, program effectiveness, and future cost saving without impairing or assuming a higher operational risk profile.

  We consider this initiative to be a serious undertaking and while the Business Renewal Initiative is a process to reengineer the entire corporation, we cannot and should not expect significant savings in the initial years of implementation. Notwithstanding the infancy of the initiative, savings are evident and have already been secured. As stated in the submissions of stakeholders, the absence of such successful initiatives will impact the on-going costs and affect the competitiveness of the Saskatchewan Industrial/Business community and financial wellness of the domestic customer.

- As outlined in section 6.3.1, SaskPower is targeting productivity savings in procurement, reducing power plant outage duration and frequency, information technology, and office space utilization. We are satisfied that the annual 2% the efficiency target and subsequent savings recommended by the Panel in its 2010 Report to the Minister, will easily be achieved and for 2013 and will, in fact, be significantly greater than the $12 million.

  We are, therefore, also satisfied that SaskPower has more than adequately followed the Panel's recommendations on the efficiency and effectiveness target. As an example, SaskPower is to be complemented on for the Planned Maintenance Program initiative as part of the review of the entire scope of the corporation to identify areas for possible production and/or efficiency improvements resulting either in cost savings or future avoided costs. The 2013 savings estimated for this aspect of SaskPower's operations alone are almost $27 million. The estimated cost reductions are calculated to be $800,000 per outage on average, based on reduced outage planning costs, mobilization and demobilization costs, labour and overtime costs and replacement energy costs. If the savings materialize to this degree, they would represent a 2.5% savings on the 2013 OM&A.

- In 2009, we had recommended that SaskPower establish and track a fuel cost variance account to become operational when the applied for rate came into effect. We are pleased SaskPower has proceeded with the review, including a dialogue between all Stakeholders to discuss, assess and resolve the merits of a fuel cost variance account. Since the review and presentation by the consultant engaged to review this matter has just occurred in October of 2012, we expect in due course SaskPower will advise what their future intentions are with respect to this matter.

- Subsequent to a request by the Panel in its 2010 Report, SaskPower engaged Itron Inc. to review its Load Forecasting Methodology. Itron found that overall, SaskPower's existing methodology was satisfactory and conformed, in all material areas, with industry norms. SaskPower incorporated three of four recommendations identified by Itron. The one recommendation not adopted by SaskPower was to add an employment component to the commercial GDP drivers used to determine the energy growth rate for the commercial class, as SaskPower believes the employment component is already included in the commercial drivers used to develop the commercial load forecast.

  SaskPower's forecasts have historically been fairly accurate, given the uncertainty with projecting the industrial requirements, as these are primarily driven by the individual production and expansion plans. We further note that SaskPower continues to use 30 year's data in defining normal weather and do not assess any greater than average weights to the most recent years.

  While the use of at least 30 years of average weather data appear to be the industry norm as evaluated by Itron, it is not clear if there is any greater weight given to the most recent years weather to recognize the apparent trend to warmer than normal temperatures. Such weighting has recently been introduced by SaskEnergy and results in an adjustment factor to define normal weather. We would suggest that SaskPower review this matter to determine if adopting a similar approach would materially impact the weather normalization process results.

- We are of the view that SaskPower's methodology of forecasting numbers of customer's accounts is reasonable, considering Saskatchewan's projected economic performance relative to the rest of Canada, and most recently in light of the economic uncertainty, nationally and internationally. The methodology has been reviewed by an external consultant who has agreed with SaskPower's forecasting process, with some "fine-tuning" recommendations which have been incorporated by SaskPower in this Application. As well, our analysis of variances between forecast and actual accounts suggests an acceptable degree of forecasting account accuracy, especially in this unsettled economic climate.

- SaskPower faces significant challenges to supply future expected load growth that is largely driven by its Power Customers, primarily in the mining and Oilfield sector. It is encouraging that SaskPower has assessed its future needs, for the first time looking beyond the usual 10-year plan, to the next 40 years and, as well has conducted extensive analysis of its northern requirements. There is expected to be a fundamental shift in the nature of future growth in that, unlike in the recent past where demand has been from the southern portions of the province, the industrial growth will largely be in the north. We are pleased that SaskPower has undertaken this review which should be a significant advantage to them in planning and addressing the future electrical supply needs of the province.

