Minimum Filing Requirements
SaskPower 2014 to 2016 Rate Application

1. Current Organization Structure
2. Rate Application Document, including:
   - Rate Changes Requested in Detail
   - Current and Anticipated Fuel Costs & Anticipated Hydro Energy Capacity
   - Current Rate Structure, Classification System and Revenue to Cost Ratios
   - Existing Service Levels on a Comparative Basis
   - Current and Projected Return on Equity
   - Planned Maintenance and Capital Programs
   - Operating, Maintenance and Administrative Costs and Variance Reports for the last five years
3. Report on Implementation of Previous Panel Recommendations
4. Recent reports on Productivity & Efficiency Improvements within SPC including progress reports on BRP, SDR and AMI
5. Current Cost of Service and Allocation Study Reports and Methodologies in Use
6. Past, Current and Future Staff Levels by Division
7. Comparison of SPC Rates/Competitive Factors Relative to Neighbouring Utilities
8. Final Reports and/or Status of special studies, including Cost of Service Study

- **Robert Watson** — President & CEO
  - **Grant Ring** — Vice President Business Development
    - **Mark Peters** — VP Project Dev & Operations
    - **Lain Lovelace** — Director Energy & Risk Management
    - **Stan Saylor** — Supervisor Environmental Studies
    - **Ranjith Narayanasamy** — Sr Generation Projects Engineer
    - **Benson Thoudsanikone** — Sr Technical Advisor
  - **Steve Sousa** — Chief Commercial Officer Commercial
    - **Vacant** — Director Major Projects
    - **Keith Moen** — General Manager Service Delivery Renewal
    - **Amit Sobti** — Manager Procurement
    - **Bonnie Hilts** — Acting Manager Properties
  - **Tom Kindred** — Vice President & CIO Information Technology & Security
    - **Brian Dalby** — General Manager Tech Delivery & Ops
    - **Grant Crawford** — General Manager Tech Planning & Innovation
    - **Sean McKim** — Manager Enterprise Security
    - **Carla Feld** — Manager IT Business Services
    - **Gwen Fex** — Manager Enterprise Info Mgmt
  - **Sandeep Kalra** — Vice President & Chief Financial Officer Finance
    - **John Scobie** — Manager Business Analysis & Risk Management
    - **Troy King** — Director Corporate Planning & Rate Design
    - **Dairen Beblow** — Treasurer
    - **Vacant** — Controller & Business Planning
    - **Jennifer Pederson** — Internal Auditor
    - **Murray Black** — Manager Finance Business Partners
    - **Ken Hoff** — Manager PMO
  - **Jim Diotte** — Vice President Human Resources, Safety & Environment
    - **Glenda Barton** — Chief Safety Officer
    - **Karen Vey** — General Manager HR Operations
    - **Debbie Nielsen** — Manager Environmental Programs
    - **Judy May** — Vice President Special Projects
  - **Rachelle Verret Morphy** — Vice President Law, Land & Regulatory Affairs
    - **Michael Anderson** — Chief Electrical Inspector
    - **Syed Asif Ali** — Chief Gas Inspector
    - **John Phillips** — Associate General Counsel & Manager
    - **Michael Crosbie** — Assistant General Counsel
    - **Jonathan Kalmakoff** — Assistant General Counsel
    - **Sharon Twardy** — Corporate Paralegal
  - **Guy Bruce** — Vice President Resource Planning; President & CEO NorthPoint
    - **Iain Harry** — General Manager Clean Energy
    - **Brian Mohr** — Manager Sustainable Supply Dev
    - **John McKenzie** — Manager Strategic Development
    - **Kelly Kramer** — Manager Fuel Supply (Acting)
    - **Kory Hayko** — Director Gas Mgmt & Electricity Trading
    - **Dean Krauss** — Director Power Marketing & Contract Mgmt
  - **Michael Monea** — President, SaskPower Carbon Capture & Storage Initiatives
    - **Doug Daverne** — Manager Carbon Capture & Storage Initiatives
    - **Rhonda Smysniuk** — Sr Technical Advisor
    - Intellectual Property I.C.C.S.
    - Shand Demo C.C.T.F.
    - CO2 Sales
    - Education
    - **Ian Yates** — General Manager Carb Cap & Strg Init
  - **Mike Marsh** — Chief Operations Officer Operations
    - **John Lebersback** — Vice President Power Production
    - **Dennis Felgate** — General Mgr Transmission Services
    - **Ted Elliott** — General Mgr Distribution Services
    - **Jim Fraser** — Manager Business Support Services
    - **Vacant** — Business Performance & Planning
    - **Vacant** — Asset Management
  - **Diane Avery** — Vice President Customer Services
    - **Blair Debruyne** — Mgr Call Centre & Collections
    - **Rhea Brown** — Mgr Customer Development & Support
    - **Daryl Deibert** — Mgr Business & Technology Support
    - **Dominic Savio** — Manager Demand Side Management
    - **Kristin Linklater** — Manager Communications
  - **Donna Dressler** — General Manager Strategic Relations
    - **Wayne Rude** — Manager Aboriginal Relations
    - **Bernie Bolen** — Manager Stakeholder Engagement & Consultation
    - **Jan Craig** — Manager Stakeholder Relations
    - **Joanne Laslo** — Coordinator Board Relations

SaskPower

Effective Octobert 3, 2013

SaskPower
2014, 2015, 2016
Rate Application

October 2013

SaskPower

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1.0 Executive Summary

Our province is going through a period of significant growth. As Saskatchewan's economy and population continue to grow, so does the need for electricity – it takes power to grow. SaskPower had a new record peak load of 3,379 megawatts (MW) on January 30, 2013 and a record of 22,129 gigawatt hours (GWh) for electricity supplied in 2012. During the next decade, system peak demand is expected to increase by approximately 2.2% per year, double the 1.1% per year recorded between 2000 and 2010. Saskatchewan sales volumes are expected to grow by 29% over the next decade, with the bulk of that growth in the next five years. Provincial load growth forecasts indicate the need for an additional 5,929 GWh over the next decade. SaskPower is committed to supporting economic growth in our province through the delivery of reliable, affordable and sustainable power to Saskatchewan's people – as customers, business owners, and residents – to give them the power to live well.

In addition to load growth, our generation, transmission and distribution infrastructure is aging, and will require us to rebuild, replace, or renew it in its entirety over the next forty years. The challenges facing SaskPower are great; we have a comprehensive action plan in place to address those challenges to meet Saskatchewan's electricity needs. SaskPower is investing an estimated $1 billion per year for the long term to renew and modernize the province's electricity system. Depreciation, finance charges, taxes and other expenses that are driven primarily by the amount of capital spending are responsible for 72% of the increase in expense in 2014. Capital spending is essential to provide for growth and renew infrastructure.

New federal regulations have eliminated conventional coal-fired generation — SaskPower's primary baseload electricity source — as a generation option in the future. To enable the continued use of this resource, SaskPower is at the centre of carbon capture innovation as construction of the Integrated Carbon Capture and Storage project at Boundary Dam Power Station Unit 3 is nearing completion to install the world's first commercial carbon capture and storage facility. Carbon capture and storage has the potential to play a central role in meeting federal and provincial greenhouse gas reduction targets by drastically reducing our carbon footprint without sacrificing economic development and growth. CO_2 emissions at Boundary Dam Unit 3 will be reduced by 90%, or one million tonnes per year — equivalent to taking more than 250,000 cars off the road each year. The addition of carbon capture and storage represents the largest environmental upgrade ever contemplated for a coal-fired power station in Canada.

Fuel and purchased power expenses are increasing not only from an increase in load growth but also as a consequence of using environmentally cleaner but more expensive generation sources. This change to SaskPower's fuel mix has a significant impact on fuel expense, 16% of the increase in total expenses in 2014 is the result of fuel and purchased power.

To recover our increased expenses, SaskPower needs to increase the price that it charges to provide electricity service to our customers. SaskPower is requesting a system-average rate increase of 5.5% effective 1 January 2014, 5% effective 1 January 2015 and 5% effective 1

January 2016. For a typical urban residential customer that means an increase of $5/month in 2014, $4/month in 2015 and $4/month in 2016. SaskPower's requested rate increases reflect a balance between the level of earnings that will provide SaskPower with a positive net income and the capacity of our customers to absorb rate increases.

The 2014 rate increase is to be implemented on an interim basis on 1 January pending the recommendations of the Saskatchewan Rate Review Panel. SaskPower is mindful of the Panel's recommendations from the 2010 review to have rate applications coincide with SaskPower's fiscal year, so the Corporation can receive the benefit of matching the proposed revenue requirement needs with a full year's revenue stream. This is of particular importance in 2014 as SaskPower is striving to maintain a positive net income with the rate increase effective at the beginning of the fiscal year. The launch of application was delayed as the magnitude of the increase required was balanced against our customer's ability to absorb large rate increases. This careful consideration resulted in a need to implement an interim increase to maintain a positive net income pending the Panel's review.

SaskPower has submitted a multi-year rate request with this application. We believe that our customers will benefit from knowing what their rates are going to be into the future and SaskPower will benefit from the financial certainty. Knowledge of the long-term rates will enable both SaskPower and our customers to conduct long-term financial planning with greater certainty.

The recommended rate will increase prices as follows:

Year 2014, 2015 and 2016 Revenue Impacts
5.5%, 5% and 5% With Rebalancing

Class of Service	2014 Revenue Change ($/Cust/month)	2015 Revenue Change ($/Cust/month)	2016 Revenue Change ($/Cust/month)
Urban Residential	5	4	4
Rural Residential	8	7	8
Total Residential	**5**	**5**	**5**
Farms	7	10	9
Urban Commercial	36	30	32
Rural Commercial	30	31	32
Total Commercial	**35**	**31**	**32**
Power - Published Rates	27,721	25,490	29,185
Power - Contract Rates	38,379	42,404	39,813
Total Power	**29,213**	**27,745**	**30,576**
Oilfields	53	58	59
Streetlights	(24)	(23)	(22)
Reseller	157,478	177,163	190,721

Notes:
- The rate increase for Power Contracts is for customers whose contracts are tied to published rates. There is also escalation included in the contract customer's existing rates revenue as per their specific contract terms.

SaskPower rates compare favourably to the average charged by other thermal utilities in Canada. A comparison of Canadian utility rates shows that for a typical residential, small commercial, standard commercial and large industrial customer Saskatchewan rates are, on average, 18% lower than the rates of other thermal utilities in Canada. SaskPower is able to achieve this despite SaskPower's extremely large service area and the fact that SaskPower has the lowest customer density in Canada.

SaskPower will rebalance rates in each year of this rate application to ensure that they reflect the actual cost of service, providing equity among rate classes and the customers within the rate class. In 2012, an independent review of SaskPower's cost of service and rate design methodology was conducted and concluded that it was consistent with generally accepted electric utility practices. SaskPower's recommendation is to rebalance the impacts of the 2012 cost of service review over a three-year period to limit the maximum rate increases to any one class of customers to avoid rate shock. By 2016, SaskPower's rates will be fully rebalanced so that all customer classes' revenue-to-revenue requirement ratios will be between the industry-standard 0.95 and 1.05.

Business Renewal is an on-going strategic priority of SaskPower to manage and reduce costs. We are committed to continuous improvement and are striving to minimize the need for rate increases. To the end of 2012 SaskPower has realized savings of $137 million from Business Renewal initiatives. It is important to note 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.

To help offset the impact of rate increases, SaskPower will continue to help customers reduce their electrical use, decrease their power bills and help protect the environment through a variety of energy efficiency and conservation programs. Through the SaskPower Demand Side Management portfolio of energy efficiency, load management, renewables and conservation programs, customers are able to make informed decisions about what they can do to reduce electrical consumption and thereby reduce their electricity bills.

2.0 Background

2.1 SaskPower Overview

SaskPower is Saskatchewan's leading energy supplier. We are committed to supporting economic growth in our province through the delivery of reliable, affordable and sustainable power to Saskatchewan's people – as customers, business owners, and residents – to give them the power to live well. Our team of employees does what it takes every day to get power to our customers, to ensure that they can take full advantage of the opportunities available in our growing province. We take great pride in getting power to when and where it is needed around the clock, striving to deliver exceptional customer experiences while keeping rates as low as possible.

SaskPower is a Crown corporation governed by *The Power Corporation Act*. The President and Chief Executive Officer of SaskPower reports to a Board of Directors appointed by the Lieutenant Governor in Council. Through the Chair, our company's Board of Directors is accountable to the Minister Responsible for SaskPower. The Minister functions as a link between SaskPower and the provincial Cabinet and the Saskatchewan Legislature. The Crown holding company, Crown Investments Corporation of Saskatchewan, 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.

With one of the largest service areas in Canada, SaskPower is dedicated to providing electricity generation, transmission, distribution and retail services to approximately 500,000 customers throughout a geographic service area of approximately 652,000 square kilometres. SaskPower manages more than $6 billion in generation, transmission and distribution assets to supply electricity to our customers.

To ensure reliability of services, SaskPower operates three coal-fired power stations, seven hydroelectric stations, six natural gas stations and two wind facilities. Combined, they generate

3,451 MW of electricity. SaskPower also buys power from independent power producers including the North Battleford Energy Centre, Red Lily Wind Power Facility, SunBridge Wind Power Facility, Prince Albert Pulp Inc., Spy Hill Generating Station, Meridian Cogeneration Station, Cory Cogeneration Station, and NRGreen Kerrobert, Loreburn, Estlin and Alameda Heat Recovery Facilities. SaskPower's total available generation capacity, from its own fleet and independent power producers, is 4,302 MW. In the last five years, SaskPower has added 801 MW of new power generation capacity.

SaskPower is at the centre of carbon capture innovation as construction of the Integrated Carbon Capture and Storage project at Boundary Dam Power Station Unit 3 is nearing completion to install the world's first commercial carbon capture and storage facility. Carbon capture and storage has the potential to play a central role in meeting federal and provincial greenhouse gas reduction targets by drastically reducing our carbon footprint without sacrificing economic development and growth. The addition of carbon capture and storage represents the largest environmental upgrade ever contemplated for coal-fired power stations in Canada. With coal currently providing the majority of the province's electricity, transformative technologies will provide SaskPower with cost-competitive options for transitioning our aging and emissions-intensive coal plants into a modern low-carbon fleet.

The new facility will begin operation in December 2013, with the first CO_2 capture following shortly afterward. Full commercial operation of the carbon capture and storage system is scheduled for April of 2014 and is expected to reduce CO_2 emissions by 90%, or one million tonnes per year — equivalent to taking more than 250,000 cars off the road each year. The captured CO_2 will be used in enhanced oil recovery. Any remaining CO_2 will be stored in deep saline aquifers. The project will also capture nearly 100% of sulphur dioxide emissions to be used in the production of sulphuric acid.

SaskPower operates and maintains an extensive grid of transmission and distribution lines throughout Saskatchewan. We maintain approximately 151,000 kilometers of power lines. Our transmission system is made up of 12,298 km of power lines and 51 high voltage switching stations located across Saskatchewan. Transmission lines are high voltage lines that transport large volumes of electricity from generating stations to load centres – cities, towns or large industrial or commercial customers. Our distribution system consists of 138,959 km of power lines, 185 distribution substations and approximately 156,000 pole and pad-mounted transformers. Distribution lines are lower voltage lines that take electricity in smaller quantities to residential users and smaller commercial customers.

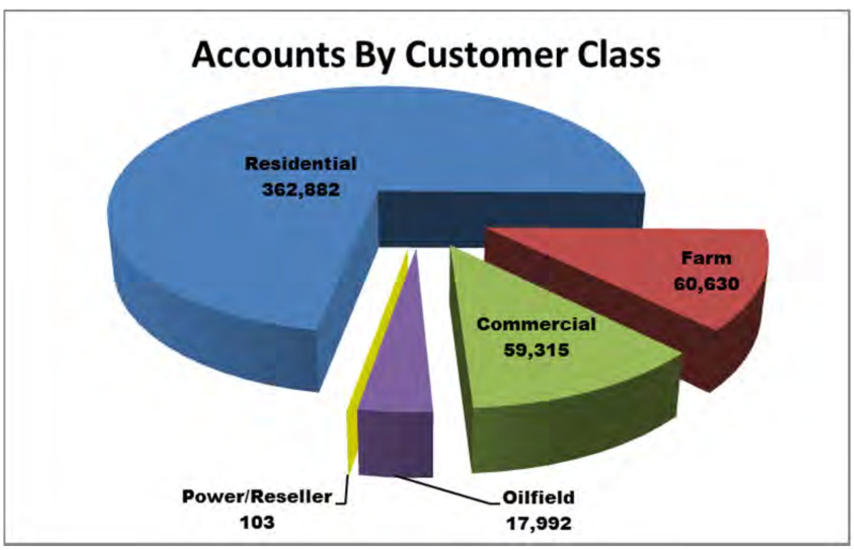
SaskPower's infrastructure includes the Grid Control Centre, which directs the safe and reliable operation of the power system and the Supervisory Control and Data Acquisition system that provides remote operations and control of our facilities. The challenge of managing our transmission and distribution system is considerable because of the large geographic size of the province, locations of various sources of generation, and a dispersed and relatively small population.

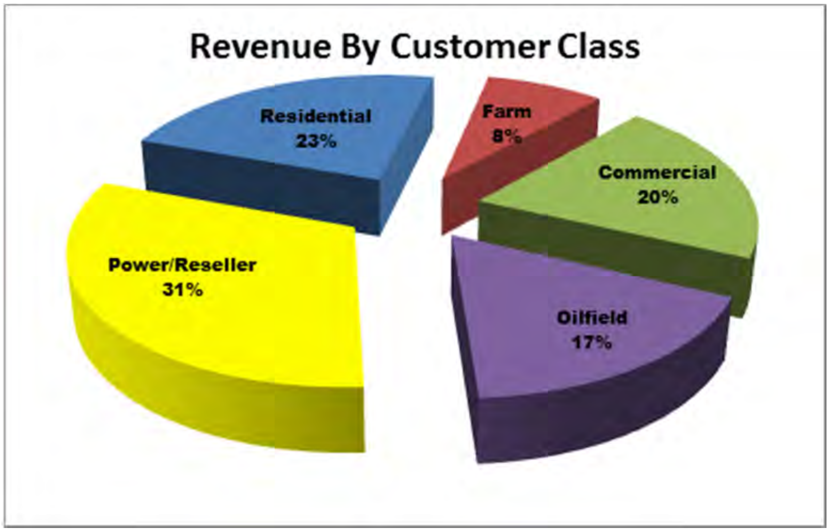
SaskPower has interconnections at the Manitoba, Alberta and North Dakota borders. These provide our company with the capability to import or export electricity to meet higher internal demand or take advantage of export market opportunities. Under normal system conditions, the import capability is up to 250 MW from Manitoba, 75 MW from Alberta, and 140 MW from North Dakota. The export capability is up to 50 MW to Manitoba, 153 MW to Alberta, and 125 MW to North Dakota. These interconnection capabilities vary with system conditions, including generation and load level. In compliance with the Open Access Transmission Tariff (OATT), SaskPower is required to compete with other suppliers for access to these interconnections. The OATT enables competitors to schedule access to our company's transmission system, allowing them to wheel power through Saskatchewan or sell to SaskPower's wholesale (Reseller) customers.

SaskPower's customer base consists of approximately 500,922 accounts, divided into a variety of classes based on size and load. The key customer classes and forecasted number of accounts for 2014 are:

- Residential – 362,882 accounts
- Farm – 60,630 accounts
- Commercial/Power (Industrial)/Oilfield /Reseller– 77,410 accounts

A single customer may have several accounts in different locations. Some oilfield and pipeline customers have many accounts by virtue of the geographical dispersal of their business. On a smaller scale, farmers may have a number of accounts depending on the location of their facilities and home. The following charts show the number of accounts and revenue forecast by customer class for 2014:





2.2 SaskPower Outlook

Our province is going through a period of significant growth. As Saskatchewan's economy and population continue to grow, so does the need for electricity. SaskPower had a new record peak load of 3,379 MW set on January 30, 2013. During the next decade, system peak demand is expected to increase by approximately 2.2% per year, double the 1.1% per year recorded between 2000 and 2010. There were 10,345 new connects to SaskPower's system in 2012, 144% more than in 2008; SaskPower made a record expenditure of $226 million on new customer connections in 2012, up 71% from 2011. SaskPower set a record of 22,129 GWh for electricity supplied in 2012. Provincial load growth forecasts indicate the need for an additional 5,929 GWh over the next decade. Saskatchewan sales volumes are expected to grow by 29% over the next decade, with the bulk of that growth in the next five years.

In addition to load growth, our generation, transmission and distribution infrastructure is aging, and will require us to rebuild, replace, or renew it in its entirety over the next forty years. Generation unit retirements will remove 200 MW of generation by 2017, including Boundary Dam units 2 and 3. New federal regulations have eliminated conventional coal-fired generation — SaskPower's primary baseload electricity source — as an option in the future.

The challenges facing SaskPower are great; we have a comprehensive action plan in place to address those challenges to meet Saskatchewan's electricity needs. SaskPower is investing an estimated $1 billion per year for the long term to renew and modernize the province's electricity system. SaskPower has been engaged in this effort to rebuild and renew the electricity system for a number of years and this effort will continue into the foreseeable future. This includes the addition of low- or non-emitting forms of generation such as biomass, coal with carbon capture and storage, natural gas and wind. Meanwhile, more than twenty new environmentally friendly power projects selected through SaskPower's Green Options Partners Program lottery will also be coming online. In addition to providing opportunities for customer self-generation, we are continuing to promote demand side management initiatives — energy efficiency, conservation and load management.

SaskPower is forecasting additional new power generation capacity by 2017, including:

- The Integrated Carbon Capture and Storage Project at Boundary Dam 3, 110 MW;
- Queen Elizabeth Power Station Expansion, 205 MW;
- Chaplin Wind Power Project, 177 MW;
- Tazi Twe Hydro Project, 50 MW; and
- Biomass and various green initiatives, 92 MW

In addition, demand side management activities will save 100 MW of capacity by 2017.

We are also simultaneously reinforcing our transmission and distribution system to ensure that electricity can be delivered in a reliable manner, through initiatives including:

- I1K transmission line – 283 km transmission line connecting Island Falls and Key Lake. The line will be the backbone of the Far North Transmission System and is needed to meet the rapidly increasing power requirements in the area;
- Infrastructure sustainment projects (wood pole and transformer replacements, rural rebuilds, urban infrastructure replacements, line upgrades and improvements);
- Transmission System Reinforcement projects;
- Saskatoon Area Reinforcement (three lines, two switching stations, and one substation).

SaskPower is also investing in information technology to support its infrastructure. This includes the purchase of smart meters and related software as part of the Advanced Metering Infrastructure project. Additional work will be done on Asset Management to ensure that capital assets are used as efficiently as possible throughout their full lifecycle.

Looking decades ahead, SaskPower is aggressively preparing to secure Saskatchewan's long-term electricity needs. We are examining possible long-term electricity supply mix scenarios looking forty years into the future. These scenarios are helping us analyze the potential implications of various paths as we search for a way to find cleaner sources of electricity to replace our retiring baseload conventional coal-fired generation. The objective of all future planning is to ensure that SaskPower is able to continue to provide safe, reliable and sustainable power at the lowest possible cost.

SaskPower is best known to our customers for being safe, reliable, community-focused and dependable. Going forward, customers have indicated that they want us to build on our current strengths to put them first, invest responsibly for the future and help them conserve electricity. We know that customers expect SaskPower to enable their quality of life and protect the environment they live in. In response to these changing expectations, SaskPower is working to create the infrastructure and culture that will enable us to consistently deliver exceptional customer experiences that are relevant and meaningful to how our customers live and work.

SaskPower has several initiatives underway to make that happen including our service modernization program with enhanced online services and responsive website, a new credit card option for bill payments and increased contact center hours of operations to serve customers at their convenience. Our social media presence has increased with the introduction of two unique twitter feeds, complementing our existing Facebook presence, so we are able to share information as it becomes available. This is only a start, however, as further initiatives are under consideration to enhance all customer interactions to deliver superior service and inspire loyalty.

2.3 Competitiveness

All Canadian utilities face the same need to replace aging infrastructure. In addition, the cost pressures faced by SaskPower and the resulting impact on rates are common across the electrical industry in Canada. Provinces that are able to generate most of their electricity through hydro power have the lowest electricity rates in Canada. However, even hydro utilities with low input costs have begun to face significant cost pressures as well.

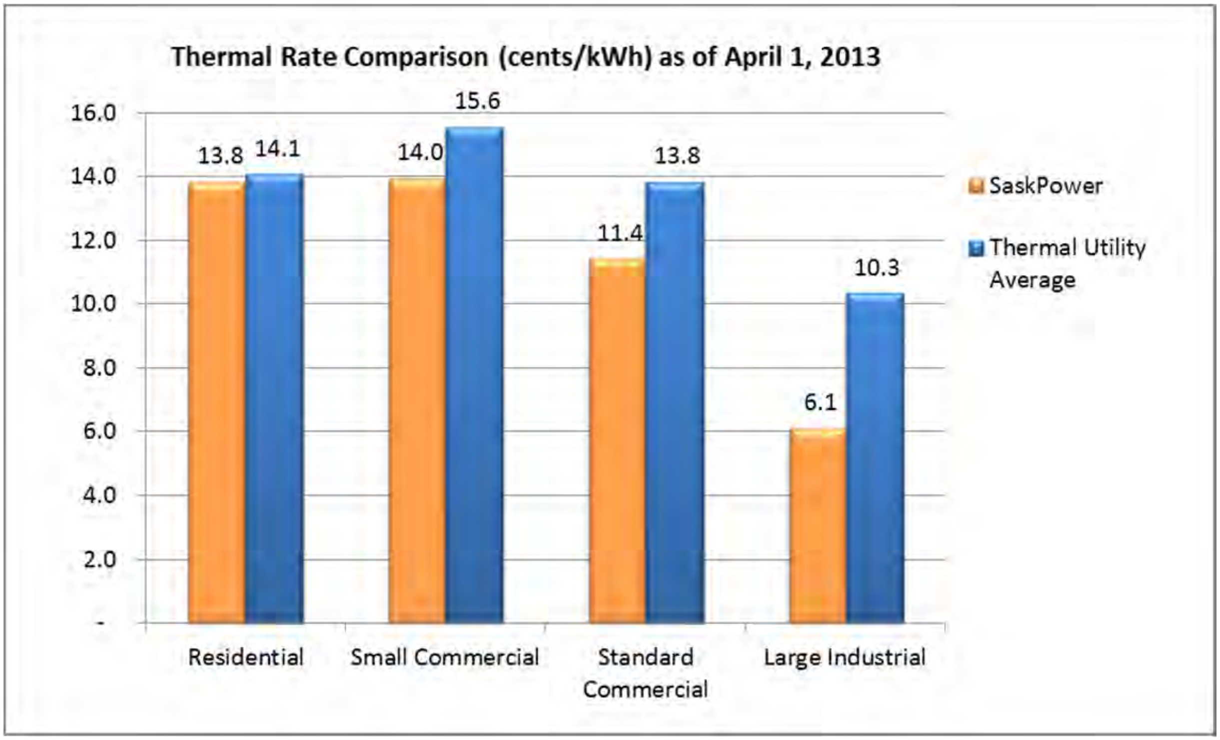
Electrical rates are rising across Canada. Comparison with some jurisdictions, such as Ontario and Alberta are difficult because their markets are structured differently from Saskatchewan's. Instead of one vertically integrated utility, they have separate entities to provide generation, transmission and distribution services. Direct comparisons are also difficult in similarly structured markets because in many jurisdictions the utilities use deferral account to postpone the present cost of existing ratepayers to a future date and future customers. SaskPower does not use deferral accounts.

Since January 2010, some of the rate adjustments that have occurred in Canada are:

- BC Hydro rates have increased by 6.11% plus a rate rider from 1 to 4% in 2010, 8% in 2011, 3.91% in 2012, and an additional 1.44% in 2013. Additional increases are forecast from 2014 to 2016;
- Fortis BC rates have risen by 6.6% in 2011, 1.5% in 2012 and 4.2% in 2013. A 3.3% increase is proposed for 2014;
- Manitoba Hydro's rates have increased by 1.9% in 2010, 2% in 2011, 2% in April of 2012, 2.5% in September of 2012, and 3.5% in 2013;

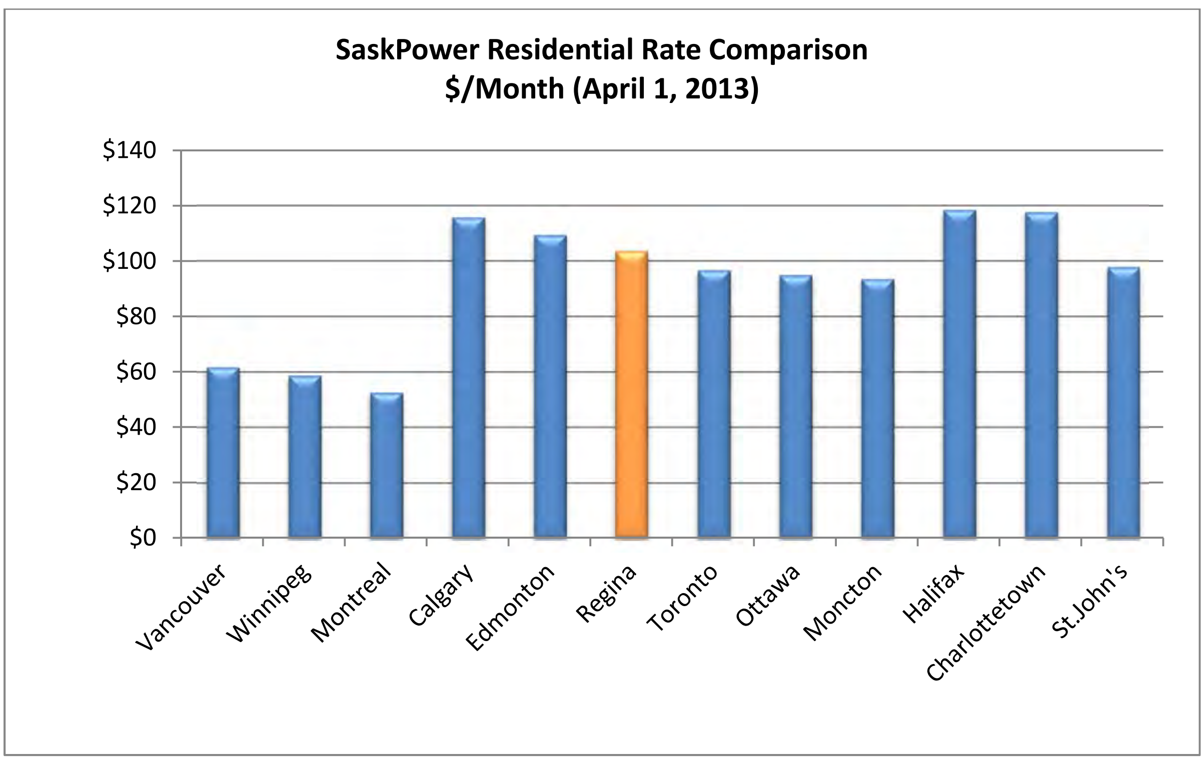
- Yukon Energy rates have increased 6.4% in 2012 and 6.5% in 2013;
- Northwest Territories' rates have increased 7.0% in 2012 and an interim 7.0% increase in 2013. 7.0% is proposed for 2014, followed by a 5.0% increase in 2015;
- Hydro Quebec's rates have decreased by 0.4% and 0.5% in 2011 and 2012, but will increase by 2.4% in 2013, a proposed 3.4% in 2014 and an approximately 1.2% increase in the heritage pool from 2014 to 2018;
- New Brunswick Power rates increased by 3.0% in 2010, followed by a three-year rate freeze. A 2.0% rate will be implemented in October 2013 and an additional 2% in October 2014 (rate increases of 2% and below are not subject to review);
- Maritime Electric rates decreased by 14% in 2011 and were frozen until a 2.2% increase in March 2013. Rate increases are capped at 2.2% for 2014 and 2015.
- Nova Scotia Power rates increased 5.6% in 2012, and 3% in each of 2013 and 2014, in addition to increases made or deferred to their fuel adjustment mechanism;
- Newfoundland Power rates increased 3.5% in 2010, 7.7% in 2011, 6.6% in 2012 and a proposed 6.0% in 2013.

SaskPower rates compare favourably to the rates of other thermal utilities in Canada. A comparison of Canadian utility rates for a typical residential, small commercial, standard commercial and large industrial customer is included in Appendix A. This combination of customers in Saskatchewan pay rates that are on average 18% lower than the rates of other thermal utilities in Canada. A comparison, (based on information available from the most current Hydro Quebec study), of SaskPower rates to the average for the other thermal utilities across Canada for a typical residential, small commercial, standard commercial and large industrial customer follows:



Note – The comparison includes the basic charge, energy charge and demand charge (if applicable) but not municipal charges or taxes.

A comparison of selected residential rates follows:



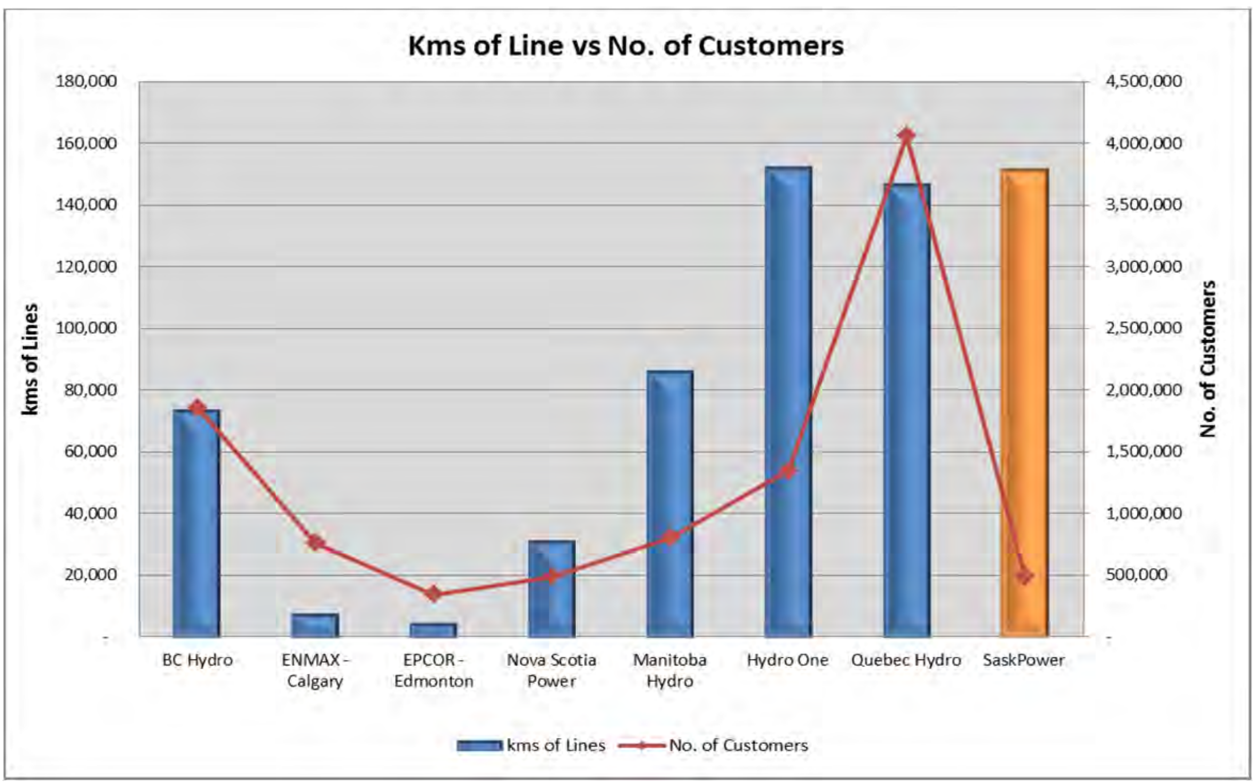
Note – The comparison includes the basic charge and the energy charge but not municipal charges or taxes.

SaskPower is able to achieve this favourable comparison with other jurisdictions despite the unique characteristics under which SaskPower operates:

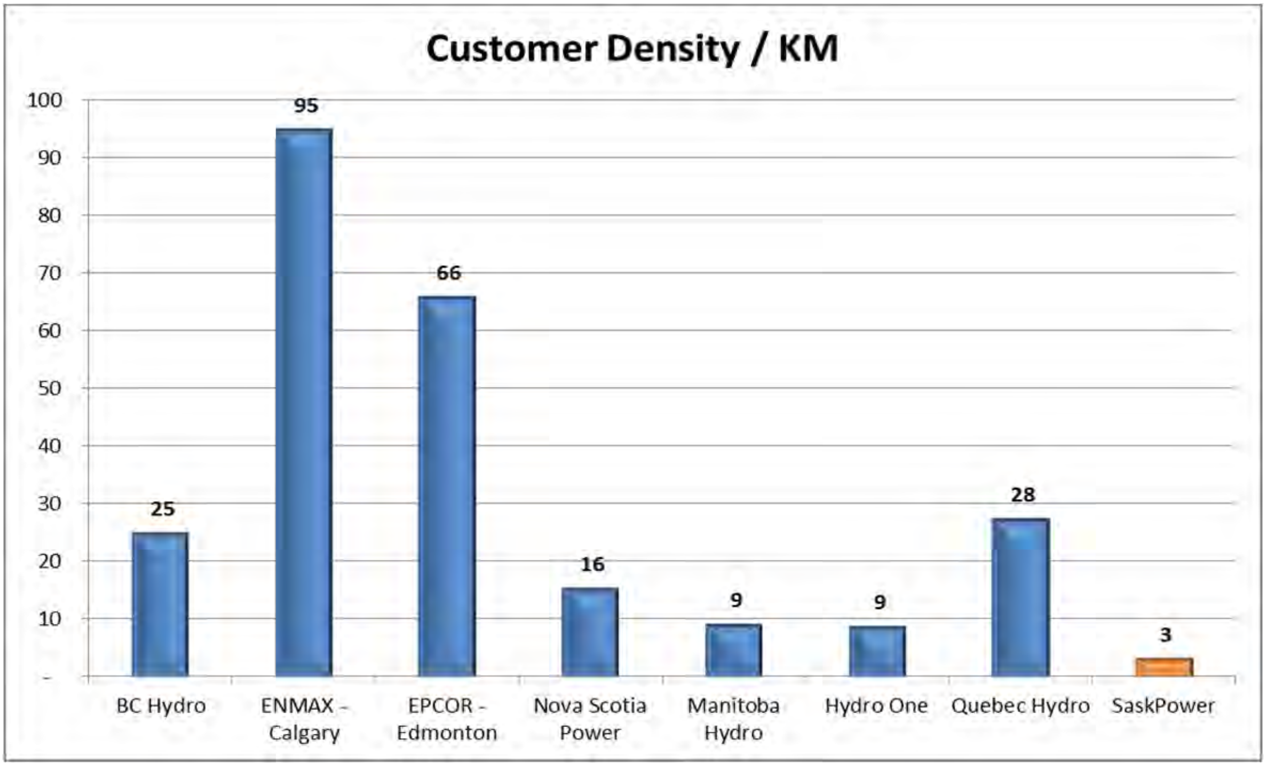
- Quebec, Manitoba and British Columbia have the capability of generating lower-cost electricity through the use of extensive hydro generation, while SaskPower's ability to generate electricity using low-cost hydro is limited.

- Rates in Quebec, Manitoba and British Columbia are heavily subsidized by substantial export earnings.

- The geography of Saskatchewan, sparsely populated rural areas, and the location of major generation facilities at great distances from major demand centers, contributes to SaskPower's cost structure. The corporation has an extensive system and fewer customers to bear the costs of service in comparison to its neighbours.
    - SaskPower serves an extremely large service area and one of the most extensive networks of transmission and distribution lines of any Canadian utility.
    - SaskPower has the lowest customer density of three customers per circuit kilometre in Canada, compared to the Canadian average of twelve customers per circuit kilometre of line.



SaskPower serves an extremely large service area and one of the most extensive networks of transmission and distribution lines of any Canadian utility.



SaskPower has the lowest customer density of three customers per circuit kilometre in Canada, compared to the Canadian average of twelve customers per circuit kilometre of line.

Customer satisfaction is a key component to competitiveness, with rates being only one facet of customer satisfaction. In a national survey conducted through the Canadian Electricity Association in 2012, SaskPower overall customer satisfaction improved to 8.0, higher than the national average of 6.9, continuing to outperform nearly all other utility companies.

Compared to national results, SaskPower customers view the company more favourably, perceive a higher level of value received for their money and are more satisfied with the price paid. However, SaskPower customers are less satisfied with the speed of restoring power when a problem occurs and the number of power outages. Building to meet demand and replacing aging facilities are a perceived weakness of SaskPower; however SaskPower customers are more likely to support investment in their electricity supply than national respondents.

2.4 Productivity

2.4.1 Business Renewal

SaskPower is taking significant steps to operate our business efficiently as well as prudently manage or reduce costs through the Business Renewal Program. In response to the Saskatchewan Rate Review Panel's recommendations on the 2009 rate application, SaskPower initiated the Business Renewal Program, to increase efficiency and effectiveness and improve performance. The Business Renewal Program is a long-term endeavour that covers a large number of initiatives across SaskPower to improve processes and results in all expense categories - including OM&A, finance charges, capital spending and fuel and purchased power costs - to achieve savings.

The program started with independent consultants analyzing our business to identify opportunities to improve efficiency, capture cost savings and improve effectiveness. SaskPower's fuel costs, operating and support area costs, capital costs and operating area costs were reviewed to identify opportunities to improve efficiency, capture cost savings and improve effectiveness.

SaskPower evaluated the improvement opportunities and then prioritized, planned and began to implement high value improvement initiatives. SaskPower has also identified and pursued other improvement opportunities not identified by the consultants. The program has evolved into a continuous improvement program wherein we manage and report on a portfolio of improvement initiatives, supplementing the portfolio with new savings initiatives as we complete existing initiatives. This new focus on continuous improvement is being supported by building corporate capabilities in: performance benchmarking, business process management and benefits realisation management. As well, we will continue to grow in our ability to measure and forecast program savings.

Implementing the Business Renewal improvement initiatives will yield significant cost savings. However, in most cost categories, costs will still be trending upwards, but at a lower rate than they would have otherwise. This is due to the fact that we must make significant re-investment in infrastructure replacement. Additionally, there is increasing customer demand for electricity service. We must, therefore, expand our investment in operating and maintenance activities to meet customer expectations for reliable service, as well as to maintain an ever growing system. Overall, this leads to increasing work volumes that are driving costs up despite our efforts to capture savings.

To the end of 2012 SaskPower has realized savings of $137M. Initiatives that have resulted in savings include:

- Finance Charges / Capital Structure - SaskPower has found 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. Both of 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. These risks are considered prudent in the current market. These measures have saved $63M to the end of 2012.
- Information Technology - SaskPower is reducing information technology costs through a number of initiatives such as implementing a new sourcing strategy, enhancing project management practices, reducing the number of printers, outsourcing the service desk, repatriation of staff 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. Information technology initiatives have saved $12 million to the end of 2012.

- Customer Connect process improvements - the customer connect quoting and construction work processes have been redesigned and has led to the introduction of standardized quick quotes, new expeditor roles, and improved crew efficiencies. These productivity gains have yielded $36 million in savings to the end of 2012. The changes have also allowed SaskPower to deliver more timely customer connect services to our customers.
- Reduce Power Plant Outage Duration and Frequency - Power Production is reducing OM&A and fuel costs by extending the annual outage cycle for power plants from 12 months to 24 months and by reducing the length of maintenance outages. This is an ambitious plan that works to optimize the maintenance schedule while still achieving the plant availability targets and avoiding forced outages. This has produced savings of $14 million to the end of 2012.
- 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. To the end of 2012 this has produced savings of $1.0 million.
- Outsourced Head Office Caretaking activities – SaskPower saved $100,000 in 2012 by outsourcing the Regina Head Office Caretaking function.

In addition to the value producing initiatives listed above, SaskPower is pursuing numerous other improvement savings initiatives which will produce significant cost savings, including:

- Procurement Transformation – This initiative entails a major redesign of the cross functional procurement process to improve efficiency and effectiveness. It also involves pursuing a strategic sourcing strategy which will leverage long term supplier relationships to capture cost savings.
- Operations Materials Management Transformation – Process changes, a new centralized warehousing strategy, and a new material transport model will allow SaskPower to significantly increase inventory turnover and reduce average inventory levels.
- Information Technology Revised Resourcing Strategy – The information technology group will continue to repatriate key staff positions, replacing more expensive contractor roles where it is prudent to do so.

Business Renewal remains an on-going strategic priority for SaskPower to control costs and meet the expectations of our customers. After implementing current improvement initiatives, we will continue to look for and pursue other opportunities to improve our service and capture cost savings. In short, we are committed to continuous improvement and minimizing the need for rate increases. However, it is important to note 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.

2.4.2 Service Delivery Renewal

Service Delivery Renewal (SDR) was established in 2009 to lead projects that will provide faster, more convenient customer service, contain costs, replace aging infrastructure and renew internal processes. When fully implemented, the projects led by SDR will ensure we provide world-class service to customers. At its core, SDR is about ensuring SaskPower becomes more efficient and customer-focused.

SDR projects are described in detail below:

Customer billing system
The replacement of SaskPower's 25-year-old billing system in 2011 was a major project of SDR. The new Customer Relationship and Billing System that was installed now provides our front-line employees with a comprehensive view of customer information, can be adapted to changing business requirements, and is capable of managing complex billing and rate structures.

Field worker technology improvement
The Field Worker technology improvement project has been a key area of focus for the SDR program. Work in this project was divided over two phases. Beginning in 2010, phase one of the Field Worker project saw the installation of 525 laptops in field worker trucks, with mobile mapping software. In Phase 2, SaskPower has used those laptops and new centralized dispatch centres to begin electronically scheduling, assigning, and providing real time updates of fieldwork. To enable this, SaskPower installed 830 automated vehicle locators in our field trucks, which provide near real-time updates of vehicle locations that are foundational to our scheduling system. These vehicle locators also increase worker safety by enabling dispatch of emergency vehicles to the exact vehicle location if an emergency situation is encountered.

A key benefit of the Field Worker project comes from the fact that work which often gets pushed to the backburner - particularly maintenance - will now be scheduled and prioritized like any other task when maintenance plans are developed. We'll also have optimized work schedules which will require the lowest possible windshield time for staff, and will ensure the highest priority work gets done first. In addition, automated scheduling reduces the vehicle "windshield time" for field workers on service calls - translating into reduced fuel consumption, an improved corporate carbon footprint, and improved staff work-life balance.

For customers, the Field Worker project will mean better overall service from SaskPower because our system will be better maintained and more reliable. In terms of workforce efficiency, the implementation of this automated work scheduling/dispatch system is forecast to improve service staff productivity by 25% and service staff overtime reduced by 30%. The bulk of these savings will come about through a reduction in overtime hours for field staff, and a reduction in contractor costs. Savings of $2 million are forecast for 2013, and a total of $11 million savings forecast by end of 2014.

Advanced metering infrastructure

Looking ahead to the future for SDR, the majority of employees and contractors working on the SDR team are now focusing their efforts on the Advanced Metering Infrastructure (AMI) program – otherwise known as smart meters. SaskPower plans to install 500,000 smart meters; we are partnering with SaskEnergy as they upgrade 370,000 gas meters.

The immediate and future benefits smart meters offer include:

- Electricity bills based on the amount a customer actually uses each month
- Automatic meter readings that are securely transmitted
- Faster service connects and disconnects for tenancy changes (beginning spring 2014)
- Sets the foundation for faster identification and tracking of power outages

The project should be completed by mid-2015. The estimated cost for SaskPower is $190 million – about $380/meter – in line with the North American average. This will generate an estimated $470 million in benefits for SaskPower between 2016 and 2036. The benefits will come from saving on labour costs, as well as expenses for vehicle maintenance, fuel and travel, since we will be able to do more work remotely. Full-time equivalent positions have been reduced by approximately 90 FTEs. We have a full workforce transition plan in place and it is our intention to retrain or redeploy affected employees.

3.0 SaskPower's Financial Requirements

The key principle behind the requested rate increase is that SaskPower should have the opportunity to recover prudently incurred costs for providing electrical services to all its customers and an appropriate return on equity. In common with most electrical utilities in North America, SaskPower establishes the rates it charges customers on a prospective basis by forecasting customer demand and estimating what its costs will be in the following year to meet that load.

SaskPower's requested rate increase for 2014 – 2016 reflects a balance between the level of earnings that will provide SaskPower with an appropriate return on equity and the capacity of our customers to absorb rate increases. SaskPower's long-term return on equity target is 8.5%. However, the requested rate increases in the current application are only expected to generate a return on equity of 1.3% in 2014, 2.0% in 2015, and 1.9% in 2016. SaskPower is proposing a below-target return on equity over the three-year period of the application in order to provide our customers with regular, moderate rate increases. SaskPower has a solid balance sheet and has had strong profits in recent years. As a result of SaskPower's strong financial position, we are able to absorb the lower than targeted return on equity over the next three years to protect our customers from large rate increases and are prepared to accept the corresponding financial risk over the short-term.

Financial Summary

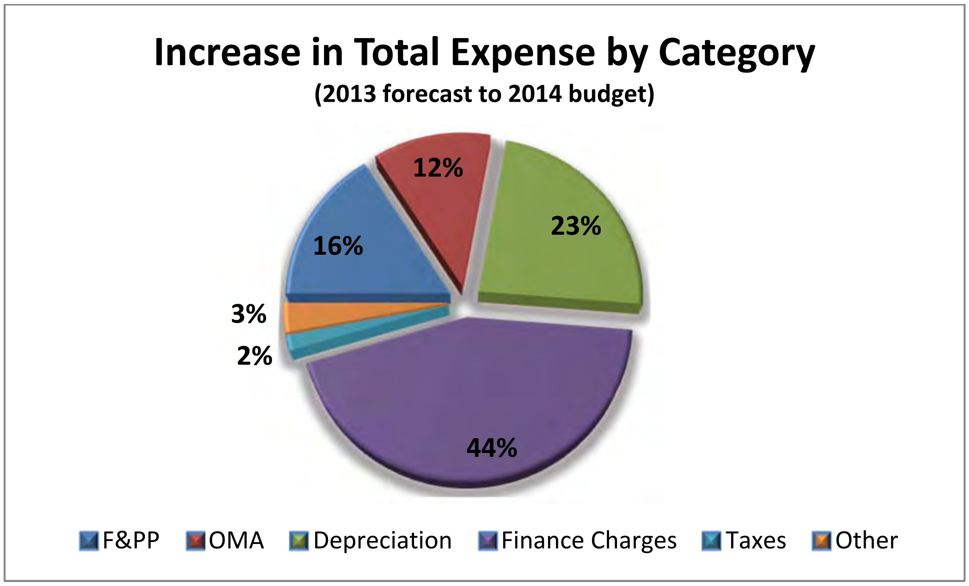
Consolidated Statement of Income					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Revenue					
Saskatchewan	$1,687.2	$1,867.7	$1,979.8	$2,154.4	$2,343.6
Export	49.1	68.9	27.5	34.9	38.9
Net Sales from Trading	14.4	8.5	7.2	7.5	7.9
Other	104.9	95.6	129.6	149.3	133.7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

2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan

SaskPower is forecasting operating income of $26.9 million in 2014, $39.9 million in 2015, and $40.4 million in 2016. This income includes the additional revenues generated by the requested rate increase of $103.2 million in 2014, $209.6 million in 2015, and $328.7 million in 2016. The revenue from the rate increase is required to cover an increase in expense that is caused primarily by higher capital related expenses and rising fuel and purchased power costs.

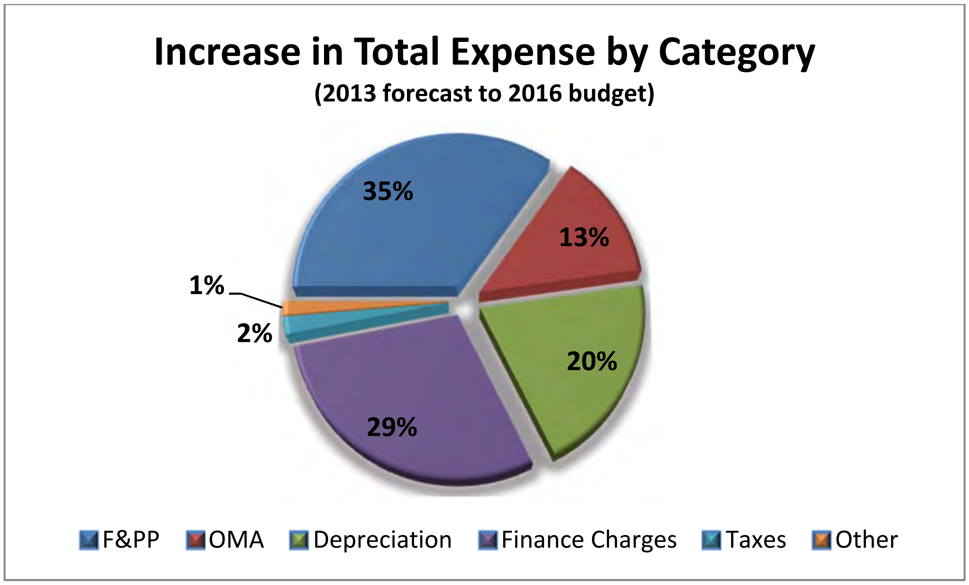
Depreciation, finance charges, taxes and other expenses are considered capital related expenses as they are driven by the level of capital investment. SaskPower is forecasting to invest $1.35 billion in 2013 plus an additional $700 million in the North Battleford Energy Centre which is owned and operated by Northland Power. In the coming years, the Corporation anticipates investing $1.2 billion in 2014, $1.1 billion in 2015, and $900 million in 2016. Over the next decade, SaskPower plans to invest $9.4 billion in its capital infrastructure plus an additional $1.7 billion on independent power projects. The capital investments are required to maintain and upgrade our existing infrastructure, connect new customers to SaskPower's network, and to add new generation, transmission and distribution capacity to ensure safe, reliable service for the future.

Total expenses are expected to increase $251.5 million in 2014 over 2013. As a result of SaskPower's capital investment, depreciation, finance charges, taxes and other expenses are forecast to increase $181.4 million in 2014 relative to 2013, accounting for 72% of the increase in expenses. Fuel and purchased power expense accounts for 16% of the increase, while operating, maintenance and administration costs are responsible for 12% of the total increase.



Finance Charges and depreciation represent the largest increase in expenses in 2014.

Total expenses are expected to increase $618 million from 2013 to 2016. This is being driven not only by capital spending but also from an increase in fuel and purchased power expense. As a result of the increased capital spending, depreciation, finance charges, taxes and other expenses are expected to increase $323.2 million from 2013 to 2016 which represents 52% of the total increase in expense. Fuel and purchased power expenses are expected to increase 35% over this same period. This is not only from an increase in load growth but also as a consequence of the need to use environmentally cleaner but more expensive generation such as natural gas. Operating, maintenance and administration expense for the same period is responsible for 13% of the total increase in expense.



Over the next three years, fuel and purchased power, finance charges and depreciation expense are driving the increase in SaskPower's expense.

3.1 Revenues

The following table shows the revenue forecast in dollars, including the financial impact of the proposed rate increase:

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

3.1.1 Saskatchewan Customer Revenues

Saskatchewan Sales represent the sale of electricity to all customer classes within the Province. The sales are subject to the effects of general economic conditions, number of customers, weather and electrical rates. An increase or decrease in sales volume will affect revenues accordingly. Saskatchewan sales are expected to grow from $1.868 billion in 2013 to $1.980 billion in 2014, $2.154 billion in 2015, and $2.344 billion in 2016. The revenue growth is driven by both the rate increases and an anticipated 11.8% increase in load over the three year period.

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

Saskatchewan Sales Volumes (Load Forecast)					
	Actual	Forecast			
(in GWh's)	**2012**	**2013**	**2014**	**2015**	**2016**
Residential	2,937.6	3,137.3	3,013.5	3,056.5	3,102.1
Farm	1,148.8	1,322.1	1,305.3	1,308.5	1,298.3
Commercial	3,532.0	3,625.0	3,609.2	3,630.6	3,673.7
Oilfields	3,177.2	3,516.6	3,685.7	3,939.6	4,016.9
Power Customers	7,447.7	7,852.4	8,233.6	8,829.7	9,796.2
Reseller	1,253.8	1,260.6	1,264.1	1,267.9	1,271.6
Total Saskatchewan Sales	**19,497.1**	**20,714.0**	**21,111.4**	**22,032.8**	**23,158.8**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

The 2013 Saskatchewan Sales and Sales Volumes revenues are based on the July 2013 forecast and are a combination of actual (January to July) and forecast (August to December) sales and volumes. The 2013 sales and volumes reflect additional revenues due to the much colder (on average 7 to 8 degrees Celsius) than normal weather in March and April. The 2014 to 2016 forecast revenue assumes normal weather, leading to decreased residential and farm sales and volumes for 2014 to 2016.

SaskPower's load forecast is developed annually to determine the long term energy requirements and peak demand for SaskPower's customers in the province of Saskatchewan. This forecast forms the basis for capacity additions, maintenance schedules, power plant operations, fuel budgets, operation budgets and revenue. Forecasting takes a number of factors into consideration:

- Historical load and weather data;
- Economic variables from the provincial economic model (potash and oil production, population, number of households and commercial GDP growth data);
- Residential end-use data; and
- Forecasts provided by industrial customers.

SaskPower undertakes an external review of its load forecasting methodology every five years. The most recent review was completed in October 2010 by Itron Inc. Itron provided verification of SaskPower's methodology using their own forecasting expertise as well as an in depth industry survey and provided recommendations for enhancements of SaskPower's methodology.

SaskPower develops both a base and demand side management or "DSM adjusted" load forecast. Once the base forecast is completed using the information described above, the demand side management energy and peak demand savings are removed, resulting in the DSM adjusted load forecast which is used for the rate application.

SaskPower is forecasting significant growth in energy demand within the province over the next three years with total Saskatchewan sales increasing to 23,159 GWh in 2016. This increase puts significant cost pressure on SaskPower to meet the additional demand. Increases are expected to be greatest in the Power Customer class and the Oilfields class. Those two customer classes account for the bulk of the total increase in Saskatchewan energy requirements through to 2016.

The load forecast is vital to SaskPower's budgeting and planning processes. The accuracy of the forecasts for our oilfield and large-scale industrial and commercial customers has the greatest impact on the total provincial load forecast as they are our largest customers. These customers are also the most difficult to forecast as the group is primarily commodity producers and their short-term plans are affected by price fluctuations and market conditions worldwide.

To ensure SaskPower is up-to-date on the load requirements for these customers, SaskPower contacts each key account customer regularly to get short and long-term expansion plans. The information provided by our customers indicates significant growth in a number of areas. In the potash sector, expansions are planned or underway at most existing mine sites with two new mines under construction. In the pipeline sector, loads are increasing as Alberta oil sands production and conventional oil production in Alberta and Saskatchewan is shipped through Saskatchewan to markets in eastern Canada and the United States. Growth is also attributed to fertilizer plants, uranium mines, universities, and seed crushing. These forecasts are then cross-referenced to market information whenever possible to ensure that SaskPower is developing its plan using the best information available.

3.1.2 Export Revenues

Exports represent the sale of SaskPower's surplus generation to other provinces in Canada and the United States. The bulk of SaskPower's exports are made to the neighboring Alberta and Midwest Independent Transmission System Operator markets. Export pricing is not subject to the rate review process but is determined based on market conditions in other jurisdictions. Export sales volumes are dependent on the availability of surplus SaskPower generation, market conditions in other jurisdictions and transmission availability.

While SaskPower ensures that domestic needs are met first, the sale of power into neighbouring jurisdictions allows any surplus generating capacity to be sold for profit. The ability to access the export market may enhance SaskPower's financial performance and reduce the level of rate increases required from Saskatchewan customers. Export revenues can be extremely volatile, however, as export transactions have numerous economic drivers and are influenced by a number of external and internal factors.

Export Revenue					
	Actual	Forecast			
	2012	**2013**	**2014**	**2015**	**2016**
SaskPower Export Revenues *(in $ millions)*	$49.1	$68.9	$27.5	$34.9	$38.9
SaskPower Export Volumes *(in GWhs)*	460.1	741.9	486.3	581.9	599.0
SaskPower Exports *(in $/MWh)*	$106.7	$92.9	$56.5	$60.0	$64.9
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

SaskPower is experiencing an exceptional year for exports in 2013, with export revenue forecast to reach $68.9 million. The strong export sales have been the result of generation shortages in Alberta as well as maintenance on the BC/Alberta tie line that impacted the amount of electricity Alberta could import from British Columbia. Export revenues are expected to decrease from $68.9 million in 2013 to near average levels over the next three years with forecast sales of $27.5 million in 2014, $34.9 million in 2015, and $38.9 million in 2016.

3.1.3 Net Sales from Electricity Trading

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

Trading revenue is the revenue from electricity and natural gas bought in external markets and sold in other external markets. Net sales from trading represents the net contribution from trading activities which is calculated as revenues less trading costs.

Net Sales From Trading					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Net Sales From Trading	**$14.4**	**$8.5**	**$7.2**	**$7.5**	**$7.9**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

Net sales from trading are forecast to decrease from $8.5 million in 2013 to $7.2 million in 2014, and then remain relatively stable at $7.5 million in 2015 and $7.9 million in 2016. The main reason for the expected decrease in net sales is due to lower price forecasts arising from the completion of the Montana-Alberta Tie-Line (MATL) transmission project in late 2013. MATL is a 300 MW, 230 KV transmission line allowing the movement of electricity between Alberta and Montana. This transmission line is expected to negatively impact the ability of SaskPower to take advantage of market opportunities in Alberta using our firm transmission position in British Columbia.

3.1.4 Other Revenues

Other revenues include various non-electricity products and services, including gas and electrical inspection permit fees, meter reading fees, late payment charges, custom work charges and other non-energy related charges.

Other Revenue					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Gas and Electrical Inspections	$17.2	$17.9	$18.7	$18.7	$18.7
Customer Connects	50.8	39.2	50.0	50.0	50.0
CO_2 Sales	0.0	0.0	17.5	20.3	20.7
CO_2 Test Facility Revenue	0.0	0.0	4.3	17.8	10.0
MRM Equity Investment	0.0	1.6	1.1	4.5	1.9
Miscellaneous Revenue	36.9	36.9	38.0	38.0	32.4
Total Other Revenue	**$104.9**	**$95.6**	**$129.6**	**$149.3**	**$133.7**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

In 2014, SaskPower is forecasting an increase in other revenue as the first CO_2 sales from the Boundary Dam Integrated Carbon Capture and Storage project are expected to be earned. Revenue from customer connects are forecast to remain at historically elevated levels, a reflection of the province's expected growth. SaskPower expects to earn $4.3 million in new revenues from the lease of the new Clean Coal Test Facility to Hitachi in 2014. Overall, other revenues are expected to increase from $95.6 million in 2013 to $129.6 million in 2014, $149.3 million in 2015, and $133.7 million in 2016.

3.2 Expenses

The following table presents SaskPower's actual operating costs by major category:

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

2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan

3.2.1 Capital Related Expenses

SaskPower is forecasting to invest $1.35 billion in 2013 plus an additional $700 million for the North Battleford Energy Centre which is owned and operated by Northland Power. In the coming years, SaskPower anticipates investing $1.2 billion in 2014, $1.073 billion in 2015, and $987 million in 2016. Over the next decade, SaskPower plans to invest $9.4 billion on its capital infrastructure plus an additional $1.7 billion on independent power projects. These capital investments are required to maintain and upgrade our existing infrastructure, connect new customers to SaskPower's network, and to add new generation, transmission and distribution capacity to ensure safe, reliable service for the future.

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

2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan

Transmission & Distribution

SaskPower owns and maintains $2.5 billion of transmission and distribution assets. This includes over 150,000 kilometers of transmission and distribution lines across Saskatchewan making it one of the largest electrical networks in the country. Capacity increases and refurbishment of the existing infrastructure is vital to ensuring the reliability and security of SaskPower's service. SaskPower is forecasting to invest $235 million annually to maintain the system. As Saskatchewan's economy continues to grow, expectations are that customer connects will remain at historically elevated levels, with $248 million, $241 million and $232 million forecast for 2014, 2015, and 2016 respectively. SaskPower is also in the process of building the I1K transmission line which is a new 300 kilometer, 230 KV transmission line that being built to reinforce the system in the far north with an expected completion date of 2015.

Power Production

SaskPower owns and operates a generation fleet with a net book value of $3.2 billion that provides 3,451 MW of available capacity from three coal-fired stations, seven hydroelectric stations, six natural gas stations and two wind facilities. SaskPower also has generating capacity of 852 MW available through long-term power purchase agreements. SaskPower is planning to invest $140 million annually to maintain and renew this generating infrastructure.

SaskPower is also in the process of adding 205 MW of generating capacity through an expansion of the existing Queen Elizabeth Power Station in Saskatoon. The expansion is expected to be complete in 2015. In addition, SaskPower is currently working to partner with the Black Lake First Nation on the Tazi Twe Hydroelectric project. Once operational, this 50 MW run of the river hydro facility would supply much needed energy to northern Saskatchewan. SaskPower has also entered into a 20-year power purchase agreement with Algonquin Power to build and operate a new 177 MW wind facility. The wind facility is expected to be commissioned at the end of 2016. Finally, the Carbon Capture Test Facility is a new complex that SaskPower is building in partnership with Hitachi Canada. The test facility will be used to test new carbon capture technologies that could benefit SaskPower as the Corporation looks to keep coal as a long-term generation option.

Other Capital

Other capital expenditures include the development of a new operations centre located at the Global Transportation Hub. The new facility is part of a larger strategy that will see the consolidation of 27 facilities at 12 locations to just four locations in Regina. The Service Delivery Renewal investment is targeted for SaskPower's Automated Metering Infrastructure (AMI) project. The AMI project will see SaskPower installing approximately 500,000 advanced power meters across the province. Advanced power meters provide near real-time monitoring of electrical consumption and operational data. SaskPower is also planning to make continued investments in its information and technology assets, buildings, land and furniture to support SaskPower's ongoing operations.

Capital Related Expenses

Depreciation, finance charges, taxes and other expenses are considered capital-related expenses as they are driven primarily by capital spending. Cumulatively these categories of expenses are expected to increase by $181.4 million in 2014, $73.3 million in 2015 and an additional $68.5 million in 2016. The full financial impact of capital expenditures is deferred as interest and depreciation charges do not take effect until the asset is completed and put into service.

3.2.1.1 Finance Charges

Finance charges include the net amount of interest on SaskPower's long and short-term borrowings and capital leases offset by interest capitalized and debt retirement fund earnings. Finance charges are expected to increase from a forecast of $272.3 million in 2013 to $383.3 million in 2014, $416.3 million in 2015, and $452.5 million in 2016.

Finance Charges					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Finance Charges					
Interest on Borrowings	$243.9	$328.2	$399.9	$431.0	$457.1
Interest Capitalized	(29.6)	(46.0)	(22.8)	(21.3)	(10.6)
Debt Retirement Fund Earnings	(22.4)	(23.4)	(9.4)	(9.3)	(10.2)
Other Interest and Charges	11.1	13.5	15.6	15.9	16.2
Total Finance Expense	**$203.0**	**$272.3**	**$383.3**	**$416.3**	**$452.5**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

The increase in finance charges is due in large part to increased borrowing required to finance SaskPower's capital program. SaskPower's debt including lease obligations is expected to increase from $5.7 billion in 2013 to $7.6 billion in 2016. Using market forecasts, SaskPower is also anticipating an increase in interest rates over the next three years that will contribute to higher finance charges. Although SaskPower's long-term debt interest is fixed, increases to interest rates will affect floating short-term debt as well as any new long-term borrowings. Short-term interest rates are forecast to increase from 1.1% in 2013 to 1.7% in 2016. Long-term interest rates are forecast to increase from 3.5% in 2013 to 4.1% in 2016. Despite the expected upward trend, interest rates continue to be at historically favourable levels. SaskPower's strategy is to take advantage of short-term rates, as well as lock in long-term rates where appropriate. Significant savings have been secured from the adoption of this strategy.

Interest capitalized represents the deferral of interest expense on capital assets under construction. During the construction period the interest on money used to fund the project is capitalized as a cost of construction and is netted against finance charges. Interest capitalized is decreasing from $46 million in 2013 to $10.6 million in 2016. SaskPower is capitalizing far less interest in future years compared to 2013 as the interest related to the financing of the Integrated Carbon Capture and Storage project will not be capitalized beyond 2014.

Debt retirement funds are monies that are set aside to retire outstanding debt upon maturity. The funds are held and invested on behalf of SaskPower by the Government of Saskatchewan. The debt retirement fund earnings represent interest earned on those funds. SaskPower has received higher than normal earnings on its debt retirement fund investments over the past couple of years. However, these have been mostly offset by unrealized losses on the market value of the funds. SaskPower is forecasting that debt retirement earnings will decrease from $23.4 million in 2013 to $10.2 million in 2016. The forecast reduction in earnings is due to an expectation that the funds' earnings will return to historical levels in the future.

3.2.1.2 Depreciation & Amortization

Depreciation represents a charge to income for the capital expenditures of SaskPower. The capital expenditures are amortized to income on a straight-line basis over the estimated life cycle of the asset group. Depreciation rates are established based on depreciation studies that are completed approximately every five years. In 2010, SaskPower retained Gannett Fleming Inc. to conduct an independent study in response to a recommendation by the Saskatchewan Rate Review Panel. The consultant did not recommend any major changes. Changes to a few depreciation rates for certain asset classes were recommended; SaskPower implemented all of the recommended changes.

Depreciation expense is also driven by capital spending. As the Corporation adds to its asset base, depreciation will increase accordingly. An asset begins its depreciation schedule when the capital project is brought into service. Depreciation expense is expected to increase from $366.5 million in 2013 to $425.3 million in 2014, $460.8 million in 2015, and $490.1 million in 2016.

Depreciation					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Depreciation					
SaskPower Depreciation	$289.3	$323.3	$367.5	$399.0	$424.3
Asset Retirement Asset - Depreciation Expense	5.2	1.4	1.4	1.4	1.4
Total SaskPower Depreciation	**294.5**	**324.7**	**368.9**	**400.4**	**425.7**
Capital Lease Amortization	21.3	41.8	56.4	60.4	64.4
Total Depreciation	**$315.8**	**$366.5**	**$425.3**	**$460.8**	**$490.1**

2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan

3.2.1.3 Taxes

Taxes represent the payment of corporate capital tax and grants-in-lieu of taxes. Corporate capital taxes are based on SaskPower's capital structure and increase as the size of the Corporation grows. Steady increases in capital taxes are expected as a result of SaskPower's capital program.

Grants-in-lieu are paid to the following 13 communities across Saskatchewan: Swift Current, Estevan, Humboldt, Lloydminster, Melfort, Melville, Moose Jaw, Prince Albert, Yorkton, Regina, North Battleford, Saskatoon and Weyburn. The payments are based on the electrical revenues received from customers in those areas - as revenue increases, so do these payments.

Taxes are expected to increase from $52.9 million in 2013 to $57.0 million in 2014, $61.3 million in 2015 and $63.9 million in 2016, as set out in the following table:

Taxes					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Taxes					
Corporate Capital Tax	$26.9	$31.7	$34.5	$37.4	$38.6
Grants in Lieu	20.8	21.2	22.5	23.9	25.3
Total Taxes	**$47.7**	**$52.9**	**$57.0**	**$61.3**	**$63.9**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

3.2.1.4 Other Expenses

The other expense category is made up primarily of gains or losses on asset disposals and retirements, that were previously classified as part of the depreciation expense. Other expenses are forecast to increase from $9.0 million in 2013 to $16.5 million in 2014, $17.0 million in 2015 and $17.4 million in 2016. The additional expense is anticipated as SaskPower replaces more assets through its capital program.

Other					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Other Expense	**$26.7**	**$9.0**	**$16.5**	**$17.0**	**$17.4**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

3.2.2 Fuel and Purchased Power

SaskPower's fuel and purchased power costs include the fuel charges associated with the electricity generated from SaskPower owned facilities, energy purchased through power purchase agreements, as well as electricity imported from markets outside Saskatchewan.

SaskPower operates a mix of power generation sources in order to meet electrical demand of our domestic customers. Fuel costs include the cost of electricity generated from SaskPower-owned and operated coal, hydro, natural gas, and wind generation facilities.

Purchased Power includes the cost of electricity obtained through power purchase agreements with the Meridian and Cory Cogeneration Stations, the Spy Hill Generation Station, the North Battleford Energy Centre, the SunBridge and Red Lily Wind Power Facilities, and various Environmentally Preferred Power projects with Independent Power Producers located in Saskatchewan.

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

Fuel and purchased power costs can vary significantly from year to year, depending on the volume and price of fuel sources, such as hydro, natural gas and imports. SaskPower manages its fleet of generation and supply options carefully in an effort to minimize annual fuel and purchased power expense. The more energy that is generated from lower cost units, the more favourable the impact on fuel and purchased power costs. SaskPower’s fuel procurement and optimization processes were reviewed by Deloitte in 2010 and no major changes were recommended.

SaskPower’s fuel cost management strategy focuses on the economic dispatch of the generating units. Units that have the lowest incremental cost are brought on stream first. Hydro and coal generation, which have a low incremental cost per unit of generation, are maximized. However, hydro generation is dependent upon water levels and river flow at SaskPower’s hydro facilities and coal generation is a product of the availability of coal plants. Wind generation cannot be dispatched on a planned basis as it is dependent upon wind conditions. Additional load must be supplied from sources with higher incremental costs such as natural gas generation, purchased power, or imports. Electricity is a unique product because it cannot be stored economically - it must be consumed at the moment that it is created.

Net fuel and purchased power expenses are forecast to be $587.4 million in 2014, $678.4 million in 2015 and $762.0 million in 2016.

Net Fuel and Purchased Power Expense					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense					
Gas	$213.8	$230.7	$255.2	$319.1	$351.9
Coal	221.8	233.6	264.9	270.9	280.8
Wind	9.6	9.9	10.3	10.4	14.1
Hydro	19.1	21.0	18.0	18.7	19.3
Imports	31.2	25.9	8.9	18.6	26.6
Other	17.8	26.2	30.1	40.7	69.3
Total Fuel and Purchased Power Expense	**$513.3**	**$547.3**	**$587.4**	**$678.4**	**$762.0**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

Net Fuel and Purchased Power Volumes					
	Actual	Forecast			
(in GWh)	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense					
Gas	4,968	6,235	7,163	8,114	9,167
Coal	11,446	11,173	11,610	11,693	11,462
Wind	655	650	674	671	736
Hydro	4,240	4,447	3,645	3,644	3,607
Imports	656	496	156	316	464
Other	164	215	262	364	581
Gross Volumes Supplied	**22,129**	**23,216**	**23,510**	**24,802**	**26,017**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

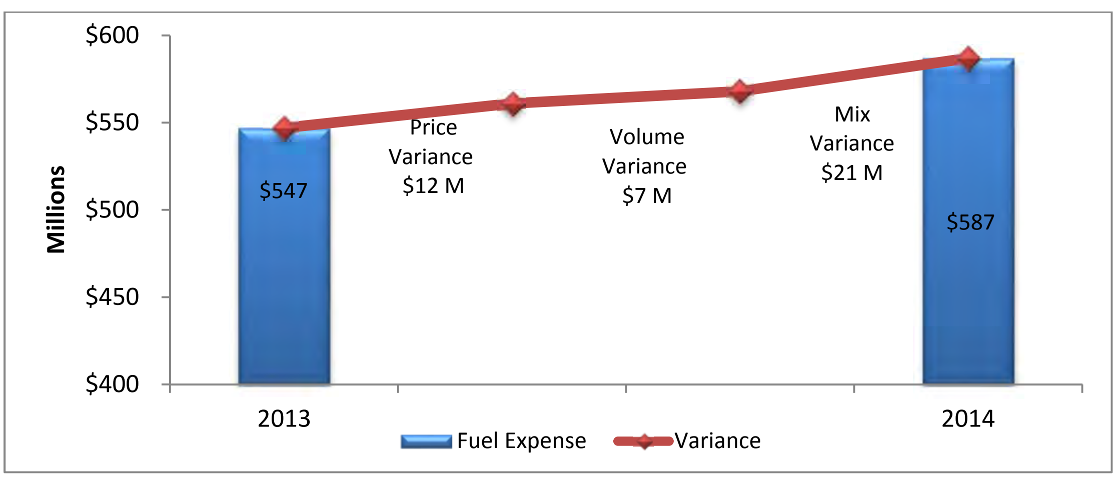
Fuel Price per Generation Source					
	Actual	Forecast			
(in $/MWh)	**2012**	**2013**	**2014**	**2015**	**2016**
Fuel Expense					
Gas	$43.05	$36.97	$35.63	$39.33	$38.39
Coal	19.38	20.91	22.82	23.17	24.50
Wind	84.57	84.77	84.43	87.39	77.47
Hydro	4.50	4.72	4.94	5.13	5.35
Imports	47.46	52.21	57.05	58.86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

Fuel and purchased power expenses are forecast to increase $40.1 million or 7% from 2013 to 2014. This increase is due to an increase in input prices (price variance), an increase in demand (volume variance), and changes to the contribution of each generation source as a percentage of overall generation (mix variance).

The average price of fuel is expected to increase largely due to an increase in coal prices. The increase in coal prices is anticipated as the result of the expiration of one of SaskPower's coal contracts. SaskPower is currently negotiating a new coal contract that is expected to include a significant increase in the price of coal. The increase in price is largely attributable to more difficult mining conditions, the need for additional equipment and higher operating costs to deliver coal to SaskPower. This is partially offset by a forecasted $1.34 /megawatt hour (MWh) decline in the cost of natural gas generation in 2014. Despite an increase in the forecast market price of natural gas, the cost per MWh is anticipated to decrease as the result of the use of more efficient natural gas generation units in 2014. The net impact is a $12 million increase in fuel and purchased power costs from higher fuel prices.

SaskPower also expects an unfavourable volume variance as a result of an increase in total generation needed to supply higher sales. Total generation is expected to increase 294 GWh to 23,510 GWhs in 2014. The net impact is a $7 million increase in fuel and purchased power costs due to higher volumes.

An unfavourable mix variance is also expected, largely due to a reduction in hydro availability in 2014 compared to 2013. Due to the effects of above average snowfall during the winter and rain in the spring, hydro generation in 2013 is expected to be well above the historical average. However, SaskPower is forecasting a return to median hydro generation in 2014. This decrease in forecast hydro generation will be replaced by an increase in more expensive natural gas generation, resulting in a $21 million increase in fuel and purchased power costs.

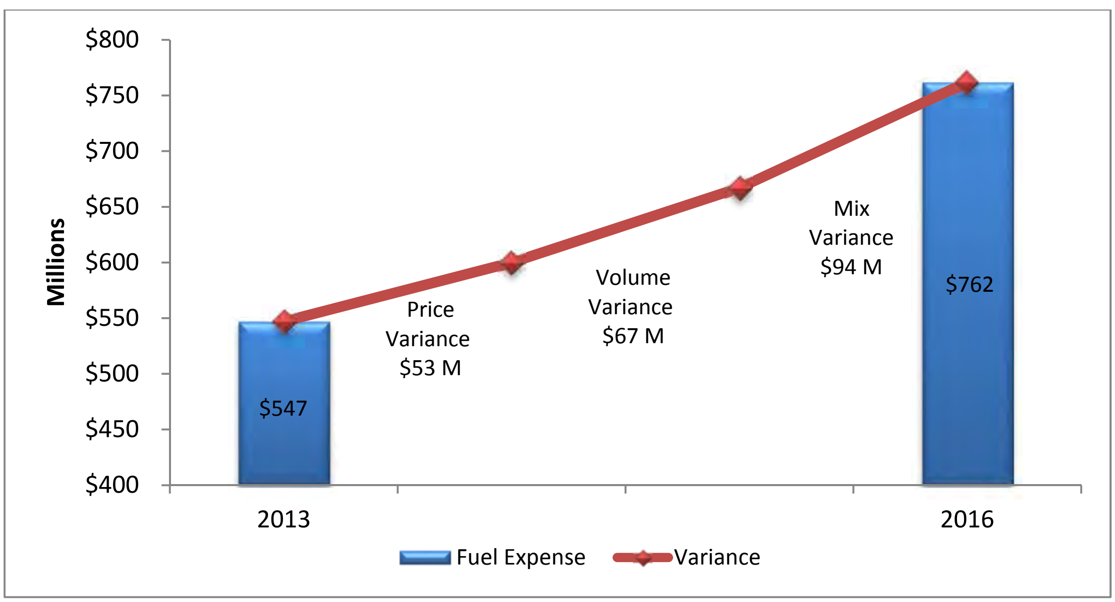


Fuel and Purchased Power is forecast to increase $40 million in 2014: $12 million due to an increase in input prices, $7 million due to an increase in volume, and $21 million due to a change in the mix of inputs.

Comparing 2013 to 2016, fuel and purchased power costs are expected to increase $215 million as a result of an unfavourable price, volume and mix variance. Increases to natural gas and coal prices represent an unfavourable price variance of $53 million. The cost of gas generation is expected to increase from $36.97/MWh in 2013 to $38.39/MWh in 2016, an increase of 3.8%. This increase in price is based on the forward price of electricity and a change in the mix of gas units used to generate electricity. The cost of coal is expected to increase from $20.91/MWh in 2013 to $24.50/MWh in 2016, an increase of 17.2%. The increase in coal price is the result of the previously discussed increases in the new coal contract.

An unfavourable volume variance is forecast due to the expected increase in load. SaskPower is forecasting Saskatchewan generation to increase from 23,216 GWhs in 2013 to 26,017 GWhs by 2016, an increase of 12.1%. The volume variance is responsible for a $67 million increase in fuel and purchased power expense from 2013 to 2016.

SaskPower is forecasting an unfavourable mix variance largely due to the increased reliance on natural gas. By 2016, most of the additional demand above 2013 levels will be serviced with natural gas generation, either through SaskPower generation or through power purchase agreements. In addition, hydro is forecast to decrease from its above-average level of 19.1% of total generation in 2013 down to 13.9% of total generation by 2016. This decline will largely be replaced by natural gas generation which is expected to increase from 26.9% of total generation in 2013 to 35.2% of total generation by 2016. The volume of coal generation is increasing slightly from 2013 to 2016 but as a percentage of total generation is decreasing from 48.1% in 2013 down to 44.1% in 2016. This change in the fuel mix contributes to a $94 million increase in fuel and purchased power expense.



Fuel and Purchased Power is forecast to increase $215 million by 2016: $53 million due to an increase in input prices, $67 million due to an increase in volume, and $94 million due to a change in the mix of inputs.

Natural Gas
SaskPower's natural gas generation is supplied by six natural gas facilities that have 813 MW of generation capacity. In addition, SaskPower has long-term power purchase agreements with independent power producers that provide an additional 784 MW of capacity from natural gas fired generation.

Natural gas is purchased on the spot market and prices are subject to significant volatility. SaskPower manages that price volatility by locking in the price on up to 50% of our anticipated natural gas consumption through long-term physical and financial hedges. In addition to providing price stability, the long-term physical contracts provide some security of supply to meet SaskPower's gas-fired facility requirements. Hedging less than our full natural gas requirements allows the Corporation to take advantage of some upside potential if prices should fall.

SaskPower is anticipating consuming 60.5 million gigajoules (GJs) of natural gas in 2014, 69.5 million GJs in 2015, and 77.8 million GJs in 2016. SaskPower's hedging program means the impact of an increase or decrease in the price of natural gas is approximately half as much as it would be if there was no hedging program in place.

SaskPower's exposure to natural gas is expected to increase in the near future. In June of 2013, the North Battleford Energy Centre (NBEC), owned by Northland Power, began operations under a 20-year Power Purchase Agreement with SaskPower. NBEC has a generation capacity of 260 MW. In 2015, the Queen Elizabeth Repowering Project will be completed which will add an additional 205 MWs of natural gas generation capacity to SaskPower's system.

Coal
SaskPower has three coal fired generation facilities that provide 1,624 MW of generation capacity and is SaskPower's largest source of generation. Coal prices are generally less volatile because they are based on long-term coal supply contracts. However, coal prices are expected to increase significantly in 2014 as a result of a new long-term coal contract. The increase in price is largely attributable to more difficult mining conditions, the need for additional equipment and higher operating costs to deliver coal to SaskPower. Despite the increase in price, coal generation is still a low-cost option for SaskPower. The bigger issue is the long-term viability of coal as a generation option.

New federal regulations will take effect on July 1, 2015, that will significantly impact SaskPower's coal fleet. Any unit that does not meet the standard of 420 tonnes of CO_2 per GWh will have to be retired or refurbished using the following guidelines:

1) For units commissioned prior to 1975, the end-of-life status is reached on the earliest of December 31st of its 50th year of service or December 31st, 2019 (Boundary Dam 4 & 5).

2) For units commissioned between and including 1975 and 1985, the end-of-life status is reached at the earliest of the 50th year of service or December 31st, 2029 (Boundary Dam 6, Poplar River 1 & 2).

3) For all other cases, the end-of-life is reached on December 31st of the 50th year of service (Shand).

These regulations emphasize the importance of the Boundary Dam Integrated Carbon Capture and Storage (ICCS) project at Boundary Dam 3, the first plant affected by the new regulations. A decision affecting the futures of Boundary Dam 4 & 5 will need to be made by 2016 or 2017.

The ICCS project is expected to reach full commercial operation by April 2014. Although this project will preserve coal generation in an economical way, the ICCS project will actually reduce the capacity of Boundary Dam 3 by 29 MWs, from 139 MW to 110 MW. This net loss in coal generation capacity combined with the retirements of Boundary Dam 1 and 2 will result in a 152 MW loss of coal generation capacity from 2013 to 2016.

Hydro

SaskPower has seven hydro facilities that have a generation capacity of 853 MW. Hydro is a low cost generation source with stable pricing. SaskPower pays a fee to rent water from the Saskatchewan Watershed Authority at a fixed price. The challenge with hydro generation is not cost but availability which can fluctuate significantly as it is largely dependent on water levels and river flows which are difficult to forecast. Hydro's cost-effectiveness and its unpredictability make it a significant factor with respect to fuel expense volatility. SaskPower uses median hydro levels from the past 40 years as a basis for forecasting hydro availability from 2014 to 2016.

SaskPower is currently working to partner with the Black Lake First Nation on the Tazi Twe Hydroelectric project. Once operational, this 50 MW run of the river hydro facility would supply much needed energy to northern Saskatchewan. The estimated completion date of the project is 2017.

Wind

SaskPower owns two wind facilities that provide 161 MW of generation capacity as well as two long-term power purchase agreements for the supply of an additional 37 MW of generation. There is no marginal cost for energy produced by SaskPower owned wind facilities. The cost of wind purchased through the power purchase agreements is fairly stable as it is governed by a long-term contract. However, generation is obviously dependent on wind conditions. In Saskatchewan, wind turbines have a relatively high capacity factor of over 40%, meaning that the turbines generate power over 40% of the time, but the generation is intermittent. Wind generation is unplanned and must be backed up by another source of generation that SaskPower can control.

SaskPower has entered into a long-term power purchase agreement with Algonquin Power to supply 177 MW of new wind generation. The Chaplin Wind Energy Project is expected to come on-line at the end of 2016.

Imports

SaskPower has interconnections at the Manitoba, Alberta and North Dakota borders. These provide our company with the capability to import (or export) electricity to meet higher internal demand or take advantage of prices that are lower than the marginal cost of our next unit of generation. Under normal conditions, the import capability is up to 250 MW from Manitoba, 75 MW from Alberta and 140 MW from North Dakota.

SaskPower is forecasting a decreased reliance on imports over the next three years. Import forecasts are based on expected market prices. SaskPower's forecast includes an agreement with Manitoba Hydro to provide 25 MW of import capacity starting in 2015.

Other

This category is made up of power purchase agreements with environmentally preferred power and small independent power producers. This includes electricity obtained from heat recovery facilities, small wind generation, flare gas, geothermal and the cost of demand response programs. These sources currently provide 30 MW of generation capacity, and SaskPower is forecasting the addition of another 92 MW of environmentally preferred capacity by the end of 2016.

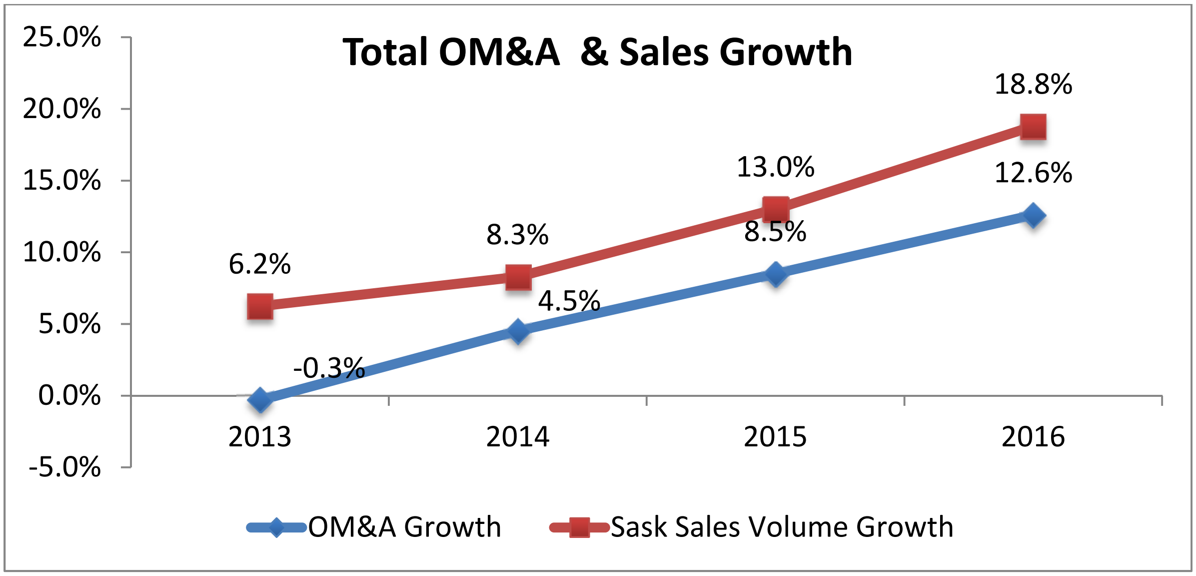
Fuel Cost Variance Account

The Saskatchewan Rate Review Panel previously recommended to the Government of Saskatchewan that SaskPower undertake a dialogue with stakeholders to resolve the need for a fuel cost variance account. In response, SaskPower retained a consultant, Christensen Associates Energy Consulting LLC, to evaluate whether a fuel cost variance account was appropriate for SaskPower and to engage in stakeholder consultations on the issue. The consultant recommended a continuation of the status quo. As a result, the fuel price risk of variance of actual costs from budget will not be transferred to SaskPower's customers. SaskPower will continue to manage the fuel cost risk. Implementation of a fuel cost variance account will not occur with this application.

3.2.3 Operating, Maintenance & Administration (OM&A)

OM&A expenses include the expenditures required to run a large electrical utility in a safe, reliable and responsible manner and deliver electricity to customers through our generation, transmission and distribution fleet. OM&A includes administrative costs like wages and salaries as well as contractor and consulting fees. It is influenced by many factors including staff levels, changes to wages and benefits, general inflation, new assets that require maintenance or support, and non-capital projects. Inflation is assumed to be 2% a year from 2014 to 2016.

SaskPower's OM&A is forecast to decrease from $619.7 million in 2012 to a forecast of $617.7 million in 2013 before increasing to a forecast of $647.7 million in 2014, $672.4 million in 2015 and $697.8 million in 2016. SaskPower has placed a priority on controlling OM&A costs while still allowing SaskPower to grow where necessary to keep up with the forecasted growth.



Compared to 2012, SaskPower's OM&A is expected to 12.6% over the next 4 years while SaskPower's domestic sales are forecast to grow 18.8%.

SaskPower Operating, Maintenance & Administration					
	Actual	Forecast			
(in $ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Power Production	$168.7	$154.6	$182.4	$183.6	$183.7
Transmission & Distribution	149.6	135.6	131.6	139.3	146.8
Asset Management	28.0	22.6	22.8	24.6	25.3
Operation Other	18.3	16.8	20.7	21.6	22.9
Subtotal Operations	**364.6**	**329.6**	**357.5**	**369.1**	**378.7**
President/Board	3.5	3.4	3.5	3.4	3.6
Finance	15.2	16.3	16.7	17.0	17.8
Customer Services	45.7	48.2	46.7	43.9	45.8
Resource Planning & NorthPoint	14.4	17.6	18.3	20.0	22.6
Law, Land, Regulatory Affairs	14.8	17.4	17.0	17.6	18.4
Information Technology & Security	56.5	61.5	70.1	79.0	85.3
Human Resources	25.6	27.2	27.0	27.7	28.9
Commercial	16.3	31.9	35.9	30.4	27.0
Business Development	3.9	1.1	1.4	1.5	1.5
Carbon Capture & Storage Initiatives	2.6	10.6	6.3	10.6	11.1
Total Core Costs	**563.1**	**564.8**	**600.4**	**620.2**	**640.7**
Demand Side Management	19.2	15.4	14.3	14.6	14.9
PPA-OMA	22.9	26.2	22.2	26.2	30.5
Other Expense	14.5	11.3	10.8	11.4	11.7
Total Other Costs	**56.6**	**52.9**	**47.3**	**52.2**	**57.1**
Total OMA	**$619.7**	**$617.7**	**$647.7**	**$672.4**	**$697.8**
% Increase	**-**	**(0.3)%**	**4.9%**	**3.8%**	**3.8%**
2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan					

OM&A costs are forecast to remain flat in 2013 and are then expected to increase $30 million or 4.9% in 2014. The bulk of this increase is targeted for the Power Production Business Area which is expected to increase $27.7 million. This increase is required to fund major generation unit overhauls at Shand, Boundary Dam Units 4 & 6, and at Western Plants. There is also a need to increase staffing levels and add materials and supplies to meet the needs of the new Integrated Carbon Capture and Sequestration Facility at Boundary Dam and Queen Elizabeth Plant D.

Over the period of 2013 to 2016, OM&A costs are forecast to increase $80.1 million or 13%. The Operations Business Area is responsible for $49 million or 60% of that increase. The additional funds are required to continue to maintain and operate SaskPower's growing generation, transmission and distribution infrastructure. The 13% increase in OM&A compares to a 25.2% growth in SaskPower's property, plant and equipment over this same period.

Labour costs make up a significant component of OM&A expenses, and Full Time Equivalents (FTEs) are being managed to help keep OM&A costs down while still supporting significant investments in SaskPower's infrastructure. An FTE is defined as an employee who works 1,800 hours per year and includes permanent, part-time and temporary employees. Our company is committed to having an appropriately sized workforce in place, while remaining mindful of our efficiency objectives.

SaskPower's FTE plan calls for both the addition of new FTE's in certain areas combined with the reduction of FTE's in other areas. The Corporation is planning a temporary increase of 126 FTEs in 2014 to address staffing vacancies at the power plants and at the new Integrated Carbon Capture and Storage Facility; to support improved service on SaskPower's transmission and distribution network; and the repatriation of contract positions with less expensive internal employees. The increase in FTE levels in 2014 are going to be partially mitigated by a decrease of 88 FTEs in 2015 largely due to the implementation of the Advanced Metering Infrastructure and the retirement of Boundary Dam Units 1 & 2. FTEs are then expected to gradually increase starting with 6 additional FTEs in 2016.

Wage rates are also being carefully monitored to ensure they are appropriate. An extensive wage study was done in the fall of 2011 for all employee groups to ensure that SaskPower's salaries were competitive within their industries. The study compared salaries to other western Canadian utilities and other comparable companies with the ultimate goal of making SaskPower's wages approximately 'P50', or in the 50th percentile of comparable salaries for a similar position in western Canada.

Saskatchewan's economic growth has had a significant impact on SaskPower's ability to hire and retain employees, especially in certain trades. Saskatchewan's average income is now the second highest in Canada and Saskatchewan saw the highest percentage increase in 2012. Because more companies in Saskatchewan are competing for similar skill sets, the upward pressure on these salaries has contributed to the significant increase in voluntary resignations at SaskPower over the past few years. This pressure is not likely to moderate in the foreseeable future, with the chief competition for our skilled workforce coming from Alberta and British Columbia.

Further complicating the problem, SaskPower has a relatively older workforce and has seen a significant increase in retirements, with retirements doubling over the past two years. Retirement is likely to remain an issue – more than half of SaskPower's total employees (approximately 57%) will be eligible to retire over the next decade. The turnover rate, while low by Canadian comparisons, has doubled at SaskPower in three years and will likely be an issue for the foreseeable future. SaskPower is combatting the loss of experienced employees with proactive techniques to recruit new employees in an effort to replace the valuable experience that will be leaving SaskPower in the near future.

4.0 Effect on Customers

4.1 SaskPower's Cost of Service & Rate Design

The fundamental building block for rates is the Corporation's overall revenue needs. Once this has been established for the system as a whole, it is necessary to allocate various cost components to each group of customers in a fair and reasonable manner. The principles underlying cost of service and rate design are well established within the industry. These principles attempt to ensure that those who pay for electrical services, whether they are residential customers or industrial/commercial customers, pay rates that are fair and reasonable. The key aspect of rate design is the principle of fairness - in that each customer class must have attributed to it a share of the costs that accurately reflects the cost of providing electrical service.

SaskPower has an independent review of its cost of service and rate design methodology approximately every five years by a consultant with experience in cost of service modelling and rate design. In 2012 Elenchus Research Associates reviewed SaskPower's cost of service and rate design methodology. The final report which was completed by Elenchus in January 2013 concluded that SaskPower's cost of service model and rate design methodologies are consistent with generally accepted electric utility practices.

Elenchus Research Associates final report included some recommendations for enhancements. The most significant changes recommended by Elenchus will be implemented immediately, and are as follows:

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

A table summarizing the impact of the changes is provided below:

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

The cost of service model and rate design is a "zero sum process", which means that any changes will result in winners and losers as the revenue to revenue requirement ratio (which measures revenues against the cost of service) for the total load must equal 1.0. The significant impacts of the 2012 review are to the Farm class (slightly higher revenue to revenue requirement ratio), Streetlight class (higher revenue to revenue requirement ratio) and to the Reseller class (lower revenue to revenue requirement ratio). The implication of the higher revenue to revenue requirement ratio for the Farm and Streetlight classes is they will experience lower than system average (all customers) rate increases. The implication of the lower revenue to revenue requirement ratio for the Reseller class is it will likely experience higher than system average rate increase.

Any changes to the revenue to revenue requirement ratios resulting from the methodology review need not be completely rebalanced in one rate adjustment. Rate stability is an important principle in setting rates. Rate increases balance the desire to rebalance rates with the need to limit the maximum rate increases to any one class of customers to avoid rate shock. The principle of gradualism allows rate realignments to occur gradually, over several rate adjustments as opposed to all at once.

It is important to note that revenue to revenue requirement ratios are not static. Each year SaskPower rebuilds the cost of service model using the latest financial information and customer revenue and load data. Cost of service model results vary from year to year for a number of reasons, including: class revenue and revenue requirement changes, non-uniform escalation of generation, transmission, distribution & customer services costs, changes to class demand at system peak, and changes to cost of service methodology.

In addition to the impacts incurred due to changes in cost of service methodology, certain customer classes are facing significant cost pressures in this rate application due to SaskPower's efforts to renew its aging infrastructure. As SaskPower holds the line on OM&A costs (relative to load growth) a larger portion of SaskPower's projected rate increases are driven by fuel, generation related capital expenditures and their associated depreciation and finance charges. Since approximately 90% of the Power and Reseller classes' required revenue is attributed to these generation related costs, these classes can expect to experience rate increases in excess of the system average.

SaskPower will rebalance rates in each year of this rate application to ensure that they reflect the actual cost of service, providing equity among rate classes and the customers within the rate class. In 2014 and 2015, SaskPower's rates will fall between the industry standard 0.95 and 1.05 revenue-to-revenue requirement ratio for each customer class, with the exception of Streetlights (1.16 in 2014 and 1.08 in 2015). This ratio range was accepted by the Saskatchewan Rate Review Panel in 2002 as the appropriate standard. All SaskPower rates will be fully rebalanced in 2016, and will fall within SaskPower's preferred narrow revenue-to-revenue requirement range of 0.98 to 1.01. SaskPower's recommendation is to rebalance the impacts of the 2012 cost of service review over a three-year period to limit the maximum rate increases to any one class of customers to avoid rate shock.

The following table summarizes the revenue-to-revenue requirement ratios for each customer class with the proposed rate change:

Year 2014-2016 R/RR Ratios & Class Increases
5.5%, 5% and 5% With Rebalancing

Class of Service	2014			2015		2016	
	R/RR Ratio (Existing Rates)	Proposed Increase	R/RR Ratio (Revised Rates)	Proposed Increase	R/RR Ratio (Revised Rates)	Proposed Increase	R/RR Ratio (Revised Rates)
Urban Residential	0.98	5.3%	0.98	4.5%	0.98	4.5%	0.98
Rural Residential	0.98	5.3%	0.98	4.5%	0.98	4.8%	0.98
Farms	1.01	3.5%	0.98	4.5%	0.98	4.0%	0.98
Urban Commercial	0.98	7.0%	1.00	5.6%	1.00	5.6%	1.01
Rural Commercial	1.03	4.8%	1.01	4.8%	1.01	4.8%	1.01
Power - Published Rates	0.99	7.0%	1.01	5.8%	1.01	5.8%	1.01
Power - Contract Rates	0.97	6.4%	0.98	6.7%	0.98	5.5%	0.99
Oilfields	1.06	3.6%	1.04	3.7%	1.02	3.7%	1.01
Streetlights	1.29	-4.8%	1.16	-4.8%	1.08	-4.8%	1.01
Reseller	0.94	7.0%	0.96	7.3%	0.97	7.3%	1.00
Total (System)	**1.00**	**5.5%**	**1.00**	**5%**	**1.00**	**5%**	**1.00**

In response to comments that revenue to revenue requirement ratios that are higher or lower than 1.0 results in cross-subsidization between SaskPower's customers, Elenchus advised that ratios close to 1.0 are deemed not to represent cross-subsidization as conducting a cost allocation study involves utilizing the best available, yet nevertheless imprecise, information with respect to how shared assets are used by various customer groups. A range of acceptable revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs. Hence, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes. Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

4.2 The Bottom Line for Customers

SaskPower is recommending system-average rate increase of 5.5% in 2014, 5.0%, in 2015 and 5.0% in 2016. The average rate increase for a typical urban residential customer is $5/month in 2014, $4/month in 2015 and $4/month in 2016. For a typical farm customer, the average rate increase is $7/month in 2014, $10/month in 2015 and $9/month in 2016. The following table illustrates the impact of the rate changes (excluding municipal surcharge and taxes) for an average customer in each customer class in dollars per month:

Year 2014, 2015 and 2016 Revenue Impacts
5.5%, 5% and 5% With Rebalancing

Class of Service	2014 Revenue Change (%)	2014 Revenue Change ($/Cust/month)	2015 Revenue Change (%)	2015 Revenue Change ($/Cust/month)	2016 Revenue Change (%)	2016 Revenue Change ($/Cust/month)
Urban Residential	5.3%	5	4.5%	4	4.5%	4
Rural Residential	5.3%	8	4.5%	7	4.8%	8
Total Residential	**5.3%**	**5**	**4.5%**	**5**	**4.6%**	**5**
Farms	3.5%	7	4.5%	10	4.0%	9
Urban Commercial	7.0%	36	5.6%	30	5.6%	32
Rural Commercial	4.8%	30	4.8%	31	4.8%	32
Total Commercial	**6.4%**	**35**	**5.4%**	**31**	**5.4%**	**32**
Power - Published Rates	7.0%	27,721	5.8%	25,490	5.8%	29,185
Power - Contract Rates	6.4%	38,379	6.7%	42,404	5.5%	39,813
Total Power	**6.9%**	**29,213**	**6.0%**	**27,745**	**5.7%**	**30,576**
Oilfields	3.6%	53	3.7%	58	3.7%	59
Streetlights	-4.8%	(24)	-4.8%	(23)	-4.8%	(22)
Reseller	7.0%	157,478	7.3%	177,163	7.3%	190,721
Total (System)	**5.5%**		**5%**		**5%**	

Notes:
- The rate increase for Power Contracts is for customers whose contracts are tied to published rates. There is also escalation included in the contract customer's existing rates revenue as per their specific contract terms.

The proposed rates for SaskPower's rate codes spread among the ten customer classes are attached as Appendix B.

One of the primary objectives of rate design is fairness. Rates are designed to recover the appropriate amount of revenue from all customers in each rate code. Essentially this means if a rate code belongs to a customer class with an overall revenue-to-revenue requirement ratio of 1.01, the rate is designed so that each customer in that rate code provides the same revenue-to-revenue requirement ratio of 1.01.

Rebalancing maintenance has been incorporated into the rate adjustments, meaning rate redesign is required to correct the imbalances within the rate codes themselves. This involves adjusting the components of the rates, which include the Basic Monthly Charge, the Demand

Charge and the Energy Charge. As a result, not all customers within a rate class will receive the same rate increase.

In this application, the proposed maximum increase is 15% to accommodate any rebalancing element. Rate redesign is an ongoing process that will continue beyond 2016. While progress on redesign is incorporated in this application, it is structured to ensure that no individual customer experiences a rate increase of more than 15% in each year. Appendix C shows details of the impact of the rate changes by rate code requested in this application.

For Commercial customers with approved time-of-day metering, SaskPower will be adjusting the calculation for those customer's recorded demand to be either the maximum demand registered during the on-peak period of the current month or 75% of the maximum demand registered at any other time during the current month. This percentage will increase to 80% in 2015, and 85% in 2016, as SaskPower continues to shift its time-of-day incentive from demand to energy related. Minimum bills for farm and commercial demand billed customers will be increased by the system average increase for each year.

In an effort to simplify SaskPower's rate structure, three rates will be eliminated with this rate application. In the oilfield class, rate codes E44 and E45 will be removed as these rates have been in place for a number of years and have no customers. The rates were intended to provide monthly demand readings for oilfield customers, which will be available to all customers when the Advanced Metering Infrastructure project is completed. In the farm class, the E42 rate for irrigation customers will be eliminated and all affected customers will be moved to rate code E19 which is exactly the same as E42. No customers will be impacted by these changes. Rate codes E10 & E12 will be closed to new customers and existing customers currently on these rates will be grandfathered.

4.3 Helping Customers Deal with Bill Impacts

To help offset the impact of rate increases, SaskPower will continue to help customers reduce their electrical use, decrease their power bills and help protect the environment through a variety of energy efficiency and conservation programs. If customers reduce their power consumption they will decrease their power bill. The benefits to SaskPower are fewer emissions and less strain on our system, particularly during peak times.

Demand Side Management (DSM) is a portfolio of programs, projects, and initiatives focused on customer based energy efficiency, load management, and conservation. Through the SaskPower DSM portfolio of energy efficiency, load management, renewables and conservation programs, customers are able to make informed decisions about what they can do to reduce electrical consumption and thereby reduce their electricity bills.

DSM programs benefit both SaskPower and customers. By working closely with customers to reduce and adjust electricity use, overall demand for power can decrease. Lower demand results in a lower economic requirement for financing additional infrastructure. By 2017, energy efficiency programming alone will deliver over 100 MW of capacity reductions. In addition, demand response initiatives, targeting industrial customers, will provide 85 MW of capacity value.

At the end of 2012, SaskPower has accumulated savings of 56 MW, and is on track to reach the goal of 100 MW. Our residential and commercial programs are currently focused on lighting, plug load, appliances and education. The focus of our industrial programs are to help facilities identify energy waste, and to provide the technical or business resources to help with the business case of energy management plan. Our renewable programs promote the use of environmentally preferred technology to generate power.

Customer programs include (but are not limited to) the following:

Residential
Refrigerator/Freezer Recycling Program: This program offers free pick-up and recycling of old inefficient refrigerators or freezers. Customers can save over $100 per year by removing their old appliance.

Lighting Discount Program: This program partners with retail stores across Saskatchewan to provide point of purchase discounts on energy efficient light bulbs and fixtures. Lighting accounts for 20% of the average household power usage. CFLs and LEDs use 75% less power than incandescent bulbs.

Block Heater Timer Program: This program encourages customers to minimize the amount of time engine block heaters are plugged in during winter months. Customers can save $25 per year on their power bill by limiting their plug-in time to only 4 hours per day.

Commercial
Commercial Lighting Incentive Program: This program provides non-residential customers access to selected premium energy efficient lighting equipment at a discounted price. Commercial customers who switch to energy efficient lighting can save up to 40% on their annual lighting electricity costs as well as lower the need for maintenance resulting in reduced maintenance costs.

Energy Performance Contracting: In partnership with Honeywell Ltd., this program allows our large commercial and institutional customers to benefit from energy and facility renewals that reduce energy consumption, reduce environmental impacts and improve comfort. Plus, it is all paid for by savings on utility bills.

Municipal Ice Rink Program: This program helps municipal ice rink customers reduce their utility costs by improving the energy efficiency of their facility's equipment and operations. Participants receive a free welcome package which includes a facility assessment, a report on retrofit recommendations, best practice resources, and information about financial incentives offered by SaskPower and SaskEnergy. Retrofits can reduce utility costs by 15-40% which equates to annual savings of $2,500 to $7,000 for the average Saskatchewan rink.

Municipal Seasonal Lighting Program: This program provides municipalities the opportunity to switch their incandescent seasonal light bulbs with commercial-grade LED seasonal light bulbs at no cost to them. One LED seasonal light bulb uses less than 0.5 watts of electricity compared to 5-7 watts for an incandescent bulb.

Parking Lot Controller Program: This program offers an incentive when customers install parking lot controllers in electrified parking lots. A parking lot controller is similar to a standard outdoor electrical outlet, except that it regulates the electricity flow to the outlet based on the outside temperature. This enables customers to reduce their electricity costs associated with their parking lots by up to 50%.

Industrial Programs

Demand Response Program: This program provides incentives to our largest industrial customers in exchange for an agreement to reduce electrical demand on SaskPower systems when requested thus providing operational and economic benefits to SaskPower.

Industrial Energy Optimization Program: This program is designed to help industrial facilities systematically identify energy waste and reduce the cost associated with electrical energy use during the production process. SaskPower will help facilities identify energy waste, and to provide the technical or business resources to help with the business case of energy management plan.

Renewable Programs

Net Metering & Rebate Program: Customers can generate their own power using renewable technology up to 100 kW and bank excess electricity production up to one year. Net metering customers can receive a rebate with a one-time capital incentive equivalent to 20% of eligible costs (equipment and installation) with a maximum payment of $20,000.

Small Power Producers: This program accommodates customers who wish to generate up to 100 kilowatts of electricity for the purpose of offsetting power that would otherwise be purchased from SaskPower or for selling all of the power generated to SaskPower.

5.0. Summary

SaskPower respectfully submits that the request contained in this application is justified and represents a fair and reasonable approach of providing reliable electrical service to its many customers at the lowest possible cost.

SaskPower is requesting a system-average rate increase of 5.5% effective 1 January 2014, 5.0% effective 1 January 2015 and 5% effective 1 January 2016. The exception is the Power – Contract Rate which is established in accordance with the pricing terms of their contracts.

With the approval of this application, SaskPower will achieve net incomes of $26.9 million in 2014, $39.9 million in 2015 and $40.4 million in 2016. The requested rate increases will achieve a return on equity of 1.3% in 2014, 2% in 2015 and 1.9% in 2016. SaskPower's target return on equity of 8.5% will not be achieved with the requested rate increases. With no rate increases approved in that time period, SaskPower would suffer net losses in each of the years and a negative return on equity.

The proposed rate changes will apply, on average, by customer class, as follows:

Year 2014, 2015 and 2016 Revenue Impacts
5.5%, 5% and 5% With Rebalancing

Class of Service	2014 Revenue Change (%)	2014 Revenue Change ($/Cust/month)	2015 Revenue Change (%)	2015 Revenue Change ($/Cust/month)	2016 Revenue Change (%)	2016 Revenue Change ($/Cust/month)
Urban Residential	5.3%	5	4.5%	4	4.5%	4
Rural Residential	5.3%	8	4.5%	7	4.8%	8
Total Residential	**5.3%**	**5**	**4.5%**	**5**	**4.6%**	**5**
Farms	3.5%	7	4.5%	10	4.0%	9
Urban Commercial	7.0%	36	5.6%	30	5.6%	32
Rural Commercial	4.8%	30	4.8%	31	4.8%	32
Total Commercial	**6.4%**	**35**	**5.4%**	**31**	**5.4%**	**32**
Power - Published Rates	7.0%	27,721	5.8%	25,490	5.8%	29,185
Power - Contract Rates	6.4%	38,379	6.7%	42,404	5.5%	39,813
Total Power	**6.9%**	**29,213**	**6.0%**	**27,745**	**5.7%**	**30,576**
Oilfields	3.6%	53	3.7%	58	3.7%	59
Streetlights	-4.8%	(24)	-4.8%	(23)	-4.8%	(22)
Reseller	7.0%	157,478	7.3%	177,163	7.3%	190,721
Total (System)	**5.5%**		**5%**		**5%**	

Notes:
- The rate increase for Power Contracts is for customers whose contracts are tied to published rates. There is also escalation included in the contract customer's existing rates revenue as per their specific contract terms.

SaskPower 2014, 2015 and 2016 Rate Application Appendices

October 2013

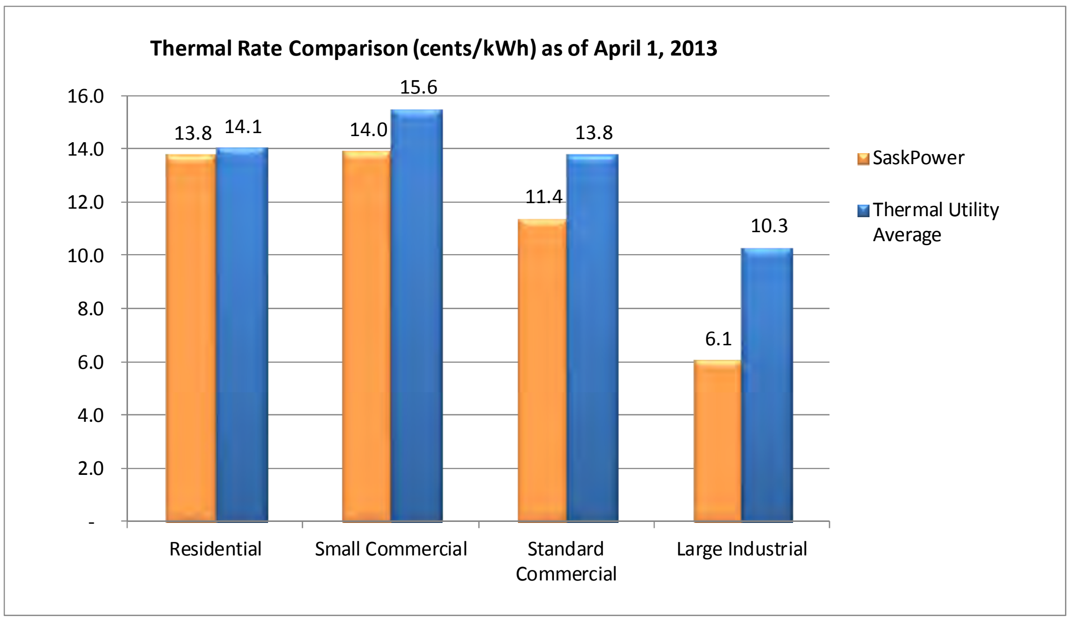
Appendix A - Canadian Electrical Utility Rate Comparison

Utility Rate Summary ($/Month)

	Residential 750 kWh	Small Commercial 6kW & 750 kWh	Standard Commercial 100kW & 25,000 kWh	Large Industrial 10,000 kW & 5,760,000 kWh
Hydro Utility Average	$58	$77	$2,248	$262,728
Thermal Utility Average	$106	$117	$3,460	$595,727
Canadian Utility Average	$93	$106	$3,129	$504,909
SaskPower	$104	$105	$2,858	$351,996

Utility Rate Summary (cents/kWh)

	Residential	Small Commercial	Standard Commercial	Large Industrial
Hydro Utility Average	7.7	10.3	9.0	4.6
Thermal Utility Average	14.1	15.6	13.8	10.3
Canadian Utility Average	12.3	14.1	12.5	8.8
SaskPower	13.8	14.0	11.4	6.1
Consumption (kWh/month)	750	750	25,000	5,760,000



Notes

- SaskPower rates are 18% lower than the thermal average for the combination of 4 classes shown.
- The comparison includes the basic charge, energy charge and demand charge (if applicable).
- Rates are based on the Hydro Quebec April 1, 2013 Survey.
- Does not include taxes or surcharges.

Appendix B

2014

SaskPower

Rate Proposal

RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E01 Existing	City	20.22	N/A	N/A	11.13	N/A	N/A	N/A	20.22		
E01 Proposed		20.22	N/A	N/A	11.93	N/A	N/A	N/A	20.22		
E02 Existing	Town, Village, Urban Resort	20.22	N/A	N/A	11.13	N/A	N/A	N/A	20.22		
E02 Proposed		20.22	N/A	N/A	11.93	N/A	N/A	N/A	20.22		
E03 Existing	Rural, Rural Resort	29.19	N/A	N/A	11.37	N/A	N/A	N/A	29.19		
E03 Proposed		29.19	N/A	N/A	11.99	N/A	N/A	N/A	29.19		

SaskPower

Rate Proposal

DIESEL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E04 Existing	Residential Diesel	29.19	650	11.37	42.35	N/A	N/A	N/A	29.19		
E04 Proposed		29.19	650	11.99	44.59	N/A	N/A	N/A	29.19		
E35 Existing	General Service	36.81	650	11.342	39.76	N/A	N/A	N/A	36.81		
E35 Proposed		36.81	650	12.118	42.00	N/A	N/A	N/A	36.81		
E36 Existing	General Service - Federal & Provincial	36.81	N/A	N/A	80.62	N/A	N/A	N/A	36.81		
E36 Proposed		36.81	N/A	N/A	85.13	N/A	N/A	N/A	36.81		
E38 Existing	General Service - Local Community	36.81	N/A	N/A	72.88	N/A	N/A	N/A	36.81		
E38 Proposed		36.81	N/A	N/A	77.00	N/A	N/A	N/A	36.81		

SaskPower
Rate Proposal
FARM

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E34 Existing	Farm	30.03	16,000	10.190	5.692	50	0	11.40	30.03	3.91	/KV.A max demand over 50
E34 Proposed		30.03	16,000	10.630	5.700	50	0	11.40	30.03	4.12	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower
Rate Proposal
IRRIGATION

RATE CODE	DESCRIPTION	BASIC ($/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/hp)	MINIMUM BILL BASIC	DEMAND	NOTES
E19 Existing	Farm - SaskPower Supplied Transformation	389.54	N/A	N/A	5.44	N/A	N/A	N/A	389.54		
E19 Proposed		416.13	N/A	N/A	5.84	N/A	N/A	N/A	416.13		
E37 Existing	General Service - SaskPower Supplied Transformation	186.62	N/A	N/A	7.08	N/A	N/A	18.78	186.62	18.78	/KV.A max demand
E37 Proposed		214.61	N/A	N/A	8.14	N/A	N/A	21.59	214.61	21.59	/KV.A max demand
E41 Existing	Mains - Interruptible - closed to new customers	655.63	N/A	N/A	4.65	N/A	N/A	N/A	655.63		
E41 Proposed		747.40	N/A	N/A	5.00	N/A	N/A	N/A	747.40		
E42 Existing	Pivots - Interruptible - closed to new customers	389.54	N/A	N/A	5.44	N/A	N/A	N/A	389.54		
E42 Proposed		416.13	N/A	N/A	5.84	N/A	N/A	N/A	416.13		

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower

Rate Proposal

GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E05 Existing	Urban - SaskPower Supplied Transformation	40.75	16,750	9.430	6.238	50	0	11.85	40.75	3.91	/KV.A max demand over 50
E05 Proposed		46.86	16,750	10.180	6.610	50	0	12.75	46.86	4.12	/KV.A max demand over 50
E06 Existing	Rural - SaskPower Supplied Transformation	57.70	15,500	9.635	5.876	50	0	12.85	57.70	3.91	/KV.A max demand over 50
E06 Proposed		57.70	15,500	10.180	6.325	50	0	12.75	57.70	4.12	/KV.A max demand over 50
E07 Existing	Urban - Customer Owned Transformation	162.60	N/A	N/A	6.009	N/A	N/A	9.97	162.60	3.91	/KV.A max demand
E07 Proposed		186.98	N/A	N/A	6.240	N/A	N/A	11.39	186.98	4.12	/KV.A max demand
E08 Existing	Rural - Customer Owned Transformation	265.40	N/A	N/A	5.698	N/A	N/A	10.81	265.40	3.91	/KV.A max demand
E08 Proposed		265.40	N/A	N/A	5.824	N/A	N/A	11.35	265.40	4.12	/KV.A max demand
E10 Existing	Customer Owned Transformation	482.54	N/A	N/A	4.877	N/A	N/A	6.69	482.54	3.91	/KV.A max demand
E10 Proposed		554.92	N/A	N/A	4.834	N/A	N/A	7.21	554.92	4.12	/KV.A max demand
E12 Existing	Customer Owned Transformation	193.02	N/A	N/A	4.825	N/A	N/A	6.71	193.02	3.91	/KV.A max demand
E12 Proposed		221.97	N/A	N/A	4.825	N/A	N/A	7.05	221.97	4.12	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E75 Existing	Urban - SaskPower Supplied Transformation	25.51	14,500	10.562	6.165	50	0	11.22	25.51	3.91	/KV.A max demand over 50
E75 Proposed		27.43	14,500	11.335	5.952	50	0	12.59	27.43	4.12	/KV.A max demand over 50
E76 Existing	Rural - SaskPower SuppliedTransformation	36.81	13,000	11.342	6.123	50	0	12.47	36.81	3.91	/KV.A max demand over 50
E76 Proposed		36.81	13,000	12.118	6.219	50	0	12.94	36.81	4.12	/KV.A max demand over 50
E77 Existing	Urban - Customer Owned Transformation	25.51	14,500	10.562	6.165	50	0	10.83	25.51	3.91	/KV.A max demand over 50
E77 Proposed		27.43	14,500	11.335	5.952	50	0	12.15	27.43	4.12	/KV.A max demand over 50
E78 Existing	Rural - Customer Owned Transformation	36.81	13,000	11.342	6.123	50	0	12.03	36.81	3.91	/KV.A max demand over 50
E78 Proposed		36.81	13,000	12.118	6.219	50	0	12.48	36.81	4.12	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E15 Existing	Unmetered - Miscellaneous	N/A	N/A	N/A	3.55	/100 Watts			14.47		
E15 Proposed		N/A	N/A	N/A	3.68	/100 Watts			16.64		
E16 Existing	Unmetered - Power Supply Units	53.71	/Power Supply Unit						53.71		
E16 Proposed		61.75	/Power Supply Unit						61.75		
E17 Existing	Unmetered - Cable Television Rectifiers	N/A	N/A	N/A	1.13	/10 Watts			22.34		
E17 Proposed		N/A	N/A	N/A	1.29	/10 Watts			25.69		
E18 Existing	Unmetered - X-rays	N/A	N/A	N/A	N/A	3.08	/kV.A installed capacity				
E18 Proposed		N/A	N/A	N/A	N/A	3.54	/kV.A installed capacity				

SaskPower

Rate Proposal

OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E43 Existing	Standard Oilfield	54.55	N/A	N/A	6.116	N/A	N/A	11.880	54.550	11.880	/KV.A max demand
E43 Proposed		54.55	N/A	N/A	6.393	N/A	N/A	11.882	54.550	11.882	/KV.A max demand

SaskPower

Rate Proposal

POWER - OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E46 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	5.486	N/A	N/A	7.794	5491.000	7.794	/KV.A max demand
E46 Proposed		5,491.00	N/A	N/A	5.790	N/A	N/A	9.265	5491.000	9.265	/KV.A max demand
E47 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	4.939	N/A	N/A	6.100	6294.000	6.100	/KV.A max demand
E47 Proposed		6,294.00	N/A	N/A	5.216	N/A	N/A	7.130	6294.000	7.130	/KV.A max demand
E48 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	4.879	N/A	N/A	6.100	6757.000	6.100	/KV.A max demand
E48 Proposed		6,757.00	N/A	N/A	5.098	N/A	N/A	6.957	6757.000	6.957	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E86 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.059	5.059	N/A	N/A	7.794	5,491.00	7.794	/KV.A max demand
E86 Proposed		5,491.00	N/A	6.363	5.363	N/A	N/A	9.265	5,491.00	9.265	/KV.A max demand
E87 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	5.512	4.512	N/A	N/A	6.10	6,294.00	6.10	/KV.A max demand
E87 Proposed		6,294.00	N/A	5.789	4.789	N/A	N/A	7.13	6,294.00	7.13	/KV.A max demand
E88 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.452	4.452	N/A	N/A	6.10	6,757.00	6.10	/KV.A max demand
E88 Proposed		6,757.00	N/A	5.671	4.671	N/A	N/A	6.96	6,757.00	6.96	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E22 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	5.486	N/A	N/A	7.794	5491.000	7.794	/KV.A max demand
E22 Proposed		5,491.00	N/A	N/A	5.790	N/A	N/A	9.265	5491.000	9.265	/KV.A max demand
E23 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	4.939	N/A	N/A	6.100	6294.000	6.100	/KV.A max demand
E23 Proposed		6,294.00	N/A	N/A	5.216	N/A	N/A	7.130	6294.000	7.130	/KV.A max demand
E24 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	4.879	N/A	N/A	6.100	6757.000	6.100	/KV.A max demand
E24 Proposed		6,757.00	N/A	N/A	5.098	N/A	N/A	6.957	6757.000	6.957	/KV.A max demand
E25 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	N/A	4.879	N/A	N/A	6.100	7081.000	6.100	/KV.A max demand
E25 Proposed		7,081.00	N/A	N/A	5.098	N/A	N/A	6.957	7081.000	6.957	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E82 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.059	5.059	N/A	N/A	7.794	5,491.00	7.794	/KV.A max demand
E82 Proposed		5,491.00	N/A	6.363	5.363	N/A	N/A	9.265	5,491.00	9.265	/KV.A max demand
E83 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	5.512	4.512	N/A	N/A	6.10	6,294.00	6.10	/KV.A max demand
E83 Proposed		6,294.00	N/A	5.789	4.789	N/A	N/A	7.13	6,294.00	7.13	/KV.A max demand
E84 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.452	4.452	N/A	N/A	6.10	6,757.00	6.10	/KV.A max demand
E84 Proposed		6,757.00	N/A	5.671	4.671	N/A	N/A	6.96	6,757.00	6.96	/KV.A max demand
E85 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	5.452	4.452	N/A	N/A	6.10	7,081.00	6.10	/KV.A max demand
E85 Proposed		7,081.00	N/A	5.671	4.671	N/A	N/A	6.96	7,081.00	6.96	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

RESELLER

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E31 Existing	Swift Current 25 kV (Non-Totalized)	5,444.00	N/A	N/A	3.623	N/A	N/A	15.781	5,444.00	15.781	/KV.A max demand
E31 Proposed		5,444.00	N/A	N/A	4.143	N/A	N/A	15.782	5,444.00	15.782	/KV.A max demand
E32 Existing	Swift Current 138 kV - (Non-Totalized)	6,241.00	N/A	N/A	3.552	N/A	N/A	13.965	6,241.00	13.965	/KV.A max demand
E32 Proposed		6,241.00	N/A	N/A	4.002	N/A	N/A	13.965	6,241.00	13.965	/KV.A max demand
E33 Existing	Saskatoon 138kV - (Totalized)	12,987.00	N/A	N/A	3.402	N/A	N/A	15.621	12,987.00	15.621	/KV.A max demand
E33 Proposed		12,987.00	N/A	N/A	3.847	N/A	N/A	15.625	12,987.00	15.625	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly ($/month)	Proposed Monthly ($/month)
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S05	Mercury Vapor - 125 W	$14.47	$14.42
S06	Mercury Vapor - 175 W	$16.13	$15.92
S13	Low Pressure Sodium Vapor - 90 W	$13.85	$13.67
S14	Low Pressure Sodium Vapor - 90 W Continuous	$16.78	$15.97
S15	Low Pressure Sodium Vapor - 135 W	$15.42	$14.67
S16	Low Pressure Sodium Vapor - 180 W	$17.06	$16.24
S17	High Pressure Sodium Vapor - 70 W	$12.07	$11.48
S18	High Pressure Sodium Vapor - 100 W	$13.47	$12.81
S19	High Pressure Sodium Vapor - 150 W	$15.65	$14.90
S20	High Pressure Sodium Vapor - 150 W Continuous	$19.18	$18.40
S21	High Pressure Sodium Vapor - 250 W	$20.35	$19.37
S22	High Pressure Sodium Vapor - 250 W Continuous	$25.85	$24.75
S23	High Pressure Sodium Vapor - 400 W	$26.37	$25.12
S24	Metal Halide - 100 W	$16.57	$15.77
S25	Metal Halide - 175 W	$19.72	$18.77
S26	Metal Halide - 250 W	$23.18	$22.06
S30	Induction - 165 W	$16.23	$15.45

2015

SaskPower

Rate Proposal

RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E01 Existing	City	20.22	N/A	N/A	11.93	N/A	N/A	N/A	20.22		
E01 Proposed		20.22	N/A	N/A	12.62	N/A	N/A	N/A	20.22		
E02 Existing	Town, Village, Urban Resort	20.22	N/A	N/A	11.93	N/A	N/A	N/A	20.22		
E02 Proposed		20.22	N/A	N/A	12.62	N/A	N/A	N/A	20.22		
E03 Existing	Rural, Rural Resort	29.19	N/A	N/A	11.99	N/A	N/A	N/A	29.19		
E03 Proposed		29.19	N/A	N/A	12.62	N/A	N/A	N/A	29.19		

SaskPower

Rate Proposal

DIESEL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E04 Existing	Residential Diesel	29.19	650	11.99	44.59	N/A	N/A	N/A	29.19		
E04 Proposed		29.19	650	12.62	46.61	N/A	N/A	N/A	29.19		
E35 Existing	General Service	36.81	650	12.118	42.00	N/A	N/A	N/A	36.81		
E35 Proposed		36.81	650	12.775	44.00	N/A	N/A	N/A	36.81		
E36 Existing	General Service - Federal & Provincial	36.81	N/A	N/A	85.13	N/A	N/A	N/A	36.81		
E36 Proposed		36.81	N/A	N/A	89.13	N/A	N/A	N/A	36.81		
E38 Existing	General Service - Local Community	36.81	N/A	N/A	77.00	N/A	N/A	N/A	36.81		
E38 Proposed		36.81	N/A	N/A	81.00	N/A	N/A	N/A	36.81		

SaskPower
Rate Proposal
FARM

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E34 Existing	Farm	30.03	16,000	10.630	5.700	50	0	11.40	30.03	4.12	/KV.A max demand over 50
E34 Proposed		31.03	16,000	11.230	4.870	50	0	11.40	31.03	4.32	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower
Rate Proposal
IRRIGATION

RATE CODE	DESCRIPTION	BASIC ($/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/hp)	MINIMUM BILL BASIC	DEMAND	NOTES
E19 Existing	Farm - SaskPower Supplied Transformation	416.13	N/A	N/A	5.84	N/A	N/A	N/A	416.13		
E19 Proposed		426.12	N/A	N/A	6.28	N/A	N/A	N/A	426.12		
E37 Existing	General Service - SaskPower Supplied Transformation	214.61	N/A	N/A	8.14	N/A	N/A	21.59	214.61	21.59	/KV.A max demand
E37 Proposed		225.34	N/A	N/A	8.55	N/A	N/A	22.67	225.34	22.67	/KV.A max demand
E41 Existing	Mains - Interruptible - closed to new customers	747.40	N/A	N/A	5.00	N/A	N/A	N/A	747.40		
E41 Proposed		803.46	N/A	N/A	5.38	N/A	N/A	N/A	803.46		
E42 Existing	Pivots - Interruptible - closed to new customers	416.13	N/A	N/A	5.84	N/A	N/A	N/A	416.13		
E42 Proposed		426.12	N/A	N/A	6.28	N/A	N/A	N/A	426.12		

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower

Rate Proposal

GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E05 Existing	Urban - SaskPower Supplied Transformation	46.86	16,750	10.180	6.610	50	0	12.75	46.86	4.12	/KV.A max demand over 50
E05 Proposed		51.40	16,750	10.635	6.809	50	0	13.84	51.40	4.32	/KV.A max demand over 50
E06 Existing	Rural - SaskPower Supplied Transformation	57.70	15,500	10.180	6.325	50	0	12.75	57.70	4.12	/KV.A max demand over 50
E06 Proposed		57.70	15,500	10.635	6.450	50	0	13.84	57.70	4.32	/KV.A max demand over 50
E07 Existing	Urban - Customer Owned Transformation	186.98	N/A	N/A	6.240	N/A	N/A	11.39	186.98	4.12	/KV.A max demand
E07 Proposed		215.02	N/A	N/A	6.435	N/A	N/A	12.38	215.02	4.32	/KV.A max demand
E08 Existing	Rural - Customer Owned Transformation	265.40	N/A	N/A	5.824	N/A	N/A	11.35	265.40	4.12	/KV.A max demand
E08 Proposed		265.40	N/A	N/A	6.435	N/A	N/A	12.38	265.40	4.32	/KV.A max demand
E10 Existing	Customer Owned Transformation	554.92	N/A	N/A	4.834	N/A	N/A	7.21	554.92	4.12	/KV.A max demand
E10 Proposed		632.61	N/A	N/A	5.058	N/A	N/A	7.56	632.61	4.32	/KV.A max demand
E12 Existing	Customer Owned Transformation	221.97	N/A	N/A	4.825	N/A	N/A	7.05	221.97	4.12	/KV.A max demand
E12 Proposed		291.00	N/A	N/A	4.967	N/A	N/A	7.45	291.00	4.32	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E75 Existing	Urban - SaskPower Supplied Transformation	27.43	14,500	11.335	5.952	50	0	12.59	27.43	4.12	/KV.A max demand over 50
E75 Proposed		27.62	14,500	12.128	6.404	50	0	13.44	27.62	4.32	/KV.A max demand over 50
E76 Existing	Rural - SaskPower SuppliedTransformation	36.81	13,000	12.118	6.219	50	0	12.94	36.81	4.12	/KV.A max demand over 50
E76 Proposed		36.81	13,000	12.775	6.571	50	0	13.73	36.81	4.32	/KV.A max demand over 50
E77 Existing	Urban - Customer Owned Transformation	27.43	14,500	11.335	5.952	50	0	12.15	27.43	4.12	/KV.A max demand over 50
E77 Proposed		27.62	14,500	12.128	6.404	50	0	12.97	27.62	4.32	/KV.A max demand over 50
E78 Existing	Rural - Customer Owned Transformation	36.81	13,000	12.118	6.219	50	0	12.48	36.81	4.12	/KV.A max demand over 50
E78 Proposed		36.81	13,000	12.775	6.571	50	0	13.24	36.81	4.32	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E15 Existing	Unmetered - Miscellaneous	N/A	N/A	N/A	3.68	/100 Watts			16.64		
E15 Proposed		N/A	N/A	N/A	3.73	/100 Watts			17.42		
E16 Existing	Unmetered - Power Supply Units	61.75	/Power Supply Unit						61.75		
E16 Proposed		64.84	/Power Supply Unit						64.84		
E17 Existing	Unmetered - Cable Television Rectifiers	N/A	N/A	N/A	1.29	/10 Watts			25.69		
E17 Proposed		N/A	N/A	N/A	1.36	/10 Watts			26.97		
E18 Existing	Unmetered - X-rays	N/A	N/A	N/A	N/A	3.54	/kV.A installed capacity				
E18 Proposed		N/A	N/A	N/A	N/A	3.72	/kV.A installed capacity				

SaskPower

Rate Proposal

OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E43 Existing	Standard Oilfield	54.55	N/A	N/A	6.393	N/A	N/A	11.88	54.55	11.88	/KV.A max demand
E43 Proposed		54.55	N/A	N/A	6.712	N/A	N/A	11.88	54.55	11.88	/KV.A max demand

SaskPower

Rate Proposal

POWER - OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E46 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	5.790	N/A	N/A	9.265	5491.000	9.265	/KV.A max demand
E46 Proposed		5,491.00	N/A	N/A	6.124	N/A	N/A	9.676	5491.000	9.676	/KV.A max demand
E47 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	5.216	N/A	N/A	7.130	6294.000	7.130	/KV.A max demand
E47 Proposed		6,294.00	N/A	N/A	5.525	N/A	N/A	7.458	6294.000	7.458	/KV.A max demand
E48 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	5.098	N/A	N/A	6.957	6757.000	6.957	/KV.A max demand
E48 Proposed		6,757.00	N/A	N/A	5.421	N/A	N/A	7.350	6757.000	7.350	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	MINIMUM BILL * NOTES
E86 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.363	5.363	N/A	N/A	9.265	5,491.00	9.265	/KV.A max demand
E86 Proposed		5,491.00	N/A	6.697	5.697	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E87 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	5.789	4.789	N/A	N/A	7.13	6,294.00	7.13	/KV.A max demand
E87 Proposed		6,294.00	N/A	6.098	5.098	N/A	N/A	7.46	6,294.00	7.46	/KV.A max demand
E88 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.671	4.671	N/A	N/A	6.96	6,757.00	6.96	/KV.A max demand
E88 Proposed		6,757.00	N/A	5.994	4.994	N/A	N/A	7.35	6,757.00	7.35	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	MINIMUM BILL * NOTES
E22 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	5.790	N/A	N/A	9.265	5491.000	9.265	/KV.A max demand
E22 Proposed		5,491.00	N/A	N/A	6.124	N/A	N/A	9.676	5491.000	9.676	/KV.A max demand
E23 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	5.216	N/A	N/A	7.130	6294.000	7.130	/KV.A max demand
E23 Proposed		6,294.00	N/A	N/A	5.525	N/A	N/A	7.458	6294.000	7.458	/KV.A max demand
E24 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	5.098	N/A	N/A	6.957	6757.000	6.957	/KV.A max demand
E24 Proposed		6,757.00	N/A	N/A	5.421	N/A	N/A	7.350	6757.000	7.350	/KV.A max demand
E25 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	N/A	5.098	N/A	N/A	6.957	7081.000	6.957	/KV.A max demand
E25 Proposed		7,081.00	N/A	N/A	5.421	N/A	N/A	7.350	7081.000	7.350	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	MINIMUM BILL * NOTES
E82 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.363	5.363	N/A	N/A	9.265	5,491.00	9.265	/KV.A max demand
E82 Proposed		5,491.00	N/A	6.697	5.697	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E83 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	5.789	4.789	N/A	N/A	7.13	6,294.00	7.13	/KV.A max demand
E83 Proposed		6,294.00	N/A	6.098	5.098	N/A	N/A	7.46	6,294.00	7.46	/KV.A max demand
E84 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.671	4.671	N/A	N/A	6.96	6,757.00	6.96	/KV.A max demand
E84 Proposed		6,757.00	N/A	5.994	4.994	N/A	N/A	7.35	6,757.00	7.35	/KV.A max demand
E85 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	5.671	4.671	N/A	N/A	6.96	7,081.00	6.96	/KV.A max demand
E85 Proposed		7,081.00	N/A	5.994	4.994	N/A	N/A	7.35	7,081.00	7.35	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

RESELLER

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	MINIMUM BILL * NOTES
E31 Existing	Swift Current 25 kV (Non-Totalized)	5,444.00	N/A	N/A	4.143	N/A	N/A	15.782	5,444.00	15.782	/KV.A max demand
E31 Proposed		5,444.00	N/A	N/A	4.490	N/A	N/A	16.606	5,444.00	16.606	/KV.A max demand
E32 Existing	Swift Current 138 kV - (Non-Totalized)	6,241.00	N/A	N/A	4.002	N/A	N/A	13.965	6,241.00	13.965	/KV.A max demand
E32 Proposed		6,241.00	N/A	N/A	4.349	N/A	N/A	14.842	6,241.00	14.842	/KV.A max demand
E33 Existing	Saskatoon 138kV - (Totalized)	12,987.00	N/A	N/A	3.847	N/A	N/A	15.625	12,987.00	15.625	/KV.A max demand
E33 Proposed		12,987.00	N/A	N/A	4.051	N/A	N/A	17.192	12,987.00	17.192	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly ($/month)	Proposed Monthly ($/month)
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S05	Mercury Vapor - 125 W	$14.42	$13.73
S06	Mercury Vapor - 175 W	$15.92	$15.16
S13	Low Pressure Sodium Vapor - 90 W	$13.67	$13.01
S14	Low Pressure Sodium Vapor - 90 W Continuous	$15.97	$15.20
S15	Low Pressure Sodium Vapor - 135 W	$14.67	$13.97
S16	Low Pressure Sodium Vapor - 180 W	$16.24	$15.46
S17	High Pressure Sodium Vapor - 70 W	$11.48	$10.92
S18	High Pressure Sodium Vapor - 100 W	$12.81	$12.19
S19	High Pressure Sodium Vapor - 150 W	$14.90	$14.18
S20	High Pressure Sodium Vapor - 150 W Continuous	$18.40	$17.52
S21	High Pressure Sodium Vapor - 250 W	$19.37	$18.44
S22	High Pressure Sodium Vapor - 250 W Continuous	$24.75	$23.56
S23	High Pressure Sodium Vapor - 400 W	$25.12	$23.91
S24	Metal Halide - 100 W	$15.77	$15.01
S25	Metal Halide - 175 W	$18.77	$17.87
S26	Metal Halide - 250 W	$22.06	$21.00
S30	Induction - 165 W	$15.45	$14.71

2016

SaskPower

Rate Proposal

RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E01 Existing	City	20.22	N/A	N/A	12.62	N/A	N/A	N/A	20.22		
E01 Proposed		20.22	N/A	N/A	13.34	N/A	N/A	N/A	20.22		
E02 Existing	Town, Village, Urban Resort	20.22	N/A	N/A	12.62	N/A	N/A	N/A	20.22		
E02 Proposed		20.22	N/A	N/A	13.34	N/A	N/A	N/A	20.22		
E03 Existing	Rural, Rural Resort	29.19	N/A	N/A	12.62	N/A	N/A	N/A	29.19		
E03 Proposed		29.19	N/A	N/A	13.34	N/A	N/A	N/A	29.19		

SaskPower

Rate Proposal

DIESEL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E04 Existing	Residential Diesel	29.19	650	12.62	46.61	N/A	N/A	N/A	29.19		
E04 Proposed		29.19	650	13.34	48.85	N/A	N/A	N/A	29.19		
E35 Existing	General Service	36.81	650	12.775	44.00	N/A	N/A	N/A	36.81		
E35 Proposed		36.81	650	13.466	47.00	N/A	N/A	N/A	36.81		
E36 Existing	General Service - Federal & Provincial	36.81	N/A	N/A	89.13	N/A	N/A	N/A	36.81		
E36 Proposed		36.81	N/A	N/A	93.32	N/A	N/A	N/A	36.81		
E38 Existing	General Service - Local Community	36.81	N/A	N/A	81.00	N/A	N/A	N/A	36.81		
E38 Proposed		36.81	N/A	N/A	84.81	N/A	N/A	N/A	36.81		

SaskPower

Rate Proposal

FARM

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
E34 Existing	Farm	31.03	16,000	11.230	4.870	50	0	11.40	31.03	4.32	/KV.A max demand over 50
E34 Proposed		32.32	16,000	11.676	5.060	50	0	11.75	32.32	4.53	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

IRRIGATION

RATE CODE	DESCRIPTION	BASIC ($/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/hp)	MINIMUM BILL BASIC	MINIMUM BILL DEMAND	NOTES
E19 Existing	Farm - SaskPower Supplied Transformation	426.12	N/A	N/A	6.28	N/A	N/A	N/A	426.12		
E19 Proposed		445.15	N/A	N/A	6.75	N/A	N/A	N/A	445.15		
E37 Existing	General Service - SaskPower Supplied Transformation	225.34	N/A	N/A	8.55	N/A	N/A	22.67	225.34	22.67	/KV.A max demand
E37 Proposed		239.76	N/A	N/A	9.10	N/A	N/A	24.12	239.76	24.12	/KV.A max demand
E41 Existing	Mains - Interruptible - closed to new customers	803.46	N/A	N/A	5.38	N/A	N/A	N/A	803.46		
E41 Proposed		863.72	N/A	N/A	5.78	N/A	N/A	N/A	863.72		
E42 Existing	Pivots - Interruptible - closed to new customers	426.12	N/A	N/A	6.28	N/A	N/A	N/A	426.12		
E42 Proposed		445.15	N/A	N/A	6.75	N/A	N/A	N/A	445.15		

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower

Rate Proposal

GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E05 Existing	Urban - SaskPower Supplied Transformation	51.40	16,750	10.635	6.809	50	0	13.84	51.40	4.32	/KV.A max demand over 50
E05 Proposed		53.98	16,750	11.121	7.150	50	0	14.50	53.98	4.53	/KV.A max demand over 50
E06 Existing	Rural - SaskPower Supplied Transformation	57.70	15,500	10.635	6.450	50	0	13.84	57.70	4.32	/KV.A max demand over 50
E06 Proposed		57.70	15,500	11.121	6.810	50	0	14.40	57.70	4.53	/KV.A max demand over 50
E07 Existing	Urban - Customer Owned Transformation	215.02	N/A	N/A	6.435	N/A	N/A	12.38	215.02	4.32	/KV.A max demand
E07 Proposed		247.27	N/A	N/A	6.796	N/A	N/A	12.94	247.27	4.53	/KV.A max demand
E08 Existing	Rural - Customer Owned Transformation	265.40	N/A	N/A	6.435	N/A	N/A	12.38	265.40	4.32	/KV.A max demand
E08 Proposed		265.40	N/A	N/A	6.796	N/A	N/A	12.94	265.40	4.53	/KV.A max demand
E10 Existing	Customer Owned Transformation	632.61	N/A	N/A	5.058	N/A	N/A	7.56	632.61	4.32	/KV.A max demand
E10 Proposed		727.00	N/A	N/A	5.258	N/A	N/A	7.90	727.00	4.53	/KV.A max demand
E12 Existing	Customer Owned Transformation	291.00	N/A	N/A	4.967	N/A	N/A	7.45	291.00	4.32	/KV.A max demand
E12 Proposed		334.00	N/A	N/A	5.178	N/A	N/A	7.85	334.00	4.53	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E75 Existing	Urban - SaskPower Supplied Transformation	27.62	14,500	12.128	6.404	50	0	13.44	27.62	4.32	/KV.A max demand over 50
E75 Proposed		29.56	14,500	12.900	6.811	50	0	14.31	29.56	4.53	/KV.A max demand over 50
E76 Existing	Rural - SaskPower SuppliedTransformation	36.81	13,000	12.775	6.571	50	0	13.73	36.81	4.32	/KV.A max demand over 50
E76 Proposed		36.81	13,000	13.466	6.908	50	0	14.55	36.81	4.53	/KV.A max demand over 50
E77 Existing	Urban - Customer Owned Transformation	27.62	14,500	12.128	6.404	50	0	12.97	27.62	4.32	/KV.A max demand over 50
E77 Proposed		29.56	14,500	12.900	6.811	50	0	13.81	29.56	4.53	/KV.A max demand over 50
E78 Existing	Rural - Customer Owned Transformation	36.81	13,000	12.775	6.571	50	0	13.24	36.81	4.32	/KV.A max demand over 50
E78 Proposed		36.81	13,000	13.466	6.908	50	0	14.03	36.81	4.53	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E15 Existing	Unmetered - Miscellaneous	N/A	N/A	N/A	3.73	/100 Watts			17.42		
E15 Proposed		N/A	N/A	N/A	3.87	/100 Watts			18.53		
E16 Existing	Unmetered - Power Supply Units	64.84	/Power Supply Unit						64.84		
E16 Proposed		68.99	/Power Supply Unit						68.99		
E17 Existing	Unmetered - Cable Television Rectifiers	N/A	N/A	N/A	1.36	/10 Watts			26.97		
E17 Proposed		N/A	N/A	N/A	1.45	/10 Watts			28.70		
E18 Existing	Unmetered - X-rays	N/A	N/A	N/A	N/A	3.72	/kV.A installed capacity				
E18 Proposed		N/A	N/A	N/A	N/A	3.96	/kV.A installed capacity				

SaskPower

Rate Proposal

OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E43 Existing	Standard Oilfield	54.55	N/A	N/A	6.712	N/A	N/A	11.88	54.55	11.88	/KV.A max demand
E43 Proposed		54.55	N/A	N/A	6.935	N/A	N/A	12.30	54.55	12.30	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E46 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	6.124	N/A	N/A	9.676	5491.000	9.676	/KV.A max demand
E46 Proposed		5,491.00	N/A	N/A	6.475	N/A	N/A	10.220	5491.000	10.220	/KV.A max demand
E47 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	5.525	N/A	N/A	7.458	6294.000	7.458	/KV.A max demand
E47 Proposed		6,294.00	N/A	N/A	5.841	N/A	N/A	7.870	6294.000	7.870	/KV.A max demand
E48 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	5.421	N/A	N/A	7.350	6757.000	7.350	/KV.A max demand
E48 Proposed		6,757.00	N/A	N/A	5.749	N/A	N/A	7.821	6757.000	7.821	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E86 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.697	5.697	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E86 Proposed		5,491.00	N/A	7.048	6.048	N/A	N/A	10.220	5,491.00	10.220	/KV.A max demand
E87 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	6.098	5.098	N/A	N/A	7.46	6,294.00	7.46	/KV.A max demand
E87 Proposed		6,294.00	N/A	6.414	5.414	N/A	N/A	7.87	6,294.00	7.87	/KV.A max demand
E88 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.994	4.994	N/A	N/A	7.35	6,757.00	7.35	/KV.A max demand
E88 Proposed		6,757.00	N/A	6.322	5.322	N/A	N/A	7.82	6,757.00	7.82	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E22 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	6.124	N/A	N/A	9.676	5491.000	9.676	/KV.A max demand
E22 Proposed		5,491.00	N/A	N/A	6.475	N/A	N/A	10.220	5491.000	10.220	/KV.A max demand
E23 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	5.525	N/A	N/A	7.458	6294.000	7.458	/KV.A max demand
E23 Proposed		6,294.00	N/A	N/A	5.841	N/A	N/A	7.870	6294.000	7.870	/KV.A max demand
E24 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	5.421	N/A	N/A	7.350	6757.000	7.350	/KV.A max demand
E24 Proposed		6,757.00	N/A	N/A	5.749	N/A	N/A	7.821	6757.000	7.821	/KV.A max demand
E25 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	N/A	5.421	N/A	N/A	7.350	7081.000	7.350	/KV.A max demand
E25 Proposed		7,081.00	N/A	N/A	5.749	N/A	N/A	7.821	7081.000	7.821	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
E82 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.697	5.697	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E82 Proposed		5,491.00	N/A	7.048	6.048	N/A	N/A	10.220	5,491.00	10.220	/KV.A max demand
E83 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	6.098	5.098	N/A	N/A	7.46	6,294.00	7.46	/KV.A max demand
E83 Proposed		6,294.00	N/A	6.414	5.414	N/A	N/A	7.87	6,294.00	7.87	/KV.A max demand
E84 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.994	4.994	N/A	N/A	7.35	6,757.00	7.35	/KV.A max demand
E84 Proposed		6,757.00	N/A	6.322	5.322	N/A	N/A	7.82	6,757.00	7.82	/KV.A max demand
E85 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	5.994	4.994	N/A	N/A	7.35	7,081.00	7.35	/KV.A max demand
E85 Proposed		7,081.00	N/A	6.322	5.322	N/A	N/A	7.82	7,081.00	7.82	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

RESELLER

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
E31 Existing	Swift Current 25 kV (Non-Totalized)	5,444.00	N/A	N/A	4.490	N/A	N/A	16.606	5,444.00	16.606	/KV.A max demand
E31 Proposed		5,444.00	N/A	N/A	4.813	N/A	N/A	17.761	5,444.00	17.761	/KV.A max demand
E32 Existing	Swift Current 138 kV - (Non-Totalized)	6,241.00	N/A	N/A	4.349	N/A	N/A	14.842	6,241.00	14.842	/KV.A max demand
E32 Proposed		6,241.00	N/A	N/A	4.672	N/A	N/A	16.007	6,241.00	16.007	/KV.A max demand
E33 Existing	Saskatoon 138kV - (Totalized)	12,987.00	N/A	N/A	4.051	N/A	N/A	17.192	12,987.00	17.192	/KV.A max demand
E33 Proposed		12,987.00	N/A	N/A	4.361	N/A	N/A	18.391	12,987.00	18.391	/KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly ($/month)	Proposed Monthly ($/month)
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S05	Mercury Vapor - 125 W	$13.73	$13.07
S06	Mercury Vapor - 175 W	$15.16	$14.43
S13	Low Pressure Sodium Vapor - 90 W	$13.01	$12.39
S14	Low Pressure Sodium Vapor - 90 W Continuous	$15.20	$14.47
S15	Low Pressure Sodium Vapor - 135 W	$13.97	$13.30
S16	Low Pressure Sodium Vapor - 180 W	$15.46	$14.72
S17	High Pressure Sodium Vapor - 70 W	$10.92	$10.39
S18	High Pressure Sodium Vapor - 100 W	$12.19	$11.60
S19	High Pressure Sodium Vapor - 150 W	$14.18	$13.50
S20	High Pressure Sodium Vapor - 150 W Continuous	$17.52	$16.68
S21	High Pressure Sodium Vapor - 250 W	$18.44	$17.54
S22	High Pressure Sodium Vapor - 250 W Continuous	$23.56	$22.43
S23	High Pressure Sodium Vapor - 400 W	$23.91	$22.76
S24	Metal Halide - 100 W	$15.01	$14.29
S25	Metal Halide - 175 W	$17.87	$17.01
S26	Metal Halide - 250 W	$21.00	$19.99
S30	Induction - 165 W	$14.71	$14.00

Appendix C

Rate Impacts

2014 Rate Impacts

Class of Service	Minimum Increase for Any One Customer (%)	Average Rate Change (%)	Maximum Increase for Any One Customer (%)
Urban Residential	0.04	5.30	7.18
Rural Residential	0.02	5.30	5.38
Farms (see note)	0.00	3.50	4.22
Urban Commercial	(0.62)	7.00	13.64
Rural Commercial	(0.11)	4.80	6.64
Power - Published Rates	0.12	7.00	10.84
Oilfields	0.05	3.60	8.41