- SaskPower's DSM programs have been structured to encourage reduction of energy consumption for residential, commercial and industrial users, in the form of energy efficient appliances and lighting, self-generated power (such as geothermal systems), and other load shifting DSM programs. Through low interest loans, technical assistance, advice and education campaigns, they are also developing other programs for commercial and industrial customers, as well as expanding the residential program. SaskPower's $ 20.0 million program for 2013 in this area is reasonable, with the targeted energy savings of 47,000 MWh expected in that year.

- In 2009, the Panel recommended that SaskPower, in conjunction with other Crown Corporations SaskEnergy, TransGas, NorthPoint and Crown Investment Corporation, review the gas supply function, including procurement, storage, daily supply management, price risk management and other related matters. On a confidential basis, we were provided a copy of the consultant's report confirming such a review has been undertaken. We also understand both SaskPower and SaskEnergy have been directed to work together to find economies in the operation of their respective assets in the gas supply and transmission function for the mutual benefit of all their customers. We again encourage such dialogue to continue with the view of increasing interaction where mutually beneficial interactions produce positive and cost saving results that can be meaningfully tracked, reported and the financial benefits substantiated.

- We find that SaskPower's approach on fuel dispatch is reasonable, certainly acceptable within industry norms, and conclude their system operation from a fuel dispatch point of view is appropriate and should be continued.

- We consider that the 2013 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. The Panel's Terms of Reference preclude the ability to recommend alterations to the current rate structure, with the final rate change to be applied uniformly to all customer classes (except the Power - Contract Rate class) and all components (basic charge, energy charge and demand charge) of the rate, as well as the budgeted capital allocation, the rate base and established corporate policies.

With the COSS methodology being currently examined by SaskPower and its external consultant (as earlier recommended by the Pane)l together with reviewing the current and forecasted results for 2013 and 2014, we find it falls with the target range as specified by the Minster's Terms of Reference. We had 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 a more generic fashion. It is our understanding that the COSS review by the external consultant may contain recommendations in this regard.

- We 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. However, we note that the R/RR for the oilfield Class, is at the outside limit of 1.05. We also note the Power – Contract Rates are just below 1.0 at 0.99.

  We also note comments by the Stakeholders that the R/RR should be set at 1.00 for all customer classes. The appeal of such a move would be the elimination on intentional cross-subsidization for all customer classes. However, recognizing that the methodologies leading to the calculation of R/RR are not a precise science and until the review of the Cost of Service methodology has been completed and formally adopted we are satisfied this application meets the goals and target defined by the Minister.

- We also recognize that from the business, industrial and power customers' perspective, the ability to obtain clear and concise information about current costs and future cost trends which they are likely to experience, is an integral aspect of their own ongoing operations and new capital investment decisions. Companies, as well as individuals, need to have a clear and reasonable forecast of future operating input costs, such as energy costs, that will impact these important decisions.

  The current process of providing information related to each specific application limits the examination of future costs and rate implications. In 2010, we supported the position put forward by the City of Saskatoon (Saskatoon Light and Power) where at least four years of future financial data, revenue and expense, should be made available for public examination at the time of a rate application. The norm in the industry is at least five years of future financial projections, with some regulators requiring that a decade of those forecasts be provided in an application. We would recommend that the Panel consider supporting greater disclosure on future cost implications and make a similar recommendation to the Minister.

- Going forward, we recognize that significant capital program for plant new and reinvestments in infrastructure will put pressures on the revenue requirements to fund the depreciation and interest costs alone. In this application, the year-over-year increase in just these two cost categories is in excess of $140 million. This, coupled with other increased cost pressures, suggests that there will be increasing upward pressure on consumers rates for the next few years, especially during those with high capital reinvestment. However, it should be comforting to the Panel that SaskPower is very sensitive to this issue and is making significant strides to operate more efficiently and lessen the impact on its customers during this capital reinvestment period.