Note: Farm class results do not include farm irrigation customers

2014 - Rate Change Impacts on E01 by Energy Intervals
Urban Residential - City

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	**11.130**	**11.931**	**Increase of 5.3%**
Basic Charge: ($/month)	**20.22**	**20.22**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	1,527	1.18	1,299	0.12	0.57	1.97	0.06	2.56
100 - 200	7,339	5.66	13,848	1.33	1.26	3.31	2.56	3.77
200 - 300	12,129	9.35	36,696	3.52	2.02	4.17	3.77	4.48
300 - 400	14,267	11.00	60,137	5.77	2.81	4.74	4.48	4.95
400 - 500	15,360	11.84	83,020	7.97	3.61	5.12	4.95	5.28
500 - 600	15,588	12.02	102,836	9.87	4.40	5.41	5.28	5.52
600 - 700	14,422	11.12	112,368	10.78	5.20	5.62	5.52	5.71
700 - 800	12,277	9.46	110,217	10.58	5.99	5.79	5.71	5.86
800 - 900	9,897	7.63	100,659	9.66	6.79	5.93	5.87	5.99
900 - 1000	7,542	5.81	85,788	8.23	7.59	6.04	5.99	6.09
1000 - 1100	5,492	4.23	68,972	6.62	8.38	6.13	6.09	6.18
1100 - 1200	3,957	3.05	54,504	5.23	9.19	6.21	6.18	6.25
1200 - 1300	2,750	2.12	41,158	3.95	9.99	6.28	6.25	6.31
1300 - 1400	1,990	1.53	32,154	3.09	10.79	6.34	6.31	6.37
1400 - 1500	1,448	1.12	25,125	2.41	11.58	6.39	6.37	6.42
1500 - 2000	2,760	2.13	55,748	5.35	13.48	6.49	6.42	6.60
2000 - 2500	597	0.46	15,712	1.51	17.57	6.64	6.60	6.71
2500 - 3000	175	0.13	5,639	0.54	21.51	6.74	6.71	6.79
3000 - 3500	66	0.05	2,517	0.24	25.46	6.81	6.79	6.84
3500 - 4000	30	0.02	1,348	0.13	29.99	6.86	6.84	6.88
4000 - 4500	13	0.01	676	0.06	34.73	6.91	6.88	6.92
4500 - 5000	5	0.00	278	0.03	37.10	6.93	6.92	6.93
5000 - 6000	13	0.01	875	0.08	44.91	6.97	6.95	6.98
6000 - 7000	6	0.00	467	0.04	51.92	7.00	6.99	7.01
7000 - 8000	8	0.01	730	0.07	60.90	7.03	7.02	7.03
8000 - 9000	6	0.00	623	0.06	69.26	7.05	7.04	7.05
9000 - 10000	3	0.00	335	0.03	74.53	7.06	7.06	7.06
>10000	55	0.04	28,408	2.73	348.84	7.15	7.06	7.18

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.06
Maximum	7.18

2014 - Rate Change Impacts on E02 by Energy Intervals
Urban Residential - Town, Village & Urban Resort

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	**11.130**	**11.931**	**Increase of 5.3%**
Basic Charge: ($/month)	**20.22**	**20.22**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	1,316	2.02	945	0.16	0.48	1.71	0.04	2.56
100 - 200	3,563	5.46	6,664	1.16	1.25	3.30	2.56	3.77
200 - 300	5,397	8.27	16,305	2.83	2.02	4.17	3.77	4.48
300 - 400	6,273	9.62	26,319	4.57	2.80	4.73	4.48	4.95
400 - 500	6,851	10.50	37,046	6.44	3.61	5.12	4.95	5.28
500 - 600	6,964	10.68	45,925	7.98	4.40	5.41	5.28	5.52
600 - 700	6,673	10.23	51,997	9.04	5.20	5.62	5.52	5.71
700 - 800	5,756	8.82	51,712	8.99	6.00	5.79	5.71	5.86
800 - 900	4,678	7.17	47,617	8.28	6.79	5.93	5.87	5.99
900 - 1000	3,816	5.85	43,416	7.55	7.59	6.04	5.99	6.09
1000 - 1100	3,036	4.65	38,181	6.64	8.39	6.13	6.09	6.18
1100 - 1200	2,283	3.50	31,429	5.46	9.19	6.21	6.18	6.25
1200 - 1300	1,757	2.69	26,326	4.58	10.00	6.28	6.25	6.31
1300 - 1400	1,336	2.05	21,612	3.76	10.80	6.34	6.31	6.37
1400 - 1500	1,064	1.63	18,493	3.21	11.60	6.39	6.37	6.42
1500 - 2000	2,819	4.32	57,674	10.02	13.66	6.50	6.42	6.60
2000 - 2500	988	1.51	26,124	4.54	17.65	6.65	6.60	6.71
2500 - 3000	403	0.62	13,114	2.28	21.72	6.74	6.71	6.79
3000 - 3500	137	0.21	5,264	0.91	25.65	6.81	6.79	6.84
3500 - 4000	50	0.08	2,236	0.39	29.84	6.86	6.84	6.88
4000 - 4500	25	0.04	1,281	0.22	34.21	6.90	6.89	6.92
4500 - 5000	7	0.01	394	0.07	37.56	6.93	6.92	6.94
5000 - 6000	4	0.01	260	0.05	43.37	6.96	6.96	6.97
6000 - 7000	6	0.01	459	0.08	51.10	7.00	6.99	7.01
7000 - 8000	2	0.00	175	0.03	58.51	7.02	7.02	7.02
8000 - 9000	3	0.00	300	0.05	66.78	7.04	7.04	7.05
9000 - 10000	3	0.00	337	0.06	75.00	7.06	7.06	7.06
>10000	19	0.03	3,755	0.65	143.77	7.11	7.06	7.15

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.04
Maximum	7.15

2014 - Rate Change Impacts on E03 by Energy Intervals
Rural Residential - Rural & Rural Resort

Rate Breakdown	Existing	Proposed	Based on Rate Class
Energy Rate: (cents/kW.h)	**11.370**	**11.987**	**Increase of 5.3%**
Basic Charge: ($/month)	**29.19**	**29.19**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	464	1.63	290	0.07	0.32	0.87	0.02	1.52
100 - 200	568	2.00	1,028	0.25	0.93	1.99	1.53	2.38
200 - 300	697	2.45	2,107	0.52	1.55	2.68	2.38	2.92
300 - 400	1,030	3.62	4,353	1.07	2.17	3.13	2.92	3.31
400 - 500	1,382	4.86	7,509	1.85	2.79	3.46	3.31	3.59
500 - 600	1,734	6.10	11,474	2.83	3.40	3.70	3.59	3.80
600 - 700	1,997	7.02	15,586	3.84	4.01	3.89	3.80	3.97
700 - 800	1,981	6.97	17,821	4.39	4.63	4.04	3.97	4.11
800 - 900	2,049	7.20	20,906	5.15	5.25	4.17	4.11	4.22
900 - 1000	2,031	7.14	23,152	5.71	5.86	4.27	4.22	4.32
1000 - 1100	1,875	6.59	23,609	5.82	6.47	4.36	4.32	4.40
1100 - 1200	1,689	5.94	23,289	5.74	7.09	4.44	4.40	4.47
1200 - 1300	1,423	5.00	21,339	5.26	7.71	4.50	4.47	4.53
1300 - 1400	1,210	4.25	19,584	4.83	8.32	4.56	4.53	4.59
1400 - 1500	1,042	3.66	18,120	4.47	8.94	4.61	4.59	4.63
1500 - 2000	3,593	12.63	74,203	18.29	10.62	4.72	4.63	4.81
2000 - 2500	1,794	6.31	47,822	11.79	13.71	4.86	4.81	4.92
2500 - 3000	975	3.43	31,828	7.85	16.78	4.96	4.92	5.00
3000 - 3500	469	1.65	18,107	4.46	19.85	5.02	5.00	5.05
3500 - 4000	184	0.65	8,187	2.02	22.88	5.07	5.06	5.10
4000 - 4500	128	0.45	6,495	1.60	26.09	5.12	5.10	5.13
4500 - 5000	53	0.19	2,996	0.74	29.06	5.15	5.13	5.16
5000 - 6000	37	0.13	2,418	0.60	33.60	5.18	5.16	5.20
6000 - 7000	16	0.06	1,236	0.30	39.72	5.22	5.20	5.23
7000 - 8000	7	0.02	617	0.15	45.35	5.24	5.24	5.25
8000 - 9000	5	0.02	526	0.13	54.05	5.27	5.27	5.28
9000 - 10000	2	0.01	228	0.06	58.59	5.28	5.28	5.29
>10000	4	0.01	838	0.21	137.03	5.33	5.28	5.38

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.02
Maximum	5.38

2014 - Rate Change Impacts on E04 by Energy Intervals
Rural Residential - Residential Diesel

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
First Block Size (kW.h/month)	**650**	**650**	**Increase of 5.3%**
Energy Rate (cents/kW.h): First Block	**11.370**	**11.987**	
Balance	**42.350**	**44.590**	
Basic Charge: ($/month)	**29.19**	**29.19**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	Number of Accounts (%)	Energy Use (MWh/year)	Energy Use (%)	Average Monthly Change ($)	% Increase Average	% Increase Low	% Increase High
0 - 100	-	0.00	-	0.00	0.00	0.00	-	-
100 - 200	1	50.00	2	28.57	1.24	2.38	2.38	2.38
200 - 300	-	0.00	-	0.00	0.00	0.00	-	-
300 - 400	-	0.00	-	0.00	0.00	0.00	-	-
400 - 500	1	50.00	5	71.43	3.07	3.57	3.57	3.57
500 - 600	-	0.00	-	0.00	0.00	0.00	-	-
600 - 700	-	0.00	-	0.00	0.00	0.00	-	-
700 - 800	-	0.00	-	0.00	0.00	0.00	-	-
800 - 900	-	0.00	-	0.00	0.00	0.00	-	-
900 - 1000	-	0.00	-	0.00	0.00	0.00	-	-
>1000	-	0.00	-	0.00	0.00	0.00	-	-

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.38
Maximum	3.57

2014 - Rate Change Impacts on E05 by Energy Intervals
General Service - Large
Urban - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**16,750**	**16,750**	
Energy Rate (cents/kW.h):	First Block	**9.430**	**10.180**	
	Balance	**6.238**	**6.610**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 7.0%**
	Balance	**11.85**	**12.75**	
Basic Charge ($/month):		**40.75**	**46.86**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	24	1.86	882	0.10	48.35	8.39	7.94	9.04
5000 - 10000	40	3.09	3,742	0.41	91.76	8.10	7.85	8.41
10000 - 15000	68	5.26	10,400	1.14	131.14	7.98	7.63	8.19
15000 - 20000	92	7.12	19,778	2.17	158.32	7.81	7.32	8.04
20000 - 25000	167	12.92	45,169	4.96	180.46	7.66	7.20	7.86
25000 - 30000	177	13.69	58,525	6.43	209.49	7.50	7.19	7.60
30000 - 35000	119	9.20	45,932	5.04	233.81	7.36	7.06	7.46
35000 - 40000	80	6.19	35,921	3.95	268.80	7.24	7.05	7.42
40000 - 45000	78	6.03	39,692	4.36	292.94	7.16	7.01	7.33
45000 - 50000	49	3.79	27,612	3.03	326.99	7.10	6.99	7.35
50000 - 55000	45	3.48	28,470	3.13	363.08	7.03	6.95	7.36
55000 - 60000	30	2.32	20,664	2.27	410.19	7.00	6.92	7.38
60000 - 65000	31	2.40	23,005	2.53	416.67	6.97	6.89	7.11
65000 - 70000	13	1.01	10,587	1.16	446.36	6.92	6.85	7.04
70000 - 75000	13	1.01	11,264	1.24	490.52	6.91	6.82	7.05
75000 - 80000	10	0.77	9,286	1.02	492.30	6.85	6.82	6.98
80000 - 85000	17	1.31	16,875	1.85	522.79	6.83	6.77	6.93
85000 - 90000	14	1.08	14,697	1.61	557.10	6.82	6.73	6.97
90000 - 95000	15	1.16	16,640	1.83	570.48	6.78	6.72	6.86
95000 - 100000	16	1.24	18,694	2.05	586.46	6.75	6.67	6.84
100000 - 125000	51	3.94	67,849	7.45	705.15	6.75	6.63	7.00
125000 - 150000	40	3.09	65,942	7.24	884.43	6.72	6.57	7.02
150000 - 175000	23	1.78	44,392	4.88	959.11	6.64	6.55	6.80
175000 - 200000	23	1.78	51,852	5.69	1,098.26	6.60	6.52	6.73
200000 - 250000	21	1.62	56,763	6.23	1,335.42	6.59	6.48	6.73
250000 - 300000	12	0.93	40,175	4.41	1,672.31	6.58	6.51	6.66
300000 - 400000	16	1.24	67,569	7.42	2,018.90	6.52	6.47	6.64
>400000	9	0.70	58,154	6.39	6,582.23	6.47	6.42	6.64

* Average monthly change does not include municipal surcharge or taxes

Minimum	6.42
Maximum	9.04

2014 - Rate Change Impacts on E06 by Energy Intervals
General Service - Large
Rural - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**15,500**	**15,500**	
Energy Rate (cents/kW.h):	First Block	**9.635**	**10.180**	
	Balance	**5.876**	**6.325**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**12.85**	**12.75**	
Basic Charge ($/month):		**57.70**	**57.70**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	15	3.28	572	0.14	14.61	2.36	(0.11)	4.98
5000 - 10000	32	7.00	3,035	0.75	39.26	3.34	1.36	5.33
10000 - 15000	26	5.69	4,052	1.01	64.58	3.79	1.27	5.30
15000 - 20000	35	7.66	7,327	1.82	84.91	3.71	0.90	5.29
20000 - 25000	33	7.22	8,992	2.23	110.77	4.49	2.03	5.84
25000 - 30000	37	8.10	12,253	3.04	131.62	4.51	2.01	5.57
30000 - 35000	38	8.32	14,773	3.67	151.13	4.40	1.92	5.77
35000 - 40000	39	8.53	17,461	4.34	171.15	4.31	1.97	5.59
40000 - 45000	22	4.81	11,267	2.80	189.22	3.89	1.59	6.01
45000 - 50000	18	3.94	10,393	2.58	218.61	4.64	2.44	5.98
50000 - 55000	20	4.38	12,648	3.14	235.26	4.31	2.17	5.73
55000 - 60000	9	1.97	6,225	1.55	245.44	3.43	2.08	4.83
60000 - 65000	11	2.41	8,235	2.05	272.01	4.15	2.15	5.62
65000 - 70000	15	3.28	11,992	2.98	293.83	4.33	2.46	5.32
70000 - 75000	6	1.31	5,200	1.29	307.27	3.69	2.32	5.44
75000 - 80000	9	1.97	8,350	2.07	336.84	4.24	2.71	5.48
80000 - 85000	7	1.53	6,981	1.73	368.37	4.67	3.26	5.76
85000 - 90000	4	0.88	4,166	1.03	371.29	3.89	2.73	5.11
90000 - 95000	1	0.22	1,083	0.27	374.47	3.17	3.17	3.17
95000 - 100000	5	1.09	5,875	1.46	429.35	4.58	3.25	5.15
100000 - 125000	14	3.06	18,970	4.71	485.74	4.24	2.39	5.34
125000 - 150000	14	3.06	22,934	5.70	594.45	4.64	3.68	5.39
150000 - 175000	10	2.19	19,269	4.79	695.77	4.61	3.86	5.40
175000 - 200000	5	1.09	11,363	2.82	819.39	4.73	3.62	5.42
200000 - 250000	8	1.75	21,501	5.34	964.05	4.63	4.14	5.41
250000 - 300000	7	1.53	22,470	5.58	1,156.60	4.92	3.57	5.50
300000 - 400000	6	1.31	25,466	6.33	1,534.27	5.08	4.71	5.34
>400000	11	2.41	99,753	24.78	4,105.42	5.16	4.71	5.48

* Average monthly change does not include municipal surcharge or taxes

Minimum (0.11)
Maximum 6.01

2014 - Rate Change Impacts on E07 by Energy Intervals
General Service - Large
Urban - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.009**	**6.240**	
Demand Rate ($/kVA):	**9.97**	**11.39**	Based on Rate Class **Increase of 7.0%**
Basic Charge ($/month):	**162.60**	**186.98**	Based on 2012 Billing

Energy Intervals (KWh/month)			Number of Accounts		Energy Use		Average Monthly	% Increase		
			Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0	-	50000	11	18.33	4,486	3.29	306.71	8.70	7.24	13.64
50000	-	100000	11	18.33	9,684	7.10	504.32	7.46	6.83	8.11
100000	-	200000	13	21.67	23,906	17.53	977.04	7.18	6.40	8.57
200000	-	300000	12	20.00	38,073	27.91	1,488.86	6.75	6.44	7.06
300000	-	400000	10	16.67	40,208	29.48	1,909.98	6.78	6.31	7.36
>400000			3	5.00	20,046	14.70	9,265.19	6.55	6.07	7.36

* Average monthly change does not include municipal surcharge or taxes

Minimum	6.07
Maximum	13.64

2014 - Rate Change Impacts on E08 by Energy Intervals
General Service - Large
Rural - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.698**	**5.824**	
			Based on Rate Class
Demand Rate ($/kVA):	**10.81**	**11.35**	**Increase of 4.8%**
Basic Charge ($/month):	**265.40**	**265.40**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 50000	2	18.18	1,020	2.96	230.02	3.65	3.46	3.84
50000 - 100000	1	9.09	838	2.43	189.67	3.02	3.02	3.02
100000 - 200000	3	27.27	4,826	14.00	370.17	3.09	2.88	3.33
200000 - 300000	1	9.09	3,278	9.51	1,024.00	3.48	3.48	3.48
300000 - 400000	-	0.00	-	0.00	0.00	0.00	-	-
>400000	4	36.36	24,501	71.09	1,251.76	3.02	2.93	3.48

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.88
Maximum	3.84

2014 - Rate Change Impacts on E10 by Energy Intervals
General Service - Large
Customer Owned Transformation - 72kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.877**	**4.834**	
Demand Rate ($/kVA):	**6.69**	**7.21**	Based on Rate Class **Increase of 4.8%**
Basic Charge ($/month):	**482.54**	**554.92**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 200000	11	68.75	12,596	32.54	396.51	4.13	2.44	5.42
200000 - 400000	3	18.75	11,274	29.13	521.52	2.18	1.72	2.58
400000 - 600000	1	6.25	5,401	13.95	492.91	1.62	1.62	1.62
>600000	1	6.25	9,438	24.38	947.84	0.95	0.95	1.62

* Average monthly change does not include municipal surcharge or taxes

Minimum 0.95
Maximum 5.42

2014 - Rate Change Impacts on E12 by Energy Intervals
General Service - Large
Customer Owned Transformation - 138kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.825**	**4.825**	
			Based on Rate Class
Demand Rate ($/kVA):	**6.71**	**7.05**	**Increase of 4.8%**
Basic Charge ($/month):	**193.02**	**221.97**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly	% Increase		
	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 200000	3	100.00	3,770	100.00	267.01	2.88	2.24	3.37
200000 - 400000	-	0.00	-	0.00	0.00	0.00	-	-
400000 - 600000	-	0.00	-	0.00	0.00	0.00	-	-

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.24
Maximum	3.37

2014 - Rate Change Impacts on E22 by Energy Intervals
Power
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.486**	**5.790**	
Demand Rate ($/kVA):	**7.794**	**9.265**	Based on Rate Class **Increase of 7.0%**
Basic Charge ($/month):	**5,491.00**	**5,491.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	12	46.15	102,877	26.66	4,695.17	8.09	0.12	8.94
1000000 - 2000000	10	38.46	155,655	40.33	7,917.99	8.10	7.65	8.67
>2000000	4	15.38	127,405	33.01	17,315.30	8.65	7.94	9.16

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.12
Maximum	9.16

2014 - Rate Change Impacts on E23 by Energy Intervals
Power
Customer Owned Transformation - 72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.939**	**5.216**	
Demand Rate ($/kVA):	**6.100**	**7.130**	Based on Rate Class **Increase of 7.0%**
Basic Charge ($/month):	**6,294.00**	**6,294.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly Change ($)	% Increase		
	Number	(%)	(MWh/year)	(%)		Average	Low	High
0 - 10000000	18	72.00	406,126	20.71	9,852.81	7.79	2.54	9.76
10000000 - 20000000	6	24.00	1,080,121	55.09	77,394.56	8.07	7.70	8.74
>20000000	1	4.00	474,311	24.19	190,426.44	7.81	7.81	7.81

* Average monthly change does not include municipal surcharge or taxes

Minimum 2.54
Maximum 9.76

2014 - Rate Change Impacts on E24 by Energy Intervals
Power
Customer Owned Transformation - 138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.879**	**5.098**	
Demand Rate ($/kVA):	**6.100**	**6.957**	Based on Rate Class **Increase of 7%**
Basic Charge ($/month):	**6,757.00**	**6,757.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	(%)	Energy Use (MWh/year)	(%)	Average Monthly Change ($)	% Increase Average	Low	High
0 - 10000000	22	81.48	858,718	36.58	13,715.34	6.46	5.91	10.84
10000000 - 20000000	1	3.70	234,877	10.00	70,391.76	6.08	6.08	6.08
>20000000	4	14.81	1,254,107	53.42	100,833.81	6.33	6.02	6.91

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.91
Maximum	10.84

2014 - Rate Change Impacts on E25 by Energy Intervals
Power
Customer Owned Transformation - 230kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.879**	**5.098**	Based on Rate Class
Demand Rate ($/kVA):	**6.100**	**6.957**	**Increase of 7%**
Basic Charge ($/month):	**7,081.00**	**7,081.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 10000000	4	66.67	141,498	12.29	12,666.61	6.49	6.16	7.18
10000000 - 20000000	-	0.00	-	0.00	0.00	0.00	-	-
>20000000	2	33.33	1,010,224	87.71	154,531.05	6.17	6.12	6.19

* Average monthly change does not include municipal surcharge or taxes

Minimum	6.12
Maximum	7.18

2014 - Rate Change Impacts on E34 by Energy Intervals
Farm

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**16,000**	**16,000**	
Energy Rate (cents/kW.h):	First Block	**10.190**	**10.630**	
	Balance	**5.692**	**5.700**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 3.5%**
	Balance	**11.40**	**11.40**	
Basic Charge ($/month):		**30.03**	**30.03**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	5,706	10.17	2,194	0.20	0.14	0.39	0.00	1.09
100 - 200	2,276	4.06	4,024	0.36	0.65	1.43	0.77	1.75
200 - 300	1,801	3.21	5,403	0.48	1.10	1.97	1.12	2.18
300 - 400	1,599	2.85	6,698	0.60	1.54	2.34	1.38	2.49
400 - 500	1,648	2.94	8,906	0.79	1.98	2.60	1.05	2.72
500 - 600	1,793	3.19	11,872	1.06	2.43	2.81	1.31	2.90
600 - 700	2,072	3.69	16,196	1.44	2.87	2.97	1.44	3.04
700 - 800	2,126	3.79	19,145	1.71	3.30	3.10	2.14	3.16
800 - 900	2,138	3.81	21,824	1.95	3.74	3.20	2.25	3.25
900 - 1000	2,310	4.12	26,364	2.35	4.18	3.30	2.43	3.34
1000 - 1100	2,311	4.12	29,093	2.59	4.62	3.37	1.41	3.41
1100 - 1200	2,179	3.88	30,075	2.68	5.06	3.44	2.48	3.47
1200 - 1300	2,160	3.85	32,415	2.89	5.50	3.49	1.67	3.52
1300 - 1400	2,101	3.74	34,014	3.03	5.94	3.54	1.52	3.57
1400 - 1500	1,996	3.56	34,718	3.09	6.38	3.58	1.48	3.61
1500 - 1600	1,774	3.16	32,976	2.94	6.81	3.62	2.63	3.65
1600 - 1700	1,617	2.88	31,999	2.85	7.25	3.66	3.22	3.68
1700 - 1800	1,572	2.80	33,008	2.94	7.70	3.69	3.01	3.71
1800 - 1900	1,424	2.54	31,611	2.82	8.13	3.72	2.34	3.74
1900 - 2000	1,332	2.37	31,163	2.78	8.57	3.75	2.94	3.76
2000 - 2500	5,201	9.27	139,169	12.40	9.78	3.80	1.84	3.86
2500 - 3000	3,288	5.86	107,661	9.60	11.93	3.87	2.40	3.93
3000 - 3500	2,028	3.61	78,623	7.01	14.09	3.93	2.28	3.98
3500 - 4000	1,125	2.00	50,348	4.49	16.08	3.94	2.26	4.02
4000 - 4500	724	1.29	36,664	3.27	18.04	3.95	1.95	4.05
4500 - 5000	495	0.88	28,107	2.51	19.68	3.91	1.58	4.08
5000 - 10000	932	1.66	70,837	6.31	24.52	3.76	1.18	4.19
10000 - 15000	128	0.23	18,669	1.66	47.95	3.80	1.62	4.22
15000 - 20000	58	0.10	11,851	1.06	60.18	3.47	1.57	4.10
20000 - 25000	30	0.05	8,263	0.74	63.09	2.82	1.05	3.47
>25000	182	0.32	128,063	11.41	81.29	1.65	0.56	3.47

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.00
Maximum	4.22

2014 - Rate Change Impacts on E43 by Energy Intervals
Oil Fields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.116**	**6.393**	
			Based on Rate Class
Demand Rate ($/kVA):	**11.880**	**11.882**	**Increase of 3.6%**
Basic Charge ($/month):	**54.55**	**54.55**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000	722	7.09	4,815	0.22	1.55	1.13	0.05	2.04
1000 - 2000	925	9.09	16,866	0.77	4.22	1.89	0.70	2.60
2000 - 3000	900	8.84	26,903	1.23	6.92	2.21	0.67	3.00
3000 - 4000	756	7.43	31,674	1.45	9.69	2.43	0.37	3.00
4000 - 5000	659	6.47	35,476	1.63	12.45	2.58	0.37	3.47
5000 - 6000	568	5.58	37,236	1.71	15.16	2.67	1.05	3.58
6000 - 7000	508	4.99	39,588	1.82	18.03	2.74	0.32	3.49
7000 - 8000	396	3.89	35,578	1.63	20.78	2.82	1.90	3.36
8000 - 9000	365	3.59	37,109	1.70	23.51	2.86	1.39	3.50
9000 - 10000	300	2.95	34,178	1.57	26.34	2.94	1.80	4.05
10000 - 15000	1,228	12.06	180,724	8.29	34.03	2.99	0.72	4.09
15000 - 20000	733	7.20	152,834	7.01	48.21	3.10	1.00	4.20
20000 - 25000	453	4.45	121,575	5.58	62.05	3.15	1.60	4.09
25000 - 30000	309	3.04	101,311	4.65	75.80	3.18	1.10	3.95
30000 - 40000	424	4.17	176,111	8.08	96.02	3.21	1.96	4.27
40000 - 50000	202	1.98	108,271	4.97	123.90	3.25	1.92	4.42
50000 - 75000	332	3.26	242,482	11.13	168.83	3.26	1.71	4.42
75000 - 100000	148	1.45	152,025	6.97	237.43	3.33	2.52	4.30
100000 - 200000	173	1.70	282,486	12.96	377.45	3.30	2.43	4.32
>200000	79	0.78	362,352	16.62	1,886.69	3.36	2.43	4.38

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.05
Maximum	4.42

2014 - Rate Change Impacts on E46 by Energy Intervals
Power - Oilfield
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.486**	**5.790**	
Demand Rate ($/kVA):	**7.794**	**9.265**	Based on Rate Class **Increase of 3.6%**
Basic Charge ($/month):	**5,491.00**	**5,491.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly	% Increase		
	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	10	52.63	66,223	30.13	3,114.70	7.21	6.41	7.91
1000000 - 2000000	8	42.11	123,119	56.02	7,204.63	7.72	7.41	8.41
>2000000	1	5.26	30,442	13.85	13,724.22	7.78	7.78	7.78

* Average monthly change does not include municipal surcharge or taxes

Minimum	6.41
Maximum	8.41

2014 - Rate Change Impacts on E48 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.879**	**5.098**	
Demand Rate ($/kVA):	**6.100**	**6.957**	Based on Rate Class **Increase of 3.6%**
Basic Charge ($/month):	**6,757.00**	**6,757.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	-	0.00	-	0.00	0.00	0.00	-	-
1000000 - 2000000	-	0.00	-	0.00	0.00	0.00	-	-
>2000000	2	100.00	314,111	100.00	46,035.65	5.99	5.82	6.00

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.82
Maximum	6.00

2014 - Rate Change Impacts on E75 by Energy Intervals
General Service - Small Commercial
Urban - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**14,500**	**14,500**	
Energy Rate (cents/kW.h):	First Block	**10.562**	**11.335**	
	Balance	**6.165**	**5.952**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 7.0%**
	Balance	**11.22**	**12.59**	
Basic Charge ($/month):		**25.51**	**27.43**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 2000	19,032	63.78	168,654	17.00	7.64	7.39	7.32	11.09
2000 - 4000	5,071	16.99	171,789	17.31	23.78	7.33	3.95	9.48
4000 - 6000	2,016	6.76	118,268	11.92	39.82	7.32	3.75	9.67
6000 - 8000	1,142	3.83	94,469	9.52	54.93	7.28	1.72	8.64
8000 - 10000	766	2.57	82,247	8.29	70.36	7.21	(0.62)	9.72
10000 - 12000	500	1.68	65,919	6.64	85.15	7.18	1.47	8.88
12000 - 14000	368	1.23	57,445	5.79	97.56	7.01	2.39	9.61
14000 - 16000	246	0.82	44,213	4.46	105.59	6.73	3.83	7.60
16000 - 18000	197	0.66	40,112	4.04	110.29	6.34	4.83	7.47
18000 - 20000	158	0.53	36,050	3.63	108.99	5.77	3.79	6.98
>20000	343	1.15	113,207	11.41	161.60	4.64	0.96	6.98

* Average monthly change does not include municipal surcharge or taxes

Minimum	(0.62)
Maximum	11.09

2014 - Rate Change Impacts on E76 by Energy Intervals
General Service - Small Commercial
Rural - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**13,000**	**13,000**	
Energy Rate (cents/kW.h):	First Block	**11.342**	**12.118**	
	Balance	**6.123**	**6.219**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**12.47**	**12.94**	
Basic Charge ($/month):		**36.81**	**36.81**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 2000	5,401	66.57	45,557	17.76	5.46	3.97	0.02	5.89
2000 - 4000	1,264	15.58	42,973	16.76	22.05	6.09	4.18	6.33
4000 - 6000	548	6.75	32,125	12.53	37.63	6.36	4.15	6.49
6000 - 8000	319	3.93	26,426	10.30	52.71	6.44	3.94	6.57
8000 - 10000	163	2.01	17,549	6.84	65.46	6.31	2.84	6.63
10000 - 12000	119	1.47	15,566	6.07	78.80	6.34	4.24	6.64
12000 - 14000	75	0.92	11,680	4.55	89.69	6.20	4.51	6.59
14000 - 16000	61	0.75	10,887	4.25	97.89	6.08	5.22	6.43
16000 - 18000	37	0.46	7,507	2.93	99.34	5.66	4.33	6.08
18000 - 20000	34	0.42	7,680	2.99	105.23	5.51	4.65	5.81
>20000	92	1.13	38,510	15.02	171.40	4.66	1.86	5.81

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.02
Maximum	6.64

2014 - Rate Change Impacts on E77 by Energy Intervals
General Service - Small Commercial
Urban - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**14,500**	**14,500**	
Energy Rate (cents/kW.h): First Block		**10.562**	**11.335**	
	Balance	**6.165**	**5.952**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 7.0%**
	Balance	**10.83**	**12.15**	
Basic Charge ($/month):		**25.51**	**27.43**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	(%)	Energy Use (MWh/year)	(%)	Average Monthly Change ($)	% Increase Average	Low	High
0 - 5000	12	70.59	208	21.71	16.81	7.57	7.33	9.51
5000 - 10000	2	11.76	186	19.42	61.85	7.33	7.32	7.33
10000 - 15000	2	11.76	323	33.72	100.91	7.08	6.91	7.25
>15000	1	5.88	241	25.16	311.48	5.61	5.61	7.25

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.61
Maximum	9.51

2014 - Rate Change Impacts on E78 by Energy Intervals
General Service - Small Commercial
Rural - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**13,000**	**13,000**	
Energy Rate (cents/kW.h):	First Block	**11.342**	**12.118**	
	Balance	**6.123**	**6.219**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**12.03**	**12.48**	
Basic Charge ($/month):		**36.81**	**36.81**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	5	45.45	173	2.95	22.28	5.64	3.30	6.42
5000 - 10000	3	27.27	215	3.66	45.97	6.46	6.43	6.48
10000 - 15000	1	9.09	153	2.61	86.54	6.23	6.23	6.23
>15000	2	18.18	5,326	90.78	701.86	2.84	2.70	6.23

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.70
Maximum	6.48

2015 Rate Impacts

Class of Service	Minimum Increase for Any One Customer (%)	Average Rate Change (%)	Maximum Increase for Any One Customer (%)
Urban Residential	0.04	4.50	5.79
Rural Residential	0.03	4.50	5.27
Farms (see note)	(8.61)	4.50	5.60
Urban Commercial	0.73	5.60	8.67
Rural Commercial	0.02	4.80	10.06
Power - Published Rates	0.07	5.80	6.19
Oilfields	0.04	3.70	6.19

Note: Farm class results do not include irrigation customers.

2015 - Rate Change Impacts on E01 by Energy Intervals
Urban Residential - City

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	**11.931**	**12.623**	**Increase of 4.5%**
Basic Charge: ($/month)	**20.22**	**20.22**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	1,527	1.18	1,299	0.12	0.49	1.67	0.05	2.15
100 - 200	7,339	5.66	13,848	1.33	1.09	2.77	2.15	3.14
200 - 300	12,129	9.35	36,696	3.52	1.74	3.46	3.14	3.71
300 - 400	14,267	11.00	60,137	5.77	2.43	3.91	3.71	4.07
400 - 500	15,360	11.84	83,020	7.97	3.12	4.21	4.07	4.33
500 - 600	15,588	12.02	102,836	9.87	3.80	4.43	4.33	4.52
600 - 700	14,422	11.12	112,368	10.78	4.49	4.60	4.52	4.67
700 - 800	12,277	9.46	110,217	10.58	5.18	4.73	4.67	4.79
800 - 900	9,897	7.63	100,659	9.66	5.87	4.83	4.79	4.88
900 - 1000	7,542	5.81	85,788	8.23	6.56	4.92	4.88	4.96
1000 - 1100	5,492	4.23	68,972	6.62	7.24	4.99	4.96	5.03
1100 - 1200	3,957	3.05	54,504	5.23	7.94	5.05	5.03	5.08
1200 - 1300	2,750	2.12	41,158	3.95	8.63	5.11	5.08	5.13
1300 - 1400	1,990	1.53	32,154	3.09	9.32	5.15	5.13	5.17
1400 - 1500	1,448	1.12	25,125	2.41	10.01	5.19	5.17	5.21
1500 - 2000	2,760	2.13	55,748	5.35	11.65	5.27	5.21	5.35
2000 - 2500	597	0.46	15,712	1.51	15.18	5.38	5.35	5.43
2500 - 3000	175	0.13	5,639	0.54	18.58	5.45	5.43	5.49
3000 - 3500	66	0.05	2,517	0.24	22.00	5.51	5.49	5.53
3500 - 4000	30	0.02	1,348	0.13	25.91	5.55	5.53	5.56
4000 - 4500	13	0.01	676	0.06	30.00	5.58	5.56	5.59
4500 - 5000	5	0.00	278	0.03	32.06	5.60	5.59	5.60
5000 - 6000	13	0.01	875	0.08	38.80	5.63	5.62	5.64
6000 - 7000	6	0.00	467	0.04	44.85	5.65	5.64	5.66
7000 - 8000	8	0.01	730	0.07	52.62	5.67	5.67	5.68
8000 - 9000	6	0.00	623	0.06	59.83	5.69	5.68	5.69
9000 - 10000	3	0.00	335	0.03	64.39	5.70	5.69	5.70
>10000	55	0.04	28,408	2.73	301.37	5.77	5.69	5.79

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.05
Maximum	5.79

2015 - Rate Change Impacts on E02 by Energy Intervals
Urban Residential - Town, Village & Urban Resort

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	11.931	12.623	**Increase of 4.5%**
Basic Charge: ($/month)	20.22	20.22	Based on 2012 Billing

Energy Intervals (KWh/month)			Number of Accounts Number	(%)	Energy Use (MWh/year)	(%)	Average Monthly Change ($)	% Increase Average	Low	High
0	-	100	1,316	2.02	945	0.16	0.41	1.45	0.04	2.15
100	-	200	3,563	5.46	6,664	1.16	1.08	2.76	2.15	3.14
200	-	300	5,397	8.27	16,305	2.83	1.74	3.46	3.14	3.71
300	-	400	6,273	9.62	26,319	4.57	2.42	3.90	3.71	4.07
400	-	500	6,851	10.50	37,046	6.44	3.12	4.21	4.07	4.33
500	-	600	6,964	10.68	45,925	7.98	3.80	4.43	4.33	4.52
600	-	700	6,673	10.23	51,997	9.04	4.49	4.60	4.52	4.67
700	-	800	5,756	8.82	51,712	8.99	5.18	4.73	4.67	4.79
800	-	900	4,678	7.17	47,617	8.28	5.87	4.83	4.79	4.88
900	-	1000	3,816	5.85	43,416	7.55	6.56	4.92	4.88	4.96
1000	-	1100	3,036	4.65	38,181	6.64	7.25	4.99	4.96	5.03
1100	-	1200	2,283	3.50	31,429	5.46	7.94	5.05	5.03	5.08
1200	-	1300	1,757	2.69	26,326	4.58	8.64	5.11	5.08	5.13
1300	-	1400	1,336	2.05	21,612	3.76	9.33	5.15	5.13	5.17
1400	-	1500	1,064	1.63	18,493	3.21	10.02	5.19	5.17	5.21
1500	-	2000	2,819	4.32	57,674	10.02	11.80	5.27	5.21	5.35
2000	-	2500	988	1.51	26,124	4.54	15.25	5.38	5.35	5.43
2500	-	3000	403	0.62	13,114	2.28	18.77	5.46	5.43	5.49
3000	-	3500	137	0.21	5,264	0.91	22.16	5.51	5.49	5.53
3500	-	4000	50	0.08	2,236	0.39	25.78	5.55	5.53	5.56
4000	-	4500	25	0.04	1,281	0.22	29.56	5.58	5.57	5.59
4500	-	5000	7	0.01	394	0.07	32.45	5.60	5.59	5.61
5000	-	6000	4	0.01	260	0.05	37.47	5.62	5.62	5.63
6000	-	7000	6	0.01	459	0.08	44.15	5.65	5.64	5.66
7000	-	8000	2	0.00	175	0.03	50.55	5.67	5.67	5.67
8000	-	9000	3	0.00	300	0.05	57.69	5.68	5.68	5.69
9000	-	10000	3	0.00	337	0.06	64.79	5.70	5.69	5.70
>10000			19	0.03	3,755	0.65	124.21	5.74	5.69	5.77

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.04
Maximum	5.77

2015 - Rate Change Impacts on E03 by Energy Intervals
Rural Residential - Rural & Rural Resort

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	**11.987**	**12.624**	**Increase of 4.5%**
Basic Charge: ($/month)	**29.19**	**29.19**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	Number of Accounts (%)	Energy Use (MWh/year)	Energy Use (%)	Average Monthly Change ($)	% Increase Average	% Increase Low	% Increase High
0 - 100	464	1.63	290	0.07	0.33	0.89	0.03	1.54
100 - 200	568	2.00	1,028	0.25	0.96	2.01	1.55	2.40
200 - 300	697	2.45	2,107	0.52	1.60	2.69	2.40	2.93
300 - 400	1,030	3.62	4,353	1.07	2.24	3.14	2.93	3.30
400 - 500	1,382	4.86	7,509	1.85	2.88	3.45	3.30	3.57
500 - 600	1,734	6.10	11,474	2.83	3.51	3.68	3.57	3.78
600 - 700	1,997	7.02	15,586	3.84	4.14	3.86	3.78	3.94
700 - 800	1,981	6.97	17,821	4.39	4.78	4.01	3.94	4.07
800 - 900	2,049	7.20	20,906	5.15	5.42	4.13	4.07	4.18
900 - 1000	2,031	7.14	23,152	5.71	6.05	4.23	4.18	4.27
1000 - 1100	1,875	6.59	23,609	5.82	6.68	4.31	4.27	4.35
1100 - 1200	1,689	5.94	23,289	5.74	7.32	4.38	4.35	4.42
1200 - 1300	1,423	5.00	21,339	5.26	7.96	4.45	4.42	4.48
1300 - 1400	1,210	4.25	19,584	4.83	8.59	4.50	4.48	4.53
1400 - 1500	1,042	3.66	18,120	4.47	9.23	4.55	4.53	4.57
1500 - 2000	3,593	12.63	74,203	18.29	10.96	4.65	4.57	4.74
2000 - 2500	1,794	6.31	47,822	11.79	14.15	4.79	4.74	4.84
2500 - 3000	975	3.43	31,828	7.85	17.33	4.88	4.84	4.91
3000 - 3500	469	1.65	18,107	4.46	20.49	4.94	4.92	4.97
3500 - 4000	184	0.65	8,187	2.02	23.62	4.99	4.97	5.01
4000 - 4500	128	0.45	6,495	1.60	26.93	5.02	5.01	5.04
4500 - 5000	53	0.19	2,996	0.74	30.01	5.05	5.04	5.07
5000 - 6000	37	0.13	2,418	0.60	34.69	5.09	5.07	5.10
6000 - 7000	16	0.06	1,236	0.30	41.01	5.12	5.11	5.13
7000 - 8000	7	0.02	617	0.15	46.82	5.14	5.14	5.15
8000 - 9000	5	0.02	526	0.13	55.80	5.17	5.17	5.17
9000 - 10000	2	0.01	228	0.06	60.49	5.18	5.18	5.18
>10000	4	0.01	838	0.21	141.47	5.23	5.18	5.27

* Average monthly change does not include municipal surcharge or taxes

Minimum 0.03
Maximum 5.27

2015 - Rate Change Impacts on E04 by Energy Intervals
Rural Residential - Residential Diesel

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
First Block Size (kW.h/month)	**650**	**650**	**Increase of 4.5%**
Energy Rate (cents/kW.h): First Block	**11.987**	**12.624**	
Balance	**44.590**	**46.610**	
Basic Charge: ($/month)	**29.19**	**29.19**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	-	0.00	-	0.00	0.00	0.00	-	-
100 - 200	1	50.00	2	28.57	1.27	2.39	2.39	2.39
200 - 300	-	0.00	-	0.00	0.00	0.00	-	-
300 - 400	-	0.00	-	0.00	0.00	0.00	-	-
400 - 500	1	50.00	5	71.43	3.10	3.48	3.48	3.48
500 - 600	-	0.00	-	0.00	0.00	0.00	-	-
600 - 700	-	0.00	-	0.00	0.00	0.00	-	-
700 - 800	-	0.00	-	0.00	0.00	0.00	-	-
800 - 900	-	0.00	-	0.00	0.00	0.00	-	-
900 - 1000	-	0.00	-	0.00	0.00	0.00	-	-
>1000	-	0.00	-	0.00	0.00	0.00	-	-

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.39
Maximum	3.48

2015 - Rate Change Impacts on E05 by Energy Intervals
General Service - Large
Urban - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**16,750**	**16,750**	
Energy Rate (cents/kW.h):	First Block	**10.180**	**10.635**	
	Balance	**6.610**	**6.809**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 5.6%**
	Balance	**12.75**	**13.84**	
Basic Charge ($/month):		**46.86**	**51.40**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	Number of Accounts (%)	Energy Use (MWh/year)	Energy Use (%)	Average Monthly Change ($)	% Increase Average	% Increase Low	% Increase High
0 - 5000	15	3.28	572	0.14	43.87	5.68	2.85	7.29
5000 - 10000	32	7.00	3,035	0.75	76.69	5.50	4.19	6.94
10000 - 15000	26	5.69	4,052	1.01	105.49	5.27	4.27	7.02
15000 - 20000	35	7.66	7,327	1.82	143.53	5.35	4.17	7.29
20000 - 25000	33	7.22	8,992	2.23	132.64	4.74	3.69	6.47
25000 - 30000	37	8.10	12,253	3.04	155.05	4.67	3.96	6.45
30000 - 35000	38	8.32	14,773	3.67	190.13	4.71	3.73	6.48
35000 - 40000	39	8.53	17,461	4.34	214.75	4.73	3.75	6.43
40000 - 45000	22	4.81	11,267	2.80	291.36	5.01	3.49	6.71
45000 - 50000	18	3.94	10,393	2.58	243.63	4.44	3.48	6.05
50000 - 55000	20	4.38	12,648	3.14	294.15	4.67	3.65	6.25
55000 - 60000	9	1.97	6,225	1.55	431.18	5.29	4.26	6.31
60000 - 65000	11	2.41	8,235	2.05	379.50	4.76	3.67	6.24
65000 - 70000	15	3.28	11,992	2.98	354.44	4.61	3.88	6.00
70000 - 75000	6	1.31	5,200	1.29	488.82	5.07	3.78	6.10
75000 - 80000	9	1.97	8,350	2.07	421.64	4.65	3.74	5.80
80000 - 85000	7	1.53	6,981	1.73	369.58	4.32	3.52	5.37
85000 - 90000	4	0.88	4,166	1.03	516.46	4.89	3.99	5.77
90000 - 95000	1	0.22	1,083	0.27	660.90	5.43	5.43	5.43
95000 - 100000	5	1.09	5,875	1.46	444.98	4.36	3.93	5.37
100000 - 125000	14	3.06	18,970	4.71	586.12	4.61	3.78	6.01
125000 - 150000	14	3.06	22,934	5.70	585.59	4.29	3.73	5.00
150000 - 175000	10	2.19	19,269	4.79	689.02	4.30	3.71	4.86
175000 - 200000	5	1.09	11,363	2.82	787.08	4.19	3.69	5.04
200000 - 250000	8	1.75	21,501	5.34	946.32	4.26	3.69	4.62
250000 - 300000	7	1.53	22,470	5.58	1,032.37	4.03	3.60	5.06
300000 - 400000	6	1.31	25,466	6.33	1,241.79	3.90	3.71	4.18
>400000	11	2.41	99,753	24.78	3,193.05	3.82	3.59	4.18

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.85
Maximum	7.29

2015 - Rate Change Impacts on E06 by Energy Intervals
General Service - Large
Rural - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**15,500**	**15,500**	
Energy Rate (cents/kW.h):	First Block	**10.180**	**10.635**	
	Balance	**6.325**	**6.450**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**12.75**	**13.84**	
Basic Charge ($/month):		**57.70**	**57.70**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts: Number	Number of Accounts: (%)	Energy Use: (MWh/year)	Energy Use: (%)	Average Monthly Change ($)	% Increase: Average	% Increase: Low	% Increase: High
0 - 5000	15	3.28	572	0.14	43.87	5.68	2.85	7.29
5000 - 10000	32	7.00	3,035	0.75	76.69	5.50	4.19	6.94
10000 - 15000	26	5.69	4,052	1.01	105.49	5.27	4.27	7.02
15000 - 20000	35	7.66	7,327	1.82	143.53	5.35	4.17	7.29
20000 - 25000	33	7.22	8,992	2.23	132.64	4.74	3.69	6.47
25000 - 30000	37	8.10	12,253	3.04	155.05	4.67	3.96	6.45
30000 - 35000	38	8.32	14,773	3.67	190.13	4.71	3.73	6.48
35000 - 40000	39	8.53	17,461	4.34	214.75	4.73	3.75	6.43
40000 - 45000	22	4.81	11,267	2.80	291.36	5.01	3.49	6.71
45000 - 50000	18	3.94	10,393	2.58	243.63	4.44	3.48	6.05
50000 - 55000	20	4.38	12,648	3.14	294.15	4.67	3.65	6.25
55000 - 60000	9	1.97	6,225	1.55	431.18	5.29	4.26	6.31
60000 - 65000	11	2.41	8,235	2.05	379.50	4.76	3.67	6.24
65000 - 70000	15	3.28	11,992	2.98	354.44	4.61	3.88	6.00
70000 - 75000	6	1.31	5,200	1.29	488.82	5.07	3.78	6.10
75000 - 80000	9	1.97	8,350	2.07	421.64	4.65	3.74	5.80
80000 - 85000	7	1.53	6,981	1.73	369.58	4.32	3.52	5.37
85000 - 90000	4	0.88	4,166	1.03	516.46	4.89	3.99	5.77
90000 - 95000	1	0.22	1,083	0.27	660.90	5.43	5.43	5.43
95000 - 100000	5	1.09	5,875	1.46	444.98	4.36	3.93	5.37
100000 - 125000	14	3.06	18,970	4.71	586.12	4.61	3.78	6.01
125000 - 150000	14	3.06	22,934	5.70	585.59	4.29	3.73	5.00
150000 - 175000	10	2.19	19,269	4.79	689.02	4.30	3.71	4.86
175000 - 200000	5	1.09	11,363	2.82	787.08	4.19	3.69	5.04
200000 - 250000	8	1.75	21,501	5.34	946.32	4.26	3.69	4.62
250000 - 300000	7	1.53	22,470	5.58	1,032.37	4.03	3.60	5.06
300000 - 400000	6	1.31	25,466	6.33	1,241.79	3.90	3.71	4.18
>400000	11	2.41	99,753	24.78	3,193.05	3.82	3.59	4.18

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.85
Maximum	7.29

2015 - Rate Change Impacts on E07 by Energy Intervals
General Service - Large
Urban - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.240**	**6.435**	
Demand Rate ($/kVA):	**11.39**	**12.38**	Based on Rate Class **Increase of 5.6%**
Basic Charge ($/month):	**186.98**	**215.02**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 50000	11	18.33	4,486	3.29	236.41	6.19	5.33	8.67
50000 - 100000	11	18.33	9,684	7.10	387.55	5.34	5.00	5.73
100000 - 200000	13	21.67	23,906	17.53	744.24	5.11	4.67	5.86
200000 - 300000	12	20.00	38,073	27.91	1,138.82	4.84	4.66	5.00
300000 - 400000	10	16.67	40,208	29.48	1,456.41	4.84	4.58	5.16
>400000	3	5.00	20,046	14.70	7,075.62	4.70	4.42	5.16

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.42
Maximum	8.67

2015 - Rate Change Impacts on E08 by Energy Intervals
General Service - Large
Rural - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.824**	**6.435**	
Demand Rate ($/kVA):	**11.35**	**12.38**	Based on Rate Class **Increase of 4.8%**
Basic Charge ($/month):	**265.40**	**265.40**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	(%)	Energy Use (MWh/year)	(%)	Average Monthly Change ($)	% Increase Average	Low	High
0 - 50000	2	18.18	1,020	2.96	596.27	9.24	9.20	9.27
50000 - 100000	1	9.09	838	2.43	620.68	9.59	9.59	9.59
100000 - 200000	3	27.27	4,826	14.00	1,202.95	9.78	9.67	9.85
200000 - 300000	1	9.09	3,278	9.51	2,965.85	9.74	9.74	9.74
300000 - 400000	-	0.00	-	0.00	0.00		-	-
>400000	4	36.36	24,501	71.09	4,279.68	9.99	9.74	10.06

* Average monthly change does not include municipal surcharge or taxes

Minimum	9.20
Maximum	10.06

2015 - Rate Change Impacts on E10 by Energy Intervals
General Service - Large
Customer Owned Transformation - 72kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.834**	**5.058**	
Demand Rate ($/kVA):	**7.21**	**7.56**	Based on Rate Class **Increase of 4.8%**
Basic Charge ($/month):	**554.92**	**632.61**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly	% Increase		
	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 200000	11	68.75	12,596	32.54	537.23	5.35	5.03	6.00
200000 - 400000	3	18.75	11,274	29.13	1,172.10	4.93	4.90	4.99
400000 - 600000	1	6.25	5,401	13.95	1,499.27	4.86	4.86	4.86
>600000	1	6.25	9,438	24.38	3,823.93	4.79	4.79	4.86

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.79
Maximum	6.00

2015 - Rate Change Impacts on E12 by Energy Intervals
General Service - Large
Customer Owned Transformation - 138kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	4.825	4.967	
			Based on Rate Class
Demand Rate ($/kVA):	7.05	7.45	**Increase of 4.8%**
Basic Charge ($/month):	221.97	291.00	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 200000	3	100.00	3,770	100.00	497.81	5.06	4.47	5.56
200000 - 400000	-	0.00	-	0.00	0.00	0.00	-	-
400000 - 600000	-	0.00	-	0.00	0.00	0.00	-	-

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.47
Maximum	5.56

2015 - Rate Change Impacts on E22 by Energy Intervals
Power
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.790**	**6.124**	
Demand Rate ($/kVA):	**9.265**	**9.676**	Based on Rate Class **Increase of 5.8%**
Basic Charge ($/month):	**5,491.00**	**5,491.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	12	46.15	86,119	22.31	2,630.40	4.84	0.07	5.00
1000000 - 2000000	10	38.46	167,506	43.40	5,875.82	5.17	5.05	5.23
>2000000	4	15.38	132,313	34.28	11,748.93	5.28	5.27	5.31

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.07
Maximum	5.31

2015 - Rate Change Impacts on E23 by Energy Intervals
Power
Customer Owned Transformation - 72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.216**	**5.525**	
Demand Rate ($/kVA):	**7.130**	**7.458**	Based on Rate Class **Increase of 5.8%**
Basic Charge ($/month):	**6,294.00**	**6,294.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly	% Increase		
	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 10000000	18	72.00	406,126	20.71	7,288.92	5.34	1.51	5.54
10000000 - 20000000	6	24.00	1,080,121	55.09	57,768.28	5.57	5.47	5.62
>20000000	1	4.00	474,311	24.19	147,910.05	5.63	5.63	5.63

* Average monthly change does not include municipal surcharge or taxes

Minimum	1.51
Maximum	5.63

2015 - Rate Change Impacts on E24 by Energy Intervals
Power
Customer Owned Transformation - 138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.098**	**5.421**	Based on Rate Class
Demand Rate ($/kVA):	**6.957**	**7.350**	**Increase of 5.8%**
Basic Charge ($/month):	**6,757.00**	**6,757.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 10000000	22	81.48	858,718	36.58	13,961.22	5.97	5.19	6.13
10000000 - 20000000	1	3.70	234,877	10.00	75,844.09	6.18	6.18	6.18
>20000000	4	14.81	1,254,107	53.42	104,391.83	6.17	6.12	6.19

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.19
Maximum	6.19

2015 - Rate Change Impacts on E25 by Energy Intervals
Power
Customer Owned Transformation - 230kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.098**	**5.421**	
Demand Rate ($/kVA):	**6.957**	**7.350**	Based on Rate Class **Increase of 5.8%**
Basic Charge ($/month):	**7,081.00**	**7,081.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 10000000	4	66.67	141,498	12.29	12,369.73	5.95	5.80	6.07
10000000 - 20000000	-	0.00	-	0.00	0.00	0.00	-	-
>20000000	2	33.33	1,010,224	87.71	164,550.69	6.19	6.18	6.19

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.80
Maximum	6.19

2015 - Rate Change Impacts on E34 by Energy Intervals
Farm

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**16,000**	**16,000**	
Energy Rate (cents/kW.h):	First Block	**10.630**	**11.230**	
	Balance	**5.700**	**4.870**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.5%**
	Balance	**11.40**	**11.40**	
Basic Charge ($/month):		**30.03**	**31.03**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	Number of Accounts (%)	Energy Use (MWh/year)	Energy Use (%)	Average Monthly Change ($)	% Increase Average	% Increase Low	% Increase High
0 - 100	5,706	10.17	2,194	0.20	1.19	3.55	3.33	3.94
100 - 200	2,276	4.06	4,024	0.36	1.88	4.11	2.59	4.29
200 - 300	1,801	3.21	5,403	0.48	2.50	4.41	2.59	4.52
300 - 400	1,599	2.85	6,698	0.60	3.09	4.60	2.68	4.69
400 - 500	1,648	2.94	8,906	0.79	3.70	4.75	1.99	4.81
500 - 600	1,793	3.19	11,872	1.06	4.31	4.85	2.31	4.90
600 - 700	2,072	3.69	16,196	1.44	4.91	4.94	2.45	4.98
700 - 800	2,126	3.79	19,145	1.71	5.50	5.01	3.52	5.04
800 - 900	2,138	3.81	21,824	1.95	6.10	5.06	3.60	5.09
900 - 1000	2,310	4.12	26,364	2.35	6.71	5.11	3.77	5.13
1000 - 1100	2,311	4.12	29,093	2.59	7.29	5.15	2.19	5.17
1100 - 1200	2,179	3.88	30,075	2.68	7.90	5.19	3.77	5.20
1200 - 1300	2,160	3.85	32,415	2.89	8.50	5.21	2.53	5.23
1300 - 1400	2,101	3.74	34,014	3.03	9.09	5.24	2.29	5.26
1400 - 1500	1,996	3.56	34,718	3.09	9.69	5.26	2.22	5.28
1500 - 1600	1,774	3.16	32,976	2.94	10.28	5.28	3.70	5.30
1600 - 1700	1,617	2.88	31,999	2.85	10.89	5.30	3.44	5.31
1700 - 1800	1,572	2.80	33,008	2.94	11.49	5.32	2.98	5.33
1800 - 1900	1,424	2.54	31,611	2.82	12.08	5.32	2.33	5.34
1900 - 2000	1,332	2.37	31,163	2.78	12.67	5.34	1.88	5.36
2000 - 2500	5,201	9.27	139,169	12.40	14.29	5.35	(0.18)	5.41
2500 - 3000	3,288	5.86	107,661	9.60	17.12	5.35	(0.98)	5.45
3000 - 3500	2,028	3.61	78,623	7.01	19.98	5.36	(1.96)	5.47
3500 - 4000	1,125	2.00	50,348	4.49	22.29	5.24	(2.38)	5.49
4000 - 4500	724	1.29	36,664	3.27	24.56	5.16	(3.94)	5.51
4500 - 5000	495	0.88	28,107	2.51	25.63	4.85	(5.36)	5.52
5000 - 10000	932	1.66	70,837	6.31	27.91	4.06	(8.38)	5.58
10000 - 15000	128	0.23	18,669	1.66	55.61	4.12	(6.51)	5.60
15000 - 20000	58	0.10	11,851	1.06	54.38	2.94	(4.37)	5.13
20000 - 25000	30	0.05	8,263	0.74	13.24	0.54	(6.59)	2.84
>25000	182	0.32	128,063	11.41	(264.35)	(3.87)	(8.61)	2.84

* Average monthly change does not include municipal surcharge or taxes

Minimum	(8.61)
Maximum	5.60

2015 - Rate Change Impacts on E43 by Energy Intervals
Oil Fields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.393**	**6.712**	
Demand Rate ($/kVA):	**11.882**	**11.882**	Based on Rate Class **Increase of 3.7%**
Basic Charge ($/month):	**54.55**	**54.55**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000	722	7.09	4,815	0.22	1.77	1.28	0.04	2.30
1000 - 2000	925	9.09	16,866	0.77	4.85	2.13	0.78	2.91
2000 - 3000	900	8.84	26,903	1.23	7.95	2.48	0.75	3.36
3000 - 4000	756	7.43	31,674	1.45	11.14	2.72	0.41	3.35
4000 - 5000	659	6.47	35,476	1.63	14.31	2.89	0.41	3.86
5000 - 6000	568	5.58	37,236	1.71	17.43	2.99	1.18	3.98
6000 - 7000	508	4.99	39,588	1.82	20.72	3.06	0.34	3.88
7000 - 8000	396	3.89	35,578	1.63	23.88	3.15	2.14	3.74
8000 - 9000	365	3.59	37,109	1.70	27.03	3.20	1.57	3.90
9000 - 10000	300	2.95	34,178	1.57	30.29	3.28	2.03	4.48
10000 - 15000	1,228	12.06	180,724	8.29	39.12	3.34	0.81	4.53
15000 - 20000	733	7.20	152,834	7.01	55.43	3.46	1.13	4.64
20000 - 25000	453	4.45	121,575	5.58	71.34	3.51	1.81	4.53
25000 - 30000	309	3.04	101,311	4.65	87.16	3.55	1.24	4.37
30000 - 40000	424	4.17	176,111	8.08	110.42	3.58	2.20	4.72
40000 - 50000	202	1.98	108,271	4.97	142.49	3.62	2.16	4.87
50000 - 75000	332	3.26	242,482	11.13	194.16	3.63	1.92	4.87
75000 - 100000	148	1.45	152,025	6.97	273.06	3.71	2.82	4.75
100000 - 200000	173	1.70	282,486	12.96	434.07	3.67	2.73	4.77
>200000	79	0.78	362,352	16.62	2,169.86	3.74	2.73	4.83

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.04
Maximum	4.87

2015 - Rate Change Impacts on E46 by Energy Intervals
Power - Oilfield
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.790**	**6.124**	
Demand Rate ($/kVA):	**9.265**	**9.676**	Based on Rate Class **Increase of 3.7%**
Basic Charge ($/month):	**5,491.00**	**5,491.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	10	52.63	66,223	30.13	2,244.73	4.85	4.21	5.13
1000000 - 2000000	8	42.11	123,119	56.02	5,207.18	5.18	5.12	5.25
>2000000	1	5.26	30,442	13.85	10,152.77	5.34	5.34	5.34

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.21
Maximum	5.34

2015 - Rate Change Impacts on E48 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.098**	**5.421**	
Demand Rate ($/kVA):	**6.957**	**7.350**	Based on Rate Class **Increase of 3.7%**
Basic Charge ($/month):	**6,757.00**	**6,757.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	-	0.00	-	0.00	0.00	0.00	-	-
1000000 - 2000000	-	0.00	-	0.00	0.00	0.00	-	-
>2000000	2	100.00	314,111	100.00	50,240.92	6.16	5.92	6.19

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.92
Maximum	6.19

2015 - Rate Change Impacts on E75 by Energy Intervals
General Service - Small Commercial
Urban - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**14,500**	**14,500**	
Energy Rate (cents/kW.h):	First Block	**11.335**	**12.128**	
	Balance	**5.952**	**6.404**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 5.6%**
	Balance	**12.59**	**13.44**	
Basic Charge ($/month):		**27.43**	**27.62**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 2000	19,032	63.78	168,654	17.00	6.06	4.79	0.73	6.47
2000 - 4000	5,071	16.99	171,789	17.31	22.62	6.48	6.32	6.68
4000 - 6000	2,016	6.76	118,268	11.92	39.08	6.70	6.64	6.84
6000 - 8000	1,142	3.83	94,469	9.52	54.87	6.78	6.75	7.02
8000 - 10000	766	2.57	82,247	8.29	71.17	6.83	6.79	7.13
10000 - 12000	500	1.68	65,919	6.64	87.13	6.87	6.83	7.10
12000 - 14000	368	1.23	57,445	5.79	102.40	6.89	6.82	7.09
14000 - 16000	246	0.82	44,213	4.46	115.72	6.92	6.89	7.05
16000 - 18000	197	0.66	40,112	4.04	128.47	6.95	6.91	7.02
18000 - 20000	158	0.53	36,050	3.63	139.33	6.99	6.94	7.09
>20000	343	1.15	113,207	11.41	253.95	7.06	6.94	7.31

* Average monthly change does not include municipal surcharge or taxes

Minimum 0.73
Maximum 7.31

2015 - Rate Change Impacts on E76 by Energy Intervals
General Service - Small Commercial
Rural - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**13,000**	**13,000**	
Energy Rate (cents/kW.h):	First Block	**12.118**	**12.775**	
	Balance	**6.219**	**6.571**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**12.94**	**13.73**	
Basic Charge ($/month):		**36.81**	**36.81**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 2000	5,401	66.57	45,557	17.76	4.63	3.22	0.02	5.22
2000 - 4000	1,264	15.58	42,973	16.76	18.81	4.89	4.71	5.89
4000 - 6000	548	6.75	32,125	12.53	32.15	5.11	5.02	5.38
6000 - 8000	319	3.93	26,426	10.30	45.25	5.20	5.16	5.53
8000 - 10000	163	2.01	17,549	6.84	57.66	5.26	5.22	5.42
10000 - 12000	119	1.47	15,566	6.07	69.82	5.29	5.26	5.43
12000 - 14000	75	0.92	11,680	4.55	81.62	5.32	5.29	5.39
14000 - 16000	61	0.75	10,887	4.25	91.21	5.34	5.31	5.46
16000 - 18000	37	0.46	7,507	2.93	99.72	5.38	5.34	5.53
18000 - 20000	34	0.42	7,680	2.99	108.74	5.39	5.36	5.55
>20000	92	1.13	38,510	15.02	223.28	5.49	5.36	5.79

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.02
Maximum	5.89

2015 - Rate Change Impacts on E77 by Energy Intervals
General Service - Small Commercial
Urban - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**14,500**	**14,500**	
Energy Rate (cents/kW.h):	First Block	**11.335**	**12.128**	
	Balance	**5.952**	**6.404**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 5.6%**
	Balance	**12.15**	**12.97**	
Basic Charge ($/month):		**27.43**	**27.62**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	12	70.59	208	21.71	13.97	5.02	1.04	6.69
5000 - 10000	2	11.76	186	19.42	61.67	6.80	6.75	6.84
10000 - 15000	2	11.76	323	33.72	105.45	6.90	6.88	6.91
>15000	1	5.88	241	25.16	355.54	7.01	6.88	7.01

* Average monthly change does not include municipal surcharge or taxes

Minimum	1.04
Maximum	7.01

2015 - Rate Change Impacts on E78 by Energy Intervals
General Service - Small Commercial
Rural - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**13,000**	**13,000**	
Energy Rate (cents/kW.h):	First Block	**12.118**	**12.775**	
	Balance	**6.219**	**6.571**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**12.48**	**13.24**	
Basic Charge ($/month):		**36.81**	**36.81**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	5	45.45	173	2.95	18.89	4.52	2.71	5.11
5000 - 10000	3	27.27	215	3.66	39.09	5.15	5.11	5.21
10000 - 15000	1	9.09	153	2.61	78.29	5.31	5.31	5.31
>15000	2	18.18	5,326	90.78	1,471.68	5.77	5.31	5.83

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.71
Maximum	5.83

2016 Rate impacts

Class of Service	Minimum Increase for Any One Customer (%)	Average Rate Change (%)	Maximum Increase for Any One Customer (%)
Urban Residential	0.04	4.50	5.66
Rural Residential	0.03	4.80	5.65
Farms (see note)	3.43	4.00	4.16
Urban Commercial	4.15	5.60	7.02
Rural Commercial	0.02	4.80	5.79
Power - Published Rates	0.08	5.80	6.12
Oilfields	0.82	3.70	6.09

Note: Farm class results do not include irrigation customers.

2016 - Rate Change Impacts on E01 by Energy Intervals
Urban Residential - City

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	**12.623**	**13.339**	**Increase of 4.5%**
Basic Charge: ($/month)	**20.22**	**20.22**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	1,527	1.18	1,299	0.12	0.51	1.69	0.05	2.18
100 - 200	7,339	5.66	13,848	1.33	1.13	2.79	2.18	3.15
200 - 300	12,129	9.35	36,696	3.52	1.81	3.46	3.15	3.70
300 - 400	14,267	11.00	60,137	5.77	2.52	3.89	3.70	4.05
400 - 500	15,360	11.84	83,020	7.97	3.22	4.18	4.05	4.30
500 - 600	15,588	12.02	102,836	9.87	3.94	4.39	4.30	4.48
600 - 700	14,422	11.12	112,368	10.78	4.65	4.55	4.48	4.62
700 - 800	12,277	9.46	110,217	10.58	5.36	4.67	4.62	4.73
800 - 900	9,897	7.63	100,659	9.66	6.07	4.77	4.73	4.82
900 - 1000	7,542	5.81	85,788	8.23	6.79	4.85	4.82	4.89
1000 - 1100	5,492	4.23	68,972	6.62	7.49	4.92	4.89	4.95
1100 - 1200	3,957	3.05	54,504	5.23	8.22	4.98	4.95	5.00
1200 - 1300	2,750	2.12	41,158	3.95	8.93	5.03	5.00	5.05
1300 - 1400	1,990	1.53	32,154	3.09	9.64	5.07	5.05	5.09
1400 - 1500	1,448	1.12	25,125	2.41	10.35	5.11	5.09	5.12
1500 - 2000	2,760	2.13	55,748	5.35	12.05	5.18	5.12	5.25
2000 - 2500	597	0.46	15,712	1.51	15.70	5.28	5.25	5.33
2500 - 3000	175	0.13	5,639	0.54	19.23	5.35	5.33	5.38
3000 - 3500	66	0.05	2,517	0.24	22.76	5.40	5.38	5.42
3500 - 4000	30	0.02	1,348	0.13	26.80	5.44	5.43	5.45
4000 - 4500	13	0.01	676	0.06	31.04	5.47	5.45	5.48
4500 - 5000	5	0.00	278	0.03	33.17	5.48	5.48	5.49
5000 - 6000	13	0.01	875	0.08	40.15	5.51	5.50	5.52
6000 - 7000	6	0.00	467	0.04	46.41	5.54	5.53	5.54
7000 - 8000	8	0.01	730	0.07	54.44	5.56	5.55	5.56
8000 - 9000	6	0.00	623	0.06	61.91	5.57	5.57	5.57
9000 - 10000	3	0.00	335	0.03	66.62	5.58	5.57	5.58
>10000	55	0.04	28,408	2.73	311.82	5.64	5.57	5.66

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.05
Maximum	5.66

2016 - Rate Change Impacts on E02 by Energy Intervals
Urban Residential - Town, Village & Urban Resort

Rate Breakdown	Existing	Proposed	Based on Rate Class
Energy Rate: (cents/kW.h)	**12.623**	**13.339**	**Increase of 4.5%**
Basic Charge: ($/month)	**20.22**	**20.22**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	1,316	2.02	945	0.16	0.43	1.47	0.04	2.18
100 - 200	3,563	5.46	6,664	1.16	1.12	2.77	2.18	3.15
200 - 300	5,397	8.27	16,305	2.83	1.80	3.46	3.15	3.70
300 - 400	6,273	9.62	26,319	4.57	2.50	3.88	3.70	4.05
400 - 500	6,851	10.50	37,046	6.44	3.23	4.18	4.05	4.30
500 - 600	6,964	10.68	45,925	7.98	3.93	4.39	4.30	4.48
600 - 700	6,673	10.23	51,997	9.04	4.65	4.55	4.48	4.62
700 - 800	5,756	8.82	51,712	8.99	5.36	4.67	4.62	4.73
800 - 900	4,678	7.17	47,617	8.28	6.07	4.77	4.73	4.82
900 - 1000	3,816	5.85	43,416	7.55	6.79	4.85	4.82	4.89
1000 - 1100	3,036	4.65	38,181	6.64	7.50	4.92	4.89	4.95
1100 - 1200	2,283	3.50	31,429	5.46	8.21	4.98	4.95	5.00
1200 - 1300	1,757	2.69	26,326	4.58	8.94	5.03	5.00	5.05
1300 - 1400	1,336	2.05	21,612	3.76	9.65	5.07	5.05	5.09
1400 - 1500	1,064	1.63	18,493	3.21	10.37	5.11	5.09	5.12
1500 - 2000	2,819	4.32	57,674	10.02	12.21	5.18	5.12	5.25
2000 - 2500	988	1.51	26,124	4.54	15.78	5.29	5.25	5.33
2500 - 3000	403	0.62	13,114	2.28	19.42	5.36	5.33	5.38
3000 - 3500	137	0.21	5,264	0.91	22.93	5.40	5.38	5.42
3500 - 4000	50	0.08	2,236	0.39	26.68	5.44	5.42	5.45
4000 - 4500	25	0.04	1,281	0.22	30.58	5.47	5.46	5.48
4500 - 5000	7	0.01	394	0.07	33.57	5.48	5.48	5.50
5000 - 6000	4	0.01	260	0.05	38.77	5.51	5.50	5.51
6000 - 7000	6	0.01	459	0.08	45.68	5.53	5.52	5.54
7000 - 8000	2	0.00	175	0.03	52.30	5.55	5.55	5.55
8000 - 9000	3	0.00	300	0.05	59.69	5.57	5.56	5.57
9000 - 10000	3	0.00	337	0.06	67.04	5.58	5.57	5.58
>10000	19	0.03	3,755	0.65	128.51	5.61	5.57	5.64

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.04
Maximum	5.64

2016 - Rate Change Impacts on E03 by Energy Intervals
Rural Residential - Rural & Rural Resort

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
Energy Rate: (cents/kW.h)	12.624	13.343	**Increase of 4.5%**
Basic Charge: ($/month)	29.19	29.19	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	Number of Accounts (%)	Energy Use (MWh/year)	Energy Use (%)	Average Monthly Change ($)	% Increase Average	% Increase Low	% Increase High
0 - 100	464	1.63	290	0.07	0.37	1.00	0.03	1.72
100 - 200	568	2.00	1,028	0.25	1.08	2.23	1.72	2.64
200 - 300	697	2.45	2,107	0.52	1.81	2.96	2.65	3.22
300 - 400	1,030	3.62	4,353	1.07	2.53	3.43	3.22	3.61
400 - 500	1,382	4.86	7,509	1.85	3.26	3.77	3.61	3.89
500 - 600	1,734	6.10	11,474	2.83	3.96	4.01	3.89	4.11
600 - 700	1,997	7.02	15,586	3.84	4.68	4.20	4.11	4.28
700 - 800	1,981	6.97	17,821	4.39	5.39	4.35	4.28	4.42
800 - 900	2,049	7.20	20,906	5.15	6.11	4.48	4.42	4.53
900 - 1000	2,031	7.14	23,152	5.71	6.83	4.58	4.53	4.63
1000 - 1100	1,875	6.59	23,609	5.82	7.54	4.67	4.63	4.71
1100 - 1200	1,689	5.94	23,289	5.74	8.26	4.74	4.71	4.78
1200 - 1300	1,423	5.00	21,339	5.26	8.99	4.81	4.78	4.84
1300 - 1400	1,210	4.25	19,584	4.83	9.70	4.86	4.84	4.89
1400 - 1500	1,042	3.66	18,120	4.47	10.42	4.91	4.89	4.93
1500 - 2000	3,593	12.63	74,203	18.29	12.37	5.02	4.93	5.11
2000 - 2500	1,794	6.31	47,822	11.79	15.97	5.16	5.11	5.21
2500 - 3000	975	3.43	31,828	7.85	19.56	5.25	5.21	5.29
3000 - 3500	469	1.65	18,107	4.46	23.13	5.31	5.29	5.34
3500 - 4000	184	0.65	8,187	2.02	26.66	5.36	5.34	5.38
4000 - 4500	128	0.45	6,495	1.60	30.40	5.40	5.38	5.42
4500 - 5000	53	0.19	2,996	0.74	33.87	5.43	5.42	5.44
5000 - 6000	37	0.13	2,418	0.60	39.15	5.46	5.44	5.48
6000 - 7000	16	0.06	1,236	0.30	46.29	5.50	5.48	5.51
7000 - 8000	7	0.02	617	0.15	52.85	5.52	5.51	5.53
8000 - 9000	5	0.02	526	0.13	62.98	5.55	5.54	5.55
9000 - 10000	2	0.01	228	0.06	68.27	5.56	5.56	5.56
>10000	4	0.01	838	0.21	159.68	5.61	5.56	5.65

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.03
Maximum	5.65

2016 - Rate Change Impacts on E04 by Energy Intervals
Rural Residential - Residential Diesel

Rate Breakdown	Existing	Proposed	
			Based on Rate Class
First Block Size (kW.h/month)	**650**	**650**	**Increase of 4.5%**
Energy Rate (cents/kW.h): First Block	**12.624**	**13.343**	
Balance	**46.61**	**48.85**	
Basic Charge: ($/month)	**29.19**	**29.19**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	-	0.00	-	0.00	0.00	0.00	-	-
100 - 200	1	50.00	2	28.57	1.44	2.64	2.64	2.64
200 - 300	-	0.00	-	0.00	0.00	0.00	-	-
300 - 400	-	0.00	-	0.00	0.00	0.00	-	-
400 - 500	1	50.00	5	71.43	3.49	3.78	3.78	3.78
500 - 600	-	0.00	-	0.00	0.00	0.00	-	-
600 - 700	-	0.00	-	0.00	0.00	0.00	-	-
700 - 800	-	0.00	-	0.00	0.00	0.00	-	-
800 - 900	-	0.00	-	0.00	0.00	0.00	-	-
900 - 1000	-	0.00	-	0.00	0.00	0.00	-	-
>1000	-	0.00	-	0.00	0.00	0.00	-	-

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.64
Maximum	3.78

2016 - Rate Change Impacts on E05 by Energy Intervals
General Service - Large
Urban - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**16,750**	**16,750**	
Energy Rate (cents/kW.h):	First Block	**10.635**	**11.121**	
	Balance	**6.809**	**7.150**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 5.6%**
	Balance	**13.84**	**14.50**	
Basic Charge ($/month):		**51.40**	**53.98**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	24	1.86	882	0.10	29.49	4.42	4.15	4.64
5000 - 10000	40	3.09	3,742	0.41	57.51	4.44	4.25	4.63
10000 - 15000	68	5.26	10,400	1.14	83.68	4.47	4.24	4.62
15000 - 20000	92	7.12	19,778	2.17	103.94	4.53	4.30	4.66
20000 - 25000	167	12.92	45,169	4.96	121.46	4.57	4.33	4.69
25000 - 30000	177	13.69	58,525	6.43	144.51	4.59	4.34	4.69
30000 - 35000	119	9.20	45,932	5.04	164.73	4.61	4.37	4.71
35000 - 40000	80	6.19	35,921	3.95	192.23	4.61	4.36	4.70
40000 - 45000	78	6.03	39,692	4.36	212.59	4.63	4.40	4.71
45000 - 50000	49	3.79	27,612	3.03	238.66	4.63	4.33	4.73
50000 - 55000	45	3.48	28,470	3.13	267.40	4.64	4.29	4.72
55000 - 60000	30	2.32	20,664	2.27	301.80	4.64	4.25	4.73
60000 - 65000	31	2.40	23,005	2.53	310.67	4.64	4.51	4.72
65000 - 70000	13	1.01	10,587	1.16	335.74	4.65	4.53	4.73
70000 - 75000	13	1.01	11,264	1.24	367.97	4.63	4.50	4.71
75000 - 80000	10	0.77	9,286	1.02	374.75	4.67	4.56	4.70
80000 - 85000	17	1.31	16,875	1.85	399.56	4.67	4.58	4.71
85000 - 90000	14	1.08	14,697	1.61	426.13	4.66	4.54	4.73
90000 - 95000	15	1.16	16,640	1.83	439.89	4.68	4.62	4.73
95000 - 100000	16	1.24	18,694	2.05	455.23	4.69	4.62	4.75
100000 - 125000	51	3.94	67,849	7.45	543.87	4.67	4.48	4.75
125000 - 150000	40	3.09	65,942	7.24	684.46	4.66	4.44	4.75
150000 - 175000	23	1.78	44,392	4.88	756.62	4.69	4.58	4.75
175000 - 200000	23	1.78	51,852	5.69	872.81	4.71	4.61	4.77
200000 - 250000	21	1.62	56,763	6.23	1,061.33	4.70	4.61	4.76
250000 - 300000	12	0.93	40,175	4.41	1,329.81	4.69	4.63	4.73
300000 - 400000	16	1.24	67,569	7.42	1,625.35	4.71	4.64	4.75
>400000	9	0.70	58,154	6.39	5,325.33	4.73	4.64	4.76

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.15
Maximum	4.77

2016 - Rate Change Impacts on E06 by Energy Intervals
General Service - Large
Rural - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**15,500**	**15,500**	
Energy Rate (cents/kW.h):	First Block	**10.635**	**11.121**	
	Balance	**6.450**	**6.810**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**13.84**	**14.40**	
Basic Charge ($/month):		**57.70**	**57.70**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	15	3.28	572	0.14	30.55	3.90	2.96	4.07
5000 - 10000	32	7.00	3,035	0.75	59.37	4.20	4.09	4.33
10000 - 15000	26	5.69	4,052	1.01	87.63	4.34	4.21	4.48
15000 - 20000	35	7.66	7,327	1.82	119.22	4.39	4.19	4.59
20000 - 25000	33	7.22	8,992	2.23	128.97	4.56	4.32	4.83
25000 - 30000	37	8.10	12,253	3.04	154.81	4.62	4.35	4.74
30000 - 35000	38	8.32	14,773	3.67	186.81	4.65	4.38	4.83
35000 - 40000	39	8.53	17,461	4.34	214.12	4.69	4.40	4.90
40000 - 45000	22	4.81	11,267	2.80	269.22	4.66	4.35	4.94
45000 - 50000	18	3.94	10,393	2.58	260.79	4.79	4.49	4.97
50000 - 55000	20	4.38	12,648	3.14	300.25	4.76	4.46	4.96
55000 - 60000	9	1.97	6,225	1.55	385.27	4.66	4.46	4.86
60000 - 65000	11	2.41	8,235	2.05	372.74	4.77	4.48	4.99
65000 - 70000	15	3.28	11,992	2.98	372.41	4.81	4.53	4.96
70000 - 75000	6	1.31	5,200	1.29	457.99	4.72	4.52	4.99
75000 - 80000	9	1.97	8,350	2.07	438.57	4.82	4.58	5.01
80000 - 85000	7	1.53	6,981	1.73	428.95	4.89	4.67	5.06
85000 - 90000	4	0.88	4,166	1.03	515.51	4.78	4.60	4.97
90000 - 95000	1	0.22	1,083	0.27	599.71	4.67	4.67	4.67
95000 - 100000	5	1.09	5,875	1.46	511.60	4.90	4.69	5.00
100000 - 125000	14	3.06	18,970	4.71	628.36	4.86	4.57	5.05
125000 - 150000	14	3.06	22,934	5.70	697.88	4.95	4.79	5.07
150000 - 175000	10	2.19	19,269	4.79	822.20	4.95	4.83	5.08
175000 - 200000	5	1.09	11,363	2.82	957.76	4.99	4.80	5.10
200000 - 250000	8	1.75	21,501	5.34	1,141.88	4.98	4.90	5.11
250000 - 300000	7	1.53	22,470	5.58	1,314.85	5.04	4.81	5.14
300000 - 400000	6	1.31	25,466	6.33	1,677.37	5.08	5.02	5.13
>400000	11	2.41	99,753	24.78	4,435.88	5.11	5.02	5.17

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.96
Maximum	5.17

2016 - Rate Change Impacts on E07 by Energy Intervals
General Service - Large
Urban - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.435**	**6.796**	
Demand Rate ($/kVA):	**12.38**	**12.94**	Based on Rate Class **Increase of 5.6%**
Basic Charge ($/month):	**215.02**	**247.27**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 50000	3	5.00	20,046	14.70	8,269.36	5.34	5.27	5.40
50000 - 100000	11	18.33	4,486	3.29	235.31	5.73	5.10	6.93
100000 - 200000	13	21.67	23,906	17.53	821.56	5.38	5.22	5.47
200000 - 300000	12	20.00	38,073	27.91	1,323.41	5.36	5.32	5.39
300000 - 400000	10	16.67	40,208	29.48	1,680.22	5.34	5.27	5.40
>400000	11	18.33	9,684	7.10	419.54	5.50	5.40	5.60

* Average monthly change does not include municipal surcharge or taxes

Minimum 5.10
Maximum 6.93

2016 - Rate Change Impacts on E08 by Energy Intervals
General Service - Large
Rural - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.435**	**6.796**	
Demand Rate ($/kVA):	**12.38**	**12.94**	Based on Rate Class **Increase of 4.8%**
Basic Charge ($/month):	**265.40**	**265.40**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly	% Increase		
	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 50000	4	36.36	24,501	71.09	2,473.85	5.25	5.06	5.30
50000 - 100000	2	18.18	1,020	2.96	336.43	4.78	4.77	4.78
100000 - 200000	3	27.27	4,826	14.00	692.64	5.13	5.04	5.18
200000 - 300000	1	9.09	3,278	9.51	1,691.20	5.06	5.06	5.06
300000 - 400000	-	0.00	-	0.00	0.00	0.00	-	-
>400000	1	9.09	838	2.43	357.58	5.04	5.04	5.04

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.88
Maximum	5.30

2016 - Rate Change Impacts on E10 by Energy Intervals
General Service - Large
Customer Owned Transformation - 72kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.058**	**5.258**	
Demand Rate ($/kVA):	**7.56**	**7.90**	Based on Rate Class **Increase of 4.8%**
Basic Charge ($/month):	**632.61**	**727.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts Number	(%)	Energy Use (MWh/year)	(%)	Average Monthly Change ($)	% Increase Average	Low	High
0 - 200000	11	68.75	12,596	32.54	524.00	4.99	4.58	5.73
200000 - 400000	3	18.75	11,274	29.13	1,102.42	4.42	4.38	4.48
400000 - 600000	1	6.25	5,401	13.95	1,396.13	4.32	4.32	4.32
>600000	1	6.25	9,438	24.38	3,534.86	4.20	4.20	4.32

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.20
Maximum	5.73

General Service - Large
Customer Owned Transformation - 138kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**4.967**	**5.178**	
			Based on Rate Class
Demand Rate ($/kVA):	**7.45**	**7.85**	**Increase of 4.8%**
Basic Charge ($/month):	**291.00**	**334.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 200000	3	100.00	3,770	100.00	544.04	5.16	4.90	5.38
200000 - 400000	-	0.00	-	0.00	0.00	0.00	-	-
400000 - 600000	-	0.00	-	0.00	0.00	0.00	-	-

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.90
Maximum	5.38

2016 - Rate Change Impacts on E22 by Energy Intervals
Power
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.124**	**6.475**	
Demand Rate ($/kVA):	**9.676**	**10.220**	Based on Rate Class **Increase of 5.8%**
Basic Charge ($/month):	**5,491.00**	**5,491.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	12	46.15	86,119	22.31	2,936.89	5.15	0.08	5.32
1000000 - 2000000	10	38.46	167,506	43.40	6,505.83	5.44	5.36	5.51
>2000000	4	15.38	132,313	34.28	13,040.19	5.57	5.54	5.61

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.08
Maximum	5.61

2016 - Rate Change Impacts on E23 by Energy Intervals
Power
Customer Owned Transformation - 72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.525**	**5.841**	
Demand Rate ($/kVA):	**7.458**	**7.870**	Based on Rate Class **Increase of 5.8%**
Basic Charge ($/month):	**6,294.00**	**6,294.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly	% Increase		
	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 10000000	18	72.00	406,126	20.71	7,799.32	5.43	1.63	5.56
10000000 - 20000000	6	24.00	1,080,121	55.09	61,741.26	5.64	5.62	5.65
>20000000	1	4.00	474,311	24.19	157,277.77	5.67	5.67	5.67

* Average monthly change does not include municipal surcharge or taxes

Minimum	1.63
Maximum	5.67

2016 - Rate Change Impacts on E24 by Energy Intervals
Power
Customer Owned Transformation - 138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.421**	**5.749**	
			Based on Rate Class
Demand Rate ($/kVA):	**7.350**	**7.821**	**Increase of 5.8%**
Basic Charge ($/month):	**6,757.00**	**6,757.00**	Based on 2012 Billing

Energy Intervals		Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)		Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0	- 10000000	22	81.48	858,718	36.58	14,809.57	5.98	5.93	6.10
10000000	- 20000000	1	3.70	234,877	10.00	79,328.10	6.08	6.04	6.08
>20000000		4	14.81	1,254,107	53.42	109,667.84	6.10	6.09	6.12

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.93
Maximum	6.12

2016 - Rate Change Impacts on E25 by Energy Intervals
Power
Customer Owned Transformation - 230kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.421**	**5.749**	
Demand Rate ($/kVA):	**7.350**	**7.821**	Based on Rate Class **Increase of 5.8%**
Basic Charge ($/month):	**7,081.00**	**7,081.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 10000000	4	66.67	141,498	12.29	13,082.39	5.94	5.88	6.00
10000000 - 20000000	-	0.00	-	0.00	0.00	0.00	-	-
>20000000	2	33.33	1,010,224	87.71	172,329.95	6.10	6.09	6.11

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.88
Maximum	6.11

2016 - Rate Change Impacts on E34 by Energy Intervals
Farm

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**16,000**	**16,000**	
Energy Rate (cents/kW.h):	First Block	**11.230**	**11.676**	
	Balance	**4.870**	**5.060**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.0%**
	Balance	**11.40**	**11.75**	
Basic Charge ($/month):		**31.03**	**32.32**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 100	5,706	10.17	2,194	0.20	1.43	4.14	4.11	4.16
100 - 200	2,276	4.06	4,024	0.36	1.95	4.09	3.75	4.11
200 - 300	1,801	3.21	5,403	0.48	2.41	4.07	3.67	4.08
300 - 400	1,599	2.85	6,698	0.60	2.85	4.05	3.65	4.06
400 - 500	1,648	2.94	8,906	0.79	3.30	4.04	3.49	4.05
500 - 600	1,793	3.19	11,872	1.06	3.76	4.03	3.54	4.04
600 - 700	2,072	3.69	16,196	1.44	4.20	4.03	3.56	4.03
700 - 800	2,126	3.79	19,145	1.71	4.64	4.02	3.75	4.02
800 - 900	2,138	3.81	21,824	1.95	5.09	4.02	3.75	4.02
900 - 1000	2,310	4.12	26,364	2.35	5.53	4.01	3.77	4.02
1000 - 1100	2,311	4.12	29,093	2.59	5.97	4.01	3.48	4.01
1100 - 1200	2,179	3.88	30,075	2.68	6.42	4.01	3.76	4.01
1200 - 1300	2,160	3.85	32,415	2.89	6.87	4.00	3.53	4.01
1300 - 1400	2,101	3.74	34,014	3.03	7.31	4.00	3.49	4.00
1400 - 1500	1,996	3.56	34,718	3.09	7.76	4.00	3.47	4.00
1500 - 1600	1,774	3.16	32,976	2.94	8.20	4.00	3.76	4.00
1600 - 1700	1,617	2.88	31,999	2.85	8.64	4.00	3.97	4.00
1700 - 1800	1,572	2.80	33,008	2.94	9.09	4.00	3.83	4.00
1800 - 1900	1,424	2.54	31,611	2.82	9.55	3.99	3.67	4.00
1900 - 2000	1,332	2.37	31,163	2.78	9.98	3.99	3.87	4.00
2000 - 2500	5,201	9.27	139,169	12.40	11.23	3.99	3.53	3.99
2500 - 3000	3,288	5.86	107,661	9.60	13.43	3.99	3.67	3.99
3000 - 3500	2,028	3.61	78,623	7.01	15.65	3.98	3.70	3.99
3500 - 4000	1,125	2.00	50,348	4.49	17.75	3.98	3.71	3.99
4000 - 4500	724	1.29	36,664	3.27	19.83	3.98	3.74	3.98
4500 - 5000	495	0.88	28,107	2.51	21.80	3.98	3.69	3.98
5000 - 10000	932	1.66	70,837	6.31	27.87	3.97	3.64	3.98
10000 - 15000	128	0.23	18,669	1.66	53.81	3.94	3.56	3.98
15000 - 20000	58	0.10	11,851	1.06	72.40	3.91	3.64	3.97
20000 - 25000	30	0.05	8,263	0.74	89.78	3.86	3.65	3.96
>25000	182	0.32	128,063	11.41	204.21	3.76	3.43	3.96

* Average monthly change does not include municipal surcharge or taxes

Minimum	3.43
Maximum	4.16

2016 - Rate Change Impacts on E43 by Energy Intervals
Oil Fields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.712**	**6.935**	
Demand Rate ($/kVA):	**11.882**	**12.303**	Based on Rate Class **Increase of 3.7%**
Basic Charge ($/month):	**54.55**	**54.55**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000	722	7.09	4,815	0.22	3.20	1.95	0.82	3.48
1000 - 2000	925	9.09	16,866	0.77	6.28	2.60	2.02	3.25
2000 - 3000	900	8.84	26,903	1.23	9.59	2.84	2.47	3.29
3000 - 4000	756	7.43	31,674	1.45	12.80	2.96	2.78	3.46
4000 - 5000	659	6.47	35,476	1.63	15.86	3.03	2.86	3.47
5000 - 6000	568	5.58	37,236	1.71	18.91	3.09	2.91	3.37
6000 - 7000	508	4.99	39,588	1.82	22.46	3.13	3.04	3.50
7000 - 8000	396	3.89	35,578	1.63	24.94	3.15	3.08	3.27
8000 - 9000	365	3.59	37,109	1.70	28.02	3.18	3.09	3.36
9000 - 10000	300	2.95	34,178	1.57	30.77	3.19	3.06	3.32
10000 - 15000	1,228	12.06	180,724	8.29	39.58	3.23	3.13	3.47
15000 - 20000	733	7.20	152,834	7.01	54.89	3.27	3.18	3.45
20000 - 25000	453	4.45	121,575	5.58	69.89	3.29	3.23	3.42
25000 - 30000	309	3.04	101,311	4.65	85.08	3.31	3.26	3.46
30000 - 40000	424	4.17	176,111	8.08	106.82	3.32	3.26	3.41
40000 - 50000	202	1.98	108,271	4.97	137.06	3.33	3.26	3.42
50000 - 75000	332	3.26	242,482	11.13	186.67	3.34	3.29	3.44
75000 - 100000	148	1.45	152,025	6.97	257.02	3.35	3.30	3.39
100000 - 200000	173	1.70	282,486	12.96	414.88	3.36	3.30	3.41
>200000	79	0.78	362,352	16.62	2,046.50	3.37	3.30	3.41

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.82
Maximum	3.50

2016 - Rate Change Impacts on E46 by Energy Intervals
Power - Oilfield
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**6.124**	**6.475**	Based on Rate Class
Demand Rate ($/kVA):	**9.676**	**10.220**	**Increase of 3.7%**
Basic Charge ($/month):	**5,491.00**	**5,491.00**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly Change ($)	% Increase		
	Number	(%)	(MWh/year)	(%)		Average	Low	High
0 - 1000000	10	52.63	66,223	30.13	2,468.47	5.08	4.49	5.34
1000000 - 2000000	8	42.11	123,119	56.02	5,724.10	5.41	5.35	5.48
>2000000	1	5.26	30,442	13.85	11,127.63	5.55	5.55	5.55

* Average monthly change does not include municipal surcharge or taxes

Minimum	4.49
Maximum	5.55

2016 - Rate Change Impacts on E48 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	**5.421**	**5.749**	
Demand Rate ($/kVA):	**7.350**	**7.821**	Based on Rate Class **Increase of 3.7%**
Basic Charge ($/month):	**6,757.00**	**6,757.00**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 1000000	-	0.00	-	0.00	0.00	0.00	-	-
1000000 - 2000000	-	0.00	-	0.00	0.00	0.00	-	-
>2000000	2	100.00	314,111	100.00	52,476.53	6.06	5.85	6.09

* Average monthly change does not include municipal surcharge or taxes

Minimum	5.85
Maximum	6.09

2016 - Rate Change Impacts on E75 by Energy Intervals
General Service - Small Commercial
Urban - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**14,500**	**14,500**	
Energy Rate (cents/kW.h):	First Block	**12.128**	**12.900**	
	Balance	**6.404**	**6.811**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 5.6%**
	Balance	**13.44**	**14.31**	
Basic Charge ($/month):		**27.62**	**29.56**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 2000	19,032	63.78	168,654	17.00	7.65	6.59	6.43	7.02
2000 - 4000	5,071	16.99	171,789	17.31	23.77	6.42	6.40	6.45
4000 - 6000	2,016	6.76	118,268	11.92	39.80	6.40	6.39	6.43
6000 - 8000	1,142	3.83	94,469	9.52	55.16	6.39	6.38	6.42
8000 - 10000	766	2.57	82,247	8.29	71.01	6.38	6.38	6.43
10000 - 12000	500	1.68	65,919	6.64	86.52	6.38	6.38	6.41
12000 - 14000	368	1.23	57,445	5.79	101.27	6.38	6.38	6.42
14000 - 16000	246	0.82	44,213	4.46	114.00	6.38	6.37	6.39
16000 - 18000	197	0.66	40,112	4.04	126.04	6.38	6.37	6.40
18000 - 20000	158	0.53	36,050	3.63	136.03	6.38	6.37	6.40
>20000	343	1.15	113,207	11.41	245.65	6.38	6.37	6.40

* Average monthly change does not include municipal surcharge or taxes

Minimum	6.37
Maximum	7.02

2016 - Rate Change Impacts on E76 by Energy Intervals
General Service - Small Commercial
Rural - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**13,000**	**13,000**	
Energy Rate (cents/kW.h):	First Block	**12.775**	**13.466**	
	Balance	**6.571**	**6.908**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**13.73**	**14.55**	
Basic Charge ($/month):		**36.81**	**36.81**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 2000	5,401	66.57	45,557	17.76	4.87	3.27	0.02	5.19
2000 - 4000	1,264	15.58	42,973	16.76	19.78	4.90	4.70	5.79
4000 - 6000	548	6.75	32,125	12.53	33.79	5.10	4.91	5.35
6000 - 8000	319	3.93	26,426	10.30	47.53	5.19	5.00	5.48
8000 - 10000	163	2.01	17,549	6.84	60.41	5.23	4.93	5.38
10000 - 12000	119	1.47	15,566	6.07	73.11	5.26	5.11	5.40
12000 - 14000	75	0.92	11,680	4.55	85.23	5.27	5.18	5.34
14000 - 16000	61	0.75	10,887	4.25	94.99	5.28	5.21	5.40
16000 - 18000	37	0.46	7,507	2.93	103.16	5.28	5.24	5.36
18000 - 20000	34	0.42	7,680	2.99	112.18	5.28	5.21	5.38
>20000	92	1.13	38,510	15.02	226.35	5.29	5.14	5.60

* Average monthly change does not include municipal surcharge or taxes

Minimum	0.02
Maximum	5.79

2016 - Rate Change Impacts on E77 by Energy Intervals
General Service - Small Commercial
Urban - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**14,500**	**14,500**	
Energy Rate (cents/kW.h):	First Block	**12.128**	**12.900**	
	Balance	**6.404**	**6.811**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 5.6%**
	Balance	**12.97**	**13.81**	
Basic Charge ($/month):		**27.62**	**29.56**	Based on 2012 Billing

Energy Intervals (KWh/month)	Number of Accounts		Energy Use		Average Monthly Change ($)	% Increase		
	Number	(%)	(MWh/year)	(%)		Average	Low	High
0 - 5000	12	70.59	208	21.71	15.47	6.57	6.40	6.99
5000 - 10000	2	11.76	186	19.42	61.80	6.39	6.38	6.39
10000 - 15000	2	11.76	323	33.72	104.23	6.38	6.38	6.38
>15000	1	5.88	241	25.16	349.33	6.38	6.38	6.38

* Average monthly change does not include municipal surcharge or taxes

Minimum	6.38
Maximum	6.99

2016 - Rate Change Impacts on E78 by Energy Intervals
General Service - Small Commercial
Rural - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		**13,000**	**13,000**	
Energy Rate (cents/kW.h):	First Block	**12.775**	**13.466**	
	Balance	**6.571**	**6.908**	Based on Rate Class
Demand Rate ($/kVA):	First 50kVA	**0**	**0**	**Increase of 4.8%**
	Balance	**13.24**	**14.03**	
Basic Charge ($/month):		**36.81**	**36.81**	Based on 2012 Billing

Energy Intervals	Number of Accounts		Energy Use		Average Monthly	% Increase		
(KWh/month)	Number	(%)	(MWh/year)	(%)	Change ($)	Average	Low	High
0 - 5000	5	45.45	173	2.95	19.86	4.54	2.77	5.11
5000 - 10000	3	27.27	215	3.66	41.09	5.15	5.12	5.20
10000 - 15000	1	9.09	153	2.61	81.72	5.26	5.26	5.26
>15000	2	18.18	5,326	90.78	1,470.26	5.44	5.26	5.50

* Average monthly change does not include municipal surcharge or taxes

Minimum	2.77
Maximum	5.50

SaskPower Operating, Maintenance & Administration - Five Year History					
	GAAP		IFRS		
(in $ millions)	**2008**	**2009**	**2010**	**2011**	**2012**
President/Board	1	1	3	3	3
Power Production	168	182	152	159	168
Transmission & Distribution*	108	115			
Transmission			31	40	53
Distribution			87	87	95
Asset Management			0	0	0
Operation Other			38	47	49
Subtotal Operations	**276**	**297**	**308**	**333**	**365**
Finance	15	18	11	14	12
Customer Services	42	46	43	45	46
Resource Planning & NorthPoint	16	18	15	16	14
Law, Land, Regulatory Affairs	4	5	13	14	15
Information Technology & Security	33	34	42	49	58
Human Resources	11	13	21	24	26
Commercial	8	12	18	16	16
Business Development	0	0	0	13	4
Carbon Capture & Storage Initiatives	0	0	1	2	2
Total Core Costs	**406**	**444**	**475**	**529**	**561**
Corporate OH Capital Credits	(5)	(5)	0	0	0
Demand Side Mangement	4	5	9	12	19
Insurance Expense	5	6	5	5	7
Pension Expense	11	36	6	3	2
Bad Debt Expense	2	3	2	2	3
Return to Work Program	1	1	1	2	2
Corporate Compensation Plans	0	1	0	0	1
Other Expense	2	1	(2)	8	0
PPA-OMA	5	7	14	18	23
ICCS - Grant Funding	0	0	0	0	0
Contingency	0	0	0	0	0
Total Other Costs	**25**	**55**	**35**	**50**	**57**
Total OM&A	**431**	**499**	**510**	**579**	**618**
Annual Increase %		**15.8%**	**2.2%**	**13.5%**	**6.7%**

** Cost grouping no longer used after the 2012 re-organization*

2013 Rate Application Update

SRRP Recommendations and SaskPower's Response

<u>Recommendation 1</u>: That the following forecasts be accepted as justified and reasonable for the purpose of setting a rate that will allow SaskPower to earn net income of $126.1 million in 2013:

- Total Fuel and Purchase Power forecast of $545.1 million
- Estimated natural gas consumption of 43.6 million Gigajoules (Gj) at a forecast cost of gas of $4.00 per (Gj)
- The total cost of Operation, Maintenance and Administration expenses of $615.2 million
- Depreciation and Amortization expenses of $363.0 million
- Corporate, municipal and other tax obligations of $53.5 million
- The Return on Equity and Overall Rate of Return of 6.4%
- Other costs set at $9.0 million

<u>SaskPower Response</u>: Accepted as recommended.

<u>Recommendation 2</u>: That SaskPower's proposed 4.9% rate increase for all customer classes, expect the Power-Contract Rate Class, resulting in a system-wide average increase of 5%, be approved. The proposed increase would be effective January 1, 2013.

<u>SaskPower Response</u>: Accepted as recommended.

<u>Recommendation 3</u>: That SaskPower continue to develop, implement and track in a consistent manner, measurable cost control, productivity and efficiency initiatives resulting from its Business Renewal program and other efficiencies on a year-over-year basis, and report these findings in future rate applications.

<u>SaskPower Response</u>: Accepted. SaskPower will report on Business Renewal initiatives to the Panel and the technical consultant during future rate applications.

Business Renewal Scorecard
as at June 30th, 2013

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Finance - Finance Charges	Actual (to 12-31-12):	Vice-President and CFO, Finance		Savings Explanation: (BLY: 2009 & AP: TBD yrs)	M
	SaskPower has made a policy change to use up to 15% short term debt which is currently cheaper than long term debt. This allows SaskPower to realize significant savings in finance charges. These savings are dependent on short term interest rates being lower than long term rates. During the years 2013-15, SaskPower is planning to continue to utilize 15% in ST debt.	$35.4M			Savings are calculated as the difference between the long term rate and the short term rate multiplied by the business plan short term debt balance. Status: • The use of short term debt started in 2009 and continues to produce savings due to the difference between short term and long term rates. • Savings estimates will vary depending upon the spread between short & long term interest rates.	
	Finance - Capital Structure	Actual (to 12-31-12):	Vice-President and CFO, Finance		Savings Explanation: (BLY: 2009 & AP: TBD yrs)	M
	Debt is currently cheaper compared to SaskPower's target return on equity and a change has been made to the capital structure to increase the debt ratio above the historical 60% which leads to considerable savings. During the 2013-15 period, SaskPower is planning to use a debt ratio between 69-74%. This strategy will be monitored and adjusted if necessary should long term interest rates rise.	$27.3M			Savings are calculated as the difference between the long term rate and the target return on equity multiplied by the amount of debt above 60%. Status: • The change to the capital structure started in 2009 and continues to produce savings due to the difference between the long term rate and the target return on equity. • Savings estimates will vary depending upon the spread between long term interest rates and the target return on equity.	

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Procurement - Strategic Sourcing & Transformation	Actual (to 12-31-12):	Chief Commercial Officer, Commercial		Savings Explanation: (BLY: Various & AP: Various/ Contract Length)	
	Implementation of a strategic sourcing strategy that will have SaskPower utilize competitive long term supplier relationships to capture cost savings. (started in 2012) Procurement Transformation: a major redesign of the cross-functional procurement process to improve process efficiency and effectiveness. (2013-15) For 2012, the savings came from the strategic sourcing strategy and the following major purchase contracts: - A major fleet purchase; and - Renegotiation of a transformer purchase arrangement with a local strategic partner. In 2013-15, savings will come from other sourcing agreements including the following: - Major purchases of wood poles - Wire & cable - Transformers - Other sourcing arrangements TBD Note: not all major sourcing agreements can be identified & estimated as they depend upon the nature & scale of the project work underway	$1M			• Savings from the strategic sourcing strategy will be planned and captured by Procurement through contract negotiations and identified efficiencies. Savings will be dependent upon the major purchase arrangements completed in a particular year and the savings will only be applicable for the term of the contract. The nature of the savings items will vary but may relate to price and/or other opportunities to reduce costs (i.e. vendor managed inventory, e-procurement, supplier development, etc.). • As an example, on the 2013 wood pole competition a contract was awarded and a volume discount to SaskPower was provided. The savings is the price difference of the original contract value and the spend amount. • Savings associated with the process redesign will result from actions to improve process efficiency and/or elimination of unnecessary activities (e.g. more electronic processing/storing of documents). • Procurement spend levels are expected to increase over time as demand increases for goods and services. Status: a. The strategic sourcing activities continue with savings planning on various sourcing arrangements. b. The major process redesign work has been completed and implementation planning is underway. Changes will be made over the period 2013-15.	

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Distribution Services - Deliver Products & Services New Connect Process Improvement	Actual (to 12-31-12):	Chief Operations Officer, Operations		Savings Explanation: (BLY: 2009-11 & AP: TBD yrs)	M
	Distribution Services has implemented the following process improvements on the Customer Connect process: a. Province-wide standardization of the quote preparation process, the use of standard price quick quotes, and the introduction of a quote expeditor role. b. Increased focus on more timely delivery of customer connect construction services by introducing a new construction expeditor role. This has led to improved cycle time performance and cost savings. The initial process redesign took place in 2009-11, however ongoing improvements have been made since that time as the process is in continuous process improvement mode. These changes are being made to both maintain performance and capture additional savings.	$36M			a. Reducing the number of site visits, introducing a quote expeditor, and the use of Standard Price quotes (CSR provides customer quote from pricing sheet based on customer's information) has led to a lower cost per quote amount. Savings are calculated as the difference between the cost of quote using the old process (includes a site visit for all quotes and no Standard Price quotes) and cost of quote using the new process (does not include site visits for all quotes and includes Standard Price quotes) multiplied by the number of quotes issued. b. Introduction of the Construction Expeditor role and specifically the rightsizing of crews led to a savings in labour. This can be seen in a lower average labour to material cost ratio (meaning for every dollar of material spent a lower amount of labour is required). The measureable savings captured have been redeployed into increasing new connect workloads so costs still trend upwards. Process performance is monitored on a regular basis and the savings for the process improvements will be accrued for a specified period (TBD) wherein a new base will be established. Status: • Process improvement a) was implemented in 2010 and b) was implemented in 2011. • The process performance continues to be measured, monitored, and opportunities to further improve the process are being pursued.	

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Power Production - Overhaul Maintenance Management	Actual (to 12-31-12):	Chief Operations Officer, Operations		Savings Explanation: (BLY: varies by unit & AP: TBD yrs)	M
	Our Power Production group is extending the time between regular maintenance overhauls in our coal plants: a. Boundary Dam and Shand plants have both moved from a 12 month to a 24 month interval for overhauls. b. The Poplar River plant will move from a 12 month to a 18 month interval for overhauls beginning in 2014. There is a risk that these changes may affect overall plant performance due to the erosive nature of the coal utilized in our plants. Plant availability performance will be monitored under the new less frequent maintenance schedule to determine whether cost savings can continue to be realized. In 2013-15, regular plant overhauls on the following units have been eliminated: -2013 Boundary Dam Units 2, 4, & 6. Shand Unit 1. -2014 Boundary Dam Units 3 & 5. Poplar River Unit 2. -2015 Boundary Dam Units 4 & 6. Shand Unit 1. Power Production has also implemented industry standard 8 to 10 year major Turbine/Generator overhaul intervals on the coal fired units in 2013. Changes are now within the maintenance schedule.	$14.3M			• Savings for both a) and b) include the avoided fuel and OM&A cost of performing a major maintenance overhaul outage. • Fuel savings are equal to the avoided cost of natural gas generation for replacement power during an overhaul outage and are calculated using the number of outage days saved multiplied by the cost of fuel. • OM&A savings represent the avoided costs of mobilization, demobilization, operations labour, overtime, and outage planning costs and are calculated using the number of avoided outages multiplied by the cost per outage. • This maintenance schedule and the attributed savings will be reviewed in 2016/2017. Overall plant operation costs are still trending upwards due to increased demand. Status: • Extended unit overhaul schedules for Boundary Dam and Shand were implemented into the maintenance schedule in 2011. • Extended unit overhauls for Poplar River is in progress and will be implemented in 2014/2015. • Once the extended overhauls schedules are implemented a review that assures the plant's reliability is maintained will be undertaken.	

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Automated Metering Infrastructure (AMI)	Actual (to 12-31-12):	Chief Operations Officer, Operations		Savings Explanation: (BLY: Varies & AP: Varies)	
	Advanced Metering Infrastructure (AMI): A technology that enables automated collection of energy consumption data. This technology consists of hardware and software that aids in the collection and sharing of meter data as well as providing two-way communication to the meter. AMI is a foundational component of a Smart Grid System. The use of AMI infrastructure will produce benefits related to: • meter reading - elimination of manual meter reading • metering operations - eliminates manual turn on/off and disconnect activities etc. • increased accuracy of meters - estimated revenue increase • increased ability to manage outage response (future with new Outage Management System) • potential for provision of information services to customers interested in managing usage (future) Savings for 2013-2015 include: a. Avoided cost of meter recalls b. Avoided meter reading costs	$0.2M			a. Avoided cost of meter recalls: SaskPower recalls a sample of meters each year to test for accuracy. Measurement Canada has granted a dispensation for meter samples due to the replacement of current meters with AMI meters. Calculation: (cost to perform a meter recall)x(number of meters that would have been recalled) This savings will accrue for the period of the dispensation (2012-2013). b. Avoided meter reading costs: Once AMI meters are installed, meter readers will no longer be required to manually visit residences and businesses to read meters. Calculation: (standard rate of a meter reader)x(number of meter readers no longer required) Status: During 2010-12, the project team selected implementation partners, built the IT infrastructure, piloted technologies in the field, and planned for full implementation. Installation of the new meters will begin in 2013 and be completed in 2015.	

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	T&D - Schedule & Dispatch	Actual (to 12-31-12):	Chief Operations Officer, Operations		Savings Explanation: (BLY: 2012 & AP: TBD yrs)	M
	The implementation of laptop computers in T&D field staff trucks and the implementation of new automated schedule & dispatch software is complete. This technology and the use of new work processes will enhance the visibility into how work gets done and will lead to productivity gains and overtime reductions for field staff. In 2013-15, the new system and processes will be integrated into district operations and as change management and operational issues are resolved benefits will accrue: a. Increased district staff productivity b. Reduced district staff overtime c. Distribution crews and other field staff will start to pilot the new technology and additional benefits will accrue	$0M			a) Productivity gains will be measured through the use of the system which will track the amount of time the worker is performing service work (i.e. average increase in tool time worked x number of district staff). b) Overtime reductions will be determined by taking the difference in average overtime hours before system implementation and after. c) Other field staff group savings will be similar and calculated as above. Overall field labour costs will still be trending upwards as labour savings will be redeployed to do more maintenance work which is required to maintain system reliability performance. Because these benefits will take significant change management activities, the benefits will accrue gradually over an extended period (TBD).	
					Status:	
					• Laptops were installed in district field staff trucks in 2010. • Initial implementation of the S&D system was completed in 2013 and sustainment activities are ongoing.	

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Operations - Materials Management Process Improvement	Actual (to 12-31-12):	Chief Operations Officer, Operations		Savings Explanation: (BLY: 2011 & AP: TBD yrs)	
	The Materials Management transformation program consists of a number of improvement opportunities: i) Move from a complex distribution network to a two warehouse model. All material will be picked, packed, and shipped from the warehouses. ii) Transition regional stores to material storage locations. iii) Outsource transportation activities and deliver material from warehouses to material storage locations or directly to job sites. iv) Introduce a new warehouse management application. These logistical process changes will be staged over a four year period. In 2013-15 the following will take place: -implement new materials management business processes -introduce short term changes to transportation model -select new warehouse management application	$0M			• The new model is designed to optimize the flow of materials and reduce capital tied up in inventory on hand. The inventory turn ratio is expected to increase and carrying costs are expected to decrease as a result. The majority of savings identified in the forecast represent avoided inventory purchases. • Each of the improvement initiatives will gradually move us to our target of having an inventory turnover of 2.0. Status: • The improvement opportunities identified in i)-iv) will be implemented over the period of 2012-2016. • Some initial material handling process changes are currently being implemented. • Feedback on the design of a Saskatoon warehouse has been provided and work to assess material storage locations continues. • The implementation plan may be modified if resource availability becomes an issue.	D

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Distribution Services - Deliver Products & Services Line Locate Outsourcing SaskPower is outsourcing line locating services to a contractor who performs locates at a lower cost per locate when compared to SaskPower. This is because the contractor is performing multiple locates at a single location. This outsourcing arrangement which started in 2011 will continue to produce savings for the length of the contract (TBD). The field staff time saved (by not having to do line locates) has been redeployed to do increased maintenance work. This work is required to maintain system reliability performance.	Actual (to 12-31-12): $8M	Chief Operations Officer, Operations		Savings Explanation: (BLY: 2011 & AP: TBD yrs) Line Locate Savings: SaskPower is currently paying a contractor less money to perform locating services than it would have cost the company to perform them in-house. Calculation: [(SaskPower cost per locate)-(contractor charge per locate)]x number of locates outsourced Note: Costs increased due to the contract. Outsourcing helps avoid the cost associated with additional maintenance work. Status: Line Locating services were outsourced in 2011 and the contractor continues to perform this work.	M
	IT&S - Sourcing Strategy IT&S has implemented a sourcing strategy that is producing measurable savings. Savings for 2013-2015 include: a. Service Desk outsourcing - to lower cost local Saskatchewan based service provider b. Repatriation of SaskPower staff - involved hiring employees (at a lower overall cost) to replace some previously contracted positions c. Standing Supply Arrangement - implement a vendor of record framework for procurement of contracted staff To the end of 2012, 39 positions have been repatriated and another 28 are planned for 2013-15.	Actual (to 12-31-12): $9.4M	Vice President & CIO, Information Technology & Security		Savings Explanation: (BLY: 2010-11 & AP: TBD yrs) a. Service Desk outsourcing: Calculation: (SaskPower cost to operate a service desk)-(cost to outsource service desk). This benefit will only accrue for a specified period (TBD). b. Repatriation of SaskPower staff: Calculation: annual cost savings per position totalled for all targeted positions. These savings will only accrue for a specified period (TBD). c. Standing Supply Arrangement: Calculation: annual costs savings per position totalled for all positions sourced through the Standing Supply Arrangement. These savings will only accrue for a specified period (TBD). Status: a. Service Desk was outsourced in 2011. b. Wave 2 of repatriation has begun. Implementation is planned to be completed in 2015.	M

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	IT&S - Other Initiatives Some of the other savings initiatives IT&S has implemented includes: a) Negotiated reduced price for desktop computers b) Elimination of targeted staff and contractor positions Savings initiatives planned for 2013-2015 include: c) decreasing the number of printers (employee to printer ratio from 2:1 to 8:1) d) repatriation of disaster recovery services e) other miscellaneous changes	Actual (to 12-31-12): $2.3M	Vice President & CIO, Information Technology & Security		Savings Explanation: (BLY: Varies & AP: TBD) a) negotiated a 24% decrease in costs for desktop computers (price difference x number of units) b) funding for 3 positions and 5 contractors has been reduced c) costs associated with the elimination of 50% of the printer fleet, a reduction of 718 printers d) eliminating the disaster recovery contract by performing these services in-house (cost of previous contract) IT&S costs are still trending upwards due to increasing IT projects and increased demand for services. Status: IT&S is implementing these initiatives and continues to look for additional savings opportunities on an ongoing basis.	M
	Corporate - Other Initiatives SaskPower is pursuing savings initiatives in addition to those included in the categories above: a) Centralization of North Point/Business Development b) Outsourcing head office caretaking services c) More efficient office space utilization d) Using paperless employee pay statements e) Managing the cost per meter read in Customer Services	Actual (to 12-31-12): $3.4M	Various Executive		Savings Explanation: (BLY: Various & AP: TBD) a) Centralization provides savings through the redeployment of 7 resources into new job assignments without having to hire additional employees. b) Outsourcing caretaking through attrition will reduce the cost associated with these services. c) Smaller workstations and fewer offices provide more efficient use of building space. d) Using paperless pay stubs reduces printing and paper costs. e) Managing staff performance with metrics has led to an increased volume of meter reads being accomplished with the same staff compliment. Status: The listed savings initiatives have been implemented since 2009. Other initiatives will be added to this list as additional savings opportunities are identified.	M

	Program/Initiative Description	Savings/Benefit Actual Realized & Forecast	Program Owner	STATUS	Savings Explanation / Initiative Status (June 30, 2013)	Progress
	Asset Management Program SaskPower is pursuing an asset management strategy which will fundamentally change our operating model. It involves an integrated asset management framework found in the international standard, PAS-55. SaskPower's three major divisions of Operations (Power Production, Transmission, and Distribution) are in various stages of the transformation. The integrated approach will facilitate capital and operating expenses being managed as a total portfolio and optimized to manage risk and service levels. This will lead to significant savings and enhanced system reliability.	Actual (to 12-31-12): $0M	Chief Operations Officer, Operations		Savings Explanation: (BLY: TBD & AP: TBD) An integrated plan which will identify the target savings is under development. Status: Initiative is in planning stage.	P
	Commercial - Major Project Delivery Transformation Transmission has established a Project Delivery Office (PDO) and are redesigning the end-to-end project delivery process. This involves refining the project governance and implementing a new set of performance metrics that will ensure more projects are delivered on time, on budget and in the most efficient manner possible. It is anticipated that the new process will be implemented in stages starting in 2014.	Actual (to 12-31-12): $0M	Chief Commercial Officer, Commercial		Savings Explanation: (BLY: TBD & AP: TBD) During the redesign phase, a number of KPI's will be developed and implemented. These KPI's and the related measurement framework will identify savings opportunities. Status: The process redesign work is underway and is expected to be completed later in 2013. An implementation plan will be developed and executed.	P

SCORECARD KEY:

● (green)	Project is progressing well
● (yellow)	Project is delayed
● (red)	Project is on hold
R	Research Phase
P	Planning Phase
D	Design Phase
I	Implementation Phase
M	Measurement & Monitoring Phase
BLY:	Baseline year used in calculating savings
AP:	Savings accumulation period

NOTES:

- Activities are currently underway to define the 'savings accumulation period' (AP) for each change item in each initiative. Generally, most initiative's AP will be for 1-5 years or if a contract is utilized to formalize the savings, then the contract term will be utilized as the AP. When the AP expires it is assumed that the achieved performance level becomes the new norm. At that point, a new baseline will be established and changes/savings will be measured from the new baseline.
- A review of the forecasted savings for each initiative is also underway. The objective is to improve 'measurability' and enhance the forecasting methodology so that these estimates can be viewed with greater confidence.
- Progress on specific initiatives is affected by ongoing resource allocation decisions. Given resource constraints and shifting priorities there is a requirement for project plans and the resulting savings estimates to be updated on a regular basis. Currently Business Renewal savings initiatives are reported on a quarterly basis.

SDR update for SRRP – October 2013

Service Delivery Renewal (SDR) was approved in 2009 to renew SaskPower's service business by increasing efficiency, productivity, electrical system reliability and delivering improved service quality to our customers. SDR's creation was prompted by the fact that SaskPower was at a point in its history where the company had to change how it did business, in response to the following factors:

- Customers want service that is faster and more convenient;
- The cost of doing business is rising, and SaskPower must show customers that it is an efficient and effective organization, providing value for money;
- As existing infrastructure is maintained or replaced, new solutions must be more efficient;
- With an aging workforce, SaskPower must have a knowledge transition plan and also look for opportunities to renew current internal processes to serve customers.

SaskPower is in the midst of an unprecedented era of corporate transformation and renewal. Over the next 10 years, the company will spend $1B annually to not only replace our existing provincial electrical infrastructure, but to also accommodate our province's strong economic growth. SDR will play a foundational role in responding to this challenge, serving as a critical program delivery organization that will deliver the multi-year, process driven, cross functional business projects required by this once-in-a-generation project.

SDR is led by a General Manager, and includes a mix of SaskPower staff and consultants who are assigned to specific projects. The Vice-President of Commercial has SDR managerial oversight; however, the Vice-Presidents of Operations, Customer Services, and Information Technology & Security also closely monitor SDR results as an executive steering committee to the program.

The following projects have been completed as part of SDR:

- Business process: End to end documentation for the Calculate and Collect Revenue; Deliver Products and Services; and Maintain Electrical System Reliability corporate business processes.
- New Connect process: by implementing a consistent process, the average time to provide a customer quote for new service 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 is capable of managing complex billing and rate structures.
- Outage Management Tactical Project: A renewed outage call management system connects customer outage notifications with customer addresses and enables automatic scheduling of field workers to respond.
- Phase 1 of Field Worker project: 525 laptop computers were installed in field worker trucks with mobile mapping software, as well as automatic vehicle locators.
- Phase 2 of Field Worker project: Using centralized scheduling and dispatch functionality in two provincial locations, connected with laptop computers in service trucks, our goal is to optimize resources for prioritizing work, minimize travel, and shorten power outage durations. All 58 SaskPower districts were live in January 2013; transition to SaskPower operations was completed in July 2013.

The following project is currently in progress within SDR:

- Advanced Metering Infrastructure (AMI): the province-wide project to install 500,000 electronic meters and 370,000 natural gas modules at residential and business locations, combined with a communication network and a meter data management system.
- To date, the AMI project has successfully completed the following milestone activities:
  - Field Test – June to September 2012
  - Network Acceptance Test – April to June 2013
  - System Acceptance Test (Phase 1) – June to October 2013
- Full scale installation of AMI meters across Saskatchewan begins on October 28, 2013. The AMI project remains on schedule to be complete by June 2015.
- In addition to a reduction in meter reading costs, eventual benefits associated with this project for customers include:
  - Electricity bills based on the amount actually used each month
  - Automatic meter readings that are securely transmitted through the new metering system
  - Faster electricity service connects and disconnects for tenancy changes
  - Faster identification and tracking of power outages in the future once supporting technology is in place
- AMI will deliver the following long-term benefits for SaskPower and its customers:
  - Part of a program to enhance infrastructure in response to Saskatchewan's growth
  - Part of an overall corporate efficiency program to keep rates as low as possible
  - Provide customers with better information to make informed, energy efficient decisions
  - Provides a foundation for future SaskPower projects:
    - Near real-time alerts on the location and duration of power outages
    - Redeployment of staff to conduct proactive maintenance work, increasing the reliability of electrical service
    - Smart grid initiatives

The following project is planned for SDR in the future:

- Outage Management System (OMS): a proactive, integrated system will identify the location of power outages and reduce the time to restore service. In 2014, a RFP will be prepared to secure a vendor for the long-term OMS solution.

Other multi-year, process-driven, cross-functional business projects within SaskPower will be evaluated for their fit within SDR.

Benefits enabled by SDR projects:
SDR is built on a return on investment (ROI) model and has delivered on 23 projects to date, for a total expenditure of $91M. SDR successes are outlined below, in alignment with SaskPower's strategic areas of focus:

Project	**Benefits Delivered**	**Alignment with SaskPower strategic focus**
Deliver Products and Services Project	The redesigned New Connect business process improved connection times by an average of 460 per cent.	Workforce Excellence; Process Efficiency and Cost Management
Customer Relationship and Billing Project	CR&B has improved the ability to bill customers automatically and has established a foundation for future improvements like outage management and AMI.	Customer Experience
Field Worker Project (Phase 1)	Automatic Vehicle Locators in 830 vehicles increase worker safety.	Workforce Excellence
Field Worker Project (Phase 2)	Automated the schedule and dispatching of field work and reduced drive times, leading to additional environmental benefits.	Workforce Excellence; Environmental Stewardship
Outage Management Tactical Project	A renewed outage call management system connects customer outage notifications with customer addresses and enables automatic scheduling of field workers to respond.	Customer Experience
Advanced Metering Infrastructure (AMI)	Implementation has just started. A fully deployed AMI system will be the foundation of the future of management and service strategies at SaskPower.	Technology Enablement; Customer Experience

SDR tracks all business benefits enabled by SDR projects in concert with the corporate Process Improvement Office. Their report on quantifiable benefits includes:

- Total benefits of $45M enabled from 2009 to 2012.
- Total benefits of $302M forecast for the 2009 to 2017 period.
- A total forecasted benefit to 2020 of $503M.

It is important to also note SDR's contribution to the development of a corporate-wide performance-driven organization, through the inclusion of four new competencies in all SDR projects:

- develop and document new business processes
- ensure effective measurement of processes
- use of measures in support of a benefits realization plan
- strong change management support for staff through business and technology changes

SaskPower

2014 – 2016 TEST
EMBEDDED
COST OF SERVICE STUDY

PREPARED BY:

CORPORATE & FINANCIAL SERVICES
PRICING & COSTING

SUBMITTED ON:
October 22, 2013

- ***BASED ON 2011 AUDITED ANNUAL FINANCIAL STATEMENTS AND THE APPROVED 2014 STRATEGIC BUSINESS PLAN***

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I. INTRODUCTION

A. Purpose

The SaskPower *2014 to 2016 Test Cost of Service* study provides an in-depth, detailed account of the annual cost to serve each of SaskPower's customer classes at the end of each Test Year of 2014, 2015, and 2016. The primary purpose of the Test Year study is to provide a detailed foundation for future years (Test) Cost of Service Studies. The secondary purpose is to provide an indication of the extent by which revenues contributed by a particular class, recover the allocated costs of serving that customer class.

SaskPower, in order to remain viable, must be given the opportunity to recover its incurred costs of providing electric service to its various classes of customers. Cost of service is usually defined to include all of a utility's operating expenses, plus a reasonable return on its investment ("rate base") devoted to the service of the rate paying public. These stakeholders and their interests are as follows:

1. **Saskatchewan Rate Review Panel (SRRP):** The Saskatchewan Rate Review Panel is interested in assuring that SaskPower only includes costs and returns that are related to SaskPower's core business. They are also interested in assuring that SaskPower applies methodologies that are reasonable and acceptable. Since the SRRP is not an expert in cost of service methodology and rate design, they rely on the opinion of an external consultant to report on the reasonableness of the embedded cost of service study.

2. **SaskPower Management / Executive / Board:** SaskPower's Executive, Management and Board are interested in ensuring that the corporation's financial targets are achieved. The cost of service model is vital to the development of rates and achieving SaskPower's revenue requirement.

3. **Customers:** The cost of service provides documentation to these stakeholders in terms of how much of the cost to provide them with service is recovered through the rates they pay.

B. Scope

A cost of service study is a study of the costs incurred by SaskPower in producing, transmitting, and distributing electricity to its customers, by customer class, in relation to revenues collected from each class under existing rates. For this report the costs analyzed are the average historical "embedded" cost of the existing plant and expenses in the "***Test Years***" of ***2014, 2015, and 2016*** as determined by SaskPower's Financial Planning department.

SaskPower owns two subsidiary companies: NorthPoint Energy Solutions and Shand Greenhouse. The financial assets and expenses from these subsidiaries have been included in this year's cost of service study. Best practices from other utilities across Canada have shown it is prudent to rate payers for a utility to include subsidiary financial results in years when the subsidiary achieves a net gain. In years of net loss, subsidiaries will not be included in the cost of service study.

C. Objectives

Cost of service studies are among the basic tools of rate-making. While non-cost concepts and principles can modify the cost-based standard, cost of service methodology remains the primary factor in determining the reasonableness of rates. SaskPower's key objectives of the cost of service study and resulting rate design are as follows:

1. Meeting revenue requirement
2. Fairness and equity
3. Economic efficiency
4. Conservation of resources
5. Simplicity and administrative ease
6. Stability and gradualism

Since these objectives do not always agree with the concept that service should be provided on a cost basis, SaskPower must use judgement and the advice of our shareholder and Cabinet as to the appropriate courses of action.

Accounting Methodology Change from GAAP to IFRS

Effective January 1, 2011, SaskPower adopted International Financial Reporting Standards (IFRS) from the previously followed General Accepted Accounting Principles (GAAP). Going forward, IFRS will be the sole accounting methodology utilized for financial reporting requirements.

II. SUMMARY OF RESULTS

Tables 1, 2, and 3 outline the summary results from the 2014 Test Cost of Service Study. Tables 4, 5, and 6 outline the summary results from the 2015 Test Cost of Service Study. Tables 7, 8, and 9 outline the summary results from the 2016 Test Cost of Service Study.

- **Table 1, 4 and 7 – Summary of Functionalized Revenue Requirement**
  This table identifies the cost of service by function (Generation, Transmission, Distribution, and Customer Service).

- **Table 2, 5, and 8 – Summary of Classified Revenue Requirement**
  This table identifies the cost of service by billing component for each customer class. The breakdown mimics the rate structure for all customer classes.

- **Table 3, 6, and 9 – Summary of Revenue to Revenue Requirement Ratios**
  This table displays the breakdown of Revenue to Revenue Requirement Ratio by customer class.

Table 1 – Summary of Functionalized Revenue Requirement (2014)

Summary of Functionalized Revenue Requirement by Customer Class
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Generation		Transmission		Distribution		Customer Service	
		($)	(%)	($)	(%)	($)	(%)	($)	(%)
Urban Residential	365.5	202.7	55.5%	28.2	7.7%	90.2	24.7%	44.5	12.2%
Rural Residential	96.9	50.8	52.4%	7.5	7.8%	31.6	32.6%	7.0	7.2%
Farms	160.4	94.4	58.9%	12.8	8.0%	44.2	27.6%	8.9	5.6%
Urban Commercial	289.3	196.5	67.9%	24.3	8.4%	61.1	21.1%	7.5	2.6%
Rural Commercial	98.9	63.5	64.3%	8.4	8.5%	24.8	25.0%	2.2	2.2%
Power - Published Rates	434.4	380.7	87.6%	43.1	9.9%	6.7	1.5%	3.9	0.9%
Power - Contract Rates	110.3	98.2	89.0%	11.0	10.0%	0.4	0.4%	0.6	0.6%
Oilfields	319.6	225.6	70.6%	25.0	7.8%	62.4	19.5%	6.5	2.0%
Streetlights	13.8	3.8	27.8%	0.4	3.1%	9.1	66.0%	0.4	3.1%
Reseller	90.7	82.9	91.5%	7.3	8.0%	0.3	0.4%	0.1	0.2%
Total	**1,979.8**	**1,399.3**	**70.7%**	**168.1**	**8.5%**	**330.8**	**16.7%**	**81.7**	**4.1%**

Table 2 – Summary of Classified Revenue Requirement (2014)

Summary of Classified Revenue Requirement by Customer Class
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Demand Related		Energy Related		Customer Related	
		($)	(%)	($)	(%)	($)	(%)
Urban Residential	365.5	192.0	52.5%	103.0	28.2%	70.5	19.3%
Rural Residential	96.9	55.4	57.2%	24.1	24.8%	17.4	18.0%
Farms	160.4	92.2	57.5%	49.1	30.6%	19.1	11.9%
Urban Commercial	289.3	158.6	54.8%	110.4	38.2%	20.4	7.0%
Rural Commercial	98.9	58.0	58.7%	33.7	34.1%	7.1	7.2%
Power - Published Rates	434.4	200.1	46.1%	228.4	52.6%	5.9	1.4%
Power - Contract Rates	110.3	49.9	45.2%	59.4	53.8%	1.1	1.0%
Oilfields	319.6	166.5	52.1%	137.0	42.9%	16.2	5.1%
Streetlights	13.8	2.8	20.4%	2.3	16.9%	8.7	62.7%
Reseller	90.7	46.6	51.4%	43.8	48.2%	0.3	0.4%
Total	**1,979.8**	**1,022.0**	**51.6%**	**791.2**	**40.0%**	**166.7**	**8.4%**

Table 3 – Summary of Revenue to Revenue Requirement Ratios (2014)

Summary of Revenue to Revenue Requirement Ratios
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Revenue ($)	Revenue Requirement ($)	Revenue to Revenue Requirement Ratio
Urban Residential	358.7	365.5	0.98
Rural Residential	94.5	96.9	0.98
Farms	158.0	160.4	0.98
Urban Commercial	288.5	289.3	1.00
Rural Commercial	100.4	98.9	1.01
Power - Published Rates	437.3	434.4	1.01
Power - Contract Rates	107.8	110.3	0.98
Oilfields	332.1	319.6	1.04
Streetlights	16.0	13.8	1.16
Reseller	86.7	90.7	0.96
Total (System)	**1,979.8**	**1,979.8**	**1.00**

Table 4 - Summary of Functionalized Revenue Requirement (2015)

Summary of Functionalized Revenue Requirement by Customer Class
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Generation		Transmission		Distribution		Customer Service	
		($)	(%)	($)	(%)	($)	(%)	($)	(%)
Urban Residential	386.5	214.4	55.5%	32.5	8.4%	95.3	24.7%	44.2	11.4%
Rural Residential	102.8	53.6	52.2%	8.7	8.5%	33.5	32.6%	7.0	6.8%
Farms	168.2	98.8	58.8%	14.6	8.7%	46.0	27.3%	8.7	5.2%
Urban Commercial	305.9	206.6	67.5%	27.9	9.1%	64.2	21.0%	7.3	2.4%
Rural Commercial	104.5	66.8	63.9%	9.6	9.2%	26.0	24.9%	2.1	2.0%
Power - Published Rates	502.6	437.2	87.0%	54.4	10.8%	7.2	1.4%	3.8	0.8%
Power - Contract Rates	115.1	101.4	88.1%	12.6	11.0%	0.5	0.4%	0.6	0.5%
Oilfields	358.4	252.7	70.5%	30.5	8.5%	68.9	19.2%	6.3	1.8%
Streetlights	14.4	4.1	28.5%	0.5	3.4%	9.4	65.2%	0.4	2.8%
Reseller	95.8	86.9	90.7%	8.4	8.8%	0.3	0.4%	0.1	0.1%
Total	**2,154.4**	**1,522.6**	**70.7%**	**199.9**	**9.3%**	**351.3**	**16.3%**	**80.6**	**3.7%**

Table 5 - Summary of Classified Revenue Requirement (2015)

Summary of Classified Revenue Requirement by Customer Class
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Demand Related		Energy Related		Customer Related	
		($)	(%)	($)	(%)	($)	(%)
Urban Residential	386.5	203.3	52.6%	111.1	28.8%	72.1	18.7%
Rural Residential	102.8	58.5	56.9%	26.0	25.3%	18.3	17.8%
Farms	168.2	96.2	57.2%	52.4	31.2%	19.6	11.6%
Urban Commercial	305.9	166.6	54.4%	118.2	38.6%	21.2	6.9%
Rural Commercial	104.5	60.8	58.2%	36.1	34.6%	7.6	7.3%
Power - Published Rates	502.6	229.9	45.7%	266.6	53.0%	6.1	1.2%
Power - Contract Rates	115.1	51.7	44.9%	62.4	54.2%	1.0	0.9%
Oilfields	358.4	185.3	51.7%	156.0	43.5%	17.2	4.8%
Streetlights	14.4	3.0	20.8%	2.5	17.6%	8.8	61.6%
Reseller	95.8	48.7	50.8%	46.8	48.8%	0.3	0.3%
Total	**2,154.4**	**1,104.0**	**51.2%**	**878.1**	**40.8%**	**172.3**	**8.0%**

Table 6 - Summary of Revenue to Revenue Requirement Ratios (2015)

Summary of Revenue to Revenue Requirement Ratios
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Revenue ($)	Revenue Requirement ($)	Revenue to Revenue Requirement Ratio
Urban Residential	380.6	386.5	0.98
Rural Residential	100.3	102.8	0.98
Farms	165.4	168.2	0.98
Urban Commercial	306.2	305.9	1.00
Rural Commercial	105.7	104.5	1.01
Power - Published Rates	507.1	502.6	1.01
Power - Contract Rates	113.3	115.1	0.98
Oilfields	367.0	358.4	1.02
Streetlights	15.5	14.4	1.08
Reseller	93.3	95.8	0.97
Total (System)	**2,154.4**	**2,154.4**	**1.00**

Table 7 - Summary of Functionalized Revenue Requirement (2016)

Summary of Functionalized Revenue Requirement by Customer Class
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Generation		Transmission		Distribution		Customer Service	
		($)	(%)	($)	(%)	($)	(%)	($)	(%)
Urban Residential	410.1	225.2	54.9%	36.9	9.0%	100.8	24.6%	47.3	11.5%
Rural Residential	109.5	56.3	51.4%	9.9	9.0%	35.8	32.7%	7.5	6.8%
Farms	175.1	101.6	58.0%	16.2	9.3%	48.0	27.4%	9.3	5.3%
Urban Commercial	323.6	216.6	66.9%	31.5	9.7%	67.9	21.0%	7.7	2.4%
Rural Commercial	111.0	70.0	63.1%	10.9	9.8%	27.9	25.1%	2.2	2.0%
Power - Published Rates	587.0	506.7	86.3%	68.3	11.6%	8.1	1.4%	3.9	0.7%
Power - Contract Rates	130.9	114.3	87.3%	15.5	11.9%	0.5	0.4%	0.6	0.5%
Oilfields	381.1	267.1	70.1%	34.8	9.1%	72.6	19.0%	6.6	1.7%
Streetlights	14.9	4.3	29.2%	0.6	3.8%	9.5	64.2%	0.4	2.9%
Reseller	100.4	90.5	90.1%	9.5	9.4%	0.4	0.4%	0.1	0.1%
Total	**2,343.6**	**1,652.6**	**70.5%**	**234.0**	**10.0%**	**371.4**	**15.8%**	**85.6**	**3.7%**

Table 8 - Summary of Classified Revenue Requirement (2016)

Summary of Classified Revenue Requirement by Customer Class
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Total Company	Demand Related		Energy Related		Customer Related	
		($)	(%)	($)	(%)	($)	(%)
Urban Residential	410.1	214.9	52.4%	118.2	28.8%	77.0	18.8%
Rural Residential	109.5	62.1	56.7%	27.7	25.3%	19.7	18.0%
Farms	175.1	99.8	57.0%	54.6	31.2%	20.7	11.8%
Urban Commercial	323.6	175.6	54.3%	125.3	38.7%	22.7	7.0%
Rural Commercial	111.0	64.3	57.9%	38.3	34.5%	8.3	7.5%
Power - Published Rates	587.0	268.5	45.7%	312.1	53.2%	6.4	1.1%
Power - Contract Rates	130.9	58.8	44.9%	71.0	54.2%	1.1	0.8%
Oilfields	381.1	195.9	51.4%	166.5	43.7%	18.7	4.9%
Streetlights	14.9	3.2	21.4%	2.7	18.2%	9.0	60.4%
Reseller	100.4	50.8	50.6%	49.2	49.0%	0.4	0.3%
Total	**2,343.6**	**1,193.9**	**50.9%**	**965.7**	**41.2%**	**184.1**	**7.9%**

Table 9 - Summary of Revenue to Revenue Requirement Ratios (2016)

Summary of Revenue to Revenue Requirement Ratios
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	Revenue ($)	Revenue Requirement ($)	Revenue to Revenue Requirement Ratio
Urban Residential	403.9	410.1	0.98
Rural Residential	106.8	109.5	0.98
Farms	170.8	175.1	0.98
Urban Commercial	327.1	323.6	1.01
Rural Commercial	112.2	111.0	1.01
Power - Published Rates	593.3	587.0	1.01
Power - Contract Rates	129.0	130.9	0.99
Oilfields	385.2	381.1	1.01
Streetlights	15.0	14.9	1.01
Reseller	100.4	100.4	1.00
Total (System)	**2,343.6**	**2,343.6**	**1.00**

III. COST OF SERVICE METHODOLOGY

The study follows a six step process:

- The first step is to ***identify*** in detail the accounting costs that are to be allocated to customer classes.
- The second step is to ***functionalize*** the costs between generation, transmission, distribution and customer services functions.
- The third step is to ***classify*** each set of functionalized costs into demand, energy and customer components.
- The fourth step is to ***allocate*** the functionally classified costs among the several customer classes.
- The fifth step is to ***compare*** between the allocated costs and the revenues collected from the customer classes to arrive at the revenue to cost ratios.
- The sixth step is to ***calculate*** "ideal" rates for each customer class.

Step 1: Identification

The initial step is to identify the accounting costs to be included in the Cost of Service Study. Corporate Financial Planning has supplied the forecasted Consolidated Financial Statements for 2014, 2015, and 2016.

Three types of accounts are separately identified in detail:

1. Rate Base Items – investments and liabilities as reported in SaskPower's Balance Sheet. Please refer to ***Schedule 1.0*** for summary of these items as well as their projections for each Test Year. Projections for each Test Year are reported for the year end in the following categories:

- Plant in service
- Accumulated Depreciation
- Allowance for Working Capital
- Inventories
- Other Assets

Plant in service is reported in more detail by function: Generation - by type of generation, Transmission - by voltage level, Distribution Plant - by type of plant, and General & Intangible Plant - by primary usage (unused land, buildings, office furniture and equipment, vehicles & equipment, computer development & equipment, communication, protection & control, and tools and equipment).

Contributions in Aid & Reconstruction were previously netted against Fixed Assets as part of the Rate Base and amortized over the estimated service life of the related asset. The amortization of these contributions was netted against Depreciation Expense under GAAP. However, with the adoption of IFRS, Contributions in Aid of Construction and

Reconstruction is recognized immediately as Other Income when the related fixed asset is available for use.

2. Revenue Requirement – this is a calculation of annual costs (from SaskPower's Income Statement) plus the Return on Rate Base (calculated as Rate Base multiplied by the system average Return on Rate Base percentage). The system average Return on Rate Base is equal to total revenue minus total expenses divided by the total rate base. Please refer to ***Schedule 1.0*** for a summary of these items as well as their projections for each of the Test Years 2014, 2015, and 2016. Projections for each Test Year are reported for the year end in the following categories:

- Fuel
- Purchased Power
- Export Revenue (Credit)
- Operating, Maintenance, & Administrative
- Depreciation and Depletion
- Corporate Capital Tax
- Grants In Lieu of Taxes
- Miscellaneous Tax
- Other Operating Revenues (Credit)
- Return on Rate Base (Rate Base multiplied by the system average Return on Rate Base)

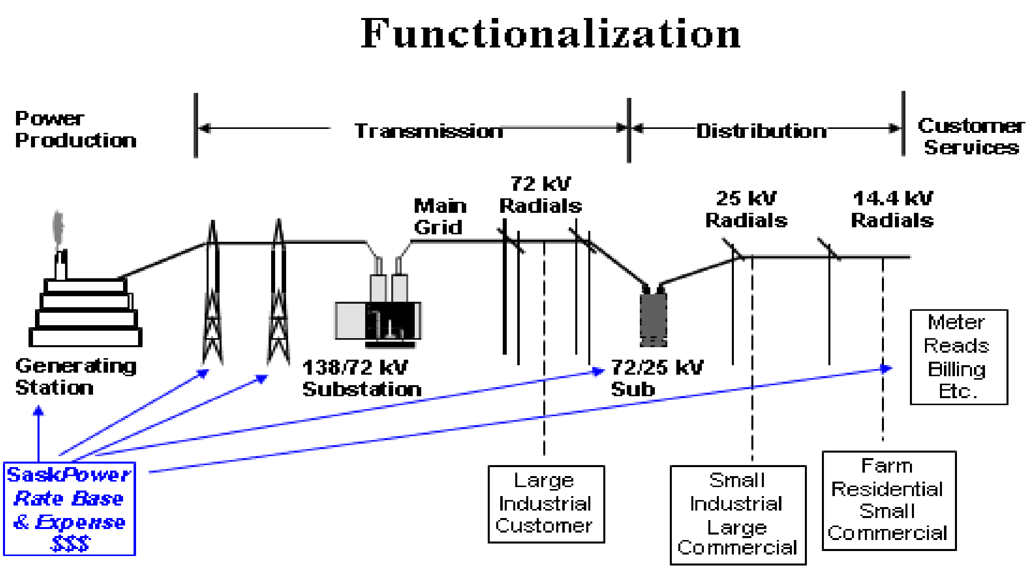
3. Revenue Items - annual domestic sales revenues as reported on SaskPower's Income Statement. The SaskPower Load & Revenue Forecasting department provides a projection of net sales within Saskatchewan. ***Schedule 7.0*** provides a summary by customer class of the annual projected revenues for the 2014, 2015, and 2016 Test Year.

Step 2: Functionalization

The second step is to functionalize all accounting costs, in terms of plant and expenses into the major functions of SaskPower's integrated electric system. Please refer to Figure 1 for a schematic of the process. Rate base and expenses are assigned to the following functions and sub functions:

1. Generation Load Losses Scheduling & Dispatch Regulation & Frequency Response Spinning Reserve Supplementary Reserve Planning Reserve Reactive Supply Grants in Lieu of Taxes Interruptible Adjustment	**3. Distribution** Area Substations Distribution Mains Urban Laterals Rural Laterals Transformers Services Customer Meters Streetlights
2. Transmission Main Grid 138kv Lines Radials 138/72kv Substations 72kv Lines Radials	**4. Customer Service** Metering Services Meter Reading Billing & Customer Service Customer Collecting Customer Service Marketing & Key Accounts

Figure 1: Functionalization Schematic



Please refer to ***Schedules 2.00 through to 2.36*** for the functionalization of the financial accounting details for each of the Test Years 2014, 2015, and 2016. A summary of the functionalization methodology is summarized below for rate base and revenue requirement which includes annual expense items from the income statement and return on rate base.

1.0 Rate Base Items

1.01 - Plant in Service & Accumulated Depreciation

- **SaskPower Generation, Transmission, and Distribution:**
All of the rate base accounts are functionalized on the basis of the plant designation; generation plant is functionalized entirely to the generation function, transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for the Centennial Wind Project are included with SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.

- **Coal Reserves:**
SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

- **Shand Greenhouse:**
The Shand Greenhouse assets are functionalized to generation. The sub-functionalization is the same as the total for all SaskPower generation.

- **Cory Cogeneration Project:**
The SaskPower International assets associated with the Cory Cogeneration Station are functionalized to generation.

- **Meters:**
Meters are included in the meters sub-function within distribution.

- **General Plant - Unused Land:**
The functionalization and sub-functionalization of Unused land is done using operations, maintenance and administration expense.

- **General Plant – Buildings:**

The functionalization of the SaskPower head office building is based on floor space analysis. All other buildings are functionalized using cost center charge backs. The asset values for buildings are then prorated to sub-functions within each function using operations, maintenance and administration expense.

- **General Plant - Office Furniture & Equipment:**

The functionalization and sub-functionalization is the same as for buildings.

- **General Plant - Vehicles & Equipment:**

The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit center. The asset values for vehicles and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

- **General Plant - Computer Development & Equipment:**

The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) is functionalized on an application by application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

- **General Plant - Communication, Protection & Control Equipment:**

Communication, protection & control equipment is functionalized to generation, transmission, distribution and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

- **General Plant - Tools & Equipment:**

The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

1.02 - Allowance for Working Capital

- The allowance for working capital is consistent with Cost of Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working is calculated as 12.5% of the sum of operations, maintenance and administration expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.03 - Inventories

- SaskPower accounting records summarizes inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-functions within the generation, transmission and distribution functions using operations, maintenance and administration expense.

1.04 - Other Assets

- Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

  - **Natural gas / coal related:**
  Functionalized to generation.

  - **Employee related:**
  Functionalized using head count by Business Unit / Support Group.

  - **Insurance expense related:**
  Functionalized using advice from SaskPower Risk management staff.

  - **Miscellaneous:**
  Prorated to sub-functions within each function using operations, maintenance and administration expense.

<u>2.0 Revenue Requirement Items</u>

A summary of the functionalization methodology for expense plus the return on rate base items is provided below.

2.01 - Fuel Expense SaskPower Units

- The fuel expense for SaskPower units is functionalized 100% to generation.

2.02 - Purchased Power and Import

- The purchased power expense is functionalized 100% to generation.

2.03 - Export & Net Electricity Trading Revenue

- Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.04 - Operating, Maintenance & Administration (O M & A) Expense

- **Power Production Business Unit:**

The O M & A expense for the Power Production Business Unit is functionalized to generation. The O M & A expense for the Cory Cogeneration Station, Meridian, Spy Hill, Flyash sales and the Centennial Wind Power Facility (credit) is functionalized to Generation.

- **Shand Greenhouse:**

The O M & A expense for the Shand Greenhouse is functionalized to Generation.

- **NorthPoint:**

The O M & A expense for NorthPoint is functionalized to Generation.

- **Transmission & Distribution Business Unit:**

A small amount of the Transmission and Distribution Business Unit's O M & A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation. The remainder of the O M & A expense for the Business Unit is split to transmission and distribution using cost centre reports. The transmission O M & A is sub-functionalized by separating transmission O M & A expense into line and station related. The line related O M & A is sub-functionalized to main grid, 138 & 72 kV radials using line lengths by sub-function. The station related O M & A expense is sub-functionalized using station assets plant in service by sub-function.

Distribution O M & A is functionalized to distribution and customer services using a combination of staff advice and detailed cost centre O M & A reports. The same analysis provides the sub-functionalization within the distribution and customer services functions. The Electrical and Gas inspections O M & A is functionalized to customer services.

- **Customer Services Business Unit:**

The O M & A for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre operation, maintenance and administration reports.

- **Customer Services - Bad Debt Expense:**

The bad debt expense is assigned to the customer collections sub-function with the Customer Services function.

- **President / Board:**

Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

- **Corporate & Financial Services:**

Functionalized based on employee head count by Business Unit and Support Group.

- **Corporate & Financial Services - Insurance Premiums & Insurable Losses:**

Functionalized based on Breakdown from SaskPower Risk Management & Insurance department staff.

- **Planning, Environment & Regulatory Affairs:**

There are 2 major cost centres: Planning and Regulatory Affairs, and Environment. The Planning cost center is assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups. The Environment cost center is allocated based on an employee analysis which was done by SaskPower Environment department staff. Sub-functionalization is completed using O M & A sub-functionalization within each function.

- **General Council / Land:**

Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

- **Communication & Public Affairs:**

Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

- **Safety:**

Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the O M & A sub-functionalization within each function.

- **Corporate Information & Technology (CI & T):**

C I & T operations, maintenance and administration expense is separated into personal computer related and Business Unit related. The personal computer related is functionalized using employee headcount. The Business Unit related is functionalized using information from the cost centre report. Sub-functionalization is completed using O M & A within each function.

- **Human Resources:**

Functionalized based on the employee head count by Business Unit and then sub-functionalized using the O M & A sub-functionalization within each function.

- **Supply Chain:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

- **Business Development:**
The O M & A expense for Business Development is functionalized to Generation.

- **Service Delivery Renewal:**
Functionalized based on costs being evenly allocated between T&D and Customer Services and then sub-functionalized using the O M & A sub-functionalization within each function.

2.05 - Depreciation & Depletion

- The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.06 - Corporate Capital Tax

- Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.07 - Grants in Lieu of Taxes

- Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.08 - Miscellaneous Tax

- The miscellaneous tax expenses have been grouped into the following categories using cost center reports:

  - **Power production related:**
  Functionalized to generation.

  - **Fuel supply related:**
  Functionalized to generation.

  - **Gas & electric inspections related:**
  Functionalized to customer services.

  - **Vehicles and equipment related:**
  Functionalized using the vehicles and equipment plant functionalization above.

  - **Buildings related:**
  Functionalized using the buildings plant functionalization above.

- **Corporate related:**
  Functionalized using total O M & A expense.

2.09 - Other Income

Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.

- **Customer services payment income:**
  Assigned to the billing and customer accounts and customer collections sub-functions within customer services.

- **Meter reading income:**
  Assigned to the meter reading sub-function within the customer services function.

- **Gas & electric inspections income:**
  Assigned to the meter reading sub-function within the customer services function.

- **Transmission related income:**
  Assigned to sub-function within the transmission function using transmission O M & A expense.

- **Distribution related income:**
  Assigned to sub-function within the distribution function using distribution O M & A expense.

- **Miscellaneous Other Income:**
  Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

- **Customer Contribution Revenue**
  As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.

- **Green power premium:**
  Functionalized to generation.

- **NorthPoint:**
  Functionalized to generation.

- **Flyash & Wind Power Sales:**
  Functionalized to generation.