- In conclusion we note that SaskPower rates compare favourably with other provinces (on average 8% lower than the Canadian average and 22% lower than the Canadian thermal average), and thus certainly remain competitive with these jurisdictions. However, we again caution that any comparisons must recognize that each utility has unique characteristics such as generation fuel mix and related hierarchy of costs, customer density, geographic population distribution and potential for export revenues.

17.0 Acknowledgments

At the beginning of our interface with SaskPower, the Chair and Forkast met with the President and Chief Executive Officer. Through-out this process we met and interacted with officials, finding those exchanges extremely beneficial and assisting us greatly in getting the Corporation's most senior policy positions on matters under discussion. We sincerely wish to thank all members who participated, but wish to specifically thank the President and the Chief Financial Officer who generously gave us their time and input.

Through-out this significant review we were assisted by the co-operative efforts of a number of SaskPower/NorthPoint officials specifically led by Mr. Ian Yeates, General Manager of Corporate Planning and Regulatory Affairs, Ms Shannon Rayner, Supervisor Rate Regulation and Senior Strategic Advisor, Mr. Tim Coucill. We wish to sincerely thank all of them for their patience, timely responses, scheduling meetings and ensuring we received the information required through-out the last four months.

We would also like to thank the stakeholder parties who participated for their continuing support, recognizing the significant amount of effort required to review the material filed, coupled with their thoughtful submissions.

Lastly, we want to thank the Chair and Panel for their input, indulgence and support during this process. We recognize that this Application presented 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 2013 proposed rate change.

We trust this report will assist them in discharging that responsibility.

Appendix 1 Documents Provided During the Review

- SaskPower 2010 Rate Proposal
- SaskPower February 2010 Rate Proposal/Application Summary together with Appendices
- Minimum Filing requirements
- Crown Investment Minister's Terms of Reference for Saskatchewan Rate Review Panel dated February 18, 2010
- SaskPower 2010 Strategic and Business Plan, Book's 1, 2, 3 and 4 all approved by SaskPower's Board of Directors September 2009
- SaskPower's 2004, 2005, 2006, 2007, 2008, 2009 Annual Reports
- SaskPower's 2010 Rate Application Minimum Filing Requirements Dated September 2009
- SaskPower's 2009 Load Forecast (June 2009)
- 2010 Revenue Forecast based on 2009/19 load forecast
- 2009 Financial Details of Subsidiaries
- 2007 COPE Report Results
- Environment Report 2010
- SaskPower's Actual Annual Energy Sales 1998/2009 and 2009/2019 Forecasts
- SaskPower's Electricity Usage History
- SaskPower 2010 Load Forecast
- SaskPower's First four months Financial Report for 2010
- SaskPower's 2009 Economic Drivers
- SaskPower's 2010 Economic Forecast
- SaskPower's 2010 Forecast to year end prepared April 2010
- SaskPower's preliminary projections for 2010 Business Plan
- SaskPower's 2010 Supply Development Assumptions for the Fuel and Purchased Power Category Budget for 2010 Business Plan
- SaskPower's 2010 Supply Development Assumptions for the Fuel and Purchased Power Category Budget
- Natural Gas Hedging Policy of SaskPower's Board
- 2010 Natural Gas Price Risk Management Plan
- Market Risk Management Manual 2010
- 2009 Depreciation Study for 2010
- SaskPower's Strategy for Generation Resource Use
- 2010 Prospective Base Cost of Service Study
- DBRS 2009 report SaskPower
- SaskPower's 2009 Embedded Cost of Service Study
- Pre-Ask, First and Second Round Interrogatories and Answers from SaskPower
- SaskPower Supplementary Information
- Questions and Answers Raised during Meeting with SaskPower Officials
- Updates as available
- March 5th and May 27th, 2010 Revised cost of natural gas
- Saskatchewan Financial Services Temporary Solvency Deficiency Payment Relief Moratorium Regulation
- 2010 Estimated Municipal Surcharge and Grant in Lieu Schedule
- Previous Reports to Saskatchewan Rate Review Panel

- Saskatchewan Rate Review Panels 2009 Recommendation to the Minister
- Written Submissions to the Panel
- Public Input at the Panel Meetings
- Confidentiality Guidelines
- Standing Committee on Crown and Central Agencies – Eighth Report