2.10 - Return on Rate Base

The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

Step 3: Classification

The classification process splits the functionalized costs into the parameters of service, which are:

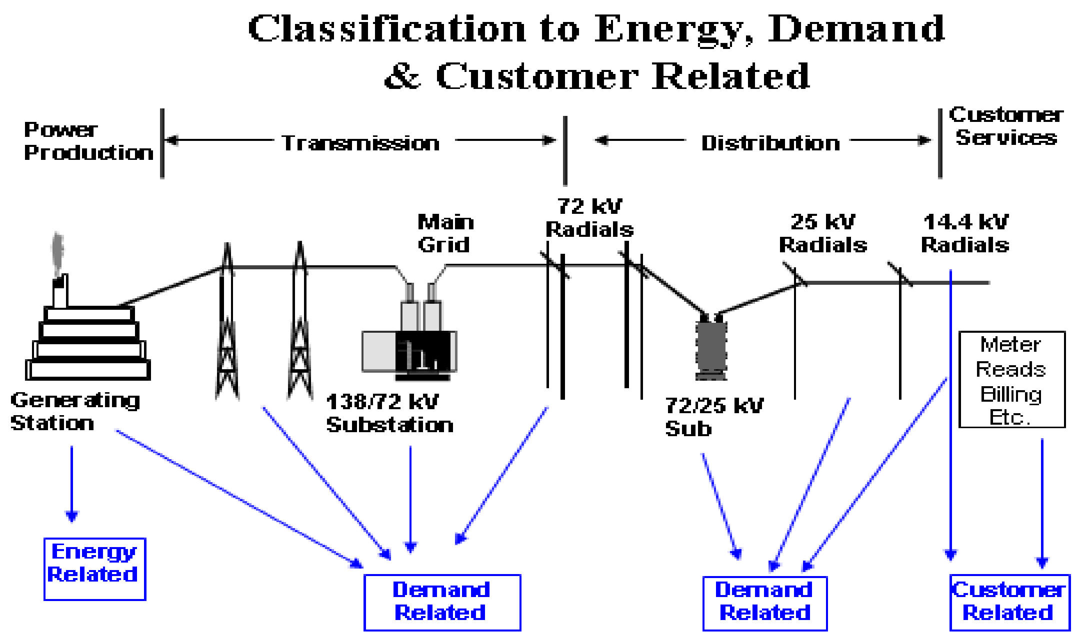
Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission and distribution systems.

Energy – costs that vary with the energy or kilowatt-hours provided by the utility, such as the cost of fuel and variable generation costs.

Customer – costs related to the number of customers served, such as customer billing, meter reading, customer service and the capital costs of meters and services.

Figure 2 below presents a schematic of the classification process.

Figure 2: Classification Schematic



A discussion of the classification of each of the functionalized costs is as follows:

- **SaskPower Generation:**

SaskPower generation rate base and expense is classified as either demand or energy related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Equivalent Peaker method, based on the NARUC Electric Utility Cost Allocation manual. This approach uses the ratio of the unit cost of new peaking capacity to the new cost of base load capacity for different generation types to classify rate base and depreciation to demand and energy.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The assets and expenses associated with the Cory Cogeneration Station are classified to demand and energy using the purchased power capacity / energy payments for this plant. The expenses and income associated with fly-ash sales are classified as energy related.

The classification of all wind power rate base and expense are classified 80% to energy based on the results of SaskPower's most recent planning study regarding the capacity value of wind generation. This is a change from previous years, when SaskPower planning staff did not attach any capacity value to wind generation.

- **Coal Reserves:**

SaskPower coal reserves are classified energy related.

- **Shand Greenhouse:**

The Shand Greenhouse assets, O M & A and depreciation expenses are classified using the classification of all SaskPower generation.

- **NorthPoint:**

The O M & A expense and other revenue associated with NorthPoint are classified 100% to energy related.

- **Transmission:**

Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% to demand.

- **Distribution:**

Substations are classified 100% to demand-related cost. Three phase feeders are classified 100% to demand-related cost. Both urban and rural single-phase primary lines are classified 65% to demand-related and 35% to customer-related cost. Line transformers are classified 70% to demand-related and 30% to customer-related cost based upon industry data. All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as customer-related.

- **Customer:**

Customer related costs are classified 100% to customer.

The results of the functionalization and classification (or functional classification) of rate base, expense, return on rate base, and revenue requirement are summarized in ***Schedules 2.00 through to 2.36***.

Step 4: Allocation

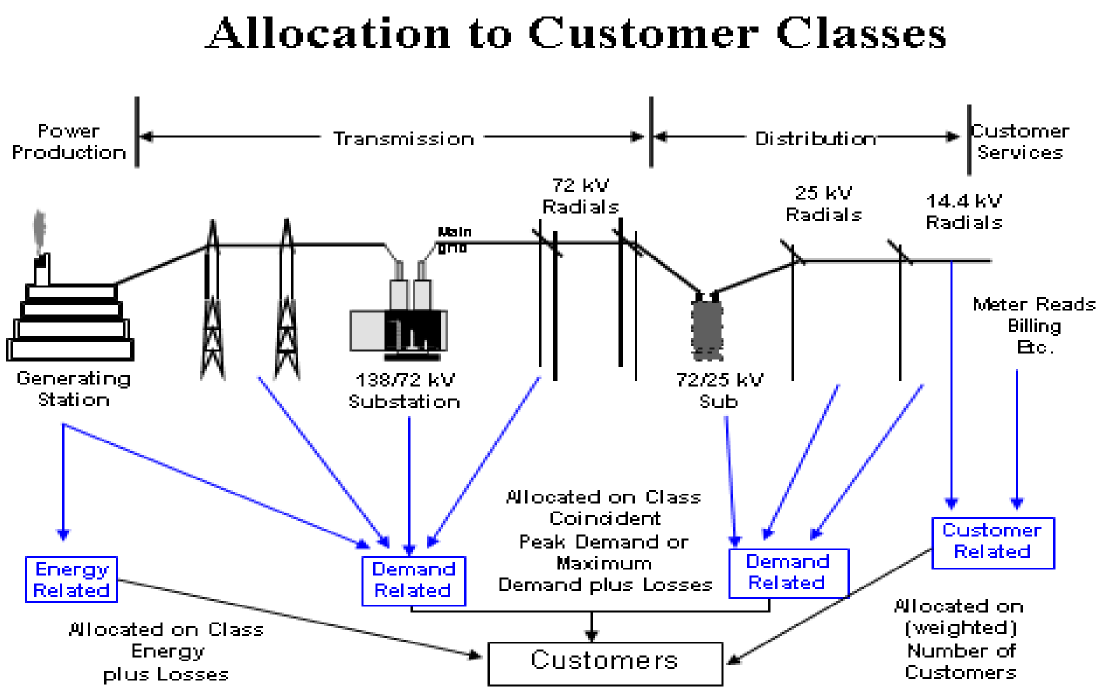
Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

Customer Classes: The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expense are allocated.

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

Figure 3 presents a schematic of the allocation process. The methodologies chosen by SaskPower for allocation are summarized in ***Schedule 3.0***. The core data used in the development of allocation factors can be found in ***Schedule 4.0***.

Figure 3: Allocation Schematic



An explanation of the allocation process by function is as follows:

Generation:
The energy related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses. The demand related rate base and expenses are allocated by the Two Coincident Peak (2CP) method, plus an estimate of losses. The 2CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

- **Interruptible Credit:**
  This interruptible credit (benefit) is allocated to the interruptible customer's class using the 2CP method. The cost of the interruptible credit is allocated to all other (non-interruptible) customers using the 2CP allocator.

Transmission:
All of the transmission functions are classified as demand and are allocated using the Two Coincident Peak (2CP) method as aforementioned.

Distribution:
The *demand functions* within distribution use a combination of the 2CP method and the Non Coincident Peak (NCP) method. The NCP method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occur, to the sum of all the class peaks, similarly determined. Only the *transformers* function uses the NCP methodology; all other functions use the 2CP methodology.

The *customer functions* within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter. Streetlight related rate base and expenses are allocated directly to streetlights.

Customer Services:
The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

- **Customer Contributions:**
  These contributions are allocated back directly to the customer classes which made the contribution.

Load Data
Customer load patterns were obtained for each class from the best available sources. Residential, Farm, Commercial, Oilfield and Streetlighting load data was estimated from typical load shapes for the customer types in each of these classes and extrapolated to the entire class in proportion to the classes billing determinants. Typical load shapes were gathered from a neighbouring utility. SaskPower is currently in the process of compiling its own load shape for Residential, Farm, Commercial and Oilfield classes through a random sample of interval meters throughout the Province. This sample will then be extrapolated to the entire class in proportion to the class billing determinants.

Power loads were analyzed based on hourly meter readings from actual customer's interval metered sites.

Loss Study
The purpose of a loss study is to properly quantify and assign to the appropriate customer class the electrical energy and demand losses in the various segments of the system. The starting point is the total energy loss in GWH, calculated as the difference between input to the system measured at the generator and output measured at the customer's meter.

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

Allocators
The allocation factors are summarized in ***Schedules 5.0 to 5.3***. The functionalization and classification of the revenue requirement is summarized in ***Tables 1 and 2*** (Summary of Results section), and the details are in ***Schedules 6.0 to 6.3***.

Step 5: Compare

The allocated rate base, allocated expenses and class revenue are the foundation for calculating the revenue to revenue requirement (R/RR) ratio by class. A R/RR measure of 1.00 indicates that the revenues exactly match the costs of providing service, or to put it simply, a customer pays the amount it costs SaskPower to provide them with service. An R/RR below 1.00 indicates that a customer class is paying less than the calculated costs SaskPower incurs to serve them while an R/RR above 1.00 indicates that a customer class is paying more. On a system-wide basis, the ratio must equal 1.00.

In response to comments that revenue to revenue requirement ratios that are higher or lower than 1.0 results in cross-subsidization between SaskPower's customers, external consultants have advised SaskPower that ratios close to 1.0 are deemed not to represent cross-subsidization as conducting a cost allocation study involves utilizing the best available, yet nevertheless imprecise, information with respect to how shared assets are used by various customer groups. A range of acceptable revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs. Hence, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes. Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

Revenue to revenue requirement (R/RR) ratios are determined by comparing the revenue collected from each class to the revenue required to serve the customer class. The revenue requirement for each customer class is calculated as the allocated rate base multiplied by the system return on rate base plus allocated expenses. Please refer to ***Table 3*** in the Summary of Results section for a R/RR ratio breakdown by customer class.

Step 6: Develop "Ideal" Rates

Each of SaskPower's customer classes is made up of one or more rate codes. A rate code outlines the specific price paid by a group of customers with similar characteristics. Separate rate codes may be required for location (urban or rural), size, the voltage level the customer is supplied at, or the type of load served i.e. streetlights. SaskPower currently has approximately 60 rate codes.

As discussed above, one of the primary objectives of rate design is fairness and equity. To satisfy this objective, SaskPower designs rates to recover the appropriate amount of revenue from each rate code within a class. Rates are also designed to collect the appropriate revenue from each customer within the rate code regardless of the customer's size or load factor. Essentially this means if a class has a R/RR ratio of 1.01, then the rate will be designed such that the overall rate code and each customer belonging to that rate code provides the same R/RR of 1.01.

Customer size is measured as the maximum customer demand in kWs. Customer annual load factor is defined as:

Load factor = annual energy / (maximum demand * 8760 hours).

A high load factor customer has a steady load which does not vary much from hour to hour. Oilfield and Power customers typically have high load factors. A low load factor customer has high peak loads relative to the amount of energy consumed. Residential customers typically have low load factors.

The cost of service model provides the energy, demand and customer related revenue requirement for each class of customers (see ***Table 2, Table 5 and Table** 7*), as well as for each rate code within a class. The energy, demand, and customer revenue requirement by rate code provides the basis for rate design.

Energy (Only) Metered Customers
All Residential, small Farm, and small Commercial customers have a simple energy meter. These meters cost much less than the demand and energy meter used for larger customers. The rate for energy metered customers includes an energy charge and a basic monthly charge. The combination of energy charge and basic monthly charge will collect the appropriate revenue for customers regardless of size. The energy charge and basic monthly charge will not, however, collect the appropriate revenue for customers of all load factors. It will collect the appropriate revenue for customers at the average load factor for the rate code. This is the trade-off for the less costly meter.

The energy charge is calculated as the energy plus demand revenue requirements divided by the rate code energy consumption. The basic monthly charge is calculated as the customer revenue requirement divided by the number of customer accounts in the rate code divided by 12 months.

Demand & Energy Metered Customers
Commercial and Farm customers over 50 kVA demand and all Power customers have a meter which measures both energy consumed in kWh and maximum monthly demand in kVA. The rates for demand & energy metered customers have separate charges for energy, demand and the basic monthly charge. The combination of energy, demand and basic monthly charge is intended to collect the appropriate revenue for each customer regardless of size or load factor.

SaskPower rates for demand & energy metered customers are designed using the cost of service model. Rates are designed by first determining the revenue requirement for a wide range of customer sizes and load factors. Then the rate is designed such that the appropriate revenue is collected for each combination of customer size and load factor.

Once the energy only and the demand & energy rates are designed for all rate codes, they are tested in SaskPower's revenue model. This is done to ensure SaskPower collects the appropriate revenue overall (meets revenue requirements) and from each customer class (fairness and equity). A check is also made to ensure that no one customer receives more than the maximum allowable rate increase of 15%. The adjusted rates are finalized, approved by the Saskatchewan Rate Review Panel and Cabinet, and then published for each individual rate code.

IV. SUPPORTING SCHEDULES (2014)

Schedule 1.0: Summary of the Functionalization of Financial Account Details

Summary of the Functionalization of Financial Account Details
2014 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)	13,352.2	7,769.5	58.2%	1,932.6	14.5%	3,544.7	26.5%	105.4	0.8%
Accumulated Depreciation (Schedule 1.2)	(5,156.8)	(3,004.2)	58.3%	(584.3)	11.3%	(1,516.8)	29.4%	(51.5)	1.0%
Allowance For Working Capital	81.0	44.6	55.0%	7.4	9.1%	17.8	22.0%	11.2	13.8%
Inventories (Schedule 1.3)	165.0	81.6	49.5%	22.7	13.8%	60.2	36.5%	0.5	0.3%
Other Assets (Schedule 1.3)	7.2	5.6	77.4%	0.3	4.5%	0.8	11.1%	0.5	7.0%
Total Rate Base	**8,448.6**	**4,897.1**	**58.0%**	**1,378.7**	**16.3%**	**2,106.8**	**24.9%**	**66.0**	**0.8%**
Revenue Requirement									
Fuel Expense SaskPower Units	394.3	394.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchased Power & Import	193.1	193.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Export & Net Electricity Trading Revenue (Credit)	(34.7)	(34.7)	100.0%	-	0.0%	-	0.0%	-	0.0%
Operating,Maintenance & Administration (Schedule 1.4)	647.7	345.2	53.3%	58.8	9.1%	146.7	22.6%	97.1	15.0%
Depreciation & Depletion (Schedule 1.5)	441.8	262.3	59.4%	50.8	11.5%	119.3	27.0%	9.4	2.1%
Corporate Capital Tax	34.0	19.8	58.1%	5.6	16.5%	8.4	24.7%	0.2	0.7%
Grants in Lieu of Taxes	22.5	22.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	86.4%	0.0	0.7%	0.0	1.6%	0.1	11.3%
Other Income (Credit) (Schedule 1.6)	(128.5)	(40.8)	31.7%	(13.8)	10.7%	(45.7)	35.5%	(28.3)	22.0%
Return on Rate Base @ 4.84%	409.1	237.1	58.0%	66.8	16.3%	102.0	24.9%	3.2	0.8%
Total Revenue Requirement	**1,979.8**	**1,399.3**	**70.7%**	**168.1**	**8.5%**	**330.8**	**16.7%**	**81.7**	**4.1%**

Schedule 1.1: Functionalization of Financial Account Details – Plant in Service

Functionalization of Financial Account Details
PLANT IN SERVICE
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Power Production	7,361.2	7,361.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	53.5	53.5	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	5.7	5.7	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**7,420.4**	**7,420.4**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	1,790.0	12.0	0.7%	1,741.1	97.3%	36.9	2.1%	-	0.0%
Total Transmission Assets	**1,790.0**	**12.0**	**0.7%**	**1,741.1**	**97.3%**	**36.9**	**2.1%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	3,068.9	-	0.0%	-	0.0%	3,068.9	100.0%	-	0.0%
Meters	176.4	-	0.0%	-	0.0%	176.4	100.0%	-	0.0%
Total Distribution Assets	**3,245.4**	**-**	**0.0%**	**-**	**0.0%**	**3,245.4**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	2.2	1.2	53.3%	0.2	9.1%	0.5	22.6%	0.3	15.0%
Buildings	200.0	90.7	45.3%	22.9	11.4%	51.5	25.8%	35.0	17.5%
Office Furniture & Equipment	36.4	16.5	45.3%	4.2	11.4%	9.4	25.8%	6.4	17.5%
Vehicles & Equipment	154.2	18.2	11.8%	38.0	24.6%	82.4	53.4%	15.6	10.1%
Computer Development & Equipment	337.0	155.4	46.1%	44.8	13.3%	93.7	27.8%	43.0	12.8%
Communication, Protection & Control	147.4	47.7	32.4%	79.2	53.7%	16.9	11.4%	3.6	2.5%
Tools & Equipment	19.2	7.4	38.4%	2.4	12.3%	8.0	41.7%	1.4	7.5%
Total General Plant Assets	**896.5**	**337.1**	**37.6%**	**191.6**	**21.4%**	**262.4**	**29.3%**	**105.4**	**11.8%**
Total Plant In Service	**13,352.2**	**7,769.5**	**58.2%**	**1,932.6**	**14.5%**	**3,544.7**	**26.5%**	**105.4**	**0.8%**

Schedule 1.2: Functionalization of Financial Account Details – Accumulated Depreciation

Functionalization of Financial Account Details
ACCUMULATED DEPRECIATION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Generation Assets	(2,795.4)	(2,795.4)	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	(27.6)	(27.6)	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International - Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse Assets	(3.0)	(3.0)	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**(2,826.0)**	**(2,826.0)**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	(498.9)	(2.6)	0.5%	(486.6)	97.5%	(9.7)	1.9%	-	0.0%
Total Transmission Assets	**(498.9)**	**(2.6)**	**0.5%**	**(486.6)**	**97.5%**	**(9.7)**	**1.9%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	(1,310.5)	-	0.0%	-	0.0%	(1,310.5)	100.0%	-	0.0%
Meters	(43.5)	-	0.0%	-	0.0%	(43.5)	100.0%	-	0.0%
Total Distribution Assets	**(1,354.0)**	**-**	**0.0%**	**-**	**0.0%**	**(1,354.0)**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Buildings	(40.2)	(20.5)	51.2%	(4.3)	10.7%	(9.5)	23.7%	(5.8)	14.4%
Office Furniture & Equipment	(16.6)	(8.5)	51.2%	(1.8)	10.7%	(3.9)	23.7%	(2.4)	14.4%
Vehicles & Equipment	(75.4)	(9.9)	13.1%	(18.3)	24.3%	(39.7)	52.7%	(7.5)	9.9%
Computer Development & Equipment	(265.5)	(107.7)	40.6%	(40.2)	15.1%	(84.7)	31.9%	(32.9)	12.4%
Communication, Protection & Control	(66.2)	(23.3)	35.2%	(33.0)	49.9%	(8.1)	12.3%	(1.7)	2.6%
Tools & Equipment	(14.0)	(5.6)	39.9%	(0.1)	1.0%	(7.0)	50.2%	(1.2)	8.9%
Total General Plant Assets	**(477.8)**	**(175.5)**	**36.7%**	**(97.7)**	**20.5%**	**(153.0)**	**32.0%**	**(51.5)**	**10.8%**
Total Accumulated Depreciation	**(5,156.8)**	**(3,004.2)**	**58.3%**	**(584.3)**	**11.3%**	**(1,516.8)**	**29.4%**	**(51.5)**	**1.0%**

Schedule 1.3: Functionalization of Financial Account Details – Inventories/Other Assets

Functionalization of Financial Account Details
INVENTORIES
2014 Test Embedded Cost of Service Study
($ Millions)

	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Inventories									
Power Production - Repair Stores	52.1	52.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production - Fuel	27.9	27.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission & Distribution	81.9	-	0.0%	22.4	27.4%	59.5	72.6%	-	0.0%
Miscellaneous (Computers, Power Shop)	3.1	1.7	53.3%	0.3	9.1%	0.7	22.6%	0.5	15.0%
Total Inventories	**165.0**	**81.6**	**49.5%**	**22.7**	**13.8%**	**60.2**	**36.5%**	**0.5**	**0.3%**

Functionalization of Financial Account Details
OTHER ASSETS
2014 Base Embedded Cost of Service Study
($ Millions)

	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	3.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Intangible Assets	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Prepaid Expenses - Insurance	0.8	0.7	90.0%	0.0	2.8%	0.0	6.1%	0.0	1.1%
Miscellaneous Prepaid Expenses	3.3	1.8	53.3%	0.3	9.1%	0.8	22.6%	0.5	15.0%
Total Generation Expenses	**7.2**	**5.6**	**77.4%**	**0.3**	**4.5%**	**0.8**	**11.1%**	**0.5**	**7.0%**

Schedule 1.4: Functionalization of Financial Account Details – O M & A Expenses

Functionalization of Financial Account Details
OM&A EXPENSES
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Expenses									
Power Plant Operation	172.1	172.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Fuel Supply	1.9	1.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production Overhead	28.3	28.3	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Cory Cogen	14.1	14.1	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Meridian	7.1	7.1	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Spy Hill	(2.2)	(2.2)	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Flyash	1.9	1.9	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Centennial Wind	5.9	5.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	1.3	1.3	100.0%	-	0.0%	-	0.0%	-	0.0%
NorthPoint Energy Solutions	7.8	7.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Expenses	**238.1**	**238.1**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission & Distribution Expenses									
T & D - Planning Support	15.5	8.4	54.0%	6.9	44.1%	-	0.0%	0.3	1.9%
T & D - Transmission Including 138 & 72 kV Radials	30.5	-	0.0%	30.5	100.0%	-	0.0%	-	0.0%
T & D - Distribution	99.1	-	0.0%	-	0.0%	99.1	100.0%	-	0.0%
T & D - Customer Services	5.4	-	0.0%	-	0.0%	-	0.0%	5.4	100.0%
T & D - Gas & Electric Inspections	12.2	-	0.0%	-	0.0%	-	0.0%	12.2	100.0%
Total Transmission & Distribution Expenses	**162.8**	**8.4**	**5.2%**	**37.4**	**23.0%**	**99.1**	**60.9%**	**17.9**	**11.0%**
Customer Services Expenses									
Meter Reading	7.5	-	0.0%	-	0.0%	-	0.0%	7.5	100.0%
Metering Services	2.9	-	0.0%	-	0.0%	-	0.0%	2.9	100.0%
Billing Services	3.5	-	0.0%	-	0.0%	-	0.0%	3.5	100.0%
Collections/Special Collections	4.1	-	0.0%	-	0.0%	-	0.0%	4.1	100.0%
Bad Debt Expense	2.3	-	0.0%	-	0.0%	-	0.0%	2.3	100.0%
Marketing & Sales	3.6	-	0.0%	-	0.0%	-	0.0%	3.6	100.0%
Demand Side Management	14.3	14.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Customer Service	16.5	-	0.0%	-	0.0%	-	0.0%	16.5	100.0%
Total Customer Services Expenses	**54.7**	**14.3**	**26.1%**	**-**	**0.0%**	**-**	**0.0%**	**40.4**	**73.9%**
Support Group Expenses									
President / Board	3.5	1.9	53.3%	0.3	9.1%	0.8	22.6%	0.5	15.0%
Corporate & Financial Services	22.7	12.8	56.4%	2.2	9.6%	4.8	21.1%	2.9	12.8%
Planning, Environment & Regulatory Affairs	16.8	10.7	63.4%	1.3	7.9%	3.1	18.4%	1.7	10.2%
General Council / Land	4.8	2.5	53.3%	0.4	9.1%	1.1	22.6%	0.7	15.0%
Communication & Public Affairs	8.6	4.6	53.3%	0.8	9.1%	1.9	22.6%	1.3	15.0%
Safety	7.9	4.1	51.9%	0.8	9.8%	1.8	23.0%	1.2	15.3%
Corporate Information & Technology	70.1	32.7	46.7%	8.1	11.5%	17.7	25.2%	11.6	16.6%
Human Resources	20.3	9.0	44.4%	2.4	12.0%	5.4	26.5%	3.5	17.1%
Supply Chain	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Business Development	1.4	1.4	100.0%	-	0.0%	-	0.0%	-	0.0%
Service Delivery Renewal	35.9	4.7	13.1%	5.0	14.0%	10.9	30.4%	15.2	42.5%
Total Support Group Expenses	**192.1**	**84.4**	**44.0%**	**21.4**	**11.1%**	**47.5**	**24.7%**	**38.7**	**20.2%**
Total OM&A Expenses	**647.7**	**345.2**	**53.3%**	**58.8**	**9.1%**	**146.7**	**22.6%**	**97.1**	**15.0%**

Schedule 1.5: Functionalization of Financial Account Details – Depreciation & Depletion Expense

Functionalization of Financial Account Details
DEPRECIATION & DEPLETION EXPENSE
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Generation Assets	232.5	232.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	1.2	1.2	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International - Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse Assets	0.2	0.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**233.9**	**233.9**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	39.1	0.2	0.6%	37.9	97.0%	0.9	2.4%	-	0.0%
Total Transmission Assets	**39.1**	**0.2**	**0.6%**	**37.9**	**97.0%**	**0.9**	**2.4%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	90.7	-	0.0%	-	0.0%	90.7	100.0%	-	0.0%
Meters	8.5	-	0.0%	-	0.0%	8.5	100.0%	-	0.0%
Total Distribution Assets	**99.2**	**-**	**0.0%**	**-**	**0.0%**	**99.2**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Buildings	1.7	1.0	55.3%	0.2	9.2%	0.4	21.0%	0.3	14.5%
Office Furniture & Equipment	1.4	0.8	55.3%	0.1	9.2%	0.3	21.0%	0.2	14.5%
Vehicles & Equipment	9.5	0.9	9.5%	2.4	25.2%	5.2	54.7%	1.0	10.6%
Computer Development & Equipment	46.1	21.9	47.5%	5.2	11.4%	11.4	24.8%	7.6	16.4%
Communication, Protection & Control	8.9	2.8	31.6%	4.8	53.9%	1.1	12.0%	0.2	2.6%
Tools & Equipment	1.8	0.8	41.4%	0.1	5.4%	0.8	45.2%	0.1	8.1%
Total General Plant Assets	**69.6**	**28.1**	**40.4%**	**12.9**	**18.5%**	**19.2**	**27.6%**	**9.4**	**13.5%**
Total Depreciation Expense	**441.8**	**262.3**	**59.4%**	**50.8**	**11.5%**	**119.3**	**27.0%**	**9.4**	**2.1%**

Schedule 1.6: Functionalization of Financial Account Details – Other Income

Functionalization of Financial Account Details
OTHER INCOME
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Other Income									
Customer Services Payment Charges	(5.2)	-	0.0%	-	0.0%	-	0.0%	(5.2)	100.0%
Meter Reading	(3.5)	-	0.0%	-	0.0%	-	0.0%	(3.5)	100.0%
Inspections	(18.7)	-	0.0%	-	0.0%	-	0.0%	(18.7)	100.0%
Transmission	(1.9)	(0.3)	17.6%	(1.6)	82.4%	-	0.0%	-	0.0%
Distribution	(5.9)	-	0.0%	-	0.0%	(5.9)	100.0%	-	0.0%
Clean Coal Project Credits	(4.3)	(4.3)	100.0%	-	0.0%	-	0.0%	-	0.0%
CO2 Sales	(17.5)	(17.5)	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Other Income	(6.2)	(3.3)	53.3%	(0.6)	9.1%	(1.4)	22.6%	(0.9)	15.0%
Customer Contribution Revenue	(50.0)	-	0.0%	(11.7)	23.3%	(38.3)	76.7%	-	0.0%
Green Power Premium	(5.6)	(5.6)	100.0%	-	0.0%	-	0.0%	-	0.0%
NorthPoint	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Flyash Sales	(9.8)	(9.8)	100.0%	-	0.0%	-	0.0%	-	0.0%
Consulting & Contracting Services	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total Other Income	**(128.5)**	**(40.8)**	**31.7%**	**(13.8)**	**10.7%**	**(45.7)**	**35.5%**	**(28.3)**	**22%**

Schedule 2.00: Functional Classification of Financial Account Details – Generation

Functionalization and Classification of Financial Account Details
GENERATION Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Basis of Classification	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
					Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Rate Base															
Plant In Service (Schedule 2.01)	13,352.2	7,769.5	58.2%	Functional Class of PIS	3,074.9	3,314.9	316.1	300.1	35.8	73.1	166.4	249.5	176.3	62.3	-
Accumulated Depreciation (Schedule 2.02)	(5,156.8)	(3,004.2)	58.3%	Functional Class of Accum. Depr'n	(1,144.5)	(1,369.6)	(117.6)	(124.0)	(17.9)	(25.2)	(50.5)	(75.8)	(53.6)	(25.5)	-
Allowance For Working Capital	81.0	44.6	55.0%	12.50% of OM&A and Taxes	26.2	9.6	2.6	0.7	0.9	0.2	0.4	0.6	0.4	0.3	2.6
Inventories (Schedule 2.03)	165.0	81.6	49.5%	Functional Class of Inventories	38.3	33.4	3.9	3.0	0.0	0.2	0.6	0.9	0.7	0.4	-
Other Assets (Schedule 2.03)	7.2	5.6	77.4%	Functional Classification of Other Assets	1.6	3.3	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Rate Base	**8,448.6**	**4,897.1**	**58.0%**		**1,996.6**	**1,991.6**	**205.1**	**180.2**	**19.0**	**48.4**	**116.9**	**175.3**	**123.9**	**37.5**	**2.6**
Revenue Requirement															
Fuel Expense SaskPower Units	394.3	394.3	100.0%	Functional Class of Fuel Exp.	-	361.4	-	32.8	-	-	-	-	-	0.1	-
Purchased Power & Import	193.1	193.1	100.0%	Functional Class of PP, Import & NP Fee	59.2	117.2	6.1	10.6	-	-	-	-	-	0.0	-
Export & Net Electricity Trading Revenue (Credit)	(34.7)	(34.7)	100.0%	Functional Class of Exports	-	(31.8)	-	(2.9)	-	-	-	-	-	(0.0)	-
Operating, Maintenance & Administration (Schedule 2.04)	647.7	345.2	53.3%	Functional Class of OM&A	219.8	75.1	21.4	5.7	8.0	1.6	3.2	4.8	3.4	2.3	-
Depreciation & Depletion (Schedule 2.05)	441.8	262.3	59.4%	Functional Class of Depr'n & Depletion	115.2	102.1	11.8	9.2	2.1	2.5	4.9	7.4	5.2	1.8	-
Corporate Capital Tax	34.0	19.8	58.1%	Functional Class of Corp. Capital Tax	8.0	8.1	0.8	0.7	0.1	0.2	0.5	0.7	0.5	0.2	-
Grants in Lieu of Taxes	22.5	22.5	100.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	22.5
Miscellaneous Tax	0.5	0.4	86.4%	Functional Class of Misc. Tax	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Other Income (Credit) (Schedule 2.06)	(128.5)	(40.8)	31.7%	Functional Class of Other Income	(12.0)	(23.1)	(1.2)	(2.1)	(0.4)	(0.2)	(0.5)	(0.7)	(0.5)	(0.2)	-
Return on Rate Base @ 4.84%	409.1	237.1	58.0%	Rate Base	96.7	96.4	9.9	8.7	0.9	2.3	5.7	8.5	6.0	1.8	0.1
Total Revenue Requirement	**1,979.8**	**1,399.3**	**70.7%**		**487.0**	**705.7**	**48.8**	**62.8**	**10.7**	**6.5**	**13.8**	**20.7**	**14.6**	**5.9**	**22.6**

Schedule 2.01: Functional Classification of Financial Account Details – Generation Plant in Service

Functionalization and Classification of Financial Account Details
GENERATION PLANT IN SERVICE
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	7,361.2	7,361.2	100.0%	2,874.4	3,199.6	296.5	290.6	-	58.2	163.4	245.2	173.2	60.2	-
Coal Reserves	53.5	53.5	100.0%	-	49.0	-	4.5	-	-	-	-	-	0.0	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	5.7	5.7	100.0%	2.4	2.7	0.3	0.2	-	-	-	-	-	-	-
Total Generation	**7,420.4**	**7,420.4**	**100.0%**	**2,876.9**	**3,251.4**	**296.7**	**295.3**	**-**	**58.2**	**163.4**	**245.2**	**173.2**	**60.2**	**-**
Transmission														
Transmission	1,790.0	12.0	0.7%	10.8	-	1.1	-	-	-	-	-	-	-	-
Total Transmission	**1,790.0**	**12.0**	**0.7%**	**10.8**	**-**	**1.1**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	3,068.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	176.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**3,245.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	2.2	1.2	53.3%	0.8	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Buildings	200.0	90.7	45.3%	60.6	18.0	5.8	1.2	0.8	0.4	0.9	1.4	1.0	0.6	-
Office Furniture & Equipment	36.4	16.5	45.3%	11.0	3.3	1.1	0.2	0.1	0.1	0.2	0.2	0.2	0.1	-
Vehicles & Equipment	154.2	18.2	11.8%	13.0	2.7	1.3	0.2	0.0	0.1	0.2	0.3	0.2	0.1	-
Computer Development & Equipment	337.0	155.4	46.1%	96.5	38.2	9.5	3.1	0.3	1.2	1.6	2.3	1.6	1.1	-
Communication, Protection & Control	147.4	47.7	32.4%	-	-	-	-	34.5	13.3	-	-	-	-	-
Tools & Equipment	19.2	7.4	38.4%	5.3	1.1	0.5	0.1	-	0.0	0.1	0.1	0.1	0.1	-
Total General Plant	**896.5**	**337.1**	**37.6%**	**187.2**	**63.5**	**18.3**	**4.8**	**35.8**	**15.0**	**2.9**	**4.4**	**3.1**	**2.1**	**-**
Total Plant In Service	**13,352.2**	**7,769.5**	**58.2%**	**3,074.9**	**3,314.9**	**316.1**	**300.1**	**35.8**	**73.1**	**166.4**	**249.5**	**176.3**	**62.3**	**-**

Schedule 2.02: Functional Classification of Financial Account Details – Generation Accumulated Depreciation

Functionalization and Classification of Financial Account Details
GENERATION ACCUMULATED DEPRECIATION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	(2,795.4)	(2,795.4)	100.0%	(1,043.8)	(1,308.9)	(107.6)	(118.9)	-	(17.4)	(49.0)	(73.5)	(51.9)	(24.4)	-
Coal Reserves	(27.6)	(27.6)	100.0%	-	(25.3)	-	(2.3)	-	-	-	-	-	(0.0)	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	(3.0)	(3.0)	100.0%	(1.2)	(1.5)	(0.1)	(0.1)	-	-	-	-	-	-	-
Total Generation	**(2,826.0)**	**(2,826.0)**	**100.0%**	**(1,045.0)**	**(1,335.8)**	**(107.8)**	**(121.3)**	**-**	**(17.4)**	**(49.0)**	**(73.5)**	**(51.9)**	**(24.4)**	**-**
Transmission														
Transmission	(498.9)	(2.6)	0.5%	(2.4)	-	(0.2)	-	-	-	-	-	-	-	-
Total Transmission	**(498.9)**	**(2.6)**	**0.5%**	**(2.4)**	**-**	**(0.2)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	(1,310.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	(43.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**(1,354.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Buildings	(40.2)	(20.5)	51.2%	(14.1)	(3.6)	(1.4)	(0.3)	(0.1)	(0.1)	(0.2)	(0.3)	(0.2)	(0.2)	-
Office Furniture & Equipment	(16.6)	(8.5)	51.2%	(5.8)	(1.5)	(0.6)	(0.1)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	-
Vehicles & Equipment	(75.4)	(9.9)	13.1%	(7.1)	(1.5)	(0.7)	(0.1)	(0.0)	(0.0)	(0.1)	(0.2)	(0.1)	(0.1)	-
Computer Development & Equipment	(265.5)	(107.7)	40.6%	(66.1)	(26.4)	(6.5)	(2.1)	(0.9)	(1.1)	(1.1)	(1.6)	(1.1)	(0.8)	-
Communication, Protection & Control	(66.2)	(23.3)	35.2%	-	-	-	-	(16.8)	(6.5)	-	-	-	-	-
Tools & Equipment	(14.0)	(5.6)	39.9%	(4.0)	(0.8)	(0.4)	(0.1)	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	-
Total General Plant	**(477.8)**	**(175.5)**	**36.7%**	**(97.1)**	**(33.8)**	**(9.6)**	**(2.7)**	**(17.9)**	**(7.7)**	**(1.6)**	**(2.3)**	**(1.6)**	**(1.1)**	**-**
Total Accumulated Depreciation	**(5,156.8)**	**(3,004.2)**	**58.3%**	**(1,144.5)**	**(1,369.6)**	**(117.6)**	**(124.0)**	**(17.9)**	**(25.2)**	**(50.5)**	**(75.8)**	**(53.6)**	**(25.5)**	**-**

Schedule 2.03: Functional Classification of Financial Account Details – Generation Inventories/Other Assets

Functionalization and Classification of Financial Account Details
GENERATION INVENTORIES
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Inventories														
Power Production - Repair Stores	52.1	52.1	100.0%	37.3	7.4	3.8	0.7	-	0.2	0.6	0.9	0.7	0.4	-
Power Production - Fuel	27.9	27.9	100.0%	-	25.6	-	2.3	-	-	-	-	-	0.0	-
Transmission & Distribution	81.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	3.1	1.7	53.3%	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Inventories	**165.0**	**81.6**	**49.5%**	**38.3**	**33.4**	**3.9**	**3.0**	**0.0**	**0.2**	**0.6**	**0.9**	**0.7**	**0.4**	**-**

Functionalization and Classification of Financial Account Details
GENERATION OTHER ASSETS
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Other Assets														
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	3.1	100.0%	-	2.9	-	0.3	-	-	-	-	-	0.0	-
Intangible Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.7	90.0%	0.5	0.1	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Miscellaneous Prepaid Expenses	3.3	1.8	53.3%	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Other Assets	**7.2**	**5.6**	**77.4%**	**1.6**	**3.3**	**0.2**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**

Schedule 2.04: Functional Classification of Financial Account Details – Generation O M & A Expenses

Functionalization and Classification of Financial Account Details
GENERATION OM&A EXPENSES
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation Expenses														
Power Plant Operation	172.1	172.1	100.0%	123.2	24.6	12.7	2.2	-	0.7	2.0	3.0	2.1	1.4	-
Fuel Supply	1.9	1.9	100.0%	-	1.7	-	0.2	-	-	-	-	-	0.0	-
Power Production Overhead	28.3	28.3	100.0%	20.2	4.0	2.1	0.4	-	0.1	0.3	0.5	0.4	0.2	-
SaskPower International (SPI) - Cory Cogen	14.1	14.1	100.0%	11.2	1.7	1.2	0.2	-	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.1	7.1	100.0%	2.1	4.4	0.2	0.4	-	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(2.2)	(2.2)	100.0%	(1.5)	(0.5)	(0.2)	(0.0)	-	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	1.9	100.0%	-	1.8	-	0.2	-	-	-	-	-	0.0	-
SaskPower International (SPI) - Centennial Wind	5.9	5.9	100.0%	-	5.4	-	0.5	-	-	-	-	-	0.0	-
Shand Greenhouse	1.3	1.3	100.0%	0.9	0.2	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
NorthPoint Energy Solutions	7.8	7.8	100.0%	-	7.1	-	0.6	-	-	-	-	-	0.0	-
Total Generation Expenses	**238.1**	**238.1**	**100.0%**	**156.1**	**50.4**	**16.1**	**4.6**	**-**	**0.8**	**2.4**	**3.6**	**2.5**	**1.7**	**-**
Transmission & Distribution Expenses														
T & D - Planning Support	15.5	8.4	54.0%	0.2	0.2	0.0	0.0	7.5	0.5	-	-	-	-	-
T & D - Transmission Including 138 & 72 kV Radials	30.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Distribution	99.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Customer Services	5.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Gas & Electric Inspections	12.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	**162.8**	**8.4**	**5.2%**	**0.2**	**0.2**	**0.0**	**0.0**	**7.5**	**0.5**	**-**	**-**	**-**	**-**	**-**
Customer Services Expenses														
Meter Reading	7.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Metering Services	2.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	4.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	2.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	14.3	14.3	100.0%	7.2	7.2	-	-	-	-	-	-	-	-	-
Customer Service	16.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	**54.7**	**14.3**	**26.1%**	**7.2**	**7.2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Support Group Expenses														
President / Board	3.5	1.9	53.3%	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Corporate & Financial Services	22.7	12.8	56.4%	8.9	2.2	0.9	0.2	0.0	0.1	0.1	0.2	0.1	0.1	-
Planning, Environment & Regulatory Affairs	16.8	10.7	63.4%	7.7	1.5	0.8	0.1	0.1	0.0	0.1	0.2	0.1	0.1	-
General Council / Land	4.8	2.5	53.3%	1.6	0.6	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	-
Communication & Public Affairs	8.6	4.6	53.3%	2.9	1.0	0.3	0.1	0.1	0.0	0.0	0.1	0.0	0.0	-
Safety	7.9	4.1	51.9%	2.7	0.8	0.3	0.1	0.1	0.0	0.0	0.1	0.0	0.0	-
Corporate Information & Technology	70.1	32.7	46.7%	21.9	6.6	2.1	0.5	0.1	0.1	0.3	0.5	0.4	0.2	-
Human Resources	20.3	9.0	44.4%	6.1	1.7	0.6	0.1	0.0	0.0	0.1	0.1	0.1	0.1	-
Supply Chain	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Business Development	1.4	1.4	100.0%	1.0	0.2	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Service Delivery Renewal	35.9	4.7	13.1%	2.3	2.3	-	-	-	-	-	-	-	-	-
Total Support Group Expenses	**192.1**	**84.4**	**44.0%**	**56.4**	**17.4**	**5.3**	**1.1**	**0.5**	**0.3**	**0.8**	**1.2**	**0.9**	**0.6**	**-**
Total OM&A Expenses	**647.7**	**345.2**	**53.3%**	**219.8**	**75.1**	**21.4**	**5.7**	**8.0**	**1.6**	**3.2**	**4.8**	**3.4**	**2.3**	**-**

Schedule 2.05: Functional Classification of Financial Account Details – Generation Depreciation & Depletion

Functionalization and Classification of Financial Account Details
GENERATION DEPRECIATION & DEPLETION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	232.5	232.5	100.0%	97.9	95.9	10.1	8.7	-	1.7	4.7	7.0	4.9	1.6	-
Coal Reserves	1.2	1.2	100.0%	-	1.1	-	0.1	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	0.2	100.0%	0.1	0.1	0.0	0.0	-	-	-	-	-	-	-
Total Generation	**233.9**	**233.9**	**100.0%**	**98.0**	**97.1**	**10.1**	**8.8**	**-**	**1.7**	**4.7**	**7.0**	**4.9**	**1.6**	**-**
Transmission														
Transmission	39.1	0.2	0.6%	0.2	-	0.0	-	-	-	-	-	-	-	-
Total Transmission	**39.1**	**0.2**	**0.6%**	**0.2**	**-**	**0.0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	90.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	8.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**99.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Buildings	1.7	1.0	55.3%	0.7	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Office Furniture & Equipment	1.4	0.8	55.3%	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Vehicles & Equipment	9.5	0.9	9.5%	0.6	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Computer Development & Equipment	46.1	21.9	47.5%	14.6	4.5	1.4	0.3	0.0	0.1	0.2	0.3	0.2	0.2	-
Communication, Protection & Control	8.9	2.8	31.6%	-	-	-	-	2.0	0.8	-	-	-	-	-
Tools & Equipment	1.8	0.8	41.4%	0.5	0.1	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Total General Plant	**69.6**	**28.1**	**40.4%**	**17.0**	**5.1**	**1.6**	**0.4**	**2.1**	**0.9**	**0.3**	**0.4**	**0.3**	**0.2**	**-**
Total Depreciation & Depletion	**441.8**	**262.3**	**59.4%**	**115.2**	**102.1**	**11.8**	**9.2**	**2.1**	**2.5**	**4.9**	**7.4**	**5.2**	**1.8**	**-**

Schedule 2.06: Functional Classification of Financial Account Details – Generation Other Income

Functionalization and Classification of Financial Account Details
GENERATION OTHER INCOME
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Other Income														
Customer Services Payment Charges	(5.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	(3.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission	(1.9)	(0.3)	17.6%	-	-	-	-	(0.3)	(0.0)	-	-	-	-	-
Distribution	(5.9)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Clean Coal Project Credits	(4.3)	(4.3)	100.0%	(3.0)	(0.6)	(0.3)	(0.1)	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	-
CO2 Sales	(17.5)	(17.5)	100.0%	(6.8)	(7.6)	(0.7)	(0.7)	-	(0.1)	(0.4)	(0.6)	(0.4)	(0.1)	-
Miscellaneous Other Income	(6.2)	(3.3)	53.3%	(2.1)	(0.7)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Customer Contributions Revenue	(50.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Green Power Premium	(5.6)	(5.6)	100.0%	-	(5.1)	-	(0.5)	-	-	-	-	-	(0.0)	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(9.8)	(9.8)	100.0%	-	(9.0)	-	(0.8)	-	-	-	-	-	(0.0)	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**(128.5)**	**(40.8)**	**31.7%**	**(12.0)**	**(23.1)**	**(1.2)**	**(2.1)**	**(0.4)**	**(0.2)**	**(0.5)**	**(0.7)**	**(0.5)**	**(0.2)**	**-**

Schedule 2.10: Functional Classification of Financial Account Details – Transmission

Functionalization and Classification of Financial Account Details
TRANSMISSION Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Basis of Classification	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kv Lines Radials
					Demand	Demand	Demand	Demand
Rate Base								
Plant In Service (Schedule 2.11)	13,352.2	1,932.6	14.5%	Functional Class of PIS	1,024.8	504.4	142.6	260.8
Accumulated Depreciation (Schedule 2.12)	(5,156.8)	(584.3)	11.3%	Functional Class of Accum. Depr'n	(328.5)	(127.6)	(48.5)	(79.7)
Allowance For Working Capital	81.0	7.4	9.1%	12.50% of OM&A and Taxes	4.1	1.4	0.5	1.4
Inventories (Schedule 2.13)	165.0	22.7	13.8%	Functional Class of Inventories	12.7	4.1	1.6	4.4
Other Assets (Schedule 2.13)	7.2	0.3	4.5%	Functional Classification of Other Assets	0.2	0.1	0.0	0.1
Total Rate Base	**8,448.6**	**1,378.7**	**16.3%**		**713.2**	**382.3**	**96.3**	**187.0**
Revenue Requirement								
Fuel Expense SaskPower Units	394.3	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-
Purchased Power & Import	193.1	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(34.7)	-	0.0%	Functional Class of Exports	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.14)	647.7	58.8	9.1%	Functional Class of OM&A	32.8	10.5	4.1	11.4
Depreciation & Depletion (Schedule 2.15)	441.8	50.8	11.5%	Functional Class of Depr'n & Depletion	28.0	11.2	3.9	7.7
Corporate Capital Tax	34.0	5.6	16.5%	Functional Class of Corp. Capital Tax	2.9	1.6	0.4	0.8
Grants in Lieu of Taxes	22.5	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-
Miscellaneous Tax	0.5	0.0	0.7%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.16)	(128.5)	(13.8)	10.7%	Functional Class of Other Income	(3.3)	(9.1)	(0.1)	(1.2)
Return on Rate Base @ 4.84%	409.1	66.8	16.3%	Rate Base	34.5	18.5	4.7	9.1
Total Revenue Requirement	**1,979.8**	**168.1**	**8.5%**		**94.9**	**32.7**	**12.9**	**27.7**

Schedule 2.11: Functional Classification of Financial Account Details – Transmission Plant in Service

Functionalization and Classification of Financial Account Details
TRANSMISSION PLANT IN SERVICE
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	7,361.2	-	0.0%	-	-	-	-
Coal Reserves	53.5	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-
Total Generation	**7,420.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	1,790.0	1,741.1	97.3%	918.0	470.1	129.3	223.6
Total Transmission	**1,790.0**	**1,741.1**	**97.3%**	**918.0**	**470.1**	**129.3**	**223.6**
Distribution							
Distribution	3,068.9	-	0.0%	-	-	-	-
Meters	176.4	-	0.0%	-	-	-	-
Total Distribution	**3,245.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	2.2	0.2	9.1%	0.1	0.0	0.0	0.0
Buildings	200.0	22.9	11.4%	12.7	4.1	1.6	4.4
Office Furniture & Equipment	36.4	4.2	11.4%	2.3	0.7	0.3	0.8
Vehicles & Equipment	154.2	38.0	24.6%	21.2	6.8	2.6	7.4
Computer Development & Equipment	337.0	44.8	13.3%	25.0	8.0	3.1	8.7
Communication, Protection & Control	147.4	79.2	53.7%	44.1	14.2	5.5	15.4
Tools & Equipment	19.2	2.4	12.3%	1.3	0.4	0.2	0.5
Total General Plant	**896.5**	**191.6**	**21.4%**	**106.8**	**34.3**	**13.3**	**37.1**
Total Plant In Service	**13,352.2**	**1,932.6**	**14.5%**	**1,024.8**	**504.4**	**142.6**	**260.8**

Schedule 2.12: Functional Classification of Financial Account Details – Transmission Accumulated Depreciation

Functionalization and Classification of Financial Account Details
TRANSMISSION ACCUMULATED DEPRECIATION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	(2,795.4)	-	0.0%	-	-	-	-
Coal Reserves	(27.6)	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	(3.0)	-	0.0%	-	-	-	-
Total Generation	**(2,826.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	(498.9)	(486.6)	97.5%	(274.0)	(110.1)	(41.7)	(60.7)
Total Transmission	**(498.9)**	**(486.6)**	**97.5%**	**(274.0)**	**(110.1)**	**(41.7)**	**(60.7)**
Distribution							
Distribution	(1,310.5)	-	0.0%	-	-	-	-
Meters	(43.5)	-	0.0%	-	-	-	-
Total Distribution	**(1,354.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	-	-	0.0%	-	-	-	-
Buildings	(40.2)	(4.3)	10.7%	(2.4)	(0.8)	(0.3)	(0.8)
Office Furniture & Equipment	(16.6)	(1.8)	10.7%	(1.0)	(0.3)	(0.1)	(0.3)
Vehicles & Equipment	(75.4)	(18.3)	24.3%	(10.2)	(3.3)	(1.3)	(3.5)
Computer Development & Equipment	(265.5)	(40.2)	15.1%	(22.4)	(7.2)	(2.8)	(7.8)
Communication, Protection & Control	(66.2)	(33.0)	49.9%	(18.4)	(5.9)	(2.3)	(6.4)
Tools & Equipment	(14.0)	(0.1)	1.0%	(0.1)	(0.0)	(0.0)	(0.0)
Total General Plant	**(477.8)**	**(97.7)**	**20.5%**	**(54.5)**	**(17.5)**	**(6.8)**	**(18.9)**
Total Accumulated Depreciation	**(5,156.8)**	**(584.3)**	**11.3%**	**(328.5)**	**(127.6)**	**(48.5)**	**(79.7)**

Schedule 2.13: Functional Classification of Financial Account Details – Transmission Inventories/Other Assets

Functionalization and Classification of Financial Account Details
TRANSMISSION INVENTORIES
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Inventories							
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-
Transmission & Distribution	81.9	22.4	27.4%	12.5	4.0	1.6	4.3
Miscellaneous (Computers, Power Shop)	3.1	0.3	9.1%	0.2	0.1	0.0	0.1
Total Inventories	**165.0**	**22.7**	**13.8%**	**12.7**	**4.1**	**1.6**	**4.4**

Functionalization and Classification of Financial Account Details
TRANSMISSION OTHER ASSETS
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Other Assets							
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	2.8%	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	3.3	0.3	9.1%	0.2	0.1	0.0	0.1
Total Other Assets	**7.2**	**0.3**	**4.5%**	**0.2**	**0.1**	**0.0**	**0.1**

Schedule 2.14: Functional Classification of Financial Account Details – Transmission O M & A Expenses

Functionalization and Classification of Financial Account Details
TRANSMISSION OM&A EXPENSE
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation Expenses							
Power Plant Operation	172.1	-	0.0%	-	-	-	-
Fuel Supply	1.9	-	0.0%	-	-	-	-
Power Production Overhead	28.3	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogen	14.1	-	0.0%	-	-	-	-
SaskPower International (SPI) - Meridian	7.1	-	0.0%	-	-	-	-
SaskPower International (SPI) - Spyhill	(2.2)		0.0%	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-
SaskPower International (SPI) - Centennial Wind	5.9	-	0.0%	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-
NorthPoint Energy Solutions	7.8	-	0.0%	-	-	-	-
Total Generation Expenses	**238.1**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses							
T & D - Planning Support	15.5	6.9	44.1%	3.6	1.9	0.5	0.9
T & D - Transmission Including 138 & 72 kV Radials	30.5	30.5	100.0%	17.2	4.8	2.1	6.4
T & D - Distribution	99.1	-	0.0%	-	-	-	-
T & D - Customer Services	5.4	-	0.0%	-	-	-	-
T & D - Gas & Electric Inspections	12.2	-	0.0%	-	-	-	-
Total Transmission & Distribution Expenses	**162.8**	**37.4**	**23.0%**	**20.8**	**6.7**	**2.6**	**7.2**
Customer Services Expenses							
Meter Reading	7.5	-	0.0%	-	-	-	-
Metering Services	2.9	-	0.0%	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-
Collections/Special Collections	4.1	-	0.0%	-	-	-	-
Bad Debt Expense	2.3	-	0.0%	-	-	-	-
Marketing & Sales	3.6	-	0.0%	-	-	-	-
Demand Side Management	14.3	-	0.0%	-	-	-	-
Customer Service	16.5	-	0.0%	-	-	-	-
Total Customer Services Expenses	**54.7**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Support Group Expenses							
President / Board	3.5	0.3	9.1%	0.2	0.1	0.0	0.1
Corporate & Financial Services	22.7	2.2	9.6%	1.2	0.4	0.2	0.4
Planning, Environment & Regulatory Affairs	16.8	1.3	7.9%	0.7	0.2	0.1	0.3
General Council / Land	4.8	0.4	9.1%	0.2	0.1	0.0	0.1
Communication & Public Affairs	8.6	0.8	9.1%	0.4	0.1	0.1	0.2
Safety	7.9	0.8	9.8%	0.4	0.1	0.1	0.2
Corporate Information & Technology	70.1	8.1	11.5%	4.5	1.4	0.6	1.6
Human Resources	20.3	2.4	12.0%	1.4	0.4	0.2	0.5
Supply Chain	-	-	0.0%	-	-	-	-
Business Development	1.4	-	0.0%	-	-	-	-
Service Delivery Renewal	35.9	5.0	14.0%	2.8	0.9	0.4	1.0
Total Support Group Expenses	**192.1**	**21.4**	**11.1%**	**11.9**	**3.8**	**1.5**	**4.1**
Total OM&A Expenses	**647.7**	**58.8**	**9.1%**	**32.8**	**10.5**	**4.1**	**11.4**

Schedule 2.15: Functional Classification of Financial Account Details – Transmission Depreciation & Depletion

Functionalization and Classification of Financial Account Details
TRANSMISSION DEPRECIATION & DEPLETION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	232.5	-	0.0%	-	-	-	-
Coal Reserves	1.2	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-
Total Generation	**233.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	39.1	37.9	97.0%	20.8	8.9	3.0	5.2
Total Transmission	**39.1**	**37.9**	**97.0%**	**20.8**	**8.9**	**3.0**	**5.2**
Distribution							
Distribution	90.7	-	0.0%	-	-	-	-
Meters	8.5	-	0.0%	-	-	-	-
Total Distribution	**99.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	-	-	0.0%	-	-	-	-
Buildings	1.7	0.2	9.2%	0.1	0.0	0.0	0.0
Office Furniture & Equipment	1.4	0.1	9.2%	0.1	0.0	0.0	0.0
Vehicles & Equipment	9.5	2.4	25.2%	1.3	0.4	0.2	0.5
Computer Development & Equipment	46.1	5.2	11.4%	2.9	0.9	0.4	1.0
Communication, Protection & Control	8.9	4.8	53.9%	2.7	0.9	0.3	0.9
Tools & Equipment	1.8	0.1	5.4%	0.1	0.0	0.0	0.0
Total General Plant	**69.6**	**12.9**	**18.5%**	**7.2**	**2.3**	**0.9**	**2.5**
Total Depreciation & Depletion	**441.8**	**50.8**	**11.5%**	**28.0**	**11.2**	**3.9**	**7.7**

Schedule 2.16: Functional Classification of Financial Account Details – Transmission Other Income

Functionalization and Classification of Financial Account Details
TRANSMISSION OTHER INCOME
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Other Income							
Customer Services Payment Charges	(5.2)	-	0.0%	-	-	-	-
Meter Reading	(3.5)	-	0.0%	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-
Transmission	(1.9)	(1.6)	82.4%	(0.9)	(0.3)	(0.1)	(0.3)
Distribution	(5.9)	-	0.0%	-	-	-	-
Clean Coal Project Credits	(4.3)	-	0.0%	-	-	-	-
CO2 Sales	(17.5)	-	0.0%	-	-	-	-
Miscellaneous Other Income	(6.2)	(0.6)	9.1%	(0.3)	(0.1)	(0.0)	(0.1)
Customer Contribution Revenue	(50.0)	(11.7)	23.3%	(2.1)	(8.7)	-	(0.8)
Green Power Premium	(5.6)	-	0.0%	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-
Flyash Sales	(9.8)	-	0.0%	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-
Total Other Income	**(128.5)**	**(13.8)**	**10.7%**	**(3.3)**	**(9.1)**	**(0.1)**	**(1.2)**

Schedule 2.20: Functional Classification of Financial Account Details – Distribution

Functionalization and Classification of Financial Account Details
DISTRIBUTION Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Basis of Classification	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
					Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Rate Base																	
Plant In Service (Schedule 2.21)	13,352.2	3,544.7	26.5%	Functional Class of PIS	306.1	986.6	263.3	141.8	490.8	264.3	281.3	120.5	437.2	-	-	176.4	76.4
Accumulated Depreciation (Schedule 2.22)	(5,156.8)	(1,516.8)	29.4%	Functional Class of Accum. Depr'n	(120.6)	(443.9)	(134.0)	(72.2)	(249.0)	(134.1)	(106.7)	(45.7)	(119.0)	-	-	(43.5)	(48.1)
Allowance For Working Capital	81.0	17.8	22.0%	12.50% of OM&A and Taxes	1.5	5.2	1.7	0.9	3.2	1.7	1.7	0.7	0.5	-	-	0.1	0.6
Inventories (Schedule 2.23)	165.0	60.2	36.5%	Functional Class of Inventories	5.1	17.7	5.8	3.1	10.9	5.8	5.8	2.5	1.4	-	-	-	2.1
Other Assets (Schedule 2.23)	7.2	0.8	11.1%	Functional Classification of Other Assets	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Rate Base	**8,448.6**	**2,106.8**	**24.9%**		**192.1**	**565.8**	**136.9**	**73.7**	**256.0**	**137.8**	**182.2**	**78.1**	**320.1**	**-**	**-**	**133.0**	**31.0**
Revenue Requirement																	
Fuel Expense SaskPower Units	394.3	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchased Power & Import	193.1	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(34.7)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.24)	647.7	146.7	22.6%	Functional Class of OM&A	12.4	43.0	14.2	7.6	26.5	14.3	14.2	6.1	3.3	-	-	-	5.0
Depreciation & Depletion (Schedule 2.25)	441.8	119.3	27.0%	Functional Class of Depr'n & Depletion	12.8	30.3	8.5	4.6	15.8	8.5	11.0	4.7	12.0	-	-	8.5	2.6
Corporate Capital Tax	34.0	8.4	24.7%	Functional Class of Corp. Capital Tax	0.8	2.3	0.5	0.3	1.0	0.5	0.7	0.3	1.3	-	-	0.6	0.1
Grants in Lieu of Taxes	22.5	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Tax	0.5	0.0	1.6%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Other Income (Credit) (Schedule 2.26)	(128.5)	(45.7)	35.5%	Functional Class of Other Income	(0.6)	(2.5)	(3.2)	(1.7)	(5.7)	(3.1)	(0.7)	(0.3)	(0.2)	-	(24.7)	-	(2.8)
Return on Rate Base @ 4.84%	409.1	102.0	24.9%	Rate Base	9.3	27.4	6.6	3.6	12.4	6.7	8.8	3.8	15.5	-	-	6.4	1.5
Total Revenue Requirement	**1,979.8**	**330.8**	**16.7%**		**34.7**	**100.4**	**26.6**	**14.3**	**50.0**	**26.9**	**34.1**	**14.6**	**32.0**	**-**	**(24.7)**	**15.5**	**6.5**

Schedule 2.21: Functional Classification of Financial Account Details – Distribution Plant in Service

Functionalization and Classification of Financial Account Details
DISTRIBUTION PLANT IN SERVICE
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	7,361.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	53.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	7,420.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																
Transmission	1,790.0	36.9	2.1%	36.9	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	1,790.0	36.9	2.1%	36.9	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																
Distribution	3,068.9	3,068.9	100.0%	247.0	909.6	237.9	128.1	443.5	238.8	255.8	109.6	431.2	-	-	-	67.4
Meters	176.4	176.4	100.0%	-	-	-	-	-	-	-	-	-	-	-	176.4	-
Total Distribution	3,245.4	3,245.4	100.0%	247.0	909.6	237.9	128.1	443.5	238.8	255.8	109.6	431.2	-	-	176.4	67.4
General Plant																
Unused Land	2.2	0.5	22.6%	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-	-	-	0.0
Buildings	200.0	51.5	25.8%	4.3	15.1	5.0	2.7	9.3	5.0	5.0	2.1	1.2	-	-	-	1.8
Office Furniture & Equipment	36.4	9.4	25.8%	0.8	2.8	0.9	0.5	1.7	0.9	0.9	0.4	0.2	-	-	-	0.3
Vehicles & Equipment	154.2	82.4	53.4%	6.9	24.2	8.0	4.3	14.9	8.0	8.0	3.4	1.9	-	-	-	2.8
Computer Development & Equipment	337.0	93.7	27.8%	7.9	27.5	9.1	4.9	16.9	9.1	9.1	3.9	2.1	-	-	-	3.2
Communication, Protection & Control	147.4	16.9	11.4%	1.4	4.9	1.6	0.9	3.0	1.6	1.6	0.7	0.4	-	-	-	0.6
Tools & Equipment	19.2	8.0	41.7%	0.7	2.4	0.8	0.4	1.4	0.8	0.8	0.3	0.2	-	-	-	0.3
Total General Plant	896.5	262.4	29.3%	22.1	77.0	25.4	13.7	47.4	25.5	25.4	10.9	6.0	-	-	-	9.0
Total Plant In Service	13,352.2	3,544.7	26.5%	306.1	986.6	263.3	141.8	490.8	264.3	281.3	120.5	437.2	-	-	176.4	76.4

Schedule 2.22: Functional Classification of Financial Account Details – Distribution Accumulated Depreciation

Functionalization and Classification of Financial Account Details
DISTRIBUTION ACCUMULATED DEPRECIATION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	(2,795.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	(27.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	(3.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	(2,826.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																
Transmission	(498.9)	(9.7)	1.9%	(9.7)	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	(498.9)	(9.7)	1.9%	(9.7)	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																
Distribution	(1,310.5)	(1,310.5)	100.0%	(98.0)	(399.0)	(119.2)	(64.2)	(221.4)	(119.2)	(91.9)	(39.4)	(115.5)	-	-	-	(42.8)
Meters	(43.5)	(43.5)	100.0%	-	-	-	-	-	-	-	-	-	-	-	(43.5)	-
Total Distribution	(1,354.0)	(1,354.0)	100.0%	(98.0)	(399.0)	(119.2)	(64.2)	(221.4)	(119.2)	(91.9)	(39.4)	(115.5)	-	-	(43.5)	(42.8)
General Plant																
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Buildings	(40.2)	(9.5)	23.7%	(0.8)	(2.8)	(0.9)	(0.5)	(1.7)	(0.9)	(0.9)	(0.4)	(0.2)	-	-	-	(0.3)
Office Furniture & Equipment	(16.6)	(3.9)	23.7%	(0.3)	(1.2)	(0.4)	(0.2)	(0.7)	(0.4)	(0.4)	(0.2)	(0.1)	-	-	-	(0.1)
Vehicles & Equipment	(75.4)	(39.7)	52.7%	(3.3)	(11.7)	(3.8)	(2.1)	(7.2)	(3.9)	(3.9)	(1.7)	(0.9)	-	-	-	(1.4)
Computer Development & Equipment	(265.5)	(84.7)	31.9%	(7.1)	(24.9)	(8.2)	(4.4)	(15.3)	(8.2)	(8.2)	(3.5)	(1.9)	-	-	-	(2.9)
Communication, Protection & Control	(66.2)	(8.1)	12.3%	(0.7)	(2.4)	(0.8)	(0.4)	(1.5)	(0.8)	(0.8)	(0.3)	(0.2)	-	-	-	(0.3)
Tools & Equipment	(14.0)	(7.0)	50.2%	(0.6)	(2.1)	(0.7)	(0.4)	(1.3)	(0.7)	(0.7)	(0.3)	(0.2)	-	-	-	(0.2)
Total General Plant	(477.8)	(153.0)	32.0%	(12.9)	(44.9)	(14.8)	(8.0)	(27.6)	(14.9)	(14.8)	(6.4)	(3.5)	-	-	-	(5.3)
Total Accumulated Depreciation	(5,156.8)	(1,516.8)	29.4%	(120.6)	(443.9)	(134.0)	(72.2)	(249.0)	(134.1)	(106.7)	(45.7)	(119.0)	-	-	(43.5)	(48.1)

Schedule 2.23: Functional Classification of Financial Account Details – Distribution Inventories/Other Assets

Functionalization and Classification of Financial Account Details
DISTRIBUTION INVENTORIES
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Inventories																
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission & Distribution	81.9	59.5	72.6%	5.0	17.5	5.8	3.1	10.7	5.8	5.8	2.5	1.4	-	-	-	2.0
Miscellaneous (Computers, Power Shop)	3.1	0.7	22.6%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Inventories	**165.0**	**60.2**	**36.5%**	**5.1**	**17.7**	**5.8**	**3.1**	**10.9**	**5.8**	**5.8**	**2.5**	**1.4**	**-**	**-**	**-**	**2.1**

Functionalization and Classification of Financial Account Details
DISTRIBUTION OTHER ASSETS
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Other Assets																
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	6.1%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Miscellaneous Prepaid Expenses	3.3	0.8	22.6%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Other Assets	**7.2**	**0.8**	**11.1%**	**0.1**	**0.2**	**0.1**	**0.0**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**-**	**-**	**-**	**0.0**

Schedule 2.24: Functional Classification of Financial Account Details – Distribution O M & A Expenses

Functionalization and Classification of Financial Account Details
DISTRIBUTION OM&A EXPENSES
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation Expenses																
Power Plant Operation	172.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Supply	1.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production Overhead	28.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogen	14.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.1		0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(2.2)		0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Centennial Wind	5.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
NorthPoint Energy Solutions	7.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation Expenses	**238.1**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses																
T & D - Planning Support	15.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Transmission Including 138 & 72 kV Radials	30.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Distribution	99.1	99.1	100.0%	8.4	29.1	9.6	5.2	17.9	9.6	9.6	4.1	2.3	-	-	-	3.4
T & D - Customer Services	5.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Gas & Electric Inspections	12.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	**162.8**	**99.1**	**60.9%**	**8.4**	**29.1**	**9.6**	**5.2**	**17.9**	**9.6**	**9.6**	**4.1**	**2.3**	**-**	**-**	**-**	**3.4**
Customer Services Expenses																
Meter Reading	7.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Metering Services	2.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	4.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	2.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	14.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	16.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	**54.7**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Support Group Expenses																
President / Board	3.5	0.8	22.6%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Corporate & Financial Services	22.7	4.8	21.1%	0.4	1.4	0.5	0.3	0.9	0.5	0.5	0.2	0.1	-	-	-	0.2
Planning, Environment & Regulatory Affairs	16.8	3.1	18.4%	0.3	0.9	0.3	0.2	0.6	0.3	0.3	0.1	0.1	-	-	-	0.1
General Council / Land	4.8	1.1	22.6%	0.1	0.3	0.1	0.1	0.2	0.1	0.1	0.0	0.0	-	-	-	0.0
Communication & Public Affairs	8.6	1.9	22.6%	0.2	0.6	0.2	0.1	0.4	0.2	0.2	0.1	0.0	-	-	-	0.1
Safety	7.9	1.8	23.0%	0.2	0.5	0.2	0.1	0.3	0.2	0.2	0.1	0.0	-	-	-	0.1
Corporate Information & Technology	70.1	17.7	25.2%	1.5	5.2	1.7	0.9	3.2	1.7	1.7	0.7	0.4	-	-	-	0.6
Human Resources	20.3	5.4	26.5%	0.5	1.6	0.5	0.3	1.0	0.5	0.5	0.2	0.1	-	-	-	0.2
Supply Chain	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Business Development	1.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Service Delivery Renewal	35.9	10.9	30.4%	0.9	3.2	1.1	0.6	2.0	1.1	1.1	0.5	0.2	-	-	-	0.4
Total Support Group Expenses	**192.1**	**47.5**	**24.7%**	**4.0**	**13.9**	**4.6**	**2.5**	**8.6**	**4.6**	**4.6**	**2.0**	**1.1**	**-**	**-**	**-**	**1.6**
Total OM&A Expenses	**647.7**	**146.7**	**22.6%**	**12.4**	**43.0**	**14.2**	**7.6**	**26.5**	**14.3**	**14.2**	**6.1**	**3.3**	**-**	**-**	**-**	**5.0**

SaskPower

Schedule 2.25: Functional Classification of Financial Account Details – Distribution Depreciation & Depletion

Functionalization and Classification of Financial Account Details
DISTRIBUTION DEPRECIATION & DEPLETION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	232.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	1.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**233.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission																
Transmission	39.1	0.9	2.4%	0.9	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	**39.1**	**0.9**	**2.4%**	**0.9**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution																
Distribution	90.7	90.7	100.0%	10.3	24.6	6.6	3.6	12.3	6.6	9.1	3.9	11.6	-	-	-	1.9
Meters	8.5	8.5	100.0%	-	-	-	-	-	-	-	-	-	-	-	8.5	-
Total Distribution	**99.2**	**99.2**	**100.0%**	**10.3**	**24.6**	**6.6**	**3.6**	**12.3**	**6.6**	**9.1**	**3.9**	**11.6**	**-**	**-**	**8.5**	**1.9**
General Plant																
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Buildings	1.7	0.4	21.0%	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-	-	-	0.0
Office Furniture & Equipment	1.4	0.3	21.0%	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-	-	-	0.0
Vehicles & Equipment	9.5	5.2	54.7%	0.4	1.5	0.5	0.3	0.9	0.5	0.5	0.2	0.1	-	-	-	0.2
Computer Development & Equipment	46.1	11.4	24.8%	1.0	3.4	1.1	0.6	2.1	1.1	1.1	0.5	0.3	-	-	-	0.4
Communication, Protection & Control	8.9	1.1	12.0%	0.1	0.3	0.1	0.1	0.2	0.1	0.1	0.0	0.0	-	-	-	0.0
Tools & Equipment	1.8	0.8	45.2%	0.1	0.2	0.1	0.0	0.2	0.1	0.1	0.0	0.0	-	-	-	0.0
Total General Plant	**69.6**	**19.2**	**27.6%**	**1.6**	**5.6**	**1.9**	**1.0**	**3.5**	**1.9**	**1.9**	**0.8**	**0.4**	**-**	**-**	**-**	**0.7**
Total Depreciation & Depletion	**441.8**	**119.3**	**27.0%**	**12.8**	**30.3**	**8.5**	**4.6**	**15.8**	**8.5**	**11.0**	**4.7**	**12.0**	**-**	**-**	**8.5**	**2.6**

Schedule 2.26: Functional Classification of Financial Account Details – Distribution Other Income

Functionalization and Classification of Financial Account Details
DISTRIBUTION OTHER INCOME
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Other Income																
Customer Services Payment Charges	(5.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	(3.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	(1.9)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution	(5.9)	(5.9)	100.0%	(0.5)	(1.7)	(0.6)	(0.3)	(1.1)	(0.6)	(0.6)	(0.2)	(0.1)	-	-	-	(0.2)
Clean Coal Project Credits	(4.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 Sales	(17.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Other Income	(6.2)	(1.4)	22.6%	(0.1)	(0.4)	(0.1)	(0.1)	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	-	-	-	(0.0)
Customer Contribution Revenue	(50.0)	(38.3)	76.7%	(0.0)	(0.4)	(2.5)	(1.4)	(4.4)	(2.4)	-	-	-	-	(24.7)	-	(2.5)
Green Power Premium	(5.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(9.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**(128.5)**	**(45.7)**	**35.5%**	**(0.6)**	**(2.5)**	**(3.2)**	**(1.7)**	**(5.7)**	**(3.1)**	**(0.7)**	**(0.3)**	**(0.2)**	**-**	**(24.7)**	**-**	**(2.8)**

Schedule 2.30: Functional Classification of Financial Account Details – Customer Service

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICE Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Basis of Classification	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
					Customer	Customer	Customer	Customer	Customer	Customer
Rate Base										
Plant In Service (Schedule 2.31)	13,352.2	105.4	0.8%	Functional Class of PIS	4.1	13.5	5.0	17.2	58.9	6.6
Accumulated Depreciation (Schedule 2.32)	(5,156.8)	(51.5)	1.0%	Functional Class of Accum. Depr'n	(1.7)	(6.1)	(2.1)	(8.5)	(30.4)	(2.9)
Allowance For Working Capital	81.0	11.2	13.8%	12.50% of OM&A and Taxes	0.6	1.7	0.7	1.8	5.6	0.8
Inventories (Schedule 2.33)	165.0	0.5	0.3%	Functional Class of Inventories	0.0	0.1	0.0	0.1	0.2	0.0
Other Assets (Schedule 2.33)	7.2	0.5	7.0%	Functional Classification of Other Assets	0.0	0.1	0.0	0.1	0.3	0.0
Total Rate Base	**8,448.6**	**66.0**	**0.8%**		**3.1**	**9.3**	**3.7**	**10.7**	**34.6**	**4.6**
Revenue Requirement										
Fuel Expense SaskPower Units	394.3	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-
Purchased Power & Import	193.1	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(34.7)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.34)	647.7	97.1	15.0%	Functional Class of OM&A	5.1	14.7	6.2	15.8	48.6	6.7
Depreciation & Depletion (Schedule 2.35)	441.8	9.4	2.1%	Functional Class of Depr'n & Depletion	0.4	1.3	0.5	1.5	5.0	0.6
Corporate Capital Tax	34.0	0.2	0.7%	Functional Class of Corp. Capital Tax	0.0	0.0	0.0	0.0	0.1	0.0
Grants in Lieu of Taxes	22.5	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-
Miscellaneous Tax	0.5	0.1	11.3%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.36)	(128.5)	(28.3)	22.0%	Functional Class of Other Income	(0.0)	(3.6)	(2.5)	(2.9)	(19.1)	(0.1)
Return on Rate Base @ 4.84%	409.1	3.2	0.8%	Rate Base	0.1	0.4	0.2	0.5	1.7	0.2
Total Revenue Requirement	**1,979.8**	**81.7**	**4.1%**		**5.7**	**12.8**	**4.4**	**14.9**	**36.3**	**7.5**

Schedule 2.31: Functional Classification of Financial Account Details – Customer Services Plant in Service

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES PLANT IN SERVICE
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	7,361.2	-	0.0%	-	-	-	-	-	-
Coal Reserves	53.5	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-	-	-
Total Generation	**7,420.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	1,790.0	-	0.0%	-	-	-	-	-	-
Total Transmission	**1,790.0**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	3,068.9	-	0.0%	-	-	-	-	-	-
Meters	176.4	-	0.0%	-	-	-	-	-	-
Total Distribution	**3,245.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	2.2	0.3	15.0%	0.0	0.1	0.0	0.1	0.2	0.0
Buildings	200.0	35.0	17.5%	1.9	5.3	2.2	5.7	17.4	2.4
Office Furniture & Equipment	36.4	6.4	17.5%	0.3	1.0	0.4	1.0	3.2	0.4
Vehicles & Equipment	154.2	15.6	10.1%	0.0	1.0	0.1	2.7	11.4	0.4
Computer Development & Equipment	337.0	43.0	12.8%	1.9	5.9	2.3	7.0	23.3	2.7
Communication, Protection & Control	147.4	3.6	2.5%	-	0.2	-	0.5	2.3	0.6
Tools & Equipment	19.2	1.4	7.5%	-	0.1	-	0.2	1.1	0.0
Total General Plant	**896.5**	**105.4**	**11.8%**	**4.1**	**13.5**	**5.0**	**17.2**	**58.9**	**6.6**
Total Plant In Service	**13,352.2**	**105.4**	**0.8%**	**4.1**	**13.5**	**5.0**	**17.2**	**58.9**	**6.6**

Schedule 2.32: Functional Classification of Financial Account Details – Customer Services Accumulated Depreciation

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES ACCUMULATED DEPRECIATION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	(2,795.4)	-	0.0%	-	-	-	-	-	-
Coal Reserves	(27.6)	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	(3.0)	-	0.0%	-	-	-	-	-	-
Total Generation	**(2,826.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	(498.9)	-	0.0%	-	-	-	-	-	-
Total Transmission	**(498.9)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	(1,310.5)	-	0.0%	-	-	-	-	-	-
Meters	(43.5)	-	0.0%	-	-	-	-	-	-
Total Distribution	**(1,354.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Buildings	(40.2)	(5.8)	14.4%	(0.3)	(0.9)	(0.4)	(0.9)	(2.9)	(0.4)
Office Furniture & Equipment	(16.6)	(2.4)	14.4%	(0.1)	(0.4)	(0.1)	(0.4)	(1.2)	(0.2)
Vehicles & Equipment	(75.4)	(7.5)	9.9%	(0.0)	(0.5)	(0.0)	(1.3)	(5.5)	(0.2)
Computer Development & Equipment	(265.5)	(32.9)	12.4%	(1.3)	(4.2)	(1.5)	(5.4)	(18.6)	(1.9)
Communication, Protection & Control	(66.2)	(1.7)	2.6%	-	(0.1)	-	(0.3)	(1.1)	(0.3)
Tools & Equipment	(14.0)	(1.2)	8.9%	-	(0.1)	-	(0.2)	(1.0)	(0.0)
Total General Plant	**(477.8)**	**(51.5)**	**10.8%**	**(1.7)**	**(6.1)**	**(2.1)**	**(8.5)**	**(30.4)**	**(2.9)**
Total Accumulated Depreciation	**(5,156.8)**	**(51.5)**	**1.0%**	**(1.7)**	**(6.1)**	**(2.1)**	**(8.5)**	**(30.4)**	**(2.9)**

Schedule 2.33: Functional Classification of Financial Account Details – Customer Services Inventories/Other Assets

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES INVENTORIES
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Inventories									
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-	-	-
Transmission & Distribution	81.9	-	0.0%	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	3.1	0.5	15.0%	0.0	0.1	0.0	0.1	0.2	0.0
Total Inventories	**165.0**	**0.5**	**0.3%**	**0.0**	**0.1**	**0.0**	**0.1**	**0.2**	**0.0**

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OTHER ASSETS
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Service	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	1.1%	-	0.0	-	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	3.3	0.5	15.0%	0.0	0.1	0.0	0.1	0.2	0.0
Total Other Assets	**7.2**	**0.5**	**7.0%**	**0.0**	**0.1**	**0.0**	**0.1**	**0.3**	**0.0**

Schedule 2.34: Functional Classification of Financial Account Details – Customer Services O M & A Expenses

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OM&A EXPENSES
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation Expenses									
Power Plant Operation	172.1	-	0.0%	-	-	-	-	-	-
Fuel Supply	1.9	-	0.0%	-	-	-	-	-	-
Power Production Overhead	28.3	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogen	14.1	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.1	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(2.2)	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Centennial Wind	5.9	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-	-	-
NorthPoint Energy Solutions	7.8	-	0.0%	-	-	-	-	-	-
Total Generation Expenses	**238.1**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses									
T & D - Planning Support	15.5	0.3	1.9%	-	-	-	-	-	0.3
T & D - Transmission Including 138 & 72 kV Radials	30.5	-	0.0%	-	-	-	-	-	-
T & D - Distribution	99.1	-	0.0%	-	-	-	-	-	-
T & D - Customer Services	5.4	5.4	100.0%	-	1.1	-	3.1	1.2	-
T & D - Gas & Electric Inspections	12.2	12.2	100.0%	-	-	-	-	12.2	-
Total Transmission & Distribution Expenses	**162.8**	**17.9**	**11.0%**	**-**	**1.1**	**-**	**3.1**	**13.4**	**0.3**
Customer Services Expenses									
Meter Reading	7.5	7.5	100.0%	-	7.5	-	-	-	-
Metering Services	2.9	2.9	100.0%	2.9	-	-	-	-	-
Billing Services	3.5	3.5	100.0%	-	-	3.5	-	-	-
Collections/Special Collections	4.1	4.1	100.0%	-	-	-	4.1	-	-
Bad Debt Expense	2.3	2.3	100.0%	-	-	-	2.3	-	-
Marketing & Sales	3.6	3.6	100.0%	-	-	-	-	-	3.6
Demand Side Management	14.3	-	0.0%	-	-	-	-	-	-
Customer Service	16.5	16.5	100.0%	-	-	-	-	16.5	-
Total Customer Services Expenses	**54.7**	**40.4**	**73.9%**	**2.9**	**7.5**	**3.5**	**6.4**	**16.5**	**3.6**
Support Group Expenses									
President / Board	3.5	0.5	15.0%	0.0	0.1	0.0	0.1	0.3	0.0
Corporate & Financial Services	22.7	2.9	12.8%	0.1	0.4	0.2	0.5	1.5	0.2
Planning, Environment & Regulatory Affairs	16.8	1.7	10.2%	0.1	0.2	0.1	0.3	0.9	0.1
General Council / Land	4.8	0.7	15.0%	0.0	0.1	0.0	0.1	0.4	0.0
Communication & Public Affairs	8.6	1.3	15.0%	0.1	0.2	0.1	0.2	0.6	0.1
Safety	7.9	1.2	15.3%	0.1	0.2	0.1	0.2	0.6	0.1
Corporate Information & Technology	70.1	11.6	16.6%	0.6	1.8	0.7	1.9	5.8	0.8
Human Resources	20.3	3.5	17.1%	0.2	0.5	0.2	0.6	1.7	0.2
Supply Chain	-	-	0.0%	-	-	-	-	-	-
Business Development	1.4	-	0.0%	-	-	-	-	-	-
Service Delivery Renewal	35.9	15.2	42.5%	1.0	2.6	1.2	2.4	6.9	1.2
Total Support Group Expenses	**192.1**	**38.7**	**20.2%**	**2.2**	**6.1**	**2.6**	**6.3**	**18.7**	**2.8**
Total OM&A Expenses	**647.7**	**97.1**	**15.0%**	**5.1**	**14.7**	**6.2**	**15.8**	**48.6**	**6.7**

Schedule 2.35: Functional Classification of Financial Account Details – Customer Services Depreciation & Depletion

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES DEPRECIATION & DEPLETION
2014 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	232.5	-	0.0%	-	-	-	-	-	-
Coal Reserves	1.2	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-
Total Generation	**233.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	39.1	-	0.0%	-	-	-	-	-	-
Total Transmission	**39.1**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	90.7	-	0.0%	-	-	-	-	-	-
Meters	8.5	-	0.0%	-	-	-	-	-	-
Total Distribution	**99.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Buildings	1.7	0.3	14.5%	0.0	0.0	0.0	0.0	0.1	0.0
Office Furniture & Equipment	1.4	0.2	14.5%	0.0	0.0	0.0	0.0	0.1	0.0
Vehicles & Equipment	9.5	1.0	10.6%	0.0	0.1	0.0	0.2	0.7	0.0
Computer Development & Equipment	46.1	7.6	16.4%	0.4	1.1	0.5	1.2	3.8	0.5
Communication, Protection & Control	8.9	0.2	2.6%	-	0.0	-	0.0	0.1	0.0
Tools & Equipment	1.8	0.1	8.1%	-	0.0	-	0.0	0.1	0.0
Total General Plant	**69.6**	**9.4**	**13.5%**	**0.4**	**1.3**	**0.5**	**1.5**	**5.0**	**0.6**
Total Depreciation & Depletion	**441.8**	**9.4**	**2.1%**	**0.4**	**1.3**	**0.5**	**1.5**	**5.0**	**0.6**

Schedule 2.36: Functional Classification of Financial Account Details – Customer Services Other Income

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OTHER INCOME
2014 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Other Income									
Customer Services Payment Charges	(5.2)	(5.2)	100.0%	-	-	(2.4)	(2.8)	-	-
Meter Reading	(3.5)	(3.5)	100.0%	-	(3.5)	-	-	-	-
Inspections	(18.7)	(18.7)	100.0%	-	-	-	-	(18.7)	-
Transmission	(1.9)	-	0.0%	-	-	-	-	-	-
Distribution	(5.9)	-	0.0%	-	-	-	-	-	-
Clean Coal Project Credits	(4.3)	-	0.0%	-	-	-	-	-	-
CO2 Sales	(17.5)	-	0.0%	-	-	-	-	-	-
Miscellaneous Other Income	(6.2)	(0.9)	15.0%	(0.0)	(0.1)	(0.1)	(0.2)	(0.5)	(0.1)
Customer Contribution Revenue	(50.0)	-	0.0%	-	-	-	-	-	-
Green Power Premium	(5.6)	-	0.0%	-	-	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-
Flyash Sales	(9.8)	-	0.0%	-	-	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-
Total Other Income	**(128.5)**	**(28.3)**	**22.0%**	**(0.0)**	**(3.6)**	**(2.5)**	**(2.9)**	**(19.1)**	**(0.1)**

Schedule 3.0: SaskPower Allocation Methodology Summary

SaskPower

SaskPower Functionalization	SaskPower Classification	SaskPower Sub-Functionalization	Allocation Methodology
GENERATION	Demand (Facilities)		Two Coincident Peak Method (2CP)
	Energy (Facilities)		Actual Energy Costs Plus Losses
	Energy (Fuel Expense)		Actual Energy Costs Plus Losses
TRANSMISSION	DEMAND	Main Grid	Two Coincident Peak Method (2CP) - Coincident Peak at output of transmission.
		138kv Radials	Two Coincident Peak Method (2CP) - at output of common 138kv Radials.
		138/72kv Substations	Two Coincident Peak Method (2CP) - at output of substations.
		72kv Radials	Two Coincident Peak Method (2CP) - at output of common 72kv radials.
DISTRIBUTION	DEMAND	Area Substations - Demand	Two Coincident Peak Method (2CP) - at output of substations.
		Distribution Mains - Demand	Two Coincident Peak Method (2CP) - at output of distribution mains.
		Urban Laterals - Demand	Two Coincident Peak Method (2CP) - at output of urban laterals.
		Rural Laterals - Demand	Two Coincident Peak Method (2CP) - at output of rural laterals.
		Transformers - Demand	Non Coincident Peak (NCP) - at output of rural laterals.
	CUSTOMER	Urban Laterals - Customer	Number of urban customers supplied through laterals.
		Rural Laterals - Customer	Number of rural customers supplied through laterals.
		Transformers - Customer	Number of customers supplied through laterals.
		Services - Customer	Direct to classes which are using services.
		Meters - Customer	Number of metered customers weighted by installed cost of a meter.
		Streetlights - Customer	Direct to Streetlight Class.
CUSTOMER SERVICES	CUSTOMER	Customer Service	Weighted number of customers.
CUSTOMER CONTRIBUTIONS	CUSTOMER	Customer Contributions	Direct to classes which made contribution.
INTERRUPTIBLE ADJUSTMENT	DEMAND	Interruptible Adjustment	Two Coincident Peak Method (2CP)

2CP METHOD

The Two Coincident Peak (2CP) method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

NCP METHOD

The Non-Coincident Peak (NCP) method allcoates responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occurr, to the sum of all the class peaks, similarly determined.

Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation
2014 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	2,374	2,207,186	482,625	12.28%	56.16%
Rural Residential	639	594,147	129,917	12.28%	56.16%
Farms	1,305	814,174	221,049	18.30%	67.41%
Urban Commercial	2,647	848,791	417,395	35.60%	72.40%
Rural Commercial	901	307,075	145,902	33.49%	70.48%
Power - Published Rates	6,526	1,076,412	797,385	69.21%	93.42%
Power - Contract Rates	1,708	261,827	205,199	74.46%	95.01%
Oilfields	3,686	622,974	436,593	67.54%	96.37%
Streetlights	61	14,852	7,318	47.12%	95.63%
Reseller	1,264	238,612	208,062	60.48%	69.36%
Total	**21,111**	**6,986,051**	**3,051,446**	**34.50%**	**78.98%**

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)

Schedule 5.0: Allocation Factors by Customer Class – Generation

Allocation Factors by Customer Class
GENERATION Related Costs
2014 Test Embedded Cost of Service Study

Customer Class	Load [1]	Load [2]	Losses [3]	Losses [4]	Scheduling & Dispatch [3]	Regulation & Frequency Response [3]	Spinning Reserve [3]	Supplementary Reserve [3]	Planning Reserve [3]	Reactive Supply [3]	Grants in Lieu of Taxes [3]	Interruptible Adjustment [3]
	Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy	Demand
Urban Residential	15.8%	11.2%	22.1%	17.4%	16.4%	16.4%	16.4%	16.4%	16.4%	16.4%	56.0%	16.6%
Rural Residential	4.3%	3.0%	5.7%	4.3%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	0.0%	4.5%
Farms	7.2%	6.2%	9.5%	8.7%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	0.0%	7.6%
Urban Commercial	13.7%	12.5%	18.9%	19.0%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	44.0%	14.4%
Rural Commercial	4.8%	4.3%	6.1%	5.7%	4.9%	4.9%	4.9%	4.9%	4.9%	4.9%	0.0%	5.0%
Power - Published Rates	24.8%	29.4%	13.8%	15.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	0.0%	24.0%
Power - Contract Rates	8.0%	9.6%	3.6%	4.3%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	0.0%	6.4%
Oilfields	14.3%	17.5%	17.2%	22.0%	14.6%	14.6%	14.6%	14.6%	14.6%	14.6%	0.0%	14.8%
Streetlights	0.2%	0.3%	0.3%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.0%	0.3%
Reseller	6.8%	6.0%	2.8%	2.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	0.0%	6.5%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (2CP) at the meter.
[2] Based on actual energy consumption at the meter.
[3] Based on Coincident Peak (2CP) & losses.
[4] Based on energy losses.

Schedule 5.1: Allocation Factors by Customer Class – Transmission

Allocation Factors by Customer Class
TRANSMISSION Related Costs
2014 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	16.4%	11.9%	21.4%	21.4%
Rural Residential	4.4%	3.2%	5.7%	5.7%
Farms	7.5%	5.7%	9.5%	9.5%
Urban Commercial	14.2%	10.2%	18.5%	18.5%
Rural Commercial	4.9%	3.4%	6.5%	6.5%
Power - Published Rates	23.7%	33.7%	18.2%	18.2%
Power - Contract Rates	7.6%	16.1%	1.7%	1.7%
Oilfields	14.6%	12.4%	17.6%	17.6%
Streetlights	0.2%	0.2%	0.3%	0.3%
Reseller	6.4%	3.2%	0.4%	0.4%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: All allocation factors based on Coincident Peak (2CP) & losses.

Schedule 5.2: Allocation Factors by Customer Class – Distribution

Allocation Factors by Customer Class
DISTRIBUTION Related Costs
2014 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]	Amortization Customer Contributions [7]	Meters [8]	Streetlights [9]
	Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer
Urban Residential	26.2%	26.3%	53.3%	84.6%	0.0%	0.0%	42.3%	60.9%	18.9%	16.6%	20.1%	0.0%
Rural Residential	7.0%	7.0%	0.0%	0.0%	15.6%	33.8%	11.4%	9.4%	11.3%	16.7%	3.1%	0.0%
Farms	11.7%	11.7%	0.0%	0.0%	25.9%	42.1%	15.4%	11.8%	2.1%	16.9%	4.4%	0.0%
Urban Commercial	22.6%	22.7%	46.0%	11.7%	0.0%	0.0%	15.5%	8.4%	26.1%	12.5%	30.5%	0.0%
Rural Commercial	7.3%	7.3%	0.0%	0.0%	16.2%	9.0%	5.2%	2.5%	12.0%	14.4%	12.4%	0.0%
Power - Published Rates	3.4%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.7%	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%	3.0%	0.0%
Oilfields	21.0%	21.0%	0.0%	0.0%	42.1%	12.5%	9.9%	3.5%	29.7%	22.8%	12.5%	0.0%
Streetlights	0.4%	0.4%	0.7%	3.7%	0.1%	2.7%	0.3%	3.4%	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%	1.3%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (2CP) & 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.

Schedule 5.3: Allocation Factors by Customer Class – Customer Service

Allocation Factors by Customer Class
CUSTOMER SERVICE Related Costs
2014 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	17.2%	62.9%	42.4%	73.6%	59.9%	10.6%
Rural Residential	2.7%	9.6%	6.6%	11.4%	9.3%	3.8%
Farms	3.8%	13.0%	10.1%	8.0%	13.2%	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%	4.6%	25.5%
Streetlights	0.0%	0.0%	1.0%	0.0%	0.8%	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.

Schedule 6.0: Functional Classification of Revenue Requirement by Customer Class – Generation

Functionalized & Classified Revenue Requirement by Customer Class
GENERATION Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes	Interruptible Adjustment
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy	Demand
Urban Residential	365.5	202.7	55.5%	77.0	79.4	10.8	11.0	1.8	1.1	2.3	3.4	2.4	1.0	12.7	0.0
Rural Residential	96.9	50.8	52.4%	20.7	21.4	2.8	2.7	0.5	0.3	0.6	0.9	0.6	0.3	-	0.0
Farms	160.4	94.4	58.9%	35.3	43.6	4.7	5.5	0.8	0.5	1.0	1.5	1.1	0.4	-	0.0
Urban Commercial	289.3	196.5	67.9%	66.6	88.5	9.2	12.0	1.5	0.9	2.0	2.9	2.1	0.8	10.0	0.0
Rural Commercial	98.9	63.5	64.3%	23.3	30.1	3.0	3.6	0.5	0.3	0.7	1.0	0.7	0.3	-	0.0
Power - Published Rates	434.4	380.7	87.6%	127.3	218.1	7.0	10.3	2.7	1.6	3.4	5.2	3.7	1.5	-	(0.0)
Power - Contract Rates	110.3	98.2	89.0%	32.8	57.1	1.5	2.3	0.7	0.4	0.9	1.3	0.9	0.4	-	0.0
Oilfields	319.6	225.6	70.6%	69.7	123.2	8.4	13.8	1.6	1.0	2.0	3.0	2.1	0.9	-	0.0
Streetlights	13.8	3.8	27.8%	1.2	2.0	0.2	0.3	0.0	0.0	0.0	0.1	0.0	0.0	-	0.0
Reseller	90.7	82.9	91.5%	33.2	42.3	1.3	1.5	0.7	0.4	0.9	1.3	0.9	0.4	-	0.0
Total	**1,979.8**	**1,399.3**	**70.7%**	**487.0**	**705.7**	**48.8**	**62.8**	**10.7**	**6.5**	**13.8**	**20.7**	**14.6**	**5.9**	**22.6**	**-**

Schedule 6.1: Functional Classification of Revenue Requirement by Customer Class – Transmission

Functionalized & Classified Revenue Requirement by Customer Class
TRANSMISSION Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kv Lines Radials	138/72 kv Substations	72 kv Lines Radials
				Demand	Demand	Demand	Demand
Urban Residential	365.5	28.2	7.7%	15.6	3.9	2.8	5.9
Rural Residential	96.9	7.5	7.8%	4.2	1.0	0.7	1.6
Farms	160.4	12.8	8.0%	7.1	1.9	1.2	2.6
Urban Commercial	289.3	24.3	8.4%	13.5	3.3	2.4	5.1
Rural Commercial	98.9	8.4	8.5%	4.7	1.1	0.8	1.8
Power - Published Rates	434.4	43.1	9.9%	23.7	12.0	2.3	5.0
Power - Contract Rates	110.3	11.0	10.0%	6.0	4.3	0.2	0.5
Oilfields	319.6	25.0	7.8%	13.8	4.1	2.3	4.9
Streetlights	13.8	0.4	3.1%	0.2	0.1	0.0	0.1
Reseller	90.7	7.3	8.0%	6.1	1.0	0.1	0.1
Total	**1,979.8**	**168.1**	**8.5%**	**94.9**	**32.7**	**12.9**	**27.7**

Schedule 6.2: Functional Classification of Revenue Requirement by Customer Class – Distribution

Functionalized & Classified Revenue Requirement by Customer Class
DISTRIBUTION Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Amortization Customer Contributions	Meters	Streetlights
				Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer
Urban Residential	365.5	90.2	24.7%	9.1	26.4	14.2	12.1	-	-	14.4	8.9	6.1	(4.1)	3.1	-
Rural Residential	96.9	31.6	32.6%	2.4	7.1	-	-	7.8	9.1	3.9	1.4	3.6	(4.1)	0.5	-
Farms	160.4	44.2	27.6%	4.0	11.8	-	-	13.0	11.3	5.3	1.7	0.7	(4.2)	0.7	-
Urban Commercial	289.3	61.1	21.1%	7.8	22.8	12.2	1.7	-	-	5.3	1.2	8.3	(3.1)	4.7	-
Rural Commercial	98.9	24.8	25.0%	2.5	7.4	-	-	8.1	2.4	1.8	0.4	3.8	(3.6)	1.9	-
Power - Published Rates	434.4	6.7	1.5%	1.2	3.5	-	-	-	-	-	-	-	-	2.0	-
Power - Contract Rates	110.3	0.4	0.4%	-	-	-	-	-	-	-	-	-	-	0.4	-
Oilfields	319.6	62.4	19.5%	7.3	21.1	-	-	21.0	3.4	3.4	0.5	9.5	(5.7)	1.9	-
Streetlights	13.8	9.1	66.0%	0.1	0.4	0.2	0.5	0.1	0.7	0.1	0.5	-	-	-	6.5
Reseller	90.7	0.3	0.4%	0.1	-	-	-	-	-	-	-	-	-	0.2	-
Total	**1,979.8**	**330.8**	**16.7%**	**34.7**	**100.4**	**26.6**	**14.3**	**50.0**	**26.9**	**34.1**	**14.6**	**32.0**	**(24.7)**	**15.5**	**6.5**

Schedule 6.3: Functional Classification of Revenue Requirement by Customer Class – Customer Service

Functionalized & Classified Revenue Requirement by Customer Class
CUSTOMER SERVICE Related Costs
2014 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Urban Residential	365.5	44.5	12.2%	1.0	8.1	1.9	11.0	21.7	0.8
Rural Residential	96.9	7.0	7.2%	0.2	1.2	0.3	1.7	3.4	0.3
Farms	160.4	8.9	5.6%	0.2	1.7	0.4	1.2	4.8	0.6
Urban Commercial	289.3	7.5	2.6%	1.2	0.9	0.5	0.7	3.1	1.0
Rural Commercial	98.9	2.2	2.2%	0.4	0.3	0.2	0.2	0.9	0.2
Power - Published Rates	434.4	3.9	0.9%	1.1	-	0.3	-	0.3	2.2
Power - Contract Rates	110.3	0.6	0.6%	0.2	-	0.0	-	0.1	0.4
Oilfields	319.6	6.5	2.0%	1.4	0.6	0.7	0.1	1.7	1.9
Streetlights	13.8	0.4	3.1%	-	-	0.0	-	0.3	0.1
Reseller	90.7	0.1	0.2%	0.0	-	0.0	-	0.0	0.1
Total	**1,979.8**	**81.7**	**4.1%**	**5.7**	**12.8**	**4.4**	**14.9**	**36.3**	**7.5**

Schedule 7.0: Customer Data for Rate Design

Customer Data
2014 Test Embedded Cost of Service Study

Customer Class	Average Annual # of Accounts	Annual Revenue ($)	Annual Sales @ Meter (MWh)	Annual Billing Demand @ Meter (kVa)
Urban Residential	314,255	358,685,772	2,374,332	-
Rural Residential	48,627	94,494,224	639,140	-
Farms	60,630	157,964,504	1,305,251	601,256
Urban Commercial	43,601	288,471,581	2,647,066	5,531,377
Rural Commercial	12,967	100,359,404	900,865	2,201,664
Power - Published Rates	86	437,293,644	6,525,682	12,683,283
Power - Contract Rates	14	107,790,317	1,707,913	3,899,153
Oilfields	17,992	332,105,929	3,685,668	7,980,805
Streetlights	2,747	15,976,564	61,308	-
Reseller	3	86,658,062	1,264,133	2,418,158
Total	**500,922**	**1,979,800,000**	**21,111,359**	**35,315,696**

V. SUPPORTING SCHEDULES (2015)

Schedule 1.0: Summary of the Functionalization of Financial Account Details

Summary of the Functionalization of Financial Account Details
2015 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)	14,606.7	8,339.8	57.1%	2,375.3	16.3%	3,773.3	25.8%	118.3	0.8%
Accumulated Depreciation (Schedule 1.2)	(5,616.1)	(3,279.9)	58.4%	(638.2)	11.4%	(1,639.2)	29.2%	(58.8)	1.0%
Allowance For Working Capital	84.1	46.7	55.6%	7.9	9.4%	18.7	22.2%	10.8	12.9%
Inventories (Schedule 1.3)	165.0	81.7	49.5%	22.7	13.8%	60.2	36.5%	0.4	0.3%
Other Assets (Schedule 1.3)	7.2	5.6	77.7%	0.3	4.5%	0.8	11.2%	0.5	6.6%
Total Rate Base	**9,246.9**	**5,193.9**	**56.2%**	**1,768.0**	**19.1%**	**2,213.8**	**23.9%**	**71.2**	**0.8%**
Revenue Requirement									
Fuel Expense SaskPower Units	441.5	441.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchased Power & Import	236.9	236.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Export & Net Electricity Trading Revenue (Credit)	(42.4)	(42.4)	100.0%	-	0.0%	-	0.0%	-	0.0%
Operating,Maintenance & Administration (Schedule 1.4)	672.4	362.5	53.9%	61.7	9.2%	154.2	22.9%	94.1	14.0%
Depreciation & Depletion (Schedule 1.5)	477.7	283.5	59.3%	58.5	12.3%	126.1	26.4%	9.6	2.0%
Corporate Capital Tax	36.9	20.8	56.3%	7.1	19.3%	8.8	23.7%	0.2	0.7%
Grants in Lieu of Taxes	23.9	23.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	86.6%	0.0	0.7%	0.0	1.6%	0.1	11.0%
Other Income (Credit) (Schedule 1.6)	(144.8)	(58.2)	40.2%	(13.8)	9.5%	(45.9)	31.7%	(26.9)	18.6%
Return on Rate Base @ 4.89%	451.8	253.7	56.2%	86.4	19.1%	108.2	23.9%	3.5	0.8%
Total Revenue Requirement	**2,154.4**	**1,522.6**	**70.7%**	**199.9**	**9.3%**	**351.3**	**16.3%**	**80.6**	**3.7%**

Schedule 1.1: Functionalization of Financial Account Details – Plant in Service

Functionalization of Financial Account Details
PLANT IN SERVICE
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Power Production	7,882.5	7,882.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	58.0	58.0	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	5.7	5.7	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**7,946.2**	**7,946.2**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	2,227.4	14.9	0.7%	2,166.5	97.3%	46.0	2.1%	-	0.0%
Total Transmission Assets	**2,227.4**	**14.9**	**0.7%**	**2,166.5**	**97.3%**	**46.0**	**2.1%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	3,227.3	-	0.0%	-	0.0%	3,227.3	100.0%	-	0.0%
Meters	203.0	-	0.0%	-	0.0%	203.0	100.0%	-	0.0%
Total Distribution Assets	**3,430.4**	**-**	**0.0%**	**-**	**0.0%**	**3,430.4**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	2.2	1.2	53.9%	0.2	9.2%	0.5	22.9%	0.3	14.0%
Buildings	243.6	111.4	45.7%	28.0	11.5%	63.1	25.9%	41.2	16.9%
Office Furniture & Equipment	44.3	20.3	45.7%	5.1	11.5%	11.5	25.9%	7.5	16.9%
Vehicles & Equipment	175.8	20.8	11.8%	43.4	24.7%	94.1	53.5%	17.5	10.0%
Computer Development & Equipment	362.5	167.2	46.1%	48.2	13.3%	100.7	27.8%	46.4	12.8%
Communication, Protection & Control	151.0	48.9	32.4%	81.1	53.7%	17.3	11.5%	3.7	2.4%
Tools & Equipment	23.4	9.0	38.4%	2.9	12.3%	9.8	41.8%	1.7	7.4%
Total General Plant Assets	**1,002.8**	**378.8**	**37.8%**	**208.8**	**20.8%**	**297.0**	**29.6%**	**118.3**	**11.8%**
Total Plant In Service	**14,606.7**	**8,339.8**	**57.1%**	**2,375.3**	**16.3%**	**3,773.3**	**25.8%**	**118.3**	**0.8%**

Schedule 1.2: Functionalization of Financial Account Details – Accumulated Depreciation

Functionalization of Financial Account Details
ACCUMULATED DEPRECIATION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Generation Assets	(3,044.4)	(3,044.4)	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	(29.1)	(29.1)	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International - Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse Assets	(3.2)	(3.2)	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**(3,076.6)**	**(3,076.6)**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	(540.7)	(2.9)	0.5%	(527.1)	97.5%	(10.7)	2.0%	-	0.0%
Total Transmission Assets	**(540.7)**	**(2.9)**	**0.5%**	**(527.1)**	**97.5%**	**(10.7)**	**2.0%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	(1,400.0)	-	0.0%	-	0.0%	(1,400.0)	100.0%	-	0.0%
Meters	(52.4)	-	0.0%	-	0.0%	(52.4)	100.0%	-	0.0%
Total Distribution Assets	**(1,452.4)**	**-**	**0.0%**	**-**	**0.0%**	**(1,452.4)**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Buildings	(41.5)	(21.3)	51.4%	(4.4)	10.7%	(9.9)	23.8%	(5.8)	14.0%
Office Furniture & Equipment	(17.1)	(8.8)	51.4%	(1.8)	10.7%	(4.1)	23.8%	(2.4)	14.0%
Vehicles & Equipment	(86.3)	(11.3)	13.1%	(21.0)	24.3%	(45.6)	52.8%	(8.4)	9.8%
Computer Development & Equipment	(315.0)	(127.8)	40.6%	(47.7)	15.1%	(100.4)	31.9%	(39.0)	12.4%
Communication, Protection & Control	(72.1)	(25.4)	35.2%	(36.0)	49.9%	(8.9)	12.3%	(1.8)	2.6%
Tools & Equipment	(14.4)	(5.8)	39.9%	(0.1)	1.0%	(7.3)	50.3%	(1.3)	8.8%
Total General Plant Assets	**(546.4)**	**(200.4)**	**36.7%**	**(111.1)**	**20.3%**	**(176.1)**	**32.2%**	**(58.8)**	**10.8%**
Total Accumulated Depreciation	**(5,616.1)**	**(3,279.9)**	**58.4%**	**(638.2)**	**11.4%**	**(1,639.2)**	**29.2%**	**(58.8)**	**1.0%**

Schedule 1.3: Functionalization of Financial Account Details – Inventories/Other Assets

Functionalization of Financial Account Details
INVENTORIES
2015 Test Embedded Cost of Service Study
($ Millions)

	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Inventories									
Power Production - Repair Stores	52.1	52.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production - Fuel	27.9	27.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission & Distribution	81.9	-	0.0%	22.4	27.4%	59.5	72.6%	-	0.0%
Miscellaneous (Computers, Power Shop)	3.1	1.7	53.9%	0.3	9.2%	0.7	22.9%	0.4	14.0%
Total Inventories	**165.0**	**81.7**	**49.5%**	**22.7**	**13.8%**	**60.2**	**36.5%**	**0.4**	**0.3%**

Functionalization of Financial Account Details
OTHER ASSETS
2015 Base Embedded Cost of Service Study
($ Millions)

	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	3.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Intangible Assets	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Prepaid Expenses - Insurance	0.8	0.7	90.0%	0.0	2.8%	0.0	6.1%	0.0	1.1%
Miscellaneous Prepaid Expenses	3.3	1.8	53.9%	0.3	9.2%	0.8	22.9%	0.5	14.0%
Total Generation Expenses	**7.2**	**5.6**	**77.7%**	**0.3**	**4.5%**	**0.8**	**11.2%**	**0.5**	**6.6%**

Schedule 1.4: Functionalization of Financial Account Details – O M & A Expenses

Functionalization of Financial Account Details
OM&A EXPENSES
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Expenses									
Power Plant Operation	177.8	177.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Fuel Supply	1.9	1.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production Overhead	29.2	29.2	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Cory Cogen	11.8	11.8	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Meridian	7.1	7.1	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Spy Hill	(0.6)	(0.6)	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Flyash	1.9	1.9	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Centennial Wind	6.0	6.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	1.3	1.3	100.0%	-	0.0%	-	0.0%	-	0.0%
NorthPoint Energy Solutions	8.5	8.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Expenses	**244.9**	**244.9**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission & Distribution Expenses									
T & D - Planning Support	16.5	8.9	54.0%	7.3	44.1%	-	0.0%	0.3	1.9%
T & D - Transmission Including 138 & 72 kV Radials	32.4	-	0.0%	32.4	100.0%	-	0.0%	-	0.0%
T & D - Distribution	105.4	-	0.0%	-	0.0%	105.4	100.0%	-	0.0%
T & D - Customer Services	5.7	-	0.0%	-	0.0%	-	0.0%	5.7	100.0%
T & D - Gas & Electric Inspections	12.7	-	0.0%	-	0.0%	-	0.0%	12.7	100.0%
Total Transmission & Distribution Expenses	**172.7**	**8.9**	**5.2%**	**39.7**	**23.0%**	**105.4**	**61.0%**	**18.7**	**10.8%**
Customer Services Expenses									
Meter Reading	7.0	-	0.0%	-	0.0%	-	0.0%	7.0	100.0%
Metering Services	2.8	-	0.0%	-	0.0%	-	0.0%	2.8	100.0%
Billing Services	3.3	-	0.0%	-	0.0%	-	0.0%	3.3	100.0%
Collections/Special Collections	3.9	-	0.0%	-	0.0%	-	0.0%	3.9	100.0%
Bad Debt Expense	2.4	-	0.0%	-	0.0%	-	0.0%	2.4	100.0%
Marketing & Sales	3.4	-	0.0%	-	0.0%	-	0.0%	3.4	100.0%
Demand Side Management	14.6	14.6	100.0%	-	0.0%	-	0.0%	-	0.0%
Customer Service	15.5	-	0.0%	-	0.0%	-	0.0%	15.5	100.0%
Total Customer Services Expenses	**52.9**	**14.6**	**27.6%**	**-**	**0.0%**	**-**	**0.0%**	**38.3**	**72.4%**
Support Group Expenses									
President / Board	3.4	1.8	53.9%	0.3	9.2%	0.8	22.9%	0.5	14.0%
Corporate & Financial Services	23.4	13.4	57.1%	2.2	9.5%	4.9	21.0%	2.9	12.4%
Planning, Environment & Regulatory Affairs	22.1	15.4	69.8%	1.5	6.6%	3.4	15.4%	1.8	8.1%
General Council / Land	4.9	2.7	53.9%	0.5	9.2%	1.1	22.9%	0.7	14.0%
Communication & Public Affairs	8.1	4.4	53.9%	0.7	9.2%	1.8	22.9%	1.1	14.0%
Safety	8.2	4.3	52.4%	0.8	9.9%	1.9	23.2%	1.2	14.6%
Corporate Information & Technology	79.0	37.1	47.0%	9.1	11.6%	20.0	25.3%	12.8	16.2%
Human Resources	20.9	9.3	44.7%	2.5	12.1%	5.6	26.6%	3.5	16.6%
Supply Chain	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Business Development	1.5	1.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Service Delivery Renewal	30.4	4.2	13.8%	4.3	14.1%	9.3	30.5%	12.7	41.6%
Total Support Group Expenses	**201.9**	**94.1**	**46.6%**	**21.9**	**10.9%**	**48.8**	**24.2%**	**37.1**	**18.4%**
Total OM&A Expenses	**672.4**	**362.5**	**53.9%**	**61.7**	**9.2%**	**154.2**	**22.9%**	**94.1**	**14.0%**

Schedule 1.5: Functionalization of Financial Account Details – Depreciation & Depletion Expense

Functionalization of Financial Account Details
DEPRECIATION & DEPLETION EXPENSE
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Generation Assets	253.8	253.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	1.4	1.4	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International - Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse Assets	0.2	0.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**255.4**	**255.4**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	48.5	0.3	0.6%	47.1	97.0%	1.1	2.4%	-	0.0%
Total Transmission Assets	**48.5**	**0.3**	**0.6%**	**47.1**	**97.0%**	**1.1**	**2.4%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	96.3	-	0.0%	-	0.0%	96.3	100.0%	-	0.0%
Meters	8.9	-	0.0%	-	0.0%	8.9	100.0%	-	0.0%
Total Distribution Assets	**105.2**	**-**	**0.0%**	**-**	**0.0%**	**105.2**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Buildings	1.0	0.6	55.6%	0.1	9.3%	0.2	21.1%	0.1	14.0%
Office Furniture & Equipment	0.8	0.5	55.6%	0.1	9.3%	0.2	21.1%	0.1	14.0%
Vehicles & Equipment	10.9	1.0	9.5%	2.8	25.3%	6.0	54.8%	1.1	10.4%
Computer Development & Equipment	49.5	23.6	47.7%	5.6	11.4%	12.3	24.8%	8.0	16.1%
Communication, Protection & Control	5.2	1.7	31.6%	2.8	53.9%	0.6	12.0%	0.1	2.5%
Tools & Equipment	1.1	0.4	41.4%	0.1	5.4%	0.5	45.3%	0.1	8.0%
Total General Plant Assets	**68.6**	**27.8**	**40.5%**	**11.4**	**16.7%**	**19.8**	**28.8%**	**9.6**	**14.0%**
Total Depreciation Expense	**477.7**	**283.5**	**59.3%**	**58.5**	**12.3%**	**126.1**	**26.4%**	**9.6**	**2.0%**

Schedule 1.6: Functionalization of Financial Account Details – Other Income

Functionalization of Financial Account Details
OTHER INCOME
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Other Income									
Customer Services Payment Charges	(5.3)	-	0.0%	-	0.0%	-	0.0%	(5.3)	100.0%
Meter Reading	(2.0)	-	0.0%	-	0.0%	-	0.0%	(2.0)	100.0%
Inspections	(18.7)	-	0.0%	-	0.0%	-	0.0%	(18.7)	100.0%
Transmission	(1.9)	(0.3)	17.6%	(1.6)	82.4%	-	0.0%	-	0.0%
Distribution	(6.1)	-	0.0%	-	0.0%	(6.1)	100.0%	-	0.0%
Clean Coal Project Credits	(17.8)	(17.8)	100.0%	-	0.0%	-	0.0%	-	0.0%
CO2 Sales	(20.3)	(20.3)	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Other Income	(6.4)	(3.5)	53.9%	(0.6)	9.2%	(1.5)	22.9%	(0.9)	14.0%
Customer Contribution Revenue	(50.0)	-	0.0%	(11.7)	23.3%	(38.3)	76.7%	-	0.0%
Green Power Premium	(5.6)	(5.6)	100.0%	-	0.0%	-	0.0%	-	0.0%
NorthPoint	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Flyash Sales	(10.8)	(10.8)	100.0%	-	0.0%	-	0.0%	-	0.0%
Consulting & Contracting Services	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total Other Income	**(144.8)**	**(58.2)**	**40.2%**	**(13.8)**	**9.5%**	**(45.9)**	**31.7%**	**(26.9)**	**19%**

Schedule 2.00: Functional Classification of Financial Account Details – Generation

Functionalization and Classification of Financial Account Details
GENERATION Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Basis of Classification	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
					Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Rate Base															
Plant In Service (Schedule 2.01)	14,606.7	8,339.8	57.1%	Functional Class of PIS	3,290.2	3,560.0	332.0	316.1	36.9	77.8	178.3	267.5	214.3	66.8	-
Accumulated Depreciation (Schedule 2.02)	(5,616.1)	(3,279.9)	58.4%	Functional Class of Accum. Depr'n	(1,246.9)	(1,495.5)	(125.8)	(132.8)	(19.5)	(27.5)	(55.1)	(82.7)	(66.2)	(27.8)	-
Allowance For Working Capital	84.1	46.7	55.6%	12.50% of OM&A and Taxes	27.4	10.0	2.6	0.8	1.0	0.2	0.4	0.7	0.5	0.3	2.7
Inventories (Schedule 2.03)	165.0	81.7	49.5%	Functional Class of Inventories	38.3	33.4	3.9	3.0	0.0	0.2	0.6	0.9	0.8	0.4	-
Other Assets (Schedule 2.03)	7.2	5.6	77.7%	Functional Classification of Other Assets	1.6	3.3	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Rate Base	**9,246.9**	**5,193.9**	**56.2%**		**2,110.7**	**2,111.2**	**212.9**	**187.4**	**18.4**	**50.7**	**124.3**	**186.5**	**149.4**	**39.7**	**2.7**
Revenue Requirement															
Fuel Expense SaskPower Units	441.5	441.5	100.0%	Functional Class of Fuel Exp.	-	405.3	-	36.1	-	-	-	-	-	0.1	-
Purchased Power & Import	236.9	236.9	100.0%	Functional Class of PP, Import & NP Fee	72.7	144.0	7.4	12.8	-	-	-	-	-	0.0	-
Export & Net Electricity Trading Revenue (Credit)	(42.4)	(42.4)	100.0%	Functional Class of Exports	-	(38.9)	-	(3.5)	-	-	-	-	-	(0.0)	-
Operating, Maintenance & Administration (Schedule 2.04)	672.4	362.5	53.9%	Functional Class of OM&A	230.6	78.8	22.1	5.9	8.5	1.7	3.4	5.1	4.1	2.4	-
Depreciation & Depletion (Schedule 2.05)	477.7	283.5	59.3%	Functional Class of Depr'n & Depletion	124.3	111.5	12.5	9.8	1.2	2.4	5.4	8.0	6.4	2.0	-
Corporate Capital Tax	36.9	20.8	56.3%	Functional Class of Corp. Capital Tax	8.4	8.5	0.8	0.8	0.1	0.2	0.5	0.8	0.6	0.2	-
Grants in Lieu of Taxes	23.9	23.9	100.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	23.9
Miscellaneous Tax	0.5	0.4	86.6%	Functional Class of Misc. Tax	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Other Income (Credit) (Schedule 2.06)	(144.8)	(58.2)	40.2%	Functional Class of Other Income	(22.8)	(27.2)	(2.3)	(2.4)	(0.4)	(0.3)	(0.7)	(1.0)	(0.8)	(0.3)	-
Return on Rate Base @ 4.89%	451.8	253.7	56.2%	Rate Base	103.1	103.1	10.4	9.2	0.9	2.5	6.1	9.1	7.3	1.9	0.1
Total Revenue Requirement	**2,154.4**	**1,522.6**	**70.7%**		**516.5**	**785.3**	**50.9**	**68.7**	**10.3**	**6.5**	**14.6**	**22.0**	**17.6**	**6.2**	**24.0**

Schedule 2.01: Functional Classification of Financial Account Details – Generation Plant in Service

Functionalization and Classification of Financial Account Details
GENERATION PLANT IN SERVICE
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	7,882.5	7,882.5	100.0%	3,060.6	3,431.6	310.0	305.8	-	62.3	175.0	262.5	210.3	64.4	-
Coal Reserves	58.0	58.0	100.0%	-	53.2	-	4.7	-	-	-	-	-	0.0	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	5.7	5.7	100.0%	2.4	2.7	0.2	0.2	-	-	-	-	-	-	-
Total Generation	**7,946.2**	**7,946.2**	**100.0%**	**3,063.1**	**3,487.6**	**310.2**	**310.8**	**-**	**62.3**	**175.0**	**262.5**	**210.3**	**64.5**	**-**
Transmission														
Transmission	2,227.4	14.9	0.7%	13.5	-	1.4	-	-	-	-	-	-	-	-
Total Transmission	**2,227.4**	**14.9**	**0.7%**	**13.5**	**-**	**1.4**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	3,227.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	203.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**3,430.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	2.2	1.2	53.9%	0.8	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Buildings	243.6	111.4	45.7%	74.4	22.2	7.0	1.5	1.0	0.5	1.1	1.7	1.3	0.8	-
Office Furniture & Equipment	44.3	20.3	45.7%	13.5	4.0	1.3	0.3	0.2	0.1	0.2	0.3	0.2	0.1	-
Vehicles & Equipment	175.8	20.8	11.8%	14.8	3.1	1.5	0.3	0.0	0.1	0.2	0.4	0.3	0.2	-
Computer Development & Equipment	362.5	167.2	46.1%	103.7	41.5	10.0	3.2	0.3	1.2	1.7	2.5	2.0	1.2	-
Communication, Protection & Control	151.0	48.9	32.4%	-	-	-	-	35.3	13.6	-	-	-	-	-
Tools & Equipment	23.4	9.0	38.4%	6.4	1.3	0.7	0.1	-	0.0	0.1	0.2	0.1	0.1	-
Total General Plant	**1,002.8**	**378.8**	**37.8%**	**213.6**	**72.4**	**20.4**	**5.4**	**36.9**	**15.5**	**3.3**	**5.0**	**4.0**	**2.3**	**-**
Total Plant In Service	**14,606.7**	**8,339.8**	**57.1%**	**3,290.2**	**3,560.0**	**332.0**	**316.1**	**36.9**	**77.8**	**178.3**	**267.5**	**214.3**	**66.8**	**-**

SaskPower

Schedule 2.02: Functional Classification of Financial Account Details – Generation Accumulated Depreciation

Functionalization and Classification of Financial Account Details
GENERATION ACCUMULATED DEPRECIATION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	(3,044.4)	(3,044.4)	100.0%	(1,131.8)	(1,427.7)	(114.6)	(127.2)	-	(19.0)	(53.3)	(80.0)	(64.1)	(26.6)	-
Coal Reserves	(29.1)	(29.1)	100.0%	-	(26.7)	-	(2.4)	-	-	-	-	-	(0.0)	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	(3.2)	(3.2)	100.0%	(1.3)	(1.6)	(0.1)	(0.1)	-	-	-	-	-	-	-
Total Generation	**(3,076.6)**	**(3,076.6)**	**100.0%**	**(1,133.0)**	**(1,456.0)**	**(114.8)**	**(129.7)**	**-**	**(19.0)**	**(53.3)**	**(80.0)**	**(64.1)**	**(26.6)**	**-**
Transmission														
Transmission	(540.7)	(2.9)	0.5%	(2.6)	-	(0.3)	-	-	-	-	-	-	-	-
Total Transmission	**(540.7)**	**(2.9)**	**0.5%**	**(2.6)**	**-**	**(0.3)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	(1,400.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	(52.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**(1,452.4)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Buildings	(41.5)	(21.3)	51.4%	(14.6)	(3.8)	(1.4)	(0.3)	(0.1)	(0.1)	(0.2)	(0.3)	(0.3)	(0.2)	-
Office Furniture & Equipment	(17.1)	(8.8)	51.4%	(6.0)	(1.6)	(0.6)	(0.1)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	-
Vehicles & Equipment	(86.3)	(11.3)	13.1%	(8.1)	(1.7)	(0.8)	(0.1)	(0.0)	(0.0)	(0.1)	(0.2)	(0.2)	(0.1)	-
Computer Development & Equipment	(315.0)	(127.8)	40.6%	(78.4)	(31.6)	(7.5)	(2.5)	(1.1)	(1.3)	(1.3)	(1.9)	(1.5)	(0.9)	-
Communication, Protection & Control	(72.1)	(25.4)	35.2%	-	-	-	-	(18.3)	(7.0)	-	-	-	-	-
Tools & Equipment	(14.4)	(5.8)	39.9%	(4.1)	(0.8)	(0.4)	(0.1)	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	-
Total General Plant	**(546.4)**	**(200.4)**	**36.7%**	**(111.2)**	**(39.5)**	**(10.7)**	**(3.1)**	**(19.5)**	**(8.5)**	**(1.8)**	**(2.7)**	**(2.1)**	**(1.3)**	**-**
Total Accumulated Depreciation	**(5,616.1)**	**(3,279.9)**	**58.4%**	**(1,246.9)**	**(1,495.5)**	**(125.8)**	**(132.8)**	**(19.5)**	**(27.5)**	**(55.1)**	**(82.7)**	**(66.2)**	**(27.8)**	**-**

Schedule 2.03: Functional Classification of Financial Account Details – Generation Inventories/Other Assets

Functionalization and Classification of Financial Account Details
GENERATION INVENTORIES
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Inventories														
Power Production - Repair Stores	52.1	52.1	100.0%	37.3	7.5	3.8	0.7	-	0.2	0.6	0.9	0.7	0.4	-
Power Production - Fuel	27.9	27.9	100.0%	-	25.6	-	2.3	-	-	-	-	-	0.0	-
Transmission & Distribution	81.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	3.1	1.7	53.9%	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Inventories	**165.0**	**81.7**	**49.5%**	**38.3**	**33.4**	**3.9**	**3.0**	**0.0**	**0.2**	**0.6**	**0.9**	**0.8**	**0.4**	**-**

Functionalization and Classification of Financial Account Details
GENERATION OTHER ASSETS
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Other Assets														
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	3.1	100.0%	-	2.9	-	0.3	-	-	-	-	-	0.0	-
Intangible Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.7	90.0%	0.5	0.1	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Miscellaneous Prepaid Expenses	3.3	1.8	53.9%	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Other Assets	**7.2**	**5.6**	**77.7%**	**1.6**	**3.3**	**0.2**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**

Schedule 2.04: Functional Classification of Financial Account Details – Generation O M & A Expenses

Functionalization and Classification of Financial Account Details
GENERATION OM&A EXPENSES
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation Expenses														
Power Plant Operation	177.8	177.8	100.0%	127.2	25.5	12.9	2.3	-	0.7	2.1	3.1	2.5	1.5	-
Fuel Supply	1.9	1.9	100.0%	-	1.8	-	0.2	-	-	-	-	-	0.0	-
Power Production Overhead	29.2	29.2	100.0%	20.9	4.2	2.1	0.4	-	0.1	0.3	0.5	0.4	0.2	-
SaskPower International (SPI) - Cory Cogen	11.8	11.8	100.0%	9.4	1.4	0.9	0.1	-	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.1	7.1	100.0%	2.1	4.4	0.2	0.4	-	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.6)	(0.6)	100.0%	(0.4)	(0.2)	(0.0)	(0.0)	-	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	1.9	100.0%	-	1.8	-	0.2	-	-	-	-	-	0.0	-
SaskPower International (SPI) - Centennial Wind	6.0	6.0	100.0%	-	5.5	-	0.5	-	-	-	-	-	0.0	-
Shand Greenhouse	1.3	1.3	100.0%	0.9	0.2	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
NorthPoint Energy Solutions	8.5	8.5	100.0%	-	7.8	-	0.7	-	-	-	-	-	0.0	-
Total Generation Expenses	**244.9**	**244.9**	**100.0%**	**160.1**	**52.3**	**16.2**	**4.7**	**-**	**0.9**	**2.5**	**3.7**	**2.9**	**1.7**	**-**
Transmission & Distribution Expenses														
T & D - Planning Support	16.5	8.9	54.0%	0.2	0.2	0.0	0.0	8.0	0.5	-	-	-	-	-
T & D - Transmission Including 138 & 72 kV Radials	32.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Distribution	105.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Customer Services	5.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Gas & Electric Inspections	12.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	**172.7**	**8.9**	**5.2%**	**0.2**	**0.2**	**0.0**	**0.0**	**8.0**	**0.5**	**-**	**-**	**-**	**-**	**-**
Customer Services Expenses														
Meter Reading	7.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Metering Services	2.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	3.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	2.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	14.6	14.6	100.0%	7.3	7.3	-	-	-	-	-	-	-	-	-
Customer Service	15.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	**52.9**	**14.6**	**27.6%**	**7.3**	**7.3**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Support Group Expenses														
President / Board	3.4	1.8	53.9%	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Corporate & Financial Services	23.4	13.4	57.1%	9.3	2.3	0.9	0.2	0.0	0.1	0.1	0.2	0.2	0.1	-
Planning, Environment & Regulatory Affairs	22.1	15.4	69.8%	11.1	2.2	1.1	0.2	0.1	0.1	0.2	0.3	0.2	0.1	-
General Council / Land	4.9	2.7	53.9%	1.7	0.6	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	-
Communication & Public Affairs	8.1	4.4	53.9%	2.8	0.9	0.3	0.1	0.1	0.0	0.0	0.1	0.0	0.0	-
Safety	8.2	4.3	52.4%	2.8	0.9	0.3	0.1	0.1	0.0	0.0	0.1	0.1	0.0	-
Corporate Information & Technology	79.0	37.1	47.0%	24.8	7.6	2.3	0.5	0.1	0.1	0.4	0.6	0.5	0.3	-
Human Resources	20.9	9.3	44.7%	6.3	1.8	0.6	0.1	0.0	0.0	0.1	0.1	0.1	0.1	-
Supply Chain	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Business Development	1.5	1.5	100.0%	1.1	0.2	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Service Delivery Renewal	30.4	4.2	13.8%	2.1	2.1	-	-	-	-	-	-	-	-	-
Total Support Group Expenses	**201.9**	**94.1**	**46.6%**	**63.1**	**18.9**	**5.8**	**1.2**	**0.5**	**0.4**	**0.9**	**1.4**	**1.1**	**0.7**	**-**
Total OM&A Expenses	**672.4**	**362.5**	**53.9%**	**230.6**	**78.8**	**22.1**	**5.9**	**8.5**	**1.7**	**3.4**	**5.1**	**4.1**	**2.4**	**-**

Schedule 2.05: Functional Classification of Financial Account Details – Generation Depreciation & Depletion

Functionalization and Classification of Financial Account Details
GENERATION DEPRECIATION & DEPLETION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	253.8	253.8	100.0%	106.4	104.8	10.8	9.3	-	1.8	5.1	7.6	6.1	1.8	-
Coal Reserves	1.4	1.4	100.0%	-	1.3	-	0.1	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	0.2	100.0%	0.1	0.1	0.0	0.0	-	-	-	-	-	-	-
Total Generation	255.4	255.4	100.0%	106.5	106.2	10.8	9.5	-	1.8	5.1	7.6	6.1	1.8	-
Transmission														
Transmission	48.5	0.3	0.6%	0.3	-	0.0	-	-	-	-	-	-	-	-
Total Transmission	48.5	0.3	0.6%	0.3	-	0.0	-	-	-	-	-	-	-	-
Distribution														
Distribution	96.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	8.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	105.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
General Plant														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Buildings	1.0	0.6	55.6%	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Office Furniture & Equipment	0.8	0.5	55.6%	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Vehicles & Equipment	10.9	1.0	9.5%	0.7	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Computer Development & Equipment	49.5	23.6	47.7%	15.7	4.9	1.5	0.3	0.0	0.1	0.2	0.4	0.3	0.2	-
Communication, Protection & Control	5.2	1.7	31.6%	-	-	-	-	1.2	0.5	-	-	-	-	-
Tools & Equipment	1.1	0.4	41.4%	0.3	0.1	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Total General Plant	68.6	27.8	40.5%	17.5	5.3	1.7	0.4	1.2	0.6	0.3	0.4	0.3	0.2	-
Total Depreciation & Depletion	477.7	283.5	59.3%	124.3	111.5	12.5	9.8	1.2	2.4	5.4	8.0	6.4	2.0	-

Schedule 2.06: Functional Classification of Financial Account Details – Generation Other Income

Functionalization and Classification of Financial Account Details
GENERATION OTHER INCOME
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Other Income														
Customer Services Payment Charges	(5.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission	(1.9)	(0.3)	17.6%	-	-	-	-	(0.3)	(0.0)	-	-	-	-	-
Distribution	(6.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Clean Coal Project Credits	(17.8)	(17.8)	100.0%	(12.7)	(2.5)	(1.3)	(0.2)	-	(0.1)	(0.2)	(0.3)	(0.3)	(0.1)	-
CO2 Sales	(20.3)	(20.3)	100.0%	(7.9)	(8.8)	(0.8)	(0.8)	-	(0.2)	(0.5)	(0.7)	(0.5)	(0.2)	-
Miscellaneous Other Income	(6.4)	(3.5)	53.9%	(2.2)	(0.8)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Customer Contributions Revenue	(50.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Green Power Premium	(5.6)	(5.6)	100.0%	-	(5.1)	-	(0.5)	-	-	-	-	-	(0.0)	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(10.8)	(10.8)	100.0%	-	(9.9)	-	(0.9)	-	-	-	-	-	(0.0)	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**(144.8)**	**(58.2)**	**40.2%**	**(22.8)**	**(27.2)**	**(2.3)**	**(2.4)**	**(0.4)**	**(0.3)**	**(0.7)**	**(1.0)**	**(0.8)**	**(0.3)**	**-**

Schedule 2.10: Functional Classification of Financial Account Details – Transmission

Functionalization and Classification of Financial Account Details
TRANSMISSION Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Basis of Classification	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kv Lines Radials
					Demand	Demand	Demand	Demand
Rate Base								
Plant In Service (Schedule 2.11)	14,606.7	2,375.3	16.3%	Functional Class of PIS	1,258.7	622.4	175.4	318.7
Accumulated Depreciation (Schedule 2.12)	(5,616.1)	(638.2)	11.4%	Functional Class of Accum. Depr'n	(357.3)	(139.7)	(53.1)	(88.1)
Allowance For Working Capital	84.1	7.9	9.4%	12.50% of OM&A and Taxes	4.4	1.5	0.5	1.5
Inventories (Schedule 2.13)	165.0	22.7	13.8%	Functional Class of Inventories	12.7	4.1	1.6	4.4
Other Assets (Schedule 2.13)	7.2	0.3	4.5%	Functional Classification of Other Assets	0.2	0.1	0.0	0.1
Total Rate Base	**9,246.9**	**1,768.0**	**19.1%**		**918.6**	**488.3**	**124.5**	**236.6**
Revenue Requirement								
Fuel Expense SaskPower Units	441.5	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-
Purchased Power & Import	236.9	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(42.4)	-	0.0%	Functional Class of Exports	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.14)	672.4	61.7	9.2%	Functional Class of OM&A	34.4	11.0	4.3	12.0
Depreciation & Depletion (Schedule 2.15)	477.7	58.5	12.3%	Functional Class of Depr'n & Depletion	32.3	13.1	4.5	8.7
Corporate Capital Tax	36.9	7.1	19.3%	Functional Class of Corp. Capital Tax	3.7	2.0	0.5	0.9
Grants in Lieu of Taxes	23.9	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-
Miscellaneous Tax	0.5	0.0	0.7%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.16)	(144.8)	(13.8)	9.5%	Functional Class of Other Income	(3.3)	(9.1)	(0.2)	(1.3)
Return on Rate Base @ 4.89%	451.8	86.4	19.1%	Rate Base	44.9	23.9	6.1	11.6
Total Revenue Requirement	**2,154.4**	**199.9**	**9.3%**		**111.9**	**40.8**	**15.2**	**31.9**

Schedule 2.11: Functional Classification of Financial Account Details – Transmission Plant in Service

Functionalization and Classification of Financial Account Details
TRANSMISSION PLANT IN SERVICE
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	7,882.5	-	0.0%	-	-	-	-
Coal Reserves	58.0	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-
Total Generation	**7,946.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	2,227.4	2,166.5	97.3%	1,142.4	585.0	160.9	278.3
Total Transmission	**2,227.4**	**2,166.5**	**97.3%**	**1,142.4**	**585.0**	**160.9**	**278.3**
Distribution							
Distribution	3,227.3	-	0.0%	-	-	-	-
Meters	203.0	-	0.0%	-	-	-	-
Total Distribution	**3,430.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	2.2	0.2	9.2%	0.1	0.0	0.0	0.0
Buildings	243.6	28.0	11.5%	15.6	5.0	1.9	5.4
Office Furniture & Equipment	44.3	5.1	11.5%	2.8	0.9	0.4	1.0
Vehicles & Equipment	175.8	43.4	24.7%	24.2	7.8	3.0	8.4
Computer Development & Equipment	362.5	48.2	13.3%	26.9	8.6	3.4	9.3
Communication, Protection & Control	151.0	81.1	53.7%	45.2	14.5	5.6	15.7
Tools & Equipment	23.4	2.9	12.3%	1.6	0.5	0.2	0.6
Total General Plant	**1,002.8**	**208.8**	**20.8%**	**116.4**	**37.4**	**14.5**	**40.5**
Total Plant In Service	**14,606.7**	**2,375.3**	**16.3%**	**1,258.7**	**622.4**	**175.4**	**318.7**

Schedule 2.12: Functional Classification of Financial Account Details – Transmission Accumulated Depreciation

Functionalization and Classification of Financial Account Details
TRANSMISSION ACCUMULATED DEPRECIATION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	(3,044.4)	-	0.0%	-	-	-	-
Coal Reserves	(29.1)	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	(3.2)	-	0.0%	-	-	-	-
Total Generation	**(3,076.6)**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	(540.7)	(527.1)	97.5%	(295.4)	(119.8)	(45.4)	(66.5)
Total Transmission	**(540.7)**	**(527.1)**	**97.5%**	**(295.4)**	**(119.8)**	**(45.4)**	**(66.5)**
Distribution							
Distribution	(1,400.0)	-	0.0%	-	-	-	-
Meters	(52.4)	-	0.0%	-	-	-	-
Total Distribution	**(1,452.4)**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	-	-	0.0%	-	-	-	-
Buildings	(41.5)	(4.4)	10.7%	(2.5)	(0.8)	(0.3)	(0.9)
Office Furniture & Equipment	(17.1)	(1.8)	10.7%	(1.0)	(0.3)	(0.1)	(0.4)
Vehicles & Equipment	(86.3)	(21.0)	24.3%	(11.7)	(3.8)	(1.5)	(4.1)
Computer Development & Equipment	(315.0)	(47.7)	15.1%	(26.6)	(8.5)	(3.3)	(9.2)
Communication, Protection & Control	(72.1)	(36.0)	49.9%	(20.1)	(6.5)	(2.5)	(7.0)
Tools & Equipment	(14.4)	(0.1)	1.0%	(0.1)	(0.0)	(0.0)	(0.0)
Total General Plant	**(546.4)**	**(111.1)**	**20.3%**	**(61.9)**	**(19.9)**	**(7.7)**	**(21.5)**
Total Accumulated Depreciation	**(5,616.1)**	**(638.2)**	**11.4%**	**(357.3)**	**(139.7)**	**(53.1)**	**(88.1)**

Schedule 2.13: Functional Classification of Financial Account Details – Transmission Inventories/Other Assets

Functionalization and Classification of Financial Account Details
TRANSMISSION INVENTORIES
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Inventories							
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-
Transmission & Distribution	81.9	22.4	27.4%	12.5	4.0	1.6	4.3
Miscellaneous (Computers, Power Shop)	3.1	0.3	9.2%	0.2	0.1	0.0	0.1
Total Inventories	**165.0**	**22.7**	**13.8%**	**12.7**	**4.1**	**1.6**	**4.4**

Functionalization and Classification of Financial Account Details
TRANSMISSION OTHER ASSETS
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Other Assets							
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	2.8%	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	3.3	0.3	9.2%	0.2	0.1	0.0	0.1
Total Other Assets	**7.2**	**0.3**	**4.5%**	**0.2**	**0.1**	**0.0**	**0.1**

Schedule 2.14: Functional Classification of Financial Account Details – Transmission O M & A Expenses

Functionalization and Classification of Financial Account Details
TRANSMISSION OM&A EXPENSE
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation Expenses							
Power Plant Operation	177.8	-	0.0%	-	-	-	-
Fuel Supply	1.9	-	0.0%	-	-	-	-
Power Production Overhead	29.2	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogen	11.8	-	0.0%	-	-	-	-
SaskPower International (SPI) - Meridian	7.1	-	0.0%	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.6)		0.0%	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-
SaskPower International (SPI) - Centennial Wind	6.0	-	0.0%	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-
NorthPoint Energy Solutions	8.5	-	0.0%	-	-	-	-
Total Generation Expenses	**244.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses							
T & D - Planning Support	16.5	7.3	44.1%	3.8	2.0	0.5	0.9
T & D - Transmission Including 138 & 72 kV Radials	32.4	32.4	100.0%	18.3	5.1	2.2	6.8
T & D - Distribution	105.4	-	0.0%	-	-	-	-
T & D - Customer Services	5.7	-	0.0%	-	-	-	-
T & D - Gas & Electric Inspections	12.7	-	0.0%	-	-	-	-
Total Transmission & Distribution Expenses	**172.7**	**39.7**	**23.0%**	**22.1**	**7.1**	**2.8**	**7.7**
Customer Services Expenses							
Meter Reading	7.0	-	0.0%	-	-	-	-
Metering Services	2.8	-	0.0%	-	-	-	-
Billing Services	3.3	-	0.0%	-	-	-	-
Collections/Special Collections	3.9	-	0.0%	-	-	-	-
Bad Debt Expense	2.4	-	0.0%	-	-	-	-
Marketing & Sales	3.4	-	0.0%	-	-	-	-
Demand Side Management	14.6	-	0.0%	-	-	-	-
Customer Service	15.5	-	0.0%	-	-	-	-
Total Customer Services Expenses	**52.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Support Group Expenses							
President / Board	3.4	0.3	9.2%	0.2	0.1	0.0	0.1
Corporate & Financial Services	23.4	2.2	9.5%	1.2	0.4	0.2	0.4
Planning, Environment & Regulatory Affairs	22.1	1.5	6.6%	0.8	0.3	0.1	0.3
General Council / Land	4.9	0.5	9.2%	0.3	0.1	0.0	0.1
Communication & Public Affairs	8.1	0.7	9.2%	0.4	0.1	0.1	0.1
Safety	8.2	0.8	9.9%	0.4	0.1	0.1	0.2
Corporate Information & Technology	79.0	9.1	11.6%	5.1	1.6	0.6	1.8
Human Resources	20.9	2.5	12.1%	1.4	0.5	0.2	0.5
Supply Chain	-	-	0.0%	-	-	-	-
Business Development	1.5	-	0.0%	-	-	-	-
Service Delivery Renewal	30.4	4.3	14.1%	2.4	0.8	0.3	0.8
Total Support Group Expenses	**201.9**	**21.9**	**10.9%**	**12.2**	**3.9**	**1.5**	**4.3**
Total OM&A Expenses	**672.4**	**61.7**	**9.2%**	**34.4**	**11.0**	**4.3**	**12.0**

Schedule 2.15: Functional Classification of Financial Account Details – Transmission Depreciation & Depletion

Functionalization and Classification of Financial Account Details
TRANSMISSION DEPRECIATION & DEPLETION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	253.8	-	0.0%	-	-	-	-
Coal Reserves	1.4	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-
Total Generation	**255.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	48.5	47.1	97.0%	25.9	11.0	3.7	6.5
Total Transmission	**48.5**	**47.1**	**97.0%**	**25.9**	**11.0**	**3.7**	**6.5**
Distribution							
Distribution	96.3	-	0.0%	-	-	-	-
Meters	8.9	-	0.0%	-	-	-	-
Total Distribution	**105.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	-	-	0.0%	-	-	-	-
Buildings	1.0	0.1	9.3%	0.1	0.0	0.0	0.0
Office Furniture & Equipment	0.8	0.1	9.3%	0.0	0.0	0.0	0.0
Vehicles & Equipment	10.9	2.8	25.3%	1.5	0.5	0.2	0.5
Computer Development & Equipment	49.5	5.6	11.4%	3.1	1.0	0.4	1.1
Communication, Protection & Control	5.2	2.8	53.9%	1.6	0.5	0.2	0.5
Tools & Equipment	1.1	0.1	5.4%	0.0	0.0	0.0	0.0
Total General Plant	**68.6**	**11.4**	**16.7%**	**6.4**	**2.1**	**0.8**	**2.2**
Total Depreciation & Depletion	**477.7**	**58.5**	**12.3%**	**32.3**	**13.1**	**4.5**	**8.7**

Schedule 2.16: Functional Classification of Financial Account Details – Transmission Other Income

Functionalization and Classification of Financial Account Details
TRANSMISSION OTHER INCOME
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Other Income							
Customer Services Payment Charges	(5.3)	-	0.0%	-	-	-	-
Meter Reading	(2.0)	-	0.0%	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-
Transmission	(1.9)	(1.6)	82.4%	(0.9)	(0.3)	(0.1)	(0.3)
Distribution	(6.1)	-	0.0%	-	-	-	-
Clean Coal Project Credits	(17.8)	-	0.0%	-	-	-	-
CO2 Sales	(20.3)	-	0.0%	-	-	-	-
Miscellaneous Other Income	(6.4)	(0.6)	9.2%	(0.3)	(0.1)	(0.0)	(0.1)
Customer Contribution Revenue	(50.0)	(11.7)	23.3%	(2.1)	(8.7)	-	(0.8)
Green Power Premium	(5.6)	-	0.0%	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-
Flyash Sales	(10.8)	-	0.0%	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-
Total Other Income	**(144.8)**	**(13.8)**	**9.5%**	**(3.3)**	**(9.1)**	**(0.2)**	**(1.3)**

Schedule 2.20: Functional Classification of Financial Account Details – Distribution

Functionalization and Classification of Financial Account Details
DISTRIBUTION Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Basis of Classification	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
					Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Rate Base																	
Plant In Service (Schedule 2.21)	14,606.7	3,773.3	25.8%	Functional Class of PIS	330.8	1,043.7	279.0	150.2	520.0	280.0	297.8	127.6	465.2	-	-	203.0	76.0
Accumulated Depreciation (Schedule 2.22)	(5,616.1)	(1,639.2)	29.2%	Functional Class of Accum. Depr'n	(134.0)	(474.7)	(142.7)	(76.8)	(265.1)	(142.7)	(118.2)	(50.7)	(131.4)	-	-	(52.4)	(50.6)
Allowance For Working Capital	84.1	18.7	22.2%	12.50% of OM&A and Taxes	1.6	5.5	1.8	1.0	3.3	1.8	1.8	0.8	0.6	-	-	0.1	0.6
Inventories (Schedule 2.23)	165.0	60.2	36.5%	Functional Class of Inventories	5.1	17.7	5.8	3.1	10.9	5.8	5.8	2.5	1.4	-	-	-	2.1
Other Assets (Schedule 2.23)	7.2	0.8	11.2%	Functional Classification of Other Assets	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Rate Base	**9,246.9**	**2,213.8**	**23.9%**		**203.5**	**592.4**	**144.0**	**77.5**	**269.2**	**145.0**	**187.3**	**80.3**	**335.8**	**-**	**-**	**150.7**	**28.2**
Revenue Requirement																	
Fuel Expense SaskPower Units	441.5	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchased Power & Import	236.9	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(42.4)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.24)	672.4	154.2	22.9%	Functional Class of OM&A	13.0	45.2	14.9	8.0	27.8	15.0	14.9	6.4	3.5	-	-	-	5.3
Depreciation & Depletion (Schedule 2.25)	477.7	126.1	26.4%	Functional Class of Depr'n & Depletion	13.7	32.0	9.0	4.8	16.7	9.0	11.6	5.0	12.9	-	-	8.9	2.6
Corporate Capital Tax	36.9	8.8	23.7%	Functional Class of Corp. Capital Tax	0.8	2.3	0.6	0.3	1.0	0.6	0.7	0.3	1.4	-	-	0.6	0.1
Grants in Lieu of Taxes	23.9	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Tax	0.5	0.0	1.6%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Other Income (Credit) (Schedule 2.26)	(144.8)	(45.9)	31.7%	Functional Class of Other Income	(0.6)	(2.6)	(3.3)	(1.8)	(5.8)	(3.1)	(0.7)	(0.3)	(0.2)	-	(24.7)	-	(2.8)
Return on Rate Base @ 4.89%	451.8	108.2	23.9%	Rate Base	9.9	28.9	7.0	3.8	13.2	7.1	9.2	3.9	16.4	-	-	7.4	1.4
Total Revenue Requirement	**2,154.4**	**351.3**	**16.3%**		**36.9**	**105.9**	**28.2**	**15.2**	**52.9**	**28.5**	**35.7**	**15.3**	**34.0**	**-**	**(24.7)**	**16.9**	**6.6**

Schedule 2.21: Functional Classification of Financial Account Details – Distribution Plant in Service

Functionalization and Classification of Financial Account Details
DISTRIBUTION PLANT IN SERVICE
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	7,882.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	58.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**7,946.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission																
Transmission	2,227.4	46.0	2.1%	46.0	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	**2,227.4**	**46.0**	**2.1%**	**46.0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution																
Distribution	3,227.3	3,227.3	100.0%	259.8	956.5	250.2	134.7	466.4	251.1	269.0	115.3	458.5	-	-	-	65.8
Meters	203.0	203.0	100.0%	-	-	-	-	-	-	-	-	-	-	-	203.0	-
Total Distribution	**3,430.4**	**3,430.4**	**100.0%**	**259.8**	**956.5**	**250.2**	**134.7**	**466.4**	**251.1**	**269.0**	**115.3**	**458.5**	**-**	**-**	**203.0**	**65.8**
General Plant																
Unused Land	2.2	0.5	22.9%	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-	-	-	0.0
Buildings	243.6	63.1	25.9%	5.3	18.5	6.1	3.3	11.4	6.1	6.1	2.6	1.4	-	-	-	2.2
Office Furniture & Equipment	44.3	11.5	25.9%	1.0	3.4	1.1	0.6	2.1	1.1	1.1	0.5	0.3	-	-	-	0.4
Vehicles & Equipment	175.8	94.1	53.5%	7.9	27.6	9.1	4.9	17.0	9.1	9.1	3.9	2.1	-	-	-	3.2
Computer Development & Equipment	362.5	100.7	27.8%	8.5	29.6	9.8	5.3	18.2	9.8	9.8	4.2	2.3	-	-	-	3.5
Communication, Protection & Control	151.0	17.3	11.5%	1.5	5.1	1.7	0.9	3.1	1.7	1.7	0.7	0.4	-	-	-	0.6
Tools & Equipment	23.4	9.8	41.8%	0.8	2.9	0.9	0.5	1.8	1.0	0.9	0.4	0.2	-	-	-	0.3
Total General Plant	**1,002.8**	**297.0**	**29.6%**	**25.0**	**87.2**	**28.8**	**15.5**	**53.6**	**28.9**	**28.8**	**12.3**	**6.7**	**-**	**-**	**-**	**10.2**
Total Plant In Service	**14,606.7**	**3,773.3**	**25.8%**	**330.8**	**1,043.7**	**279.0**	**150.2**	**520.0**	**280.0**	**297.8**	**127.6**	**465.2**	**-**	**-**	**203.0**	**76.0**

Schedule 2.22: Functional Classification of Financial Account Details – Distribution Accumulated Depreciation

Functionalization and Classification of Financial Account Details
DISTRIBUTION ACCUMULATED DEPRECIATION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	(3,044.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	(29.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	(3.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**(3,076.6)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission																
Transmission	(540.7)	(10.7)	2.0%	(10.7)	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	**(540.7)**	**(10.7)**	**2.0%**	**(10.7)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution																
Distribution	(1,400.0)	(1,400.0)	100.0%	(108.5)	(423.0)	(125.6)	(67.6)	(233.3)	(125.6)	(101.2)	(43.4)	(127.4)	-	-	-	(44.5)
Meters	(52.4)	(52.4)	100.0%	-	-	-	-	-	-	-	-	-	-	-	(52.4)	-
Total Distribution	**(1,452.4)**	**(1,452.4)**	**100.0%**	**(108.5)**	**(423.0)**	**(125.6)**	**(67.6)**	**(233.3)**	**(125.6)**	**(101.2)**	**(43.4)**	**(127.4)**	**-**	**-**	**(52.4)**	**(44.5)**
General Plant																
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Buildings	(41.5)	(9.9)	23.8%	(0.8)	(2.9)	(1.0)	(0.5)	(1.8)	(1.0)	(1.0)	(0.4)	(0.2)	-	-	-	(0.3)
Office Furniture & Equipment	(17.1)	(4.1)	23.8%	(0.3)	(1.2)	(0.4)	(0.2)	(0.7)	(0.4)	(0.4)	(0.2)	(0.1)	-	-	-	(0.1)
Vehicles & Equipment	(86.3)	(45.6)	52.8%	(3.8)	(13.4)	(4.4)	(2.4)	(8.2)	(4.4)	(4.4)	(1.9)	(1.0)	-	-	-	(1.6)
Computer Development & Equipment	(315.0)	(100.4)	31.9%	(8.5)	(29.5)	(9.7)	(5.2)	(18.1)	(9.8)	(9.7)	(4.2)	(2.3)	-	-	-	(3.5)
Communication, Protection & Control	(72.1)	(8.9)	12.3%	(0.7)	(2.6)	(0.9)	(0.5)	(1.6)	(0.9)	(0.9)	(0.4)	(0.2)	-	-	-	(0.3)
Tools & Equipment	(14.4)	(7.3)	50.3%	(0.6)	(2.1)	(0.7)	(0.4)	(1.3)	(0.7)	(0.7)	(0.3)	(0.2)	-	-	-	(0.2)
Total General Plant	**(546.4)**	**(176.1)**	**32.2%**	**(14.8)**	**(51.7)**	**(17.1)**	**(9.2)**	**(31.8)**	**(17.1)**	**(17.1)**	**(7.3)**	**(4.0)**	**-**	**-**	**-**	**(6.1)**
Total Accumulated Depreciation	**(5,616.1)**	**(1,639.2)**	**29.2%**	**(134.0)**	**(474.7)**	**(142.7)**	**(76.8)**	**(265.1)**	**(142.7)**	**(118.2)**	**(50.7)**	**(131.4)**	**-**	**-**	**(52.4)**	**(50.6)**

Schedule 2.23: Functional Classification of Financial Account Details – Distribution Inventories/Other Assets

Functionalization and Classification of Financial Account Details
DISTRIBUTION INVENTORIES
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Inventories																
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission & Distribution	81.9	59.5	72.6%	5.0	17.5	5.8	3.1	10.7	5.8	5.8	2.5	1.4	-	-	-	2.0
Miscellaneous (Computers, Power Shop)	3.1	0.7	22.9%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Inventories	165.0	60.2	36.5%	5.1	17.7	5.8	3.1	10.9	5.8	5.8	2.5	1.4	-	-	-	2.1

Functionalization and Classification of Financial Account Details
DISTRIBUTION OTHER ASSETS
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Other Assets																
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	6.1%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Miscellaneous Prepaid Expenses	3.3	0.8	22.9%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Other Assets	7.2	0.8	11.2%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0

Schedule 2.24: Functional Classification of Financial Account Details – Distribution O M & A Expenses

Functionalization and Classification of Financial Account Details
DISTRIBUTION OM&A EXPENSES
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation Expenses																
Power Plant Operation	177.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Supply	1.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production Overhead	29.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogen	11.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.1		0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.6)		0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Centennial Wind	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
NorthPoint Energy Solutions	8.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation Expenses	**244.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses																
T & D - Planning Support	16.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Transmission Including 138 & 72 kV Radials	32.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Distribution	105.4	105.4	100.0%	8.9	30.9	10.2	5.5	19.0	10.2	10.2	4.4	2.4	-	-	-	3.6
T & D - Customer Services	5.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Gas & Electric Inspections	12.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	**172.7**	**105.4**	**61.0%**	**8.9**	**30.9**	**10.2**	**5.5**	**19.0**	**10.2**	**10.2**	**4.4**	**2.4**	**-**	**-**	**-**	**3.6**
Customer Services Expenses																
Meter Reading	7.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Metering Services	2.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	3.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	2.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	14.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	15.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	**52.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Support Group Expenses																
President / Board	3.4	0.8	22.9%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Corporate & Financial Services	23.4	4.9	21.0%	0.4	1.4	0.5	0.3	0.9	0.5	0.5	0.2	0.1	-	-	-	0.2
Planning, Environment & Regulatory Affairs	22.1	3.4	15.4%	0.3	1.0	0.3	0.2	0.6	0.3	0.3	0.1	0.1	-	-	-	0.1
General Council / Land	4.9	1.1	22.9%	0.1	0.3	0.1	0.1	0.2	0.1	0.1	0.0	0.0	-	-	-	0.0
Communication & Public Affairs	8.1	1.8	22.9%	0.2	0.5	0.2	0.1	0.3	0.2	0.2	0.1	0.0	-	-	-	0.1
Safety	8.2	1.9	23.2%	0.2	0.6	0.2	0.1	0.3	0.2	0.2	0.1	0.0	-	-	-	0.1
Corporate Information & Technology	79.0	20.0	25.3%	1.7	5.9	1.9	1.0	3.6	1.9	1.9	0.8	0.5	-	-	-	0.7
Human Resources	20.9	5.6	26.6%	0.5	1.6	0.5	0.3	1.0	0.5	0.5	0.2	0.1	-	-	-	0.2
Supply Chain	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Business Development	1.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Service Delivery Renewal	30.4	9.3	30.5%	0.8	2.7	0.9	0.5	1.7	0.9	0.9	0.4	0.2	-	-	-	0.3
Total Support Group Expenses	**201.9**	**48.8**	**24.2%**	**4.1**	**14.3**	**4.7**	**2.5**	**8.8**	**4.7**	**4.7**	**2.0**	**1.1**	**-**	**-**	**-**	**1.7**
Total OM&A Expenses	**672.4**	**154.2**	**22.9%**	**13.0**	**45.2**	**14.9**	**8.0**	**27.8**	**15.0**	**14.9**	**6.4**	**3.5**	**-**	**-**	**-**	**5.3**

Schedule 2.25: Functional Classification of Financial Account Details – Distribution Depreciation & Depletion

Functionalization and Classification of Financial Account Details
DISTRIBUTION DEPRECIATION & DEPLETION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	253.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	1.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**255.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission																
Transmission	48.5	1.1	2.4%	1.1	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	**48.5**	**1.1**	**2.4%**	**1.1**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution																
Distribution	96.3	96.3	100.0%	10.9	26.1	7.1	3.8	13.1	7.1	9.7	4.2	12.4	-	-	-	1.9
Meters	8.9	8.9	100.0%	-	-	-	-	-	-	-	-	-	-	-	8.9	-
Total Distribution	**105.2**	**105.2**	**100.0%**	**10.9**	**26.1**	**7.1**	**3.8**	**13.1**	**7.1**	**9.7**	**4.2**	**12.4**	**-**	**-**	**8.9**	**1.9**
General Plant																
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Buildings	1.0	0.2	21.1%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Office Furniture & Equipment	0.8	0.2	21.1%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Vehicles & Equipment	10.9	6.0	54.8%	0.5	1.8	0.6	0.3	1.1	0.6	0.6	0.2	0.1	-	-	-	0.2
Computer Development & Equipment	49.5	12.3	24.8%	1.0	3.6	1.2	0.6	2.2	1.2	1.2	0.5	0.3	-	-	-	0.4
Communication, Protection & Control	5.2	0.6	12.0%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Tools & Equipment	1.1	0.5	45.3%	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-	-	-	0.0
Total General Plant	**68.6**	**19.8**	**28.8%**	**1.7**	**5.8**	**1.9**	**1.0**	**3.6**	**1.9**	**1.9**	**0.8**	**0.4**	**-**	**-**	**-**	**0.7**
Total Depreciation & Depletion	**477.7**	**126.1**	**26.4%**	**13.7**	**32.0**	**9.0**	**4.8**	**16.7**	**9.0**	**11.6**	**5.0**	**12.9**	**-**	**-**	**8.9**	**2.6**

Schedule 2.26: Functional Classification of Financial Account Details – Distribution Other Income

Functionalization and Classification of Financial Account Details
DISTRIBUTION OTHER INCOME
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Other Income																
Customer Services Payment Charges	(5.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	(1.9)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution	(6.1)	(6.1)	100.0%	(0.5)	(1.8)	(0.6)	(0.3)	(1.1)	(0.6)	(0.6)	(0.3)	(0.1)	-	-	-	(0.2)
Clean Coal Project Credits	(17.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 Sales	(20.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Other Income	(6.4)	(1.5)	22.9%	(0.1)	(0.4)	(0.1)	(0.1)	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	-	-	-	(0.1)
Customer Contribution Revenue	(50.0)	(38.3)	76.7%	(0.0)	(0.4)	(2.5)	(1.4)	(4.4)	(2.4)	-	-	-	-	(24.7)	-	(2.5)
Green Power Premium	(5.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(10.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**(144.8)**	**(45.9)**	**31.7%**	**(0.6)**	**(2.6)**	**(3.3)**	**(1.8)**	**(5.8)**	**(3.1)**	**(0.7)**	**(0.3)**	**(0.2)**	**-**	**(24.7)**	**-**	**(2.8)**

Schedule 2.30: Functional Classification of Financial Account Details – Customer Service

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICE Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Basis of Classification	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
					Customer	Customer	Customer	Customer	Customer	Customer
Rate Base										
Plant In Service (Schedule 2.31)	14,606.7	118.3	0.8%	Functional Class of PIS	4.7	15.2	5.6	19.8	65.6	7.3
Accumulated Depreciation (Schedule 2.32)	(5,616.1)	(58.8)	1.0%	Functional Class of Accum. Depr'n	(2.0)	(7.0)	(2.4)	(9.9)	(34.3)	(3.3)
Allowance For Working Capital	84.1	10.8	12.9%	12.50% of OM&A and Taxes	0.6	1.6	0.7	1.8	5.4	0.7
Inventories (Schedule 2.33)	165.0	0.4	0.3%	Functional Class of Inventories	0.0	0.1	0.0	0.1	0.2	0.0
Other Assets (Schedule 2.33)	7.2	0.5	6.6%	Functional Classification of Other Assets	0.0	0.1	0.0	0.1	0.2	0.0
Total Rate Base	**9,246.9**	**71.2**	**0.8%**		**3.3**	**10.0**	**4.0**	**11.9**	**37.1**	**4.9**
Revenue Requirement										
Fuel Expense SaskPower Units	441.5	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-
Purchased Power & Import	236.9	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(42.4)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.34)	672.4	94.1	14.0%	Functional Class of OM&A	4.8	14.0	5.8	15.7	47.4	6.3
Depreciation & Depletion (Schedule 2.35)	477.7	9.6	2.0%	Functional Class of Depr'n & Depletion	0.4	1.3	0.5	1.6	5.1	0.6
Corporate Capital Tax	36.9	0.2	0.7%	Functional Class of Corp. Capital Tax	0.0	0.0	0.0	0.0	0.1	0.0
Grants in Lieu of Taxes	23.9	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-
Miscellaneous Tax	0.5	0.1	11.0%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.36)	(144.8)	(26.9)	18.6%	Functional Class of Other Income	(0.0)	(2.1)	(2.5)	(3.0)	(19.1)	(0.1)
Return on Rate Base @ 4.89%	451.8	3.5	0.8%	Rate Base	0.2	0.5	0.2	0.6	1.8	0.2
Total Revenue Requirement	**2,154.4**	**80.6**	**3.7%**		**5.4**	**13.7**	**4.0**	**15.0**	**35.3**	**7.2**

Schedule 2.31: Functional Classification of Financial Account Details – Customer Services Plant in Service

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES PLANT IN SERVICE
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	7,882.5	-	0.0%	-	-	-	-	-	-
Coal Reserves	58.0	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-	-	-
Total Generation	**7,946.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	2,227.4	-	0.0%	-	-	-	-	-	-
Total Transmission	**2,227.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	3,227.3	-	0.0%	-	-	-	-	-	-
Meters	203.0	-	0.0%	-	-	-	-	-	-
Total Distribution	**3,430.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	2.2	0.3	14.0%	0.0	0.0	0.0	0.1	0.2	0.0
Buildings	243.6	41.2	16.9%	2.2	6.2	2.6	6.9	20.5	2.9
Office Furniture & Equipment	44.3	7.5	16.9%	0.4	1.1	0.5	1.3	3.7	0.5
Vehicles & Equipment	175.8	17.5	10.0%	0.1	1.2	0.1	3.0	12.8	0.4
Computer Development & Equipment	362.5	46.4	12.8%	2.0	6.3	2.5	7.8	24.8	2.9
Communication, Protection & Control	151.0	3.7	2.4%	-	0.2	-	0.5	2.3	0.6
Tools & Equipment	23.4	1.7	7.4%	-	0.1	-	0.3	1.3	0.0
Total General Plant	**1,002.8**	**118.3**	**11.8%**	**4.7**	**15.2**	**5.6**	**19.8**	**65.6**	**7.3**
Total Plant In Service	**14,606.7**	**118.3**	**0.8%**	**4.7**	**15.2**	**5.6**	**19.8**	**65.6**	**7.3**

Schedule 2.32: Functional Classification of Financial Account Details – Customer Services Accumulated Depreciation

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES ACCUMULATED DEPRECIATION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	(3,044.4)	-	0.0%	-	-	-	-	-	-
Coal Reserves	(29.1)	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	(3.2)	-	0.0%	-	-	-	-	-	-
Total Generation	**(3,076.6)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	(540.7)	-	0.0%	-	-	-	-	-	-
Total Transmission	**(540.7)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	(1,400.0)	-	0.0%	-	-	-	-	-	-
Meters	(52.4)	-	0.0%	-	-	-	-	-	-
Total Distribution	**(1,452.4)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Buildings	(41.5)	(5.8)	14.0%	(0.3)	(0.9)	(0.4)	(1.0)	(2.9)	(0.4)
Office Furniture & Equipment	(17.1)	(2.4)	14.0%	(0.1)	(0.4)	(0.1)	(0.4)	(1.2)	(0.2)
Vehicles & Equipment	(86.3)	(8.4)	9.8%	(0.0)	(0.6)	(0.0)	(1.5)	(6.2)	(0.2)
Computer Development & Equipment	(315.0)	(39.0)	12.4%	(1.5)	(5.0)	(1.8)	(6.6)	(21.9)	(2.2)
Communication, Protection & Control	(72.1)	(1.8)	2.6%	-	(0.1)	-	(0.3)	(1.2)	(0.3)
Tools & Equipment	(14.4)	(1.3)	8.8%	-	(0.1)	-	(0.2)	(1.0)	(0.0)
Total General Plant	**(546.4)**	**(58.8)**	**10.8%**	**(2.0)**	**(7.0)**	**(2.4)**	**(9.9)**	**(34.3)**	**(3.3)**
Total Accumulated Depreciation	**(5,616.1)**	**(58.8)**	**1.0%**	**(2.0)**	**(7.0)**	**(2.4)**	**(9.9)**	**(34.3)**	**(3.3)**

Schedule 2.33: Functional Classification of Financial Account Details – Customer Services Inventories/Other Assets

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES INVENTORIES
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Inventories									
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-	-	-
Transmission & Distribution	81.9	-	0.0%	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	3.1	0.4	14.0%	0.0	0.1	0.0	0.1	0.2	0.0
Total Inventories	**165.0**	**0.4**	**0.3%**	**0.0**	**0.1**	**0.0**	**0.1**	**0.2**	**0.0**

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OTHER ASSETS
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Service	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	1.1%	-	0.0	-	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	3.3	0.5	14.0%	0.0	0.1	0.0	0.1	0.2	0.0
Total Other Assets	**7.2**	**0.5**	**6.6%**	**0.0**	**0.1**	**0.0**	**0.1**	**0.2**	**0.0**

Schedule 2.34: Functional Classification of Financial Account Details – Customer Services O M & A Expenses

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OM&A EXPENSES
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation Expenses									
Power Plant Operation	177.8	-	0.0%	-	-	-	-	-	-
Fuel Supply	1.9	-	0.0%	-	-	-	-	-	-
Power Production Overhead	29.2	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogen	11.8	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.1	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.6)	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Centennial Wind	6.0	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-	-	-
NorthPoint Energy Solutions	8.5	-	0.0%	-	-	-	-	-	-
Total Generation Expenses	**244.9**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses									
T & D - Planning Support	16.5	0.3	1.9%	-	-	-	-	-	0.3
T & D - Transmission Including 138 & 72 kV Radials	32.4	-	0.0%	-	-	-	-	-	-
T & D - Distribution	105.4	-	0.0%	-	-	-	-	-	-
T & D - Customer Services	5.7	5.7	100.0%	-	1.2	-	3.3	1.3	-
T & D - Gas & Electric Inspections	12.7	12.7	100.0%	-	-	-	-	12.7	-
Total Transmission & Distribution Expenses	**172.7**	**18.7**	**10.8%**	**-**	**1.2**	**-**	**3.3**	**14.0**	**0.3**
Customer Services Expenses									
Meter Reading	7.0	7.0	100.0%	-	7.0	-	-	-	-
Metering Services	2.8	2.8	100.0%	2.8	-	-	-	-	-
Billing Services	3.3	3.3	100.0%	-	-	3.3	-	-	-
Collections/Special Collections	3.9	3.9	100.0%	-	-	-	3.9	-	-
Bad Debt Expense	2.4	2.4	100.0%	-	-	-	2.4	-	-
Marketing & Sales	3.4	3.4	100.0%	-	-	-	-	-	3.4
Demand Side Management	14.6	-	0.0%	-	-	-	-	-	-
Customer Service	15.5	15.5	100.0%	-	-	-	-	15.5	-
Total Customer Services Expenses	**52.9**	**38.3**	**72.4%**	**2.8**	**7.0**	**3.3**	**6.3**	**15.5**	**3.4**
Support Group Expenses									
President / Board	3.4	0.5	14.0%	0.0	0.1	0.0	0.1	0.2	0.0
Corporate & Financial Services	23.4	2.9	12.4%	0.1	0.4	0.2	0.5	1.5	0.2
Planning, Environment & Regulatory Affairs	22.1	1.8	8.1%	0.1	0.3	0.1	0.3	0.9	0.1
General Council / Land	4.9	0.7	14.0%	0.0	0.1	0.0	0.1	0.3	0.0
Communication & Public Affairs	8.1	1.1	14.0%	0.1	0.2	0.1	0.2	0.6	0.1
Safety	8.2	1.2	14.6%	0.1	0.2	0.1	0.2	0.6	0.1
Corporate Information & Technology	79.0	12.8	16.2%	0.7	1.9	0.8	2.1	6.4	0.9
Human Resources	20.9	3.5	16.6%	0.2	0.5	0.2	0.6	1.7	0.2
Supply Chain	-	-	0.0%	-	-	-	-	-	-
Business Development	1.5	-	0.0%	-	-	-	-	-	-
Service Delivery Renewal	30.4	12.7	41.6%	0.8	2.1	1.0	2.1	5.7	1.0
Total Support Group Expenses	**201.9**	**37.1**	**18.4%**	**2.0**	**5.8**	**2.5**	**6.2**	**18.0**	**2.7**
Total OM&A Expenses	**672.4**	**94.1**	**14.0%**	**4.8**	**14.0**	**5.8**	**15.7**	**47.4**	**6.3**

Schedule 2.35: Functional Classification of Financial Account Details – Customer Services Depreciation & Depletion

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES DEPRECIATION & DEPLETION
2015 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	253.8	-	0.0%	-	-	-	-	-	-
Coal Reserves	1.4	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-
Total Generation	**255.4**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	48.5	-	0.0%	-	-	-	-	-	-
Total Transmission	**48.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	96.3	-	0.0%	-	-	-	-	-	-
Meters	8.9	-	0.0%	-	-	-	-	-	-
Total Distribution	**105.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Buildings	1.0	0.1	14.0%	0.0	0.0	0.0	0.0	0.1	0.0
Office Furniture & Equipment	0.8	0.1	14.0%	0.0	0.0	0.0	0.0	0.1	0.0
Vehicles & Equipment	10.9	1.1	10.4%	0.0	0.1	0.0	0.2	0.8	0.0
Computer Development & Equipment	49.5	8.0	16.1%	0.4	1.2	0.5	1.3	4.0	0.6
Communication, Protection & Control	5.2	0.1	2.5%	-	0.0	-	0.0	0.1	0.0
Tools & Equipment	1.1	0.1	8.0%	-	0.0	-	0.0	0.1	0.0
Total General Plant	**68.6**	**9.6**	**14.0%**	**0.4**	**1.3**	**0.5**	**1.6**	**5.1**	**0.6**
Total Depreciation & Depletion	**477.7**	**9.6**	**2.0%**	**0.4**	**1.3**	**0.5**	**1.6**	**5.1**	**0.6**

Schedule 2.36: Functional Classification of Financial Account Details – Customer Services Other Income

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OTHER INCOME
2015 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Other Income									
Customer Services Payment Charges	(5.3)	(5.3)	100.0%	-	-	(2.4)	(2.9)	-	-
Meter Reading	(2.0)	(2.0)	100.0%	-	(2.0)	-	-	-	-
Inspections	(18.7)	(18.7)	100.0%	-	-	-	-	(18.7)	-
Transmission	(1.9)	-	0.0%	-	-	-	-	-	-
Distribution	(6.1)	-	0.0%	-	-	-	-	-	-
Clean Coal Project Credits	(17.8)	-	0.0%	-	-	-	-	-	-
CO2 Sales	(20.3)	-	0.0%	-	-	-	-	-	-
Miscellaneous Other Income	(6.4)	(0.9)	14.0%	(0.0)	(0.1)	(0.1)	(0.2)	(0.5)	(0.1)
Customer Contribution Revenue	(50.0)	-	0.0%	-	-	-	-	-	-
Green Power Premium	(5.6)	-	0.0%	-	-	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-
Flyash Sales	(10.8)	-	0.0%	-	-	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-
Total Other Income	**(144.8)**	**(26.9)**	**18.6%**	**(0.0)**	**(2.1)**	**(2.5)**	**(3.0)**	**(19.1)**	**(0.1)**

Schedule 3.0: SaskPower Allocation Methodology Summary

SaskPower

SaskPower Functionalization	SaskPower Classification	SaskPower Sub-Functionalization	Allocation Methodology
GENERATION	Demand (Facilities)		Two Coincident Peak Method (2CP)
	Energy (Facilities)		Actual Energy Costs Plus Losses
	Energy (Fuel Expense)		Actual Energy Costs Plus Losses
TRANSMISSION	DEMAND	Main Grid	Two Coincident Peak Method (2CP) - Coincident Peak at output of transmission.
		138kv Radials	Two Coincident Peak Method (2CP) - at output of common 138kv Radials.
		138/72kv Substations	Two Coincident Peak Method (2CP) - at output of substations.
		72kv Radials	Two Coincident Peak Method (2CP) - at output of common 72kv radials.
DISTRIBUTION	DEMAND	Area Substations - Demand	Two Coincident Peak Method (2CP) - at output of substations.
		Distribution Mains - Demand	Two Coincident Peak Method (2CP) - at output of distribution mains.
		Urban Laterals - Demand	Two Coincident Peak Method (2CP) - at output of urban laterals.
		Rural Laterals - Demand	Two Coincident Peak Method (2CP) - at output of rural laterals.
		Transformers - Demand	Non Coincident Peak (NCP) - at output of rural laterals.
	CUSTOMER	Urban Laterals - Customer	Number of urban customers supplied through laterals.
		Rural Laterals - Customer	Number of rural customers supplied through laterals.
		Transformers - Customer	Number of customers supplied through laterals.
		Services - Customer	Direct to classes which are using services.
		Meters - Customer	Number of metered customers weighted by installed cost of a meter.
		Streetlights - Customer	Direct to Streetlight Class.
CUSTOMER SERVICES	CUSTOMER	Customer Service	Weighted number of customers.
CUSTOMER CONTRIBUTIONS	CUSTOMER	Customer Contributions	Direct to classes which made contribution.
INTERRUPTIBLE ADJUSTMENT	DEMAND	Interruptible Adjustment	Two Coincident Peak Method (2CP)

2CP METHOD

The Two Coincident Peak (2CP) method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

NCP METHOD

The Non-Coincident Peak (NCP) method allcoates responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occurr, to the sum of all the class peaks, similarly determined.

Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation
2015 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	2,408	2,238,673	489,510	12.28%	56.16%
Rural Residential	648	602,672	131,781	12.28%	56.16%
Farms	1,309	816,213	221,588	18.30%	67.41%
Urban Commercial	2,662	853,617	419,769	35.60%	72.40%
Rural Commercial	906	308,825	146,734	33.49%	70.48%
Power - Published Rates	7,146	1,176,834	873,742	69.32%	93.37%
Power - Contract Rates	1,683	255,686	201,901	75.16%	95.18%
Oilfields	3,940	664,445	466,638	67.68%	96.37%
Streetlights	62	15,128	7,454	47.12%	95.63%
Reseller	1,268	239,313	208,674	60.48%	69.36%
Total	**22,033**	**7,171,406**	**3,167,792**	**35.07%**	**79.40%**

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)

Schedule 5.0: Allocation Factors by Customer Class – Generation

Allocation Factors by Customer Class
GENERATION Related Costs
2015 Test Embedded Cost of Service Study

Customer Class	Load [1]	Load [2]	Losses [3]	Losses [4]	Scheduling & Dispatch [3]	Regulation & Frequency Response [3]	Spinning Reserve [3]	Supplementary Reserve [3]	Planning Reserve [3]	Reactive Supply [3]	Grants in Lieu of Taxes [3]	Interruptible Adjustment [3]
	Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy	Demand
Urban Residential	15.5%	10.9%	21.8%	17.2%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	56.2%	16.3%
Rural Residential	4.2%	2.9%	5.6%	4.2%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	0.0%	4.4%
Farms	7.0%	5.9%	9.3%	8.4%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	0.0%	7.3%
Urban Commercial	13.3%	12.1%	18.4%	18.6%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	43.8%	14.0%
Rural Commercial	4.6%	4.1%	6.0%	5.6%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	0.0%	4.8%
Power - Published Rates	26.3%	30.9%	14.8%	16.7%	25.2%	25.2%	25.2%	25.2%	25.2%	25.2%	0.0%	25.3%
Power - Contract Rates	7.6%	9.1%	3.4%	4.0%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	0.0%	6.1%
Oilfields	14.7%	17.9%	17.8%	22.6%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	0.0%	15.3%
Streetlights	0.2%	0.3%	0.3%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.0%	0.2%
Reseller	6.6%	5.8%	2.7%	2.3%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	0.0%	6.3%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (2CP) at the meter.
[2] Based on actual energy consumption at the meter.
[3] Based on Coincident Peak (2CP) & losses.
[4] Based on energy losses.

Schedule 5.1: Allocation Factors by Customer Class – Transmission

Allocation Factors by Customer Class
TRANSMISSION Related Costs
2015 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	16.1%	11.7%	20.8%	20.8%
Rural Residential	4.3%	3.1%	5.6%	5.6%
Farms	7.2%	5.5%	9.1%	9.1%
Urban Commercial	13.8%	10.0%	17.8%	17.8%
Rural Commercial	4.8%	3.4%	6.2%	6.2%
Power - Published Rates	25.2%	34.7%	20.2%	20.2%
Power - Contract Rates	7.2%	15.4%	1.6%	1.6%
Oilfields	15.0%	12.9%	18.0%	18.0%
Streetlights	0.2%	0.2%	0.3%	0.3%
Reseller	6.2%	3.1%	0.4%	0.4%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: All allocation factors based on Coincident Peak (2CP) & losses.

Schedule 5.2: Allocation Factors by Customer Class – Distribution

Allocation Factors by Customer Class
DISTRIBUTION Related Costs
2015 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]	Amortization Customer Contributions [7]	Meters [8]	Streetlights [9]
	Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer
Urban Residential	26.0%	26.1%	53.5%	84.6%	0.0%	0.0%	42.3%	61.1%	18.9%	16.6%	20.0%	0.0%
Rural Residential	7.0%	7.0%	0.0%	0.0%	15.4%	33.9%	11.4%	9.4%	11.3%	16.7%	3.1%	0.0%
Farms	11.4%	11.5%	0.0%	0.0%	25.3%	41.4%	15.2%	11.5%	2.1%	16.9%	4.3%	0.0%
Urban Commercial	22.3%	22.4%	45.8%	11.7%	0.0%	0.0%	15.3%	8.4%	26.1%	12.5%	30.1%	0.0%
Rural Commercial	7.2%	7.2%	0.0%	0.0%	15.9%	9.0%	5.2%	2.5%	12.0%	14.4%	12.2%	0.0%
Power - Published Rates	3.4%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.3%	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%	2.9%	0.0%
Oilfields	21.9%	22.0%	0.0%	0.0%	43.4%	13.0%	10.3%	3.6%	29.7%	22.8%	12.9%	0.0%
Streetlights	0.4%	0.4%	0.7%	3.7%	0.1%	2.7%	0.3%	3.4%	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%	1.2%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (2CP) & 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.

Schedule 5.3: Allocation Factors by Customer Class – Customer Service

Allocation Factors by Customer Class
CUSTOMER SERVICE Related Costs
2015 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	17.3%	62.9%	42.4%	73.6%	60.0%	10.6%
Rural Residential	2.7%	9.6%	6.6%	11.4%	9.3%	3.8%
Farms	3.7%	13.0%	10.1%	8.0%	13.0%	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	20.0%	0.0%	6.0%	0.0%	0.9%	29.6%
Power - Contract Rates	3.3%	0.0%	1.0%	0.0%	0.1%	4.9%
Oilfields	24.7%	4.9%	16.6%	1.0%	4.8%	25.2%
Streetlights	0.0%	0.0%	1.0%	0.0%	0.8%	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.

Schedule 6.0: Functional Classification of Revenue Requirement by Customer Class – Generation

Functionalized & Classified Revenue Requirement by Customer Class
GENERATION Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes	Interruptible Adjustment
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy	Demand
Urban Residential	386.5	214.4	55.5%	79.8	85.8	11.1	11.8	1.7	1.0	2.4	3.5	2.8	1.0	13.5	0.0
Rural Residential	102.8	53.6	52.2%	21.5	23.1	2.8	2.9	0.4	0.3	0.6	0.9	0.8	0.3	-	0.0
Farms	168.2	98.8	58.8%	36.1	46.6	4.7	5.8	0.7	0.5	1.1	1.6	1.3	0.4	-	0.0
Urban Commercial	305.9	206.6	67.5%	68.4	94.9	9.4	12.8	1.4	0.9	2.0	3.0	2.4	0.9	10.5	0.0
Rural Commercial	104.5	66.8	63.9%	23.9	32.3	3.0	3.8	0.5	0.3	0.7	1.0	0.8	0.3	-	0.0
Power - Published Rates	502.6	437.2	87.0%	142.5	254.7	7.8	11.9	2.7	1.7	3.9	5.8	4.6	1.6	-	(0.0)
Power - Contract Rates	115.1	101.4	88.1%	32.9	60.0	1.5	2.4	0.6	0.4	0.9	1.3	1.1	0.4	-	0.0
Oilfields	358.4	252.7	70.5%	76.1	140.4	9.0	15.5	1.5	1.0	2.2	3.3	2.6	0.9	-	0.0
Streetlights	14.4	4.1	28.5%	1.2	2.2	0.2	0.3	0.0	0.0	0.0	0.1	0.0	0.0	-	0.0
Reseller	95.8	86.9	90.7%	34.0	45.2	1.4	1.6	0.6	0.4	0.9	1.4	1.1	0.4	-	0.0
Total	**2,154.4**	**1,522.6**	**70.7%**	**516.5**	**785.3**	**50.9**	**68.7**	**10.3**	**6.5**	**14.6**	**22.0**	**17.6**	**6.2**	**24.0**	**-**

Schedule 6.1: Functional Classification of Revenue Requirement by Customer Class – Transmission

Functionalized & Classified Revenue Requirement by Customer Class
TRANSMISSION Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kv Lines Radials	138/72 kv Substations	72 kv Lines Radials
				Demand	Demand	Demand	Demand
Urban Residential	386.5	32.5	8.4%	18.0	4.8	3.2	6.6
Rural Residential	102.8	8.7	8.5%	4.8	1.3	0.8	1.8
Farms	168.2	14.6	8.7%	8.1	2.3	1.4	2.9
Urban Commercial	305.9	27.9	9.1%	15.4	4.1	2.7	5.7
Rural Commercial	104.5	9.6	9.2%	5.3	1.4	1.0	2.0
Power - Published Rates	502.6	54.4	10.8%	29.5	15.4	3.1	6.4
Power - Contract Rates	115.1	12.6	11.0%	6.8	5.1	0.2	0.5
Oilfields	358.4	30.5	8.5%	16.8	5.3	2.7	5.7
Streetlights	14.4	0.5	3.4%	0.3	0.1	0.0	0.1
Reseller	95.8	8.4	8.8%	6.9	1.3	0.1	0.1
Total	**2,154.4**	**199.9**	**9.3%**	**111.9**	**40.8**	**15.2**	**31.9**

Schedule 6.2: Functional Classification of Revenue Requirement by Customer Class – Distribution

Functionalized & Classified Revenue Requirement by Customer Class
DISTRIBUTION Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Amortization Customer Contributions	Meters	Streetlights
				Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer
Urban Residential	386.5	95.3	24.7%	9.6	27.6	15.1	12.9	-	-	15.1	9.3	6.4	(4.1)	3.4	-
Rural Residential	102.8	33.5	32.6%	2.6	7.4	-	-	8.1	9.7	4.1	1.4	3.8	(4.1)	0.5	-
Farms	168.2	46.0	27.3%	4.2	12.2	-	-	13.4	11.8	5.4	1.8	0.7	(4.2)	0.7	-
Urban Commercial	305.9	64.2	21.0%	8.2	23.7	12.9	1.8	-	-	5.5	1.3	8.9	(3.1)	5.1	-
Rural Commercial	104.5	26.0	24.9%	2.6	7.6	-	-	8.4	2.6	1.9	0.4	4.1	(3.6)	2.1	-
Power - Published Rates	502.6	7.2	1.4%	1.3	3.6	-	-	-	-	-	-	-	-	2.3	-
Power - Contract Rates	115.1	0.5	0.4%	-	-	-	-	-	-	-	-	-	-	0.5	-
Oilfields	358.4	68.9	19.2%	8.1	23.3	-	-	22.9	3.7	3.7	0.6	10.1	(5.7)	2.2	-
Streetlights	14.4	9.4	65.2%	0.1	0.4	0.2	0.6	0.1	0.8	0.1	0.5	-	-	-	6.6
Reseller	95.8	0.3	0.4%	0.1	-	-	-	-	-	-	-	-	-	0.2	-
Total	**2,154.4**	**351.3**	**16.3%**	**36.9**	**105.9**	**28.2**	**15.2**	**52.9**	**28.5**	**35.7**	**15.3**	**34.0**	**(24.7)**	**16.9**	**6.6**

Schedule 6.3: Functional Classification of Revenue Requirement by Customer Class – Customer Service

Functionalized & Classified Revenue Requirement by Customer Class
CUSTOMER SERVICE Related Costs
2015 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Urban Residential	386.5	44.2	11.4%	0.9	8.6	1.7	11.0	21.2	0.8
Rural Residential	102.8	7.0	6.8%	0.1	1.3	0.3	1.7	3.3	0.3
Farms	168.2	8.7	5.2%	0.2	1.8	0.4	1.2	4.6	0.6
Urban Commercial	305.9	7.3	2.4%	1.1	1.0	0.5	0.7	3.0	0.9
Rural Commercial	104.5	2.1	2.0%	0.4	0.3	0.1	0.2	0.9	0.2
Power - Published Rates	502.6	3.8	0.8%	1.1	-	0.2	-	0.3	2.1
Power - Contract Rates	115.1	0.6	0.5%	0.2	-	0.0	-	0.0	0.3
Oilfields	358.4	6.3	1.8%	1.3	0.7	0.7	0.1	1.7	1.8
Streetlights	14.4	0.4	2.8%	-	-	0.0	-	0.3	0.1
Reseller	95.8	0.1	0.1%	0.0	-	0.0	-	0.0	0.1
Total	**2,154.4**	**80.6**	**3.7%**	**5.4**	**13.7**	**4.0**	**15.0**	**35.3**	**7.2**

Schedule 7.0: Customer Data for Rate Design

Customer Data
2015 Test Embedded Cost of Service Study

Customer Class	Average Annual # of Accounts	Annual Revenue ($)	Annual Sales @ Meter (MWh)	Annual Billing Demand @ Meter (kVa)
Urban Residential	320,088	380,592,862	2,408,203	-
Rural Residential	49,532	100,275,587	648,312	-
Farms	60,481	165,364,503	1,308,537	601,189
Urban Commercial	44,078	306,195,055	2,662,124	5,548,773
Rural Commercial	13,109	105,748,298	906,000	2,208,383
Power - Published Rates	91	507,078,393	7,146,271	13,832,424
Power - Contract Rates	14	113,321,389	1,683,424	3,840,759
Oilfields	19,034	367,047,443	3,939,561	8,488,085
Streetlights	2,798	15,486,442	62,446	-
Reseller	3	93,290,029	1,267,856	2,425,267
Total	**509,228**	**2,154,400,000**	**22,032,735**	**36,944,880**

VI. SUPPORTING SCHEDULES (2016)

Schedule 1.0: Summary of the Functionalization of Financial Account Details

Summary of the Functionalization of Financial Account Details
2016 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)	15,429.1	8,536.8	55.3%	2,777.1	18.0%	3,985.6	25.8%	129.6	0.8%
Accumulated Depreciation (Schedule 1.2)	(6,104.7)	(3,572.9)	58.5%	(702.1)	11.5%	(1,763.7)	28.9%	(66.1)	1.1%
Allowance For Working Capital	87.2	48.2	55.3%	8.4	9.6%	19.5	22.4%	11.1	12.7%
Inventories (Schedule 1.3)	165.0	81.7	49.5%	22.7	13.8%	60.2	36.5%	0.4	0.3%
Other Assets (Schedule 1.3)	7.2	5.6	77.6%	0.3	4.6%	0.8	11.3%	0.5	6.5%
Total Rate Base	**9,583.8**	**5,099.4**	**53.2%**	**2,106.4**	**22.0%**	**2,302.5**	**24.0%**	**75.5**	**0.8%**
Revenue Requirement									
Fuel Expense SaskPower Units	488.7	488.7	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchased Power & Import	273.3	273.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Export & Net Electricity Trading Revenue (Credit)	(46.8)	(46.8)	100.0%	-	0.0%	-	0.0%	-	0.0%
Operating,Maintenance & Administration (Schedule 1.4)	697.8	375.3	53.8%	64.5	9.2%	161.4	23.1%	96.6	13.8%
Depreciation & Depletion (Schedule 1.5)	507.5	301.8	59.5%	66.9	13.2%	129.0	25.4%	9.8	1.9%
Corporate Capital Tax	38.1	20.3	53.2%	8.5	22.3%	9.1	23.8%	0.3	0.7%
Grants in Lieu of Taxes	25.3	25.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.5	0.4	86.6%	0.0	0.7%	0.0	1.6%	0.1	11.0%
Other Income (Credit) (Schedule 1.6)	(131.8)	(47.0)	35.6%	(13.8)	10.4%	(46.1)	35.0%	(25.0)	19.0%
Return on Rate Base @ 5.12%	491.0	261.3	53.2%	107.9	22.0%	118.0	24.0%	3.9	0.8%
Total Revenue Requirement	**2,343.6**	**1,652.6**	**70.5%**	**234.0**	**10.0%**	**371.4**	**15.8%**	**85.6**	**3.7%**

Schedule 1.1: Functionalization of Financial Account Details – Plant in Service

Functionalization of Financial Account Details
PLANT IN SERVICE
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Power Production	8,042.4	8,042.4	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	60.2	60.2	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	5.7	5.7	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**8,108.2**	**8,108.2**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	2,626.3	17.6	0.7%	2,554.6	97.3%	54.2	2.1%	-	0.0%
Total Transmission Assets	**2,626.3**	**17.6**	**0.7%**	**2,554.6**	**97.3%**	**54.2**	**2.1%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	3,394.4	-	0.0%	-	0.0%	3,394.4	100.0%	-	0.0%
Meters	211.3	-	0.0%	-	0.0%	211.3	100.0%	-	0.0%
Total Distribution Assets	**3,605.7**	**-**	**0.0%**	**-**	**0.0%**	**3,605.7**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	2.2	1.2	53.8%	0.2	9.2%	0.5	23.1%	0.3	13.8%
Buildings	274.4	125.3	45.7%	31.6	11.5%	71.3	26.0%	46.2	16.8%
Office Furniture & Equipment	49.9	22.8	45.7%	5.7	11.5%	13.0	26.0%	8.4	16.8%
Vehicles & Equipment	196.1	23.2	11.8%	48.4	24.7%	105.0	53.6%	19.4	9.9%
Computer Development & Equipment	387.4	178.9	46.2%	51.5	13.3%	107.4	27.7%	49.6	12.8%
Communication, Protection & Control	152.6	49.4	32.4%	81.9	53.7%	17.5	11.5%	3.7	2.4%
Tools & Equipment	26.4	10.1	38.4%	3.3	12.3%	11.0	41.9%	1.9	7.4%
Total General Plant Assets	**1,089.0**	**411.0**	**37.7%**	**222.6**	**20.4%**	**325.8**	**29.9%**	**129.6**	**11.9%**
Total Plant In Service	**15,429.1**	**8,536.8**	**55.3%**	**2,777.1**	**18.0%**	**3,985.6**	**25.8%**	**129.6**	**0.8%**

Schedule 1.2: Functionalization of Financial Account Details – Accumulated Depreciation

Functionalization of Financial Account Details
ACCUMULATED DEPRECIATION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Generation Assets	(3,312.1)	(3,312.1)	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	(30.6)	(30.6)	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International - Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse Assets	(3.3)	(3.3)	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**(3,346.1)**	**(3,346.1)**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	(592.4)	(3.2)	0.5%	(577.4)	97.5%	(11.9)	2.0%	-	0.0%
Total Transmission Assets	**(592.4)**	**(3.2)**	**0.5%**	**(577.4)**	**97.5%**	**(11.9)**	**2.0%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	(1,490.4)	-	0.0%	-	0.0%	(1,490.4)	100.0%	-	0.0%
Meters	(62.6)	-	0.0%	-	0.0%	(62.6)	100.0%	-	0.0%
Total Distribution Assets	**(1,553.0)**	**-**	**0.0%**	**-**	**0.0%**	**(1,553.0)**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Buildings	(39.3)	(20.2)	51.4%	(4.2)	10.7%	(9.4)	23.9%	(5.5)	14.0%
Office Furniture & Equipment	(16.2)	(8.3)	51.4%	(1.7)	10.7%	(3.9)	23.9%	(2.3)	14.0%
Vehicles & Equipment	(98.7)	(13.0)	13.1%	(24.0)	24.3%	(52.1)	52.8%	(9.6)	9.7%
Computer Development & Equipment	(367.2)	(149.2)	40.6%	(55.6)	15.1%	(116.9)	31.8%	(45.5)	12.4%
Communication, Protection & Control	(78.2)	(27.5)	35.2%	(39.0)	49.9%	(9.7)	12.3%	(2.0)	2.5%
Tools & Equipment	(13.7)	(5.5)	39.9%	(0.1)	1.0%	(6.9)	50.4%	(1.2)	8.8%
Total General Plant Assets	**(613.3)**	**(223.6)**	**36.5%**	**(124.7)**	**20.3%**	**(198.9)**	**32.4%**	**(66.1)**	**10.8%**
Total Accumulated Depreciation	**(6,104.7)**	**(3,572.9)**	**58.5%**	**(702.1)**	**11.5%**	**(1,763.7)**	**28.9%**	**(66.1)**	**1.1%**

Schedule 1.3: Functionalization of Financial Account Details – Inventories/Other Assets

Functionalization of Financial Account Details
INVENTORIES
2016 Test Embedded Cost of Service Study
($ Millions)

	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Inventories									
Power Production - Repair Stores	52.1	52.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production - Fuel	27.9	27.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission & Distribution	81.9	-	0.0%	22.4	27.4%	59.5	72.6%	-	0.0%
Miscellaneous (Computers, Power Shop)	3.1	1.7	53.8%	0.3	9.2%	0.7	23.1%	0.4	13.8%
Total Inventories	**165.0**	**81.7**	**49.5%**	**22.7**	**13.8%**	**60.2**	**36.5%**	**0.4**	**0.3%**

Functionalization of Financial Account Details
OTHER ASSETS
2016 Base Embedded Cost of Service Study
($ Millions)

	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	3.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Intangible Assets	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Prepaid Expenses - Insurance	0.8	0.7	90.0%	0.0	2.8%	0.0	6.1%	0.0	1.1%
Miscellaneous Prepaid Expenses	3.3	1.8	53.8%	0.3	9.2%	0.8	23.1%	0.5	13.8%
Total Generation Expenses	**7.2**	**5.6**	**77.6%**	**0.3**	**4.6%**	**0.8**	**11.3%**	**0.5**	**6.5%**

Schedule 1.4: Functionalization of Financial Account Details – O M & A Expenses

Functionalization of Financial Account Details
OM&A EXPENSES
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Expenses									
Power Plant Operation	181.9	181.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Fuel Supply	2.0	2.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production Overhead	29.9	29.9	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Cory Cogen	12.1	12.1	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Meridian	7.4	7.4	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Spy Hill	(0.7)	(0.7)	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Flyash	1.9	1.9	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International (SPI) - Centennial Wind	6.0	6.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	1.3	1.3	100.0%	-	0.0%	-	0.0%	-	0.0%
NorthPoint Energy Solutions	9.6	9.6	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Expenses	**251.5**	**251.5**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission & Distribution Expenses									
T & D - Planning Support	17.4	9.4	54.0%	7.7	44.1%	-	0.0%	0.3	1.9%
T & D - Transmission Including 138 & 72 kV Radials	34.1	-	0.0%	34.1	100.0%	-	0.0%	-	0.0%
T & D - Distribution	110.9	-	0.0%	-	0.0%	110.9	100.0%	-	0.0%
T & D - Customer Services	6.0	-	0.0%	-	0.0%	-	0.0%	6.0	100.0%
T & D - Gas & Electric Inspections	13.2	-	0.0%	-	0.0%	-	0.0%	13.2	100.0%
Total Transmission & Distribution Expenses	**181.6**	**9.4**	**5.2%**	**41.8**	**23.0%**	**110.9**	**61.0%**	**19.6**	**10.8%**
Customer Services Expenses									
Meter Reading	7.3	-	0.0%	-	0.0%	-	0.0%	7.3	100.0%
Metering Services	2.9	-	0.0%	-	0.0%	-	0.0%	2.9	100.0%
Billing Services	3.5	-	0.0%	-	0.0%	-	0.0%	3.5	100.0%
Collections/Special Collections	4.0	-	0.0%	-	0.0%	-	0.0%	4.0	100.0%
Bad Debt Expense	2.4	-	0.0%	-	0.0%	-	0.0%	2.4	100.0%
Marketing & Sales	3.5	-	0.0%	-	0.0%	-	0.0%	3.5	100.0%
Demand Side Management	15.2	15.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Customer Service	16.1	-	0.0%	-	0.0%	-	0.0%	16.1	100.0%
Total Customer Services Expenses	**55.0**	**15.2**	**27.7%**	**-**	**0.0%**	**-**	**0.0%**	**39.8**	**72.3%**
Support Group Expenses									
President / Board	3.6	1.9	53.8%	0.3	9.2%	0.8	23.1%	0.5	13.8%
Corporate & Financial Services	24.5	14.0	57.1%	2.3	9.5%	5.1	21.0%	3.0	12.3%
Planning, Environment & Regulatory Affairs	24.1	16.6	68.7%	1.7	6.9%	3.9	16.0%	2.0	8.3%
General Council / Land	5.1	2.8	53.8%	0.5	9.2%	1.2	23.1%	0.7	13.8%
Communication & Public Affairs	8.4	4.5	53.8%	0.8	9.2%	1.9	23.1%	1.2	13.8%
Safety	8.5	4.5	52.3%	0.8	9.9%	2.0	23.3%	1.2	14.5%
Corporate Information & Technology	85.2	40.0	47.0%	9.9	11.6%	21.5	25.3%	13.8	16.2%
Human Resources	21.8	9.7	44.7%	2.6	12.1%	5.8	26.7%	3.6	16.6%
Supply Chain	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Business Development	1.5	1.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Service Delivery Renewal	26.9	3.7	0.0%	3.8	0.0%	8.2	0.0%	11.2	0.0%
Total Support Group Expenses	**209.6**	**99.2**	**47.3%**	**22.7**	**10.8%**	**50.5**	**24.1%**	**37.2**	**17.8%**
Total OM&A Expenses	**697.8**	**375.3**	**53.8%**	**64.5**	**9.2%**	**161.4**	**23.1%**	**96.6**	**13.8%**

Schedule 1.5: Functionalization of Financial Account Details – Depreciation & Depletion Expense

Functionalization of Financial Account Details
DEPRECIATION & DEPLETION EXPENSE
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Generation Assets	272.8	272.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	1.5	1.5	100.0%	-	0.0%	-	0.0%	-	0.0%
SaskPower International - Cogeneration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse Assets	0.2	0.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	**274.5**	**274.5**	**100.0%**	**-**	**0.0%**	**-**	**0.0%**	**-**	**0.0%**
Transmission Assets									
Transmission Assets	58.7	0.4	0.6%	56.9	97.0%	1.4	2.4%	-	0.0%
Total Transmission Assets	**58.7**	**0.4**	**0.6%**	**56.9**	**97.0%**	**1.4**	**2.4%**	**-**	**0.0%**
Distribution Assets									
Distribution Assets	97.3	-	0.0%	-	0.0%	97.3	100.0%	-	0.0%
Meters	10.2	-	0.0%	-	0.0%	10.2	100.0%	-	0.0%
Total Distribution Assets	**107.5**	**-**	**0.0%**	**-**	**0.0%**	**107.5**	**100.0%**	**-**	**0.0%**
General Plant Assets									
Unused Land	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Buildings	0.3	0.2	55.6%	0.0	9.3%	0.1	21.2%	0.0	13.9%
Office Furniture & Equipment	0.2	0.1	55.6%	0.0	9.3%	0.1	21.2%	0.0	13.9%
Vehicles & Equipment	12.4	1.2	9.5%	3.1	25.3%	6.8	54.9%	1.3	10.3%
Computer Development & Equipment	52.2	24.9	47.7%	5.9	11.4%	13.0	24.8%	8.4	16.0%
Communication, Protection & Control	1.5	0.5	31.6%	0.8	53.9%	0.2	12.1%	0.0	2.5%
Tools & Equipment	0.3	0.1	41.4%	0.0	5.4%	0.1	45.3%	0.0	7.9%
Total General Plant Assets	**66.9**	**27.0**	**40.3%**	**9.9**	**14.9%**	**20.2**	**30.2%**	**9.8**	**14.6%**
Total Depreciation Expense	**507.5**	**301.8**	**59.5%**	**66.9**	**13.2%**	**129.0**	**25.4%**	**9.8**	**1.9%**

Schedule 1.6: Functionalization of Financial Account Details – Other Income

Functionalization of Financial Account Details
OTHER INCOME
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Other Income									
Customer Services Payment Charges	(5.4)	-	0.0%	-	0.0%	-	0.0%	(5.4)	100.0%
Meter Reading	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Inspections	(18.7)	-	0.0%	-	0.0%	-	0.0%	(18.7)	100.0%
Transmission	(1.8)	(0.3)	17.6%	(1.5)	82.4%	-	0.0%	-	0.0%
Distribution	(6.3)	-	0.0%	-	0.0%	(6.3)	100.0%	-	0.0%
Clean Coal Project Credits	(10.0)	(10.0)	100.0%	-	0.0%	-	0.0%	-	0.0%
CO2 Sales	(20.7)	(20.7)	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Other Income	(6.5)	(3.5)	53.8%	(0.6)	9.2%	(1.5)	23.1%	(0.9)	13.8%
Customer Contribution Revenue	(50.0)	-	0.0%	(11.7)	23.3%	(38.3)	76.7%	-	0.0%
Green Power Premium	(1.8)	(1.8)	100.0%	-	0.0%	-	0.0%	-	0.0%
NorthPoint	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Flyash Sales	(10.7)	(10.7)	100.0%	-	0.0%	-	0.0%	-	0.0%
Consulting & Contracting Services	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total Other Income	**(131.8)**	**(47.0)**	**35.6%**	**(13.8)**	**10.4%**	**(46.1)**	**35.0%**	**(25.0)**	**19%**

Schedule 2.00: Functional Classification of Financial Account Details – Generation

Functionalization and Classification of Financial Account Details
GENERATION Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Basis of Classification	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
					Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Rate Base															
Plant In Service (Schedule 2.01)	15,429.1	8,536.8	55.3%	Functional Class of PIS	3,378.1	3,658.8	313.0	302.5	37.4	79.4	182.2	273.3	243.9	68.3	-
Accumulated Depreciation (Schedule 2.02)	(6,104.7)	(3,572.9)	58.5%	Functional Class of Accum. Depr'n	(1,362.5)	(1,636.9)	(126.2)	(135.3)	(21.2)	(30.0)	(60.0)	(90.0)	(80.3)	(30.3)	-
Allowance For Working Capital	87.2	48.2	55.3%	12.50% of OM&A and Taxes	28.4	10.4	2.5	0.7	1.0	0.2	0.5	0.7	0.6	0.3	2.9
Inventories (Schedule 2.03)	165.0	81.7	49.5%	Functional Class of Inventories	38.5	33.6	3.6	2.8	0.0	0.2	0.6	0.9	0.8	0.4	-
Other Assets (Schedule 2.03)	7.2	5.6	77.6%	Functional Classification of Other Assets	1.6	3.4	0.1	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Rate Base	**9,583.8**	**5,099.4**	**53.2%**		**2,084.1**	**2,069.3**	**193.0**	**170.9**	**17.3**	**49.8**	**123.3**	**184.9**	**165.0**	**38.8**	**2.9**
Revenue Requirement															
Fuel Expense SaskPower Units	488.7	488.7	100.0%	Functional Class of Fuel Exp.	-	451.2	-	37.4	-	-	-	-	-	0.1	-
Purchased Power & Import	273.3	273.3	100.0%	Functional Class of PP, Import & NP Fee	84.5	167.0	7.9	13.9	-	-	-	-	-	0.0	-
Export & Net Electricity Trading Revenue (Credit)	(46.8)	(46.8)	100.0%	Functional Class of Exports	-	(43.2)	-	(3.6)	-	-	-	-	-	(0.0)	-
Operating, Maintenance & Administration (Schedule 2.04)	697.8	375.3	53.8%	Functional Class of OM&A	239.5	82.3	21.1	5.7	9.0	1.8	3.5	5.3	4.7	2.5	-
Depreciation & Depletion (Schedule 2.05)	507.5	301.8	59.5%	Functional Class of Depr'n & Depletion	132.8	120.2	12.2	9.9	0.4	2.2	5.7	8.6	7.7	2.1	-
Corporate Capital Tax	38.1	20.3	53.2%	Functional Class of Corp. Capital Tax	8.2	8.3	0.8	0.7	0.1	0.2	0.5	0.7	0.7	0.2	-
Grants in Lieu of Taxes	25.3	25.3	100.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	25.3
Miscellaneous Tax	0.5	0.4	86.6%	Functional Class of Misc. Tax	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Other Income (Credit) (Schedule 2.06)	(131.8)	(47.0)	35.6%	Functional Class of Other Income	(17.5)	(22.7)	(1.6)	(1.9)	(0.4)	(0.2)	(0.6)	(0.9)	(0.8)	(0.3)	-
Return on Rate Base @ 5.12%	491.0	261.3	53.2%	Rate Base	106.8	106.0	9.9	8.8	0.9	2.6	6.3	9.5	8.5	2.0	0.1
Total Revenue Requirement	**2,343.6**	**1,652.6**	**70.5%**		**554.5**	**869.3**	**50.2**	**70.9**	**9.9**	**6.5**	**15.5**	**23.2**	**20.7**	**6.5**	**25.4**

Schedule 2.01: Functional Classification of Financial Account Details – Generation Plant in Service

Functionalization and Classification of Financial Account Details
GENERATION PLANT IN SERVICE
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	8,042.4	8,042.4	100.0%	3,123.9	3,521.0	290.6	292.2	-	63.5	178.6	267.8	239.0	65.7	-
Coal Reserves	60.2	60.2	100.0%	-	55.6	-	4.6	-	-	-	-	-	0.0	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	5.7	5.7	100.0%	2.5	2.8	0.2	0.2	-	-	-	-	-	-	-
Total Generation	**8,108.2**	**8,108.2**	**100.0%**	**3,126.4**	**3,579.3**	**290.8**	**297.0**	**-**	**63.5**	**178.6**	**267.8**	**239.0**	**65.7**	**-**
Transmission														
Transmission	2,626.3	17.6	0.7%	16.1	-	1.5	-	-	-	-	-	-	-	-
Total Transmission	**2,626.3**	**17.6**	**0.7%**	**16.1**	**-**	**1.5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	3,394.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	211.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**3,605.7**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	2.2	1.2	53.8%	0.8	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Buildings	274.4	125.3	45.7%	84.1	25.2	7.2	1.6	1.2	0.5	1.2	1.9	1.7	0.9	-
Office Furniture & Equipment	49.9	22.8	45.7%	15.3	4.6	1.3	0.3	0.2	0.1	0.2	0.3	0.3	0.2	-
Vehicles & Equipment	196.1	23.2	11.8%	16.6	3.5	1.5	0.3	0.0	0.1	0.3	0.4	0.4	0.2	-
Computer Development & Equipment	387.4	178.9	46.2%	111.6	44.5	9.8	3.2	0.3	1.3	1.8	2.7	2.4	1.3	-
Communication, Protection & Control	152.6	49.4	32.4%	-	-	-	-	35.7	13.7	-	-	-	-	-
Tools & Equipment	26.4	10.1	38.4%	7.3	1.5	0.7	0.1	-	0.0	0.1	0.2	0.2	0.1	-
Total General Plant	**1,089.0**	**411.0**	**37.7%**	**235.6**	**79.5**	**20.7**	**5.5**	**37.4**	**15.8**	**3.6**	**5.5**	**4.9**	**2.6**	**-**
Total Plant In Service	**15,429.1**	**8,536.8**	**55.3%**	**3,378.1**	**3,658.8**	**313.0**	**302.5**	**37.4**	**79.4**	**182.2**	**273.3**	**243.9**	**68.3**	**-**

Schedule 2.02: Functional Classification of Financial Account Details – Generation Accumulated Depreciation

Functionalization and Classification of Financial Account Details
GENERATION ACCUMULATED DEPRECIATION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	(3,312.1)	(3,312.1)	100.0%	(1,233.3)	(1,562.1)	(114.7)	(129.6)	-	(20.7)	(58.0)	(87.1)	(77.7)	(28.9)	-
Coal Reserves	(30.6)	(30.6)	100.0%	-	(28.3)	-	(2.3)	-	-	-	-	-	(0.0)	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	(3.3)	(3.3)	100.0%	(1.3)	(1.7)	(0.1)	(0.1)	-	-	-	-	-	-	-
Total Generation	**(3,346.1)**	**(3,346.1)**	**100.0%**	**(1,234.7)**	**(1,592.1)**	**(114.9)**	**(132.1)**	**-**	**(20.7)**	**(58.0)**	**(87.1)**	**(77.7)**	**(28.9)**	**-**
Transmission														
Transmission	(592.4)	(3.2)	0.5%	(2.9)	-	(0.3)	-	-	-	-	-	-	-	-
Total Transmission	**(592.4)**	**(3.2)**	**0.5%**	**(2.9)**	**-**	**(0.3)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	(1,490.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	(62.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**(1,553.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Buildings	(39.3)	(20.2)	51.4%	(14.0)	(3.6)	(1.2)	(0.2)	(0.1)	(0.1)	(0.2)	(0.3)	(0.3)	(0.2)	-
Office Furniture & Equipment	(16.2)	(8.3)	51.4%	(5.7)	(1.5)	(0.5)	(0.1)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	-
Vehicles & Equipment	(98.7)	(13.0)	13.1%	(9.3)	(1.9)	(0.9)	(0.2)	(0.0)	(0.1)	(0.2)	(0.2)	(0.2)	(0.1)	-
Computer Development & Equipment	(367.2)	(149.2)	40.6%	(92.0)	(37.0)	(8.1)	(2.7)	(1.2)	(1.5)	(1.5)	(2.2)	(2.0)	(1.0)	-
Communication, Protection & Control	(78.2)	(27.5)	35.2%	-	-	-	-	(19.9)	(7.6)	-	-	-	-	-
Tools & Equipment	(13.7)	(5.5)	39.9%	(3.9)	(0.8)	(0.4)	(0.1)	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	-
Total General Plant	**(613.3)**	**(223.6)**	**36.5%**	**(124.9)**	**(44.9)**	**(11.1)**	**(3.2)**	**(21.2)**	**(9.3)**	**(2.0)**	**(3.0)**	**(2.7)**	**(1.4)**	**-**
Total Accumulated Depreciation	**(6,104.7)**	**(3,572.9)**	**58.5%**	**(1,362.5)**	**(1,636.9)**	**(126.2)**	**(135.3)**	**(21.2)**	**(30.0)**	**(60.0)**	**(90.0)**	**(80.3)**	**(30.3)**	**-**

Schedule 2.03: Functional Classification of Financial Account Details – Generation Inventories/Other Assets

Functionalization and Classification of Financial Account Details
GENERATION INVENTORIES
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Inventories														
Power Production - Repair Stores	52.1	52.1	100.0%	37.5	7.5	3.5	0.6	-	0.2	0.6	0.9	0.8	0.4	-
Power Production - Fuel	27.9	27.9	100.0%	-	25.8	-	2.1	-	-	-	-	-	0.0	-
Transmission & Distribution	81.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	3.1	1.7	53.8%	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Inventories	**165.0**	**81.7**	**49.5%**	**38.5**	**33.6**	**3.6**	**2.8**	**0.0**	**0.2**	**0.6**	**0.9**	**0.8**	**0.4**	**-**

Functionalization and Classification of Financial Account Details
GENERATION INVENTORIES
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Other Assets														
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	3.1	100.0%	-	2.9	-	0.2	-	-	-	-	-	0.0	-
Intangible Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.7	90.0%	0.5	0.1	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Miscellaneous Prepaid Expenses	3.3	1.8	53.8%	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Total Other Assets	**7.2**	**5.6**	**77.6%**	**1.6**	**3.4**	**0.1**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**

Schedule 2.04: Functional Classification of Financial Account Details – Generation O M & A Expenses

Functionalization and Classification of Financial Account Details
GENERATION OM&A EXPENSES
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation Expenses														
Power Plant Operation	181.9	181.9	100.0%	130.9	26.2	12.2	2.2	-	0.8	2.1	3.2	2.9	1.5	-
Fuel Supply	2.0	2.0	100.0%	-	1.8	-	0.2	-	-	-	-	-	0.0	-
Power Production Overhead	29.9	29.9	100.0%	21.5	4.3	2.0	0.4	-	0.1	0.4	0.5	0.5	0.2	-
SaskPower International (SPI) - Cory Cogen	12.1	12.1	100.0%	9.7	1.4	0.9	0.1	-	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.4	7.4	100.0%	2.2	4.6	0.2	0.4	-	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.7)	(0.7)	100.0%	(0.5)	(0.2)	(0.0)	(0.0)	-	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	1.9	100.0%	-	1.8	-	0.1	-	-	-	-	-	0.0	-
SaskPower International (SPI) - Centennial Wind	6.0	6.0	100.0%	-	5.6	-	0.5	-	-	-	-	-	0.0	-
Shand Greenhouse	1.3	1.3	100.0%	1.0	0.2	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
NorthPoint Energy Solutions	9.6	9.6	100.0%	-	8.9	-	0.7	-	-	-	-	-	0.0	-
Total Generation Expenses	**251.5**	**251.5**	**100.0%**	**164.7**	**54.6**	**15.3**	**4.5**	**-**	**0.9**	**2.5**	**3.8**	**3.4**	**1.8**	**-**
Transmission & Distribution Expenses														
T & D - Planning Support	17.4	9.4	54.0%	0.2	0.2	0.0	0.0	8.4	0.5	-	-	-	-	-
T & D - Transmission Including 138 & 72 kV Radials	34.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Distribution	110.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Customer Services	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
T & D - Gas & Electric Inspections	13.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	**181.6**	**9.4**	**5.2%**	**0.2**	**0.2**	**0.0**	**0.0**	**8.4**	**0.5**	**-**	**-**	**-**	**-**	**-**
Customer Services Expenses														
Meter Reading	7.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Metering Services	2.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	4.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	2.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	15.2	15.2	100.0%	7.6	7.6	-	-	-	-	-	-	-	-	-
Customer Service	16.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	**55.0**	**15.2**	**27.7%**	**7.6**	**7.6**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Support Group Expenses														
President / Board	3.6	1.9	53.8%	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Corporate & Financial Services	24.5	14.0	57.1%	9.8	2.4	0.9	0.2	0.0	0.1	0.2	0.2	0.2	0.1	-
Planning, Environment & Regulatory Affairs	24.1	16.6	68.7%	11.9	2.3	1.1	0.2	0.1	0.1	0.2	0.3	0.3	0.1	-
General Council / Land	5.1	2.8	53.8%	1.8	0.6	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	-
Communication & Public Affairs	8.4	4.5	53.8%	2.9	1.0	0.3	0.1	0.1	0.0	0.0	0.1	0.1	0.0	-
Safety	8.5	4.5	52.3%	3.0	0.9	0.3	0.1	0.1	0.0	0.0	0.1	0.1	0.0	-
Corporate Information & Technology	85.2	40.0	47.0%	26.9	8.2	2.3	0.5	0.1	0.1	0.4	0.6	0.5	0.3	-
Human Resources	21.8	9.7	44.7%	6.6	1.9	0.6	0.1	0.0	0.0	0.1	0.1	0.1	0.1	-
Supply Chain	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Business Development	1.5	1.5	100.0%	1.1	0.2	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Service Delivery Renewal	26.9	3.7	0.0%	1.9	1.9	-	-	-	-	-	-	-	-	-
Total Support Group Expenses	**209.6**	**99.2**	**47.3%**	**67.0**	**19.8**	**5.7**	**1.2**	**0.5**	**0.4**	**1.0**	**1.5**	**1.3**	**0.7**	**-**
Total OM&A Expenses	**697.8**	**375.3**	**53.8%**	**239.5**	**82.3**	**21.1**	**5.7**	**9.0**	**1.8**	**3.5**	**5.3**	**4.7**	**2.5**	**-**

Schedule 2.05: Functional Classification of Financial Account Details – Generation Depreciation & Depletion

Functionalization and Classification of Financial Account Details
GENERATION DEPRECIATION & DEPLETION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Generation														
Power Production	272.8	272.8	100.0%	114.6	113.3	10.7	9.4	-	1.9	5.5	8.2	7.3	1.9	-
Coal Reserves	1.5	1.5	100.0%	-	1.4	-	0.1	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	0.2	100.0%	0.1	0.1	0.0	0.0	-	-	-	-	-	-	-
Total Generation	**274.5**	**274.5**	**100.0%**	**114.6**	**114.8**	**10.7**	**9.5**	**-**	**1.9**	**5.5**	**8.2**	**7.3**	**1.9**	**-**
Transmission														
Transmission	58.7	0.4	0.6%	0.3	-	0.0	-	-	-	-	-	-	-	-
Total Transmission	**58.7**	**0.4**	**0.6%**	**0.3**	**-**	**0.0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution														
Distribution	97.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	10.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution	**107.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Buildings	0.3	0.2	55.6%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Office Furniture & Equipment	0.2	0.1	55.6%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Vehicles & Equipment	12.4	1.2	9.5%	0.8	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Computer Development & Equipment	52.2	24.9	47.7%	16.7	5.2	1.4	0.3	0.0	0.1	0.3	0.4	0.3	0.2	-
Communication, Protection & Control	1.5	0.5	31.6%	-	-	-	-	0.3	0.1	-	-	-	-	-
Tools & Equipment	0.3	0.1	41.4%	0.1	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Total General Plant	**66.9**	**27.0**	**40.3%**	**17.8**	**5.4**	**1.5**	**0.4**	**0.4**	**0.2**	**0.3**	**0.4**	**0.4**	**0.2**	**-**
Total Depreciation & Depletion	**507.5**	**301.8**	**59.5%**	**132.8**	**120.2**	**12.2**	**9.9**	**0.4**	**2.2**	**5.7**	**8.6**	**7.7**	**2.1**	**-**

Schedule 2.06: Functional Classification of Financial Account Details – Generation Other Income

Functionalization and Classification of Financial Account Details
GENERATION OTHER INCOME
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy
Other Income														
Customer Services Payment Charges	(5.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission	(1.8)	(0.3)	17.6%	-	-	-	-	(0.3)	(0.0)	-	-	-	-	-
Distribution	(6.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Clean Coal Project Credits	(10.0)	(10.0)	100.0%	(7.2)	(1.4)	(0.7)	(0.1)	-	(0.0)	(0.1)	(0.2)	(0.2)	(0.1)	-
CO2 Sales	(20.7)	(20.7)	100.0%	(8.0)	(9.1)	(0.7)	(0.8)	-	(0.2)	(0.5)	(0.7)	(0.6)	(0.2)	-
Miscellaneous Other Income	(6.5)	(3.5)	53.8%	(2.2)	(0.8)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Customer Contributions Revenue	(50.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Green Power Premium	(1.8)	(1.8)	100.0%	-	(1.6)	-	(0.1)	-	-	-	-	-	(0.0)	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(10.7)	(10.7)	100.0%	-	(9.8)	-	(0.8)	-	-	-	-	-	(0.0)	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**(131.8)**	**(47.0)**	**35.6%**	**(17.5)**	**(22.7)**	**(1.6)**	**(1.9)**	**(0.4)**	**(0.2)**	**(0.6)**	**(0.9)**	**(0.8)**	**(0.3)**	**-**

Schedule 2.10: Functional Classification of Financial Account Details – Transmission

Functionalization and Classification of Financial Account Details
TRANSMISSION Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Basis of Classification	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kv Lines Radials
					Demand	Demand	Demand	Demand
Rate Base								
Plant In Service (Schedule 2.11)	15,429.1	2,777.1	18.0%	Functional Class of PIS	1,471.0	729.6	205.2	371.3
Accumulated Depreciation (Schedule 2.12)	(6,104.7)	(702.1)	11.5%	Functional Class of Accum. Depr'n	(391.4)	(154.2)	(58.6)	(97.9)
Allowance For Working Capital	87.2	8.4	9.6%	12.50% of OM&A and Taxes	4.6	1.6	0.6	1.6
Inventories (Schedule 2.13)	165.0	22.7	13.8%	Functional Class of Inventories	12.7	4.1	1.6	4.4
Other Assets (Schedule 2.13)	7.2	0.3	4.6%	Functional Classification of Other Assets	0.2	0.1	0.0	0.1
Total Rate Base	**9,583.8**	**2,106.4**	**22.0%**		**1,097.1**	**581.2**	**148.8**	**279.4**
Revenue Requirement								
Fuel Expense SaskPower Units	488.7	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-
Purchased Power & Import	273.3	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(46.8)	-	0.0%	Functional Class of Exports	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.14)	697.8	64.5	9.2%	Functional Class of OM&A	36.0	11.6	4.5	12.5
Depreciation & Depletion (Schedule 2.15)	507.5	66.9	13.2%	Functional Class of Depr'n & Depletion	36.8	15.1	5.2	9.8
Corporate Capital Tax	38.1	8.5	22.3%	Functional Class of Corp. Capital Tax	4.4	2.4	0.6	1.1
Grants in Lieu of Taxes	25.3	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-
Miscellaneous Tax	0.5	0.0	0.7%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.16)	(131.8)	(13.8)	10.4%	Functional Class of Other Income	(3.3)	(9.1)	(0.1)	(1.2)
Return on Rate Base @ 5.12%	491.0	107.9	22.0%	Rate Base	56.2	29.8	7.6	14.3
Total Revenue Requirement	**2,343.6**	**234.0**	**10.0%**		**130.1**	**49.7**	**17.8**	**36.4**

Schedule 2.11: Functional Classification of Financial Account Details – Transmission Plant in Service

Functionalization and Classification of Financial Account Details
TRANSMISSION PLANT IN SERVICE
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	8,042.4	-	0.0%	-	-	-	-
Coal Reserves	60.2	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-
Total Generation	**8,108.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	2,626.3	2,554.6	97.3%	1,346.9	689.7	189.8	328.1
Total Transmission	**2,626.3**	**2,554.6**	**97.3%**	**1,346.9**	**689.7**	**189.8**	**328.1**
Distribution							
Distribution	3,394.4	-	0.0%	-	-	-	-
Meters	211.3	-	0.0%	-	-	-	-
Total Distribution	**3,605.7**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	2.2	0.2	9.2%	0.1	0.0	0.0	0.0
Buildings	274.4	31.6	11.5%	17.6	5.7	2.2	6.1
Office Furniture & Equipment	49.9	5.7	11.5%	3.2	1.0	0.4	1.1
Vehicles & Equipment	196.1	48.4	24.7%	27.0	8.7	3.4	9.4
Computer Development & Equipment	387.4	51.5	13.3%	28.7	9.2	3.6	10.0
Communication, Protection & Control	152.6	81.9	53.7%	45.7	14.7	5.7	15.9
Tools & Equipment	26.4	3.3	12.3%	1.8	0.6	0.2	0.6
Total General Plant	**1,089.0**	**222.6**	**20.4%**	**124.1**	**39.9**	**15.5**	**43.2**
Total Plant In Service	**15,429.1**	**2,777.1**	**18.0%**	**1,471.0**	**729.6**	**205.2**	**371.3**

Schedule 2.12: Functional Classification of Financial Account Details – Transmission Accumulated Depreciation

Functionalization and Classification of Financial Account Details
TRANSMISSION ACCUMULATED DEPRECIATION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	(3,312.1)	-	0.0%	-	-	-	-
Coal Reserves	(30.6)	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	(3.3)	-	0.0%	-	-	-	-
Total Generation	**(3,346.1)**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	(592.4)	(577.4)	97.5%	(321.9)	(131.8)	(50.0)	(73.7)
Total Transmission	**(592.4)**	**(577.4)**	**97.5%**	**(321.9)**	**(131.8)**	**(50.0)**	**(73.7)**
Distribution							
Distribution	(1,490.4)	-	0.0%	-	-	-	-
Meters	(62.6)	-	0.0%	-	-	-	-
Total Distribution	**(1,553.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	-	-	0.0%	-	-	-	-
Buildings	(39.3)	(4.2)	10.7%	(2.4)	(0.8)	(0.3)	(0.8)
Office Furniture & Equipment	(16.2)	(1.7)	10.7%	(1.0)	(0.3)	(0.1)	(0.3)
Vehicles & Equipment	(98.7)	(24.0)	24.3%	(13.4)	(4.3)	(1.7)	(4.7)
Computer Development & Equipment	(367.2)	(55.6)	15.1%	(31.0)	(10.0)	(3.9)	(10.8)
Communication, Protection & Control	(78.2)	(39.0)	49.9%	(21.8)	(7.0)	(2.7)	(7.6)
Tools & Equipment	(13.7)	(0.1)	1.0%	(0.1)	(0.0)	(0.0)	(0.0)
Total General Plant	**(613.3)**	**(124.7)**	**20.3%**	**(69.5)**	**(22.3)**	**(8.7)**	**(24.2)**
Total Accumulated Depreciation	**(6,104.7)**	**(702.1)**	**11.5%**	**(391.4)**	**(154.2)**	**(58.6)**	**(97.9)**

Schedule 2.13: Functional Classification of Financial Account Details – Transmission Inventories/Other Assets

Functionalization and Classification of Financial Account Details
TRANSMISSION INVENTORIES
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Inventories							
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-
Transmission & Distribution	81.9	22.4	27.4%	12.5	4.0	1.6	4.3
Miscellaneous (Computers, Power Shop)	3.1	0.3	9.2%	0.2	0.1	0.0	0.1
Total Inventories	**165.0**	**22.7**	**13.8%**	**12.7**	**4.1**	**1.6**	**4.4**

Functionalization and Classification of Financial Account Details
TRANSMISSION OTHER ASSETS
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Other Assets							
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	2.8%	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	3.3	0.3	9.2%	0.2	0.1	0.0	0.1
Total Other Assets	**7.2**	**0.3**	**4.6%**	**0.2**	**0.1**	**0.0**	**0.1**

Schedule 2.14: Functional Classification of Financial Account Details – Transmission O M & A Expenses

Functionalization and Classification of Financial Account Details
TRANSMISSION OM&A EXPENSE
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation Expenses							
Power Plant Operation	181.9	-	0.0%	-	-	-	-
Fuel Supply	2.0	-	0.0%	-	-	-	-
Power Production Overhead	29.9	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogen	12.1	-	0.0%	-	-	-	-
SaskPower International (SPI) - Meridian	7.4	-	0.0%	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.7)		0.0%	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-
SaskPower International (SPI) - Centennial Wind	6.0	-	0.0%	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-
NorthPoint Energy Solutions	9.6	-	0.0%	-	-	-	-
Total Generation Expenses	**251.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses							
T & D - Planning Support	17.4	7.7	44.1%	4.0	2.1	0.6	1.0
T & D - Transmission Including 138 & 72 kV Radials	34.1	34.1	100.0%	19.3	5.4	2.3	7.1
T & D - Distribution	110.9	-	0.0%	-	-	-	-
T & D - Customer Services	6.0	-	0.0%	-	-	-	-
T & D - Gas & Electric Inspections	13.2	-	0.0%	-	-	-	-
Total Transmission & Distribution Expenses	**181.6**	**41.8**	**23.0%**	**23.3**	**7.5**	**2.9**	**8.1**
Customer Services Expenses							
Meter Reading	7.3	-	0.0%	-	-	-	-
Metering Services	2.9	-	0.0%	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-
Collections/Special Collections	4.0	-	0.0%	-	-	-	-
Bad Debt Expense	2.4	-	0.0%	-	-	-	-
Marketing & Sales	3.5	-	0.0%	-	-	-	-
Demand Side Management	15.2	-	0.0%	-	-	-	-
Customer Service	16.1	-	0.0%	-	-	-	-
Total Customer Services Expenses	**55.0**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Support Group Expenses							
President / Board	3.6	0.3	9.2%	0.2	0.1	0.0	0.1
Corporate & Financial Services	24.5	2.3	9.5%	1.3	0.4	0.2	0.5
Planning, Environment & Regulatory Affairs	24.1	1.7	6.9%	0.9	0.3	0.1	0.3
General Council / Land	5.1	0.5	9.2%	0.3	0.1	0.0	0.1
Communication & Public Affairs	8.4	0.8	9.2%	0.4	0.1	0.1	0.2
Safety	8.5	0.8	9.9%	0.5	0.2	0.1	0.2
Corporate Information & Technology	85.2	9.9	11.6%	5.5	1.8	0.7	1.9
Human Resources	21.8	2.6	12.1%	1.5	0.5	0.2	0.5
Supply Chain	-	-	0.0%	-	-	-	-
Business Development	1.5	-	0.0%	-	-	-	-
Service Delivery Renewal	26.9	3.8	0.0%	2.1	0.7	0.3	0.7
Total Support Group Expenses	**209.6**	**22.7**	**10.8%**	**12.7**	**4.1**	**1.6**	**4.4**
Total OM&A Expenses	**697.8**	**64.5**	**9.2%**	**36.0**	**11.6**	**4.5**	**12.5**

Schedule 2.15: Functional Classification of Financial Account Details – Transmission Depreciation & Depletion

Functionalization and Classification of Financial Account Details
TRANSMISSION DEPRECIATION & DEPLETION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Generation							
Power Production	272.8	-	0.0%	-	-	-	-
Coal Reserves	1.5	-	0.0%	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-
Total Generation	**274.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**
Transmission							
Transmission	58.7	56.9	97.0%	31.3	13.3	4.5	7.8
Total Transmission	**58.7**	**56.9**	**97.0%**	**31.3**	**13.3**	**4.5**	**7.8**
Distribution							
Distribution	97.3	-	0.0%	-	-	-	-
Meters	10.2	-	0.0%	-	-	-	-
Total Distribution	**107.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**
General Plant							
Unused Land	-	-	0.0%	-	-	-	-
Buildings	0.3	0.0	9.3%	0.0	0.0	0.0	0.0
Office Furniture & Equipment	0.2	0.0	9.3%	0.0	0.0	0.0	0.0
Vehicles & Equipment	12.4	3.1	25.3%	1.7	0.6	0.2	0.6
Computer Development & Equipment	52.2	5.9	11.4%	3.3	1.1	0.4	1.2
Communication, Protection & Control	1.5	0.8	53.9%	0.4	0.1	0.1	0.2
Tools & Equipment	0.3	0.0	5.4%	0.0	0.0	0.0	0.0
Total General Plant	**66.9**	**9.9**	**14.9%**	**5.5**	**1.8**	**0.7**	**1.9**
Total Depreciation & Depletion	**507.5**	**66.9**	**13.2%**	**36.8**	**15.1**	**5.2**	**9.8**

Schedule 2.16: Functional Classification of Financial Account Details – Transmission Other Income

Functionalization and Classification of Financial Account Details
TRANSMISSION OTHER INCOME
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kV Lines Radials	138/72 kV Substations	72 kV Lines Radials
				Demand	Demand	Demand	Demand
Other Income							
Customer Services Payment Charges	(5.4)	-	0.0%	-	-	-	-
Meter Reading	-	-	0.0%	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-
Transmission	(1.8)	(1.5)	82.4%	(0.8)	(0.3)	(0.1)	(0.3)
Distribution	(6.3)	-	0.0%	-	-	-	-
Clean Coal Project Credits	(10.0)	-	0.0%	-	-	-	-
CO2 Sales	(20.7)	-	0.0%	-	-	-	-
Miscellaneous Other Income	(6.5)	(0.6)	9.2%	(0.3)	(0.1)	(0.0)	(0.1)
Customer Contribution Revenue	(50.0)	(11.7)	23.3%	(2.1)	(8.7)	-	(0.8)
Green Power Premium	(1.8)	-	0.0%	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-
Flyash Sales	(10.7)	-	0.0%	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-
Total Other Income	**(131.8)**	**(13.8)**	**10.4%**	**(3.3)**	**(9.1)**	**(0.1)**	**(1.2)**

Schedule 2.20: Functional Classification of Financial Account Details – Distribution

Functionalization and Classification of Financial Account Details
DISTRIBUTION Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Basis of Classification	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
					Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Rate Base																	
Plant In Service (Schedule 2.21)	15,429.1	3,985.6	25.8%	Functional Class of PIS	354.8	1,101.3	294.6	158.6	549.1	295.7	314.4	134.8	495.5	-	-	211.3	75.5
Accumulated Depreciation (Schedule 2.22)	(6,104.7)	(1,763.7)	28.9%	Functional Class of Accum. Depr'n	(147.7)	(505.6)	(151.3)	(81.5)	(281.2)	(151.4)	(129.8)	(55.6)	(144.1)	-	-	(62.6)	(52.9)
Allowance For Working Capital	87.2	19.5	22.4%	12.50% of OM&A and Taxes	1.7	5.7	1.9	1.0	3.5	1.9	1.9	0.8	0.6	-	-	0.1	0.6
Inventories (Schedule 2.23)	165.0	60.2	36.5%	Functional Class of Inventories	5.1	17.7	5.8	3.1	10.9	5.8	5.8	2.5	1.4	-	-	-	2.1
Other Assets (Schedule 2.23)	7.2	0.8	11.3%	Functional Classification of Other Assets	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Rate Base	**9,583.8**	**2,302.5**	**24.0%**		**213.9**	**619.3**	**151.0**	**81.3**	**282.4**	**152.1**	**192.5**	**82.5**	**353.4**	**-**	**-**	**148.8**	**25.4**
Revenue Requirement																	
Fuel Expense SaskPower Units	488.7	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchased Power & Import	273.3	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(46.8)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.24)	697.8	161.4	23.1%	Functional Class of OM&A	13.6	47.4	15.6	8.4	29.1	15.7	15.7	6.7	3.7	-	-	-	5.6
Depreciation & Depletion (Schedule 2.25)	507.5	129.0	25.4%	Functional Class of Depr'n & Depletion	14.1	32.3	9.1	4.9	16.9	9.1	11.8	5.0	13.2	-	-	10.2	2.5
Corporate Capital Tax	38.1	9.1	23.8%	Functional Class of Corp. Capital Tax	0.8	2.4	0.6	0.3	1.1	0.6	0.8	0.3	1.4	-	-	0.6	0.1
Grants in Lieu of Taxes	25.3	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Tax	0.5	0.0	1.6%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Other Income (Credit) (Schedule 2.26)	(131.8)	(46.1)	35.0%	Functional Class of Other Income	(0.7)	(2.7)	(3.3)	(1.8)	(5.8)	(3.1)	(0.8)	(0.3)	(0.2)	-	(24.7)	-	(2.8)
Return on Rate Base @ 5.12%	491.0	118.0	24.0%	Rate Base	11.0	31.7	7.7	4.2	14.5	7.8	9.9	4.2	18.1	-	-	7.6	1.3
Total Revenue Requirement	**2,343.6**	**371.4**	**15.8%**		**38.9**	**111.2**	**29.7**	**16.0**	**55.8**	**30.0**	**37.3**	**16.0**	**36.2**	**-**	**(24.7)**	**18.4**	**6.6**

Schedule 2.21: Functional Classification of Financial Account Details – Distribution Plant in Service

Functionalization and Classification of Financial Account Details
DISTRIBUTION PLANT IN SERVICE
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	8,042.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	60.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**8,108.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission																
Transmission	2,626.3	54.2	2.1%	54.2	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	**2,626.3**	**54.2**	**2.1%**	**54.2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution																
Distribution	3,394.4	3,394.4	100.0%	273.1	1,005.7	263.1	141.7	490.3	264.0	282.9	121.2	488.1	-	-	-	64.3
Meters	211.3	211.3	100.0%	-	-	-	-	-	-	-	-	-	-	-	211.3	-
Total Distribution	**3,605.7**	**3,605.7**	**100.0%**	**273.1**	**1,005.7**	**263.1**	**141.7**	**490.3**	**264.0**	**282.9**	**121.2**	**488.1**	**-**	**-**	**211.3**	**64.3**
General Plant																
Unused Land	2.2	0.5	23.1%	0.0	0.2	0.0	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Buildings	274.4	71.3	26.0%	6.0	20.9	6.9	3.7	12.9	6.9	6.9	3.0	1.6	-	-	-	2.5
Office Furniture & Equipment	49.9	13.0	26.0%	1.1	3.8	1.3	0.7	2.3	1.3	1.3	0.5	0.3	-	-	-	0.4
Vehicles & Equipment	196.1	105.0	53.6%	8.9	30.8	10.2	5.5	19.0	10.2	10.2	4.4	2.4	-	-	-	3.6
Computer Development & Equipment	387.4	107.4	27.7%	9.1	31.5	10.4	5.6	19.4	10.4	10.4	4.5	2.4	-	-	-	3.7
Communication, Protection & Control	152.6	17.5	11.5%	1.5	5.1	1.7	0.9	3.2	1.7	1.7	0.7	0.4	-	-	-	0.6
Tools & Equipment	26.4	11.0	41.9%	0.9	3.2	1.1	0.6	2.0	1.1	1.1	0.5	0.3	-	-	-	0.4
Total General Plant	**1,089.0**	**325.8**	**29.9%**	**27.5**	**95.6**	**31.5**	**17.0**	**58.8**	**31.7**	**31.6**	**13.5**	**7.4**	**-**	**-**	**-**	**11.2**
Total Plant In Service	**15,429.1**	**3,985.6**	**25.8%**	**354.8**	**1,101.3**	**294.6**	**158.6**	**549.1**	**295.7**	**314.4**	**134.8**	**495.5**	**-**	**-**	**211.3**	**75.5**

Schedule 2.22: Functional Classification of Financial Account Details – Distribution Accumulated Depreciation

Functionalization and Classification of Financial Account Details
DISTRIBUTION ACCUMULATED DEPRECIATION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	(3,312.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	(30.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	(3.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	(3,346.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																
Transmission	(592.4)	(11.9)	2.0%	(11.9)	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	(592.4)	(11.9)	2.0%	(11.9)	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																
Distribution	(1,490.4)	(1,490.4)	100.0%	(119.1)	(447.3)	(132.1)	(71.1)	(245.3)	(132.1)	(110.5)	(47.4)	(139.6)	-	-	-	(46.0)
Meters	(62.6)	(62.6)	100.0%	-	-	-	-	-	-	-	-	-	-	-	(62.6)	-
Total Distribution	(1,553.0)	(1,553.0)	100.0%	(119.1)	(447.3)	(132.1)	(71.1)	(245.3)	(132.1)	(110.5)	(47.4)	(139.6)	-	-	(62.6)	(46.0)
General Plant																
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Buildings	(39.3)	(9.4)	23.9%	(0.8)	(2.8)	(0.9)	(0.5)	(1.7)	(0.9)	(0.9)	(0.4)	(0.2)	-	-	-	(0.3)
Office Furniture & Equipment	(16.2)	(3.9)	23.9%	(0.3)	(1.1)	(0.4)	(0.2)	(0.7)	(0.4)	(0.4)	(0.2)	(0.1)	-	-	-	(0.1)
Vehicles & Equipment	(98.7)	(52.1)	52.8%	(4.4)	(15.3)	(5.0)	(2.7)	(9.4)	(5.1)	(5.1)	(2.2)	(1.2)	-	-	-	(1.8)
Computer Development & Equipment	(367.2)	(116.9)	31.8%	(9.9)	(34.3)	(11.3)	(6.1)	(21.1)	(11.4)	(11.3)	(4.9)	(2.7)	-	-	-	(4.0)
Communication, Protection & Control	(78.2)	(9.7)	12.3%	(0.8)	(2.8)	(0.9)	(0.5)	(1.7)	(0.9)	(0.9)	(0.4)	(0.2)	-	-	-	(0.3)
Tools & Equipment	(13.7)	(6.9)	50.4%	(0.6)	(2.0)	(0.7)	(0.4)	(1.2)	(0.7)	(0.7)	(0.3)	(0.2)	-	-	-	(0.2)
Total General Plant	(613.3)	(198.9)	32.4%	(16.8)	(58.4)	(19.3)	(10.4)	(35.9)	(19.3)	(19.3)	(8.3)	(4.5)	-	-	-	(6.8)
Total Accumulated Depreciation	(6,104.7)	(1,763.7)	28.9%	(147.7)	(505.6)	(151.3)	(81.5)	(281.2)	(151.4)	(129.8)	(55.6)	(144.1)	-	-	(62.6)	(52.9)

Schedule 2.23: Functional Classification of Financial Account Details – Distribution Inventories/Other Assets

Functionalization and Classification of Financial Account Details
DISTRIBUTION INVENTORIES
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Inventories																
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission & Distribution	81.9	59.5	72.6%	5.0	17.5	5.8	3.1	10.7	5.8	5.8	2.5	1.4	-	-	-	2.0
Miscellaneous (Computers, Power Shop)	3.1	0.7	23.1%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Inventories	**165.0**	**60.2**	**36.5%**	**5.1**	**17.7**	**5.8**	**3.1**	**10.9**	**5.8**	**5.8**	**2.5**	**1.4**	**-**	**-**	**-**	**2.1**

Functionalization and Classification of Financial Account Details
DISTRIBUTION OTHER ASSETS
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Other Assets																
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	6.1%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Miscellaneous Prepaid Expenses	3.3	0.8	23.1%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Total Other Assets	**7.2**	**0.8**	**11.3%**	**0.1**	**0.2**	**0.1**	**0.0**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**-**	**-**	**-**	**0.0**

Schedule 2.24: Functional Classification of Financial Account Details – Distribution O M & A Expenses

Functionalization and Classification of Financial Account Details
DISTRIBUTION OM&A EXPENSES
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation Expenses																
Power Plant Operation	181.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Supply	2.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production Overhead	29.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogen	12.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.4		0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.7)		0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Centennial Wind	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
NorthPoint Energy Solutions	9.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation Expenses	**251.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses																
T & D - Planning Support	17.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Transmission Including 138 & 72 kV Radials	34.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Distribution	110.9	110.9	100.0%	9.3	32.5	10.7	5.8	20.0	10.8	10.8	4.6	2.5	-	-	-	3.8
T & D - Customer Services	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D - Gas & Electric Inspections	13.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	**181.6**	**110.9**	**61.0%**	**9.3**	**32.5**	**10.7**	**5.8**	**20.0**	**10.8**	**10.8**	**4.6**	**2.5**	**-**	**-**	**-**	**3.8**
Customer Services Expenses																
Meter Reading	7.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Metering Services	2.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	4.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	2.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	15.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	16.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	**55.0**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Support Group Expenses																
President / Board	3.6	0.8	23.1%	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0
Corporate & Financial Services	24.5	5.1	21.0%	0.4	1.5	0.5	0.3	0.9	0.5	0.5	0.2	0.1	-	-	-	0.2
Planning, Environment & Regulatory Affairs	24.1	3.9	16.0%	0.3	1.1	0.4	0.2	0.7	0.4	0.4	0.2	0.1	-	-	-	0.1
General Council / Land	5.1	1.2	23.1%	0.1	0.3	0.1	0.1	0.2	0.1	0.1	0.0	0.0	-	-	-	0.0
Communication & Public Affairs	8.4	1.9	23.1%	0.2	0.6	0.2	0.1	0.4	0.2	0.2	0.1	0.0	-	-	-	0.1
Safety	8.5	2.0	23.3%	0.2	0.6	0.2	0.1	0.4	0.2	0.2	0.1	0.0	-	-	-	0.1
Corporate Information & Technology	85.2	21.5	25.3%	1.8	6.3	2.1	1.1	3.9	2.1	2.1	0.9	0.5	-	-	-	0.7
Human Resources	21.8	5.8	26.7%	0.5	1.7	0.6	0.3	1.0	0.6	0.6	0.2	0.1	-	-	-	0.2
Supply Chain	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Business Development	1.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Service Delivery Renewal	26.9	8.2	30.5%	0.7	2.4	0.8	0.4	1.5	0.8	0.8	0.3	0.2	-	-	-	0.3
Total Support Group Expenses	**209.6**	**50.5**	**24.1%**	**4.3**	**14.8**	**4.9**	**2.6**	**9.1**	**4.9**	**4.9**	**2.1**	**1.1**	**-**	**-**	**-**	**1.7**
Total OM&A Expenses	**697.8**	**161.4**	**23.1%**	**13.6**	**47.4**	**15.6**	**8.4**	**29.1**	**15.7**	**15.7**	**6.7**	**3.7**	**-**	**-**	**-**	**5.6**

Schedule 2.25: Functional Classification of Financial Account Details – Distribution Depreciation & Depletion

Functionalization and Classification of Financial Account Details
DISTRIBUTION DEPRECIATION & DEPLETION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Generation																
Power Production	272.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	1.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	274.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																
Transmission	58.7	1.4	2.4%	1.4	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission	58.7	1.4	2.4%	1.4	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																
Distribution	97.3	97.3	100.0%	11.0	26.4	7.1	3.8	13.2	7.1	9.8	4.2	12.7	-	-	-	1.8
Meters	10.2	10.2	100.0%	-	-	-	-	-	-	-	-	-	-	-	10.2	-
Total Distribution	107.5	107.5	100.0%	11.0	26.4	7.1	3.8	13.2	7.1	9.8	4.2	12.7	-	-	10.2	1.8
General Plant																
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Buildings	0.3	0.1	21.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Office Furniture & Equipment	0.2	0.1	21.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Vehicles & Equipment	12.4	6.8	54.9%	0.6	2.0	0.7	0.4	1.2	0.7	0.7	0.3	0.2	-	-	-	0.2
Computer Development & Equipment	52.2	13.0	24.8%	1.1	3.8	1.3	0.7	2.3	1.3	1.3	0.5	0.3	-	-	-	0.4
Communication, Protection & Control	1.5	0.2	12.1%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Tools & Equipment	0.3	0.1	45.3%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0
Total General Plant	66.9	20.2	30.2%	1.7	5.9	2.0	1.1	3.6	2.0	2.0	0.8	0.5	-	-	-	0.7
Total Depreciation & Depletion	507.5	129.0	25.4%	14.1	32.3	9.1	4.9	16.9	9.1	11.8	5.0	13.2	-	-	10.2	2.5

Schedule 2.26: Functional Classification of Financial Account Details – Distribution Other Income

Functionalization and Classification of Financial Account Details
DISTRIBUTION OTHER INCOME
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Unamortized Customer Contributions	Amortization Customer Contributions	Meters	Streetlights
				Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
Other Income																
Customer Services Payment Charges	(5.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Inspections	(18.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	(1.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution	(6.3)	(6.3)	100.0%	(0.5)	(1.8)	(0.6)	(0.3)	(1.1)	(0.6)	(0.6)	(0.3)	(0.1)	-	-	-	(0.2)
Clean Coal Project Credits	(10.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 Sales	(20.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Other Income	(6.5)	(1.5)	23.1%	(0.1)	(0.4)	(0.1)	(0.1)	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	-	-	-	(0.1)
Customer Contribution Revenue	(50.0)	(38.3)	76.7%	(0.0)	(0.4)	(2.5)	(1.4)	(4.4)	(2.4)	-	-	-	-	(24.7)	-	(2.5)
Green Power Premium	(1.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(10.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**(131.8)**	**(46.1)**	**35.0%**	**(0.7)**	**(2.7)**	**(3.3)**	**(1.8)**	**(5.8)**	**(3.1)**	**(0.8)**	**(0.3)**	**(0.2)**	**-**	**(24.7)**	**-**	**(2.8)**

Schedule 2.30: Functional Classification of Financial Account Details – Customer Service

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICE Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Rate Base and Expense Categories	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Basis of Classification	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
					Customer	Customer	Customer	Customer	Customer	Customer
Rate Base										
Plant In Service (Schedule 2.31)	15,429.1	129.6	0.8%	Functional Class of PIS	5.1	16.8	6.2	21.7	71.7	8.0
Accumulated Depreciation (Schedule 2.32)	(6,104.7)	(66.1)	1.1%	Functional Class of Accum. Depr'n	(2.2)	(7.9)	(2.7)	(11.1)	(38.5)	(3.7)
Allowance For Working Capital	87.2	11.1	12.7%	12.50% of OM&A and Taxes	0.6	1.6	0.7	1.9	5.6	0.7
Inventories (Schedule 2.33)	165.0	0.4	0.3%	Functional Class of Inventories	0.0	0.1	0.0	0.1	0.2	0.0
Other Assets (Schedule 2.33)	7.2	0.5	6.5%	Functional Classification of Other Assets	0.0	0.1	0.0	0.1	0.2	0.0
Total Rate Base	**9,583.8**	**75.5**	**0.8%**		**3.5**	**10.7**	**4.3**	**12.6**	**39.2**	**5.2**
Revenue Requirement										
Fuel Expense SaskPower Units	488.7	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-
Purchased Power & Import	273.3	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(46.8)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-
Operating,Maintenance & Administration (Schedule 2.34)	697.8	96.6	13.8%	Functional Class of OM&A	4.9	14.3	5.9	16.1	48.8	6.5
Depreciation & Depletion (Schedule 2.35)	507.5	9.8	1.9%	Functional Class of Depr'n & Depletion	0.4	1.4	0.5	1.6	5.2	0.6
Corporate Capital Tax	38.1	0.3	0.7%	Functional Class of Corp. Capital Tax	0.0	0.0	0.0	0.0	0.1	0.0
Grants in Lieu of Taxes	25.3	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-
Miscellaneous Tax	0.5	0.1	11.0%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.36)	(131.8)	(25.0)	19.0%	Functional Class of Other Income	(0.0)	(0.1)	(2.5)	(3.1)	(19.1)	(0.1)
Return on Rate Base @ 5.12%	491.0	3.9	0.8%	Rate Base	0.2	0.5	0.2	0.6	2.0	0.3
Total Revenue Requirement	**2,343.6**	**85.6**	**3.7%**		**5.5**	**16.2**	**4.2**	**15.4**	**37.0**	**7.3**

Schedule 2.31: Functional Classification of Financial Account Details – Customer Services Plant in Service

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES PLANT IN SERVICE
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	8,042.4	-	0.0%	-	-	-	-	-	-
Coal Reserves	60.2	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	5.7	-	0.0%	-	-	-	-	-	-
Total Generation	**8,108.2**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	2,626.3	-	0.0%	-	-	-	-	-	-
Total Transmission	**2,626.3**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	3,394.4	-	0.0%	-	-	-	-	-	-
Meters	211.3	-	0.0%	-	-	-	-	-	-
Total Distribution	**3,605.7**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	2.2	0.3	13.8%	0.0	0.0	0.0	0.1	0.2	0.0
Buildings	274.4	46.2	16.8%	2.4	7.0	2.9	7.7	23.0	3.2
Office Furniture & Equipment	49.9	8.4	16.8%	0.4	1.3	0.5	1.4	4.2	0.6
Vehicles & Equipment	196.1	19.4	9.9%	0.1	1.3	0.1	3.4	14.1	0.5
Computer Development & Equipment	387.4	49.6	12.8%	2.2	6.8	2.7	8.3	26.5	3.1
Communication, Protection & Control	152.6	3.7	2.4%	-	0.2	-	0.5	2.3	0.7
Tools & Equipment	26.4	1.9	7.4%	-	0.1	-	0.3	1.5	0.0
Total General Plant	**1,089.0**	**129.6**	**11.9%**	**5.1**	**16.8**	**6.2**	**21.7**	**71.7**	**8.0**
Total Plant In Service	**15,429.1**	**129.6**	**0.8%**	**5.1**	**16.8**	**6.2**	**21.7**	**71.7**	**8.0**

Schedule 2.32: Functional Classification of Financial Account Details – Customer Services Accumulated Depreciation

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES ACCUMULATED DEPRECIATION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	(3,312.1)	-	0.0%	-	-	-	-	-	-
Coal Reserves	(30.6)	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	(3.3)	-	0.0%	-	-	-	-	-	-
Total Generation	**(3,346.1)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	(592.4)	-	0.0%	-	-	-	-	-	-
Total Transmission	**(592.4)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	(1,490.4)	-	0.0%	-	-	-	-	-	-
Meters	(62.6)	-	0.0%	-	-	-	-	-	-
Total Distribution	**(1,553.0)**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Buildings	(39.3)	(5.5)	14.0%	(0.3)	(0.8)	(0.3)	(0.9)	(2.8)	(0.4)
Office Furniture & Equipment	(16.2)	(2.3)	14.0%	(0.1)	(0.3)	(0.1)	(0.4)	(1.1)	(0.2)
Vehicles & Equipment	(98.7)	(9.6)	9.7%	(0.0)	(0.6)	(0.0)	(1.7)	(7.0)	(0.2)
Computer Development & Equipment	(367.2)	(45.5)	12.4%	(1.8)	(5.9)	(2.2)	(7.7)	(25.4)	(2.6)
Communication, Protection & Control	(78.2)	(2.0)	2.5%	-	(0.1)	-	(0.3)	(1.3)	(0.3)
Tools & Equipment	(13.7)	(1.2)	8.8%	-	(0.1)	-	(0.2)	(0.9)	(0.0)
Total General Plant	**(613.3)**	**(66.1)**	**10.8%**	**(2.2)**	**(7.9)**	**(2.7)**	**(11.1)**	**(38.5)**	**(3.7)**
Total Accumulated Depreciation	**(6,104.7)**	**(66.1)**	**1.1%**	**(2.2)**	**(7.9)**	**(2.7)**	**(11.1)**	**(38.5)**	**(3.7)**

Schedule 2.33: Functional Classification of Financial Account Details – Customer Services Inventories/Other Assets

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES INVENTORIES
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Inventories									
Power Production - Repair Stores	52.1	-	0.0%	-	-	-	-	-	-
Power Production - Fuel	27.9	-	0.0%	-	-	-	-	-	-
Transmission & Distribution	81.9	-	0.0%	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	3.1	0.4	13.8%	0.0	0.1	0.0	0.1	0.2	0.0
Total Inventories	**165.0**	**0.4**	**0.3%**	**0.0**	**0.1**	**0.0**	**0.1**	**0.2**	**0.0**

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OTHER ASSETS
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Service	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	3.1	-	0.0%	-	-	-	-	-	-
Intangible Assets	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	0.8	0.0	1.1%	-	0.0	-	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	3.3	0.5	13.8%	0.0	0.1	0.0	0.1	0.2	0.0
Total Other Assets	**7.2**	**0.5**	**6.5%**	**0.0**	**0.1**	**0.0**	**0.1**	**0.2**	**0.0**

Schedule 2.34: Functional Classification of Financial Account Details – Customer Services O M & A Expenses

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OM&A EXPENSES
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation Expenses									
Power Plant Operation	181.9	-	0.0%	-	-	-	-	-	-
Fuel Supply	2.0	-	0.0%	-	-	-	-	-	-
Power Production Overhead	29.9	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogen	12.1	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Meridian	7.4	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Spyhill	(0.7)	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Flyash	1.9	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Centennial Wind	6.0	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	1.3	-	0.0%	-	-	-	-	-	-
NorthPoint Energy Solutions	9.6	-	0.0%	-	-	-	-	-	-
Total Generation Expenses	**251.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission & Distribution Expenses									
T & D - Planning Support	17.4	0.3	1.9%	-	-	-	-	-	0.3
T & D - Transmission Including 138 & 72 kV Radials	34.1	-	0.0%	-	-	-	-	-	-
T & D - Distribution	110.9	-	0.0%	-	-	-	-	-	-
T & D - Customer Services	6.0	6.0	100.0%	-	1.2	-	3.4	1.3	-
T & D - Gas & Electric Inspections	13.2	13.2	100.0%	-	-	-	-	13.2	-
Total Transmission & Distribution Expenses	**181.6**	**19.6**	**10.8%**	**-**	**1.2**	**-**	**3.4**	**14.6**	**0.3**
Customer Services Expenses									
Meter Reading	7.3	7.3	100.0%	-	7.3	-	-	-	-
Metering Services	2.9	2.9	100.0%	2.9	-	-	-	-	-
Billing Services	3.5	3.5	100.0%	-	-	3.5	-	-	-
Collections/Special Collections	4.0	4.0	100.0%	-	-	-	4.0	-	-
Bad Debt Expense	2.4	2.4	100.0%	-	-	-	2.4	-	-
Marketing & Sales	3.5	3.5	100.0%	-	-	-	-	-	3.5
Demand Side Management	15.2	-	0.0%	-	-	-	-	-	-
Customer Service	16.1	16.1	100.0%	-	-	-	-	16.1	-
Total Customer Services Expenses	**55.0**	**39.8**	**72.3%**	**2.9**	**7.3**	**3.5**	**6.5**	**16.1**	**3.5**
Support Group Expenses									
President / Board	3.6	0.5	13.8%	0.0	0.1	0.0	0.1	0.2	0.0
Corporate & Financial Services	24.5	3.0	12.3%	0.2	0.4	0.2	0.5	1.5	0.2
Planning, Environment & Regulatory Affairs	24.1	2.0	8.3%	0.1	0.3	0.1	0.3	1.0	0.1
General Council / Land	5.1	0.7	13.8%	0.0	0.1	0.0	0.1	0.4	0.0
Communication & Public Affairs	8.4	1.2	13.8%	0.1	0.2	0.1	0.2	0.6	0.1
Safety	8.5	1.2	14.5%	0.1	0.2	0.1	0.2	0.6	0.1
Corporate Information & Technology	85.2	13.8	16.2%	0.7	2.1	0.9	2.3	6.9	1.0
Human Resources	21.8	3.6	16.6%	0.2	0.5	0.2	0.6	1.8	0.2
Supply Chain	-	-	0.0%	-	-	-	-	-	-
Business Development	1.5	-	0.0%	-	-	-	-	-	-
Service Delivery Renewal	26.9	11.2	41.6%	0.7	1.9	0.8	1.8	5.0	0.9
Total Support Group Expenses	**209.6**	**37.2**	**17.8%**	**2.0**	**5.8**	**2.5**	**6.2**	**18.1**	**2.7**
Total OM&A Expenses	**697.8**	**96.6**	**13.8%**	**4.9**	**14.3**	**5.9**	**16.1**	**48.8**	**6.5**

Schedule 2.35: Functional Classification of Financial Account Details – Customer Services Depreciation & Depletion

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES DEPRECIATION & DEPLETION
2016 Test Embedded Cost of Service Study
($ Millions)

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Generation									
Power Production	272.8	-	0.0%	-	-	-	-	-	-
Coal Reserves	1.5	-	0.0%	-	-	-	-	-	-
SaskPower International (SPI) - Cory Cogeneration	-	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-
Total Generation	**274.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Transmission									
Transmission	58.7	-	0.0%	-	-	-	-	-	-
Total Transmission	**58.7**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
Distribution									
Distribution	97.3	-	0.0%	-	-	-	-	-	-
Meters	10.2	-	0.0%	-	-	-	-	-	-
Total Distribution	**107.5**	**-**	**0.0%**	**-**	**-**	**-**	**-**	**-**	**-**
General Plant									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Buildings	0.3	0.0	13.9%	0.0	0.0	0.0	0.0	0.0	0.0
Office Furniture & Equipment	0.2	0.0	13.9%	0.0	0.0	0.0	0.0	0.0	0.0
Vehicles & Equipment	12.4	1.3	10.3%	0.0	0.1	0.0	0.2	0.9	0.0
Computer Development & Equipment	52.2	8.4	16.0%	0.4	1.3	0.5	1.4	4.2	0.6
Communication, Protection & Control	1.5	0.0	2.5%	-	0.0	-	0.0	0.0	0.0
Tools & Equipment	0.3	0.0	7.9%	-	0.0	-	0.0	0.0	0.0
Total General Plant	**66.9**	**9.8**	**14.6%**	**0.4**	**1.4**	**0.5**	**1.6**	**5.2**	**0.6**
Total Depreciation & Depletion	**507.5**	**9.8**	**1.9%**	**0.4**	**1.4**	**0.5**	**1.6**	**5.2**	**0.6**

Schedule 2.36: Functional Classification of Financial Account Details – Customer Services Other Income

Functionalization and Classification of Financial Account Details
CUSTOMER SERVICES OTHER INCOME
2016 Test Embedded Cost of Service Study
($ Millions)

Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collecting	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Other Income									
Customer Services Payment Charges	(5.4)	(5.4)	100.0%	-	-	(2.5)	(2.9)	-	-
Meter Reading	-	-	0.0%	-	-	-	-	-	-
Inspections	(18.7)	(18.7)	100.0%	-	-	-	-	(18.7)	-
Transmission	(1.8)	-	0.0%	-	-	-	-	-	-
Distribution	(6.3)	-	0.0%	-	-	-	-	-	-
Clean Coal Project Credits	(10.0)	-	0.0%	-	-	-	-	-	-
CO2 Sales	(20.7)	-	0.0%	-	-	-	-	-	-
Miscellaneous Other Income	(6.5)	(0.9)	13.8%	(0.0)	(0.1)	(0.1)	(0.2)	(0.5)	(0.1)
Customer Contribution Revenue	(50.0)	-	0.0%	-	-	-	-	-	-
Green Power Premium	(1.8)	-	0.0%	-	-	-	-	-	-
NorthPoint	-	-	0.0%	-	-	-	-	-	-
Flyash Sales	(10.7)	-	0.0%	-	-	-	-	-	-
Consulting & Contracting Services	-	-	0.0%	-	-	-	-	-	-
Total Other Income	**(131.8)**	**(25.0)**	**19.0%**	**(0.0)**	**(0.1)**	**(2.5)**	**(3.1)**	**(19.1)**	**(0.1)**

Schedule 3.0: SaskPower Allocation Methodology Summary

SaskPower

SaskPower Functionalization	SaskPower Classification	SaskPower Sub-Functionalization	Allocation Methodology
GENERATION	Demand (Facilities)		Two Coincident Peak Method (2CP)
	Energy (Facilities)		Actual Energy Costs Plus Losses
	Energy (Fuel Expense)		Actual Energy Costs Plus Losses
TRANSMISSION	DEMAND	Main Grid	Two Coincident Peak Method (2CP) - Coincident Peak at output of transmission.
		138kv Radials	Two Coincident Peak Method (2CP) - at output of common 138kv Radials.
		138/72kv Substations	Two Coincident Peak Method (2CP) - at output of substations.
		72kv Radials	Two Coincident Peak Method (2CP) - at output of common 72kv radials.
DISTRIBUTION	DEMAND	Area Substations - Demand	Two Coincident Peak Method (2CP) - at output of substations.
		Distribution Mains - Demand	Two Coincident Peak Method (2CP) - at output of distribution mains.
		Urban Laterals - Demand	Two Coincident Peak Method (2CP) - at output of urban laterals.
		Rural Laterals - Demand	Two Coincident Peak Method (2CP) - at output of rural laterals.
		Transformers - Demand	Non Coincident Peak (NCP) - at output of rural laterals.
	CUSTOMER	Urban Laterals - Customer	Number of urban customers supplied through laterals.
		Rural Laterals - Customer	Number of rural customers supplied through laterals.
		Transformers - Customer	Number of customers supplied through laterals.
		Services - Customer	Direct to classes which are using services.
		Meters - Customer	Number of metered customers weighted by installed cost of a meter.
		Streetlights - Customer	Direct to Streetlight Class.
CUSTOMER SERVICES	CUSTOMER	Customer Service	Weighted number of customers.
CUSTOMER CONTRIBUTIONS	CUSTOMER	Customer Contributions	Direct to classes which made contribution.
INTERRUPTIBLE ADJUSTMENT	DEMAND	Interruptible Adjustment	Two Coincident Peak Method (2CP)

2CP METHOD

The Two Coincident Peak (2CP) method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

NCP METHOD

The Non-Coincident Peak (NCP) method allcoates responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occurr, to the sum of all the class peaks, similarly determined.

Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation
2016 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	2,444	2,265,827	495,448	12.31%	56.31%
Rural Residential	658	610,034	133,391	12.31%	56.31%
Farms	1,298	807,663	219,313	18.35%	67.58%
Urban Commercial	2,693	861,291	423,544	35.70%	72.59%
Rural Commercial	917	311,610	148,057	33.58%	70.68%
Power - Published Rates	7,970	1,302,407	971,524	69.86%	93.65%
Power - Contract Rates	1,826	274,906	218,144	75.82%	95.55%
Oilfields	4,017	671,456	474,565	68.29%	96.62%
Streetlights	64	15,365	7,571	47.25%	95.89%
Reseller	1,272	239,360	208,717	60.64%	69.55%
Total	**23,159**	**7,359,919**	**3,300,274**	**35.92%**	**80.11%**

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)

Schedule 5.0: Allocation Factors by Customer Class – Generation

Allocation Factors by Customer Class
GENERATION Related Costs
2016 Test Embedded Cost of Service Study

Customer Class	Load [1]	Load [2]	Losses [3]	Losses [4]	Scheduling & Dispatch [3]	Regulation & Frequency Response [3]	Spinning Reserve [3]	Supplementary Reserve [3]	Planning Reserve [3]	Reactive Supply [3]	Grants in Lieu of Taxes [3]	Interruptible Adjustment [3]
	Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy	Demand
Urban Residential	15.0%	10.6%	21.7%	17.1%	15.6%	15.6%	15.6%	15.6%	15.6%	15.6%	56.3%	15.9%
Rural Residential	4.0%	2.8%	5.6%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%	0.0%	4.3%
Farms	6.6%	5.6%	9.0%	8.2%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	0.0%	7.0%
Urban Commercial	12.8%	11.6%	18.3%	18.5%	13.3%	13.3%	13.3%	13.3%	13.3%	13.3%	43.7%	13.6%
Rural Commercial	4.5%	4.0%	5.9%	5.5%	4.6%	4.6%	4.6%	4.6%	4.6%	4.6%	0.0%	4.7%
Power - Published Rates	28.2%	33.0%	15.8%	17.6%	27.1%	27.1%	27.1%	27.1%	27.1%	27.1%	0.0%	26.8%
Power - Contract Rates	7.8%	9.3%	3.5%	4.0%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	0.0%	6.4%
Oilfields	14.4%	17.3%	17.5%	22.2%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	0.0%	15.0%
Streetlights	0.2%	0.3%	0.3%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.0%	0.2%
Reseller	6.3%	5.5%	2.5%	2.1%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	0.0%	6.1%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (2CP) at the meter.
[2] Based on actual energy consumption at the meter.
[3] Based on Coincident Peak (2CP) & losses.
[4] Based on energy losses.

Schedule 5.1: Allocation Factors by Customer Class – Transmission

Allocation Factors by Customer Class
TRANSMISSION Related Costs
2016 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	15.6%	11.3%	20.2%	20.2%
Rural Residential	4.2%	3.0%	5.4%	5.4%
Farms	6.9%	5.2%	8.7%	8.7%
Urban Commercial	13.3%	9.6%	17.3%	17.3%
Rural Commercial	4.6%	3.2%	6.1%	6.1%
Power - Published Rates	27.1%	36.2%	22.4%	22.4%
Power - Contract Rates	7.4%	15.7%	1.7%	1.7%
Oilfields	14.7%	12.6%	17.4%	17.4%
Streetlights	0.2%	0.2%	0.3%	0.3%
Reseller	6.0%	2.9%	0.4%	0.4%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: All allocation factors based on Coincident Peak (2 CP) & losses.

Schedule 5.2: Allocation Factors by Customer Class – Distribution

Allocation Factors by Customer Class
DISTRIBUTION Related Costs
2016 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]	Amortization Customer Contributions [7]	Meters [8]	Streetlights [9]
	Demand	Energy	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer
Urban Residential	26.0%	26.1%	53.6%	84.7%	0.0%	0.0%	42.6%	61.2%	18.9%	16.6%	20.0%	0.0%
Rural Residential	7.0%	7.0%	0.0%	0.0%	15.7%	34.2%	11.5%	9.5%	11.3%	16.7%	3.1%	0.0%
Farms	11.2%	11.2%	0.0%	0.0%	25.3%	40.9%	15.0%	11.3%	2.1%	16.9%	4.2%	0.0%
Urban Commercial	22.2%	22.3%	45.7%	11.6%	0.0%	0.0%	15.4%	8.4%	26.1%	12.5%	30.0%	0.0%
Rural Commercial	7.2%	7.2%	0.0%	0.0%	16.2%	9.0%	5.2%	2.5%	12.0%	14.4%	12.2%	0.0%
Power - Published Rates	3.7%	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.4%	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%	2.8%	0.0%
Oilfields	21.9%	22.0%	0.0%	0.0%	42.7%	13.3%	10.0%	3.7%	29.7%	22.8%	13.0%	0.0%
Streetlights	0.4%	0.4%	0.7%	3.7%	0.1%	2.7%	0.3%	3.4%	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%	1.2%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

[1] Based on Coincident Peak (2CP) & 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.

Schedule 5.3: Allocation Factors by Customer Class – Customer Service

Allocation Factors by Customer Class
CUSTOMER SERVICE Related Costs
2016 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	17.3%	62.9%	42.4%	73.6%	60.2%	10.6%
Rural Residential	2.7%	9.6%	6.6%	11.4%	9.3%	3.8%
Farms	3.6%	13.0%	10.1%	8.0%	12.8%	7.8%
Urban Commercial	21.0%	7.3%	12.3%	4.7%	8.5%	13.0%
Rural Commercial	6.6%	2.3%	3.7%	1.3%	2.5%	2.9%
Power - Published Rates	20.2%	0.0%	6.1%	0.0%	0.9%	29.8%
Power - Contract Rates	3.3%	0.0%	1.0%	0.0%	0.1%	4.9%
Oilfields	24.7%	4.9%	16.6%	1.0%	4.8%	25.0%
Streetlights	0.0%	0.0%	1.0%	0.0%	0.8%	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.

Schedule 6.0: Functional Classification of Revenue Requirement by Customer Class – Generation

Functionalized & Classified Revenue Requirement by Customer Class
GENERATION Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes	Interruptible Adjustment
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Energy	Demand
Urban Residential	410.1	225.2	54.9%	83.2	91.7	10.9	12.1	1.5	1.0	2.4	3.6	3.2	1.0	14.3	0.0
Rural Residential	109.5	56.3	51.4%	22.4	24.7	2.8	3.0	0.4	0.3	0.6	1.0	0.9	0.3	-	0.0
Farms	175.1	101.6	58.0%	36.8	48.7	4.5	5.8	0.7	0.4	1.1	1.6	1.4	0.4	-	0.0
Urban Commercial	323.6	216.6	66.9%	71.2	101.1	9.2	13.1	1.3	0.9	2.1	3.1	2.8	0.9	11.1	0.0
Rural Commercial	111.0	70.0	63.1%	24.9	34.4	3.0	3.9	0.5	0.3	0.7	1.1	1.0	0.3	-	0.0
Power - Published Rates	587.0	506.7	86.3%	163.2	299.2	8.2	12.9	2.8	1.8	4.4	6.6	5.8	1.8	-	(0.0)
Power - Contract Rates	130.9	114.3	87.3%	36.7	68.5	1.5	2.5	0.6	0.4	1.0	1.5	1.3	0.4	-	0.0
Oilfields	381.1	267.1	70.1%	79.7	150.8	8.8	15.7	1.4	1.0	2.3	3.4	3.0	1.0	-	0.0
Streetlights	14.9	4.3	29.2%	1.3	2.4	0.2	0.3	0.0	0.0	0.0	0.1	0.0	0.0	-	0.0
Reseller	100.4	90.5	90.1%	35.1	47.7	1.3	1.5	0.6	0.4	0.9	1.4	1.2	0.4	-	0.0
Total	**2,343.6**	**1,652.6**	**70.5%**	**554.5**	**869.3**	**50.2**	**70.9**	**9.9**	**6.5**	**15.5**	**23.2**	**20.7**	**6.5**	**25.4**	**0.0**

Schedule 6.1: Functional Classification of Revenue Requirement by Customer Class – Transmission

Functionalized & Classified Revenue Requirement by Customer Class
TRANSMISSION Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	138 kv Lines Radials	138/72 kv Substations	72 kv Lines Radials
				Demand	Demand	Demand	Demand
Urban Residential	410.1	36.9	9.0%	20.3	5.6	3.6	7.4
Rural Residential	109.5	9.9	9.0%	5.4	1.5	1.0	2.0
Farms	175.1	16.2	9.3%	8.9	2.6	1.5	3.2
Urban Commercial	323.6	31.5	9.7%	17.3	4.8	3.1	6.3
Rural Commercial	111.0	10.9	9.8%	6.0	1.6	1.1	2.2
Power - Published Rates	587.0	68.3	11.6%	36.8	19.4	4.0	8.2
Power - Contract Rates	130.9	15.5	11.9%	8.2	6.4	0.3	0.6
Oilfields	381.1	34.8	9.1%	19.1	6.3	3.1	6.4
Streetlights	14.9	0.6	3.8%	0.3	0.1	0.1	0.1
Reseller	100.4	9.5	9.4%	7.8	1.5	0.1	0.1
Total	**2,343.6**	**234.0**	**10.0%**	**130.1**	**49.7**	**17.8**	**36.4**

Schedule 6.2: Functional Classification of Revenue Requirement by Customer Class – Distribution

Functionalized & Classified Revenue Requirement by Customer Class
DISTRIBUTION Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Urban Laterals	Rural Laterals	Rural Laterals	Transformers	Transformers	Services	Amortization Customer Contributions	Meters	Streetlights
				Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer
Urban Residential	410.1	100.8	24.6%	10.1	29.1	15.9	13.6	-	-	15.9	9.8	6.9	(4.1)	3.7	-
Rural Residential	109.5	35.8	32.7%	2.7	7.8	-	-	8.8	10.3	4.3	1.5	4.1	(4.1)	0.6	-
Farms	175.1	48.0	27.4%	4.4	12.5	-	-	14.1	12.3	5.6	1.8	0.8	(4.2)	0.8	-
Urban Commercial	323.6	67.9	21.0%	8.6	24.8	13.6	1.9	-	-	5.7	1.3	9.4	(3.1)	5.5	-
Rural Commercial	111.0	27.9	25.1%	2.8	8.0	-	-	9.0	2.7	1.9	0.4	4.3	(3.6)	2.2	-
Power - Published Rates	587.0	8.1	1.4%	1.4	4.1	-	-	-	-	-	-	-	-	2.5	-
Power - Contract Rates	130.9	0.5	0.4%	-	-	-	-	-	-	-	-	-	-	0.5	-
Oilfields	381.1	72.6	19.0%	8.5	24.4	-	-	23.8	4.0	3.7	0.6	10.7	(5.7)	2.4	-
Streetlights	14.9	9.5	64.2%	0.2	0.4	0.2	0.6	0.1	0.8	0.1	0.6	-	-	-	6.6
Reseller	100.4	0.4	0.4%	0.1	-	-	-	-	-	-	-	-	-	0.2	-
Total	**2,343.6**	**371.4**	**15.8%**	**38.9**	**111.2**	**29.7**	**16.0**	**55.8**	**30.0**	**37.3**	**16.0**	**36.2**	**(24.7)**	**18.4**	**6.6**

Schedule 6.3: Functional Classification of Revenue Requirement by Customer Class – Customer Service

Functionalized & Classified Revenue Requirement by Customer Class
CUSTOMER SERVICE Related Costs
2016 Test Embedded Cost of Service Study
($ Millions)

Customer Class	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Customer Service	Marketing
				Customer	Customer	Customer	Customer	Customer	Customer
Urban Residential	410.1	47.3	11.5%	1.0	10.2	1.8	11.3	22.3	0.8
Rural Residential	109.5	7.5	6.8%	0.1	1.6	0.3	1.8	3.4	0.3
Farms	175.1	9.3	5.3%	0.2	2.1	0.4	1.2	4.7	0.6
Urban Commercial	323.6	7.7	2.4%	1.2	1.2	0.5	0.7	3.2	1.0
Rural Commercial	111.0	2.2	2.0%	0.4	0.4	0.2	0.2	0.9	0.2
Power - Published Rates	587.0	3.9	0.7%	1.1	-	0.3	-	0.3	2.2
Power - Contract Rates	130.9	0.6	0.5%	0.2	-	0.0	-	0.1	0.3
Oilfields	381.1	6.6	1.7%	1.4	0.8	0.7	0.2	1.8	1.8
Streetlights	14.9	0.4	2.9%	-	-	0.0	-	0.3	0.1
Reseller	100.4	0.1	0.1%	0.0	-	0.0	-	0.0	0.1
Total	**2,343.6**	**85.6**	**3.7%**	**5.5**	**16.2**	**4.2**	**15.4**	**37.0**	**7.3**

Schedule 7.0: Customer Data for Rate Design

Customer Data
2016 Test Embedded Cost of Service Study

Customer Class	Average Annual # of Accounts	Annual Revenue ($)	Annual Sales @ Meter (MWh)	Annual Billing Demand @ Meter (kVa)
Urban Residential	326,001	403,872,138	2,444,091	-
Rural Residential	50,448	106,778,049	658,029	-
Farms	60,341	170,773,603	1,298,322	598,022
Urban Commercial	44,561	327,108,330	2,693,430	5,628,506
Rural Commercial	13,253	112,168,307	916,677	2,240,319
Power - Published Rates	93	593,349,144	7,970,253	15,290,121
Power - Contract Rates	14	128,950,825	1,825,902	4,161,771
Oilfields	19,608	385,160,064	4,016,868	8,586,298
Streetlights	2,850	15,010,004	63,599	-
Reseller	3	100,429,536	1,271,590	2,432,396
Total	**517,172**	**2,343,600,000**	**23,158,761**	**38,937,432**

SASKPOWER FULL-TIME EQUIVALENT (FTE) PLAN

SaskPower's 5-Year FTE plan calls for both the addition of new FTE's in certain areas combined with the reduction of FTE's in other areas. The increase in FTE's in 2014 is required to address growth, to improve service levels, and to source efficiency initiatives. The FTE levels are then expected to decrease in 2015 with the expected implementation of AMI and the retirement of Boundary Dam Units 1 & 2. FTE's are then expected to begin to gradually increase starting in 2016.

SaskPower 5 Year FTE Plan To December 31, 2016					
	2013 Target	2014	2015	2016	Change 2013-2016
President's Office	16	16	16	16	-
Power Production	850	897	869	865	15
Transmission	299	307	307	310	11
Distribution	655	663	685	690	35
Asset Management	137	144	144	144	7
Operation's Other	146	169	165	165	19
Finance	114	114	114	114	-
Customer Services	413	385	337	337	(76)
Resource Planning & NRPT	76	75	75	77	1
Law, Land & Reg Affairs	130	144	144	144	14
Info Technology & Security	170	192	194	194	24
Human Resources	187	177	174	174	(13)
Commercial	135	160	135	135	-
Business Development	7	7	7	7	-
ICCS	17	28	24	24	7
Total	3,352	3,478	3,390	3,396	44
Annual Change		126	(88)	6	44

SaskPower 5 Year FTE Plan - Annual Change To December 31, 2016					
	2013 Target	2014	2015	2016	Change 2013-2016
President's Office	16	-	-	-	-
Power Production	850	47	(28)	(4)	15
Transmission	299	8	-	3	11
Distribution	655	8	22	5	35
Asset Management	137	7	-	-	7
Operation's Other	146	23	(4)	-	19
Finance	114	-	-	-	-
Customer Services	413	(28)	(48)	-	(76)
Resource Planning & NRPT	76	(1)	-	2	1
Law, Land & Reg Affairs	130	14	-	-	14
Info Technology & Security	170	22	2	-	24
Human Resources	187	(10)	(3)	-	(13)
Commercial	135	25	(25)	-	-
Business Development	7	-	-	-	-
ICCS	17	11	(4)	-	7
Total	3,352	126	(88)	6	44

SaskPower 2014 FTE Additions		
Business Area	**2014 FTE Change**	**Explanation**
President's Office	-	
Power Production	47	New FTE's for Boundary Dam ICCS facility and to fill on-going operational short-falls. The increases in 2014 are to be partially offset by a reduction in FTE's in 2015 from the retirement of BD 1 & 2.
Transmission	8	New transmission crew for Saskatoon; system technologists and ground patrol employees
Distribution	8	New positions for operations support and temp positions to develop the OMS
Asset Management	7	Additional chemists; analysts
Operation's Other	23	Fleet apprentice program; logistics; metering technicians; schedule & dispatch support
Finance	-	
Customer Services	(28)	Meter reading reductions due to the implementation of AMI
Resource Planning	(1)	Temporary reduction of NorthPoint positions that will be restored in 2016
Law, Land & Reg Affairs	14	Additional gas and electrical inspectors and land officers
Info Technology & Security	22	Repatriation and AMI support
Human Resources	(10)	Reduction in FTE's through attrition and restructuring
Commercial	25	Expanded PMO Office and Purchasing Organization. Expect an equal FTE reduction in 2015 through a transfer of SDR FTE's to Distribution.
Business Development	-	
ICCS	11	To support current and future ICCS projects and the Clean Coal Test Facility
Total	**126**	

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Commercial	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Major Projects	00011	00001	00000	00000	00000	00000	11	1	00000	00000
President's Office Admin	00001	00001	00001	00000	00000	00000	2	1	00000	00000
Strategic Relations-Pres Off	00013	00001	00001	00000	00000	00000	14	1	00000	00000
Service Delivery Renewal	00034	00000	00010	00000	00001	00000	45	0	00000	00003
Supply Chain	00062	00001	00008	00000	00002	00000	72	1	00000	00006
Commercial	**00122**	**00004**	**00020**	**00000**	**00003**	**00000**	**145**	**4**	**00000**	**00009**
President's Office	00001	00000	00000	00000	00000	00000	1	0	00000	00000
President's Office	**00001**	**00000**	**00000**	**00000**	**00000**	**00000**	**1**	**0**	**00000**	**00000**
Finance	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Finance Business Partners	00015	00000	00000	00000	00000	00000	15	0	00000	00000
Corporate Planning & Rate Desi	00032	00001	00002	00000	00000	00000	34	1	00001	00001
Bus Analy & Risk Mgmt	00008	00001	00002	00000	00000	00000	10	1	00000	00000
Corporate Accounting & Busines	00027	00001	00002	00000	00000	00000	29	1	00001	00002
Internal Audit	00009	00000	00000	00000	00000	00000	9	0	00000	00000
Treasury	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Finance	**00098**	**00003**	**00006**	**00000**	**00000**	**00000**	**104**	**3**	**00002**	**00003**
Information Technology & Secur	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Application Development & Supp	00018	00000	00001	00000	00000	00000	19	0	00000	00001
Portfolio Management Office	00017	00000	00000	00000	00000	00000	17	0	00000	00000
IT Business Services	00012	00000	00001	00000	00000	00000	13	0	00000	00001
Enterprise Programs	00008	00000	00000	00000	00000	00000	8	0	00000	00000
Infrastructure Services	00051	00001	00005	00000	00000	00000	56	1	00000	00004
Enterprise Arch Sec & Plng	00021	00000	00000	00000	00000	00000	21	0	00000	00000
Enterprise Security	00010	00000	00000	00000	00000	00000	10	0	00000	00000
Information Technology & Secur	**00139**	**00001**	**00007**	**00000**	**00000**	**00000**	**146**	**1**	**00000**	**00006**
Customer Services	00001	00000	00000	00000	00001	00000	2	0	00000	00000
Customer Strategy	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Customer Programs	00015	00000	00000	00000	00000	00000	15	0	00000	00000
Business & Technology Support	00064	00002	00044	00000	00020	00003	128	5	00005	00000
Customer Care & Billing	00152	00005	00037	00000	00065	00005	254	10	00005	00026
Communications	00025	00001	00001	00000	00000	00000	26	1	00002	00000
Customer Relations	00021	00001	00005	00000	00002	00000	28	1	00001	00004
Customer Services	**00284**	**00009**	**00087**	**00000**	**00088**	**00008**	**459**	**17**	**00013**	**00030**
Resource Plng & NRPT	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Resource Plng	00019	00001	00000	00000	00000	00000	19	1	00000	00000
NorthPoint Energy Solutions	00041	00004	00004	00000	00001	00000	46	4	00000	00003
Resource Plng & NRPT	**00061**	**00005**	**00004**	**00000**	**00001**	**00000**	**66**	**5**	**00000**	**00003**
Operations	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Asset Management	00104	00003	00014	00000	00001	00000	119	3	00003	00009
Transmission Services	00288	00003	00009	00000	00000	00000	297	3	00002	00008
Business Perf & Plng	00029	00001	00000	00000	00000	00000	29	1	00000	00000
Distribution Services	00613	00010	00031	00000	00017	00000	661	10	00003	00018
Logistics Mgmt	00080	00002	00017	00000	00002	00000	99	2	00000	00014
Power Production	00787	00010	00086	00000	00003	00000	876	10	00012	00025
Operations	**01902**	**00029**	**00157**	**00000**	**00023**	**00000**	**2082**	**29**	**00020**	**00074**
Carb Cap & Strg Init	00002	00000	00000	00000	00000	00000	2	0	00000	00000
CCS Init-Administration	00002	00000	00001	00000	00000	00000	3	0	00000	00000
CCS Init-Consortium	00002	00000	00001	00000	00000	00000	3	0	00000	00000
CCS Init-Boundary Dam 3	00015	00000	00000	00000	00000	00000	15	0	00000	00000
Carb Cap & Strg Init	**00021**	**00000**	**00002**	**00000**	**00000**	**00000**	**23**	**0**	**00000**	**00000**

SaskPower
SaskPower Employee Inventory Summary

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Corporate Relations	00000	00001	00000	00000	00000	00000	0	1	00000	00000
Corporate Relations	**00000**	**00001**	**00000**	**00000**	**00000**	**00000**	**0**	**1**	**00000**	**00000**
Law, Land, Regulatory Affairs	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Law & Privacy Department	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Governance, Reg Aff & Land	00025	00000	00002	00000	00000	00000	27	0	00000	00002
Regulatory Affairs	00003	00000	00001	00000	00000	00000	4	0	00000	00001
Law Department	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Electrical Inspections	00050	00000	00001	00000	00000	00000	51	0	00001	00001
Gas Inspections	00039	00000	00000	00000	00000	00000	39	0	00003	00000
Law, Land, Regulatory Affairs	**00124**	**00000**	**00004**	**00000**	**00000**	**00000**	**128**	**0**	**00004**	**00004**
HR, Safety & Environment	00003	00000	00000	00000	00000	00000	3	0	00000	00000
HR Special Projects	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Corporate Human Resources	00129	00004	00023	00000	00002	00000	154	4	00013	00003
Environment	00033	00001	00010	00000	00000	00000	43	1	00000	00001
HR, Safety & Environment	**00166**	**00005**	**00033**	**00000**	**00002**	**00000**	**201**	**5**	**00013**	**00004**
Business Development	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Business Development	**00007**	**00000**	**00000**	**00000**	**00000**	**00000**	**7**	**0**	**00000**	**00000**
Total SaskPower 06-13-2013	**02925**	**00057**	**00320**	**00000**	**00117**	**00008**	**3362**	**65**	**00052**	**00133**

SaskPower
Management & In-Scope Summary

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Total Management	00953	00022	00021	00000	00000	00000	974	22	00008	00000
Total CEP	00598	00020	00165	00000	00117	00008	880	28	00025	00079
Total IBEW	01374	00015	00134	00000	00000	00000	1508	15	00019	00054
Total SaskPower 06-13-2013	**02925**	**00057**	**00320**	**00000**	**00117**	**00008**	**3362**	**65**	**00052**	**00133**

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Secondments	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Secondments	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Presidents Office	00004	00000	00000	00000	00000	00000	4	0	00000	00000
People & Processes	00073	00001	00005	00000	00000	00000	78	1	00000	00000
Corp Infor & Technology	00055	00001	00003	00000	00001	00000	59	1	00000	00000
Human Resources	00056	00004	00001	00000	00001	00001	58	5	00012	00000
Presidents Office	00188	00006	00009	00000	00002	00001	199	7	00012	00000
Corp & Financial Services	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Business & Financial Plng	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Bus Analy & Risk Mgmt	00006	00001	00001	00000	00000	00000	7	1	00000	00000
Controller	00018	00000	00001	00000	00001	00000	20	0	00000	00000
Corporate Services	00074	00000	00002	00000	00006	00000	82	0	00000	00001
Internal Audit	00008	00001	00000	00000	00000	00000	8	1	00000	00000
Risk Management	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Treasury	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Corp & Financial Services	00126	00002	00004	00000	00007	00000	137	2	00000	00001
Customer Services	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Business & Technology Support	00109	00001	00003	00000	00024	00001	136	2	00001	00000
Call Centres & Collections	00136	00003	00010	00000	00068	00000	214	3	00003	00000
Customer & Community Relations	00001	00000	00000	00000	00002	00001	3	1	00001	00000
Human Resources	00005	00000	00000	00000	00000	00000	5	0	00000	00000
Initiatives	00008	00000	00000	00000	00000	00000	8	0	00000	00000
Internet Portfolio Services	00002	00000	00002	00000	00000	00000	4	0	00000	00000
Marketing Services	00012	00000	00002	00000	00000	00000	14	0	00000	00000
Pricing & Energy Forecasting	00008	00000	00000	00000	00000	00000	8	0	00000	00000
Sales	00020	00001	00001	00000	00003	00000	24	1	00001	00000
Customer Services	00303	00005	00018	00000	00097	00002	418	7	00006	00000
NorthPoint Energy Solutions	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Energy Trading	00013	00000	00001	00000	00000	00000	14	0	00000	00001
Energy & Risk Mgmt	00006	00000	00001	00000	00000	00000	7	0	00000	00001
Financial & Business Supp	00005	00000	00000	00000	00000	00000	5	0	00000	00000
Gas Management	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Power Mktg & Contract Mgt	00004	00000	00000	00000	00000	00000	4	0	00000	00000
NorthPoint Energy Solutions	00033	00000	00002	00000	00000	00000	35	0	00000	00002
Plng, Envir & Reg Affairs	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Clean Coal Project	00003	00000	00001	00000	00000	00000	4	0	00000	00000
Corp Plng & Regul Affairs	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Strategic Corporate Devt	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Sustainable Supply Devt	00008	00000	00000	00000	00000	00000	8	0	00000	00000
Environmental Programs	00016	00000	00003	00000	00000	00000	19	0	00000	00000
Plng, Envir & Reg Affairs	00037	00000	00004	00000	00000	00000	41	0	00000	00000
Power Production	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Boundary Dam Power Stn	00280	00001	00013	00000	00002	00000	295	1	00001	00000
Northern Hydro	00067	00000	00003	00000	00001	00000	71	0	00000	00000
Poplar River Power Stn	00140	00001	00008	00000	00001	00001	149	2	00002	00000
Shand Power Station	00104	00002	00004	00000	00001	00000	109	2	00001	00000
Western Plants	00085	00001	00006	00000	00000	00000	91	1	00002	00000
Business Perf & Plng	00016	00000	00003	00000	00000	00000	19	0	00000	00001
Engineering Services	00053	00000	00005	00000	00001	00000	59	0	00001	00001
Fuel Supply	00009	00001	00001	00000	00001	00000	11	1	00000	00000
Human Resources PP	00004	00000	00000	00000	00001	00000	5	0	00000	00000
Operations Support	00036	00000	00004	00000	00000	00000	40	0	00000	00000

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
'ower Production	00796	00006	00047	00000	00008	00001	851	7	00007	00002
'ransmission & Distribution	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Regina Region T&D	00206	00003	00008	00000	00005	00001	219	4	00000	00001
Saskatoon Region T&D	00219	00004	00003	00000	00002	00000	224	4	00001	00000
Prince Albert Region T&D	00124	00000	00006	00000	00001	00000	131	0	00000	00000
Weyburn Region T&D	00170	00003	00008	00000	00001	00000	179	3	00001	00000
Business Support Services T&D	00025	00000	00003	00000	00000	00001	28	1	00000	00001
Communs, Protec & Scada	00022	00000	00002	00000	00000	00000	24	0	00000	00001
Electrical Inspections	00036	00000	00001	00000	00001	00000	38	0	00000	00000
Gas Inspections	00026	00000	00001	00000	00000	00000	27	0	00000	00000
Grid Control Centre	00053	00000	00000	00000	00001	00000	54	0	00000	00000
Materials & Engineering	00063	00001	00002	00000	00000	00000	65	1	00000	00000
Network Development	00014	00000	00000	00000	00000	00000	14	0	00000	00000
'ransmission & Distribution	00960	00011	00034	00000	00011	00002	1005	13	00002	00003
'askPower International	00006	00000	00000	00000	00000	00000	6	0	00001	00000
Project Devt & Operations	00003	00000	00000	00000	00000	00000	3	0	00000	00000
SPI Cogeneration	00001	00000	00000	00000	00000	00000	1	0	00000	00000
ProjDevt InvMgmt&Consultg	00003	00000	00000	00000	00000	00000	3	0	00000	00000
'askPower International	00013	00000	00000	00000	00000	00000	13	0	00001	00000
'otal SaskPower 12-31-2006	02458	00030	00118	00000	00125	00006	2701	36	00028	00008

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Total Management	00666	00003	00016	00000	00000	00000	682	3	00003	00000
Total CEP	00511	00011	00051	00000	00125	00006	687	17	00015	00007
Total IBEW	01281	00016	00051	00000	00000	00000	1332	16	00010	00001
Total SaskPower 12-31-2006	02458	00030	00118	00000	00125	00006	2701	36	00028	00008

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	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
residents Office	00005	00000	00000	00000	00000	00000	5	0	00000	00000
People & Processes	00076	00001	00007	00000	00000	00000	83	1	00000	00002
Corp Infor & Technology	00056	00002	00008	00000	00000	00000	64	2	00000	00002
Human Resources	00056	00002	00004	00000	00001	00000	61	2	00015	00002
residents Office	00193	00005	00019	00000	00001	00000	213	5	00015	00006
orp & Financial Services	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Business & Financial Plng	00004	00000	00001	00000	00000	00000	5	0	00000	00001
Bus Analy & Risk Mgmt	00006	00001	00001	00000	00000	00000	7	1	00000	00001
Controller	00019	00000	00002	00000	00001	00000	22	0	00000	00001
Corporate Services	00075	00002	00004	00000	00006	00000	85	2	00001	00001
Internal Audit	00007	00002	00001	00000	00000	00000	8	2	00000	00000
Risk Management	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Treasury	00007	00000	00000	00000	00000	00000	7	0	00000	00000
orp & Financial Services	00123	00005	00009	00000	00007	00000	139	5	00001	00004
ustomer Services	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Human Resources	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Business & Technology Support	00093	00001	00007	00000	00024	00001	124	2	00002	00001
Call Centres & Collections	00141	00003	00019	00000	00065	00001	225	4	00007	00001
Customer & Community Relations	00001	00000	00001	00000	00001	00001	3	1	00000	00000
Service Delivery Renewal	00017	00000	00000	00000	00000	00000	17	0	00000	00000
Internet Portfolio Services	00001	00000	00004	00001	00000	00000	5	1	00000	00000
Marketing Services	00015	00000	00002	00000	00000	00000	17	0	00000	00001
Pricing & Energy Forecasting	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Sales	00021	00000	00002	00000	00002	00000	25	0	00001	00001
ustomer Services	00302	00004	00035	00001	00092	00003	429	8	00010	00004
orthPoint Energy Solutions	00003	00000	00001	00000	00000	00000	4	0	00000	00001
Energy Trading	00015	00000	00002	00000	00000	00000	17	0	00000	00002
Energy & Risk Mgmt	00008	00001	00002	00000	00000	00000	10	1	00000	00001
Financial & Business Supp	00005	00000	00000	00000	00000	00000	5	0	00000	00000
Gas Management	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Power Mktg & Contract Mgt	00004	00000	00000	00000	00000	00000	4	0	00000	00000
orthPoint Energy Solutions	00039	00001	00005	00000	00000	00000	44	1	00000	00004
lng, Envir & Reg Affairs	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Clean Coal Project	00002	00000	00002	00000	00000	00000	4	0	00000	00000
Corp Plng & Regul Affairs	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Strategic Corporate Devt	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Sustainable Supply Devt	00008	00002	00001	00000	00000	00000	9	2	00000	00000
Environmental Programs	00019	00001	00004	00000	00000	00000	23	1	00000	00003
Network Development	00017	00000	00001	00000	00000	00000	18	0	00000	00001
lng, Envir & Reg Affairs	00058	00003	00008	00000	00000	00000	66	3	00000	00004
ower Production	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Boundary Dam Power Stn	00294	00002	00037	00000	00000	00000	331	2	00003	00000
Northern Hydro	00071	00001	00009	00000	00000	00001	80	2	00000	00002
Poplar River Power Stn	00135	00004	00010	00000	00001	00001	146	5	00002	00000
Shand Power Station	00101	00002	00005	00000	00001	00000	107	2	00000	00000
Western Plants	00084	00002	00006	00001	00000	00000	90	3	00004	00000
Business Perf & Plng	00015	00000	00001	00000	00000	00000	16	0	00000	00001
Engineering Services	00058	00000	00006	00000	00000	00000	64	0	00001	00004
Fuel Supply	00010	00000	00000	00000	00001	00000	11	0	00000	00000
Human Resources PP	00004	00000	00001	00000	00001	00000	6	0	00000	00000
Operations Support	00042	00000	00007	00000	00000	00000	49	0	00000	00004
ower Production	00816	00011	00082	00001	00004	00002	902	14	00010	00011

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	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
ransmission & Distribution	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Regina Region T&D	00211	00006	00026	00000	00004	00000	241	6	00001	00018
Saskatoon Region T&D	00222	00004	00009	00000	00007	00000	238	4	00000	00002
Prince Albert Region T&D	00124	00000	00016	00000	00002	00000	142	0	00000	00007
Weyburn Region T&D	00171	00001	00014	00000	00002	00000	187	1	00001	00004
Business Support Services T&D	00030	00000	00003	00000	00001	00000	34	0	00000	00000
Communs, Protec & Scada	00023	00002	00001	00000	00000	00000	24	2	00000	00001
Electrical Inspections	00036	00002	00001	00000	00002	00000	39	2	00003	00000
Gas Inspections	00025	00002	00003	00000	00000	00000	28	2	00000	00000
Grid Control Centre	00054	00000	00000	00000	00000	00000	54	0	00001	00000
Materials & Engineering	00072	00001	00006	00000	00000	00000	78	1	00000	00003
Field Services	00010	00000	00000	00000	00000	00000	10	0	00000	00000
ransmission & Distribution	00980	00018	00079	00000	00018	00000	1077	18	00006	00035
askPower International	00004	00000	00001	00000	00000	00000	5	0	00000	00000
Project Devt & Operations	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Cory Cogeneration Station	00002	00000	00000	00000	00000	00000	2	0	00000	00000
ProjDevt InvMgmt&Consuitg	00002	00000	00000	00000	00000	00000	2	0	00000	00000
askPower International	00010	00000	00001	00000	00000	00000	11	0	00000	00000
otal SaskPower 08-31-2008	02521	00047	00238	00002	00122	00005	2881	54	00042	00068

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
otal Management	00688	00011	00022	00001	00000	00000	710	12	00005	00000
otal CEP	00528	00018	00094	00000	00122	00005	744	23	00022	00031
otal IBEW	01305	00018	00122	00001	00000	00000	1427	19	00015	00037
otal SaskPower 08-31-2008	02521	00047	00238	00002	00122	00005	2881	54	00042	00068

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	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
esidents Office	00005	00000	00000	00000	00000	00000	5	0	00000	00000
People & Processes	00077	00000	00006	00000	00001	00000	84	0	00001	00000
Corp Infor & Technology	00052	00001	00007	00000	00000	00000	59	1	00000	00001
Human Resources	00053	00002	00002	00000	00002	00000	57	2	00013	00000
esidents Office	00187	00003	00015	00000	00003	00000	205	3	00014	00001
rp & Financial Services	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Business & Financial Plng	00004	00000	00001	00000	00000	00000	5	0	00000	00001
Bus Analy & Risk Mgmt	00006	00001	00001	00000	00000	00000	7	1	00000	00000
Controller	00018	00000	00001	00000	00001	00000	20	0	00000	00000
Corporate Services	00078	00001	00002	00000	00006	00000	86	1	00000	00002
Internal Audit	00007	00001	00000	00000	00000	00000	7	1	00000	00000
Risk Management	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Treasury	00007	00000	00000	00000	00000	00000	7	0	00000	00000
rp & Financial Services	00126	00003	00005	00000	00007	00000	138	3	00000	00003
stomer Services	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Business & Technology Support	00112	00001	00010	00000	00023	00003	145	4	00002	00000
Call Centres & Collections	00130	00002	00011	00000	00061	00001	202	3	00008	00000
Customer & Community Relations	00001	00000	00000	00000	00002	00000	3	0	00000	00000
Service Delivery Renewal	00025	00000	00000	00000	00000	00000	25	0	00000	00000
Internet Portfolio Services	00001	00000	00003	00000	00000	00000	4	0	00000	00000
Marketing Services	00011	00000	00003	00000	00000	00000	14	0	00000	00000
Pricing & Energy Forecasting	00007	00001	00000	00000	00000	00000	7	1	00000	00000
Sales	00021	00000	00000	00000	00003	00000	24	0	00001	00000
stomer Services	00310	00004	00027	00000	00089	00004	426	8	00011	00000
rthPoint Energy Solutions	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Energy Trading	00011	00000	00003	00000	00000	00000	14	0	00000	00002
Energy & Risk Mgmt	00006	00000	00001	00000	00000	00000	7	0	00000	00001
Financial & Business Supp	00005	00000	00000	00000	00000	00000	5	0	00000	00000
Gas Management	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Power Mktg & Contract Mgt	00004	00000	00000	00000	00000	00000	4	0	00000	00000
rthPoint Energy Solutions	00032	00000	00004	00000	00000	00000	36	0	00000	00003
ng, Envir & Reg Affairs	00005	00000	00000	00000	00000	00000	5	0	00000	00000
Clean Coal Project	00002	00000	00002	00000	00000	00000	4	0	00000	00000
Corp Plng & Regul Affairs	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Strategic Corporate Devt	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Sustainable Supply Devt	00009	00001	00000	00000	00000	00000	9	1	00000	00000
Environmental Programs	00015	00000	00003	00000	00000	00000	18	0	00000	00001
Network Development	00015	00000	00000	00000	00000	00000	15	0	00000	00000
ng, Envir & Reg Affairs	00053	00001	00005	00000	00000	00000	58	1	00000	00001
wer Production	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Boundary Dam Power Stn	00286	00002	00006	00000	00003	00000	295	2	00001	00000
Northern Hydro	00067	00003	00007	00000	00001	00000	75	3	00000	00000
Poplar River Power Stn	00140	00001	00006	00000	00002	00000	148	1	00001	00000
Shand Power Station	00103	00002	00005	00000	00001	00000	109	2	00001	00000
Western Plants	00086	00002	00005	00000	00000	00000	91	2	00003	00000
Business Perf & Plng	00017	00000	00003	00000	00000	00000	20	0	00000	00002
Engineering Services	00051	00001	00007	00000	00001	00000	59	1	00001	00002
Fuel Supply	00010	00000	00000	00000	00000	00000	10	0	00000	00000
Human Resources PP	00004	00000	00001	00000	00001	00000	6	0	00000	00000
Operations Support	00037	00000	00007	00000	00000	00000	44	0	00000	00001
wer Production	00803	00011	00047	00000	00009	00000	859	11	00007	00005
ansmission & Distribution	00002	00000	00000	00000	00000	00000	2	0	00000	00000

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	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Regina Region T&D	00210	00002	00012	00000	00003	00000	225	2	00001	00003
Saskatoon Region T&D	00221	00004	00008	00000	00003	00000	232	4	00000	00001
Prince Albert Region T&D	00127	00000	00008	00000	00001	00000	136	0	00000	00000
Weyburn Region T&D	00165	00002	00014	00000	00003	00000	182	2	00001	00000
Business Support Services T&D	00030	00000	00001	00000	00001	00000	32	0	00000	00001
Communs, Protec & Scada	00026	00000	00000	00000	00000	00000	26	0	00000	00000
Electrical Inspections	00039	00002	00000	00000	00001	00000	40	2	00002	00000
Gas Inspections	00025	00000	00001	00000	00000	00000	26	0	00000	00000
Grid Control Centre	00054	00000	00000	00000	00001	00000	55	0	00000	00000
Materials & Engineering	00065	00000	00004	00000	00000	00000	69	0	00000	00001
ansmission & Distribution	00964	00010	00048	00000	00013	00000	1025	10	00004	00006
skPower International	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Project Devt & Operations	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Cory Cogeneration Station	00002	00000	00000	00000	00000	00000	2	0	00000	00000
ProjDevt InvMgmt&Consultg	00003	00000	00000	00000	00000	00000	3	0	00000	00000
skPower International	00013	00000	00000	00000	00000	00000	13	0	00000	00000
tal SaskPower 12-31-2007	02488	00032	00151	00000	00121	00004	2760	36	00036	00019

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
tal Management	00676	00004	00021	00000	00000	00000	697	4	00004	00000
tal CEP	00514	00013	00071	00000	00121	00004	706	17	00020	00012
tal IBEW	01298	00015	00059	00000	00000	00000	1357	15	00012	00007
tal SaskPower 12-31-2007	02488	00032	00151	00000	00121	00004	2760	36	00036	00019

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	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Secondments	00000	00001	00000	00000	00000	00000	0	1	00000	00000
Secondments	00000	00001	00000	00000	00000	00000	0	1	00000	00000
Presidents Office	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Presidents Office Admin	00001	00000	00000	00000	00000	00000	1	0	00000	00000
People & Processes	00027	00001	00002	00000	00000	00000	29	1	00000	00000
Human Resources	00058	00004	00000	00000	00001	00000	59	4	00013	00000
Presidents Office	00088	00005	00002	00000	00001	00000	91	5	00013	00000
Corp & Financial Services	00001	00000	00000	00000	00000	00000	1	0	00000	00000
PMPP Admin	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Corporate & Business Plng	00013	00000	00001	00000	00000	00000	14	0	00000	00001
Bus Analy & Risk Mgmt	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Controller	00019	00002	00001	00000	00000	00000	20	2	00000	00000
Corporate Services	00089	00001	00004	00000	00005	00000	98	1	00000	00000
Internal Audit	00009	00001	00000	00000	00000	00000	9	1	00000	00000
Treasury	00008	00000	00000	00000	00000	00000	8	0	00000	00000
Enterprise Risk Mgmt	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Corp & Financial Services	00153	00004	00006	00000	00005	00000	164	4	00000	00001
Corp Infor & Technology	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Application Development & Supp	00011	00000	00000	00000	00000	00000	11	0	00000	00000
Portfolio Management Office	00006	00000	00000	00000	00000	00000	6	0	00000	00000
IT Business Services	00007	00002	00004	00000	00000	00000	11	2	00000	00001
Enterprise Programs	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Customer Support & Operations	00010	00001	00005	00000	00000	00000	15	1	00000	00000
Customer Planning & Solutions	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Corp Infor & Technology	00043	00003	00009	00000	00000	00000	52	3	00000	00001
Customer Services	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Clerical Support	00002	00000	00001	00000	00002	00000	5	0	00000	00000
Human Resources	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Demand Side Mgmt Program	00019	00000	00000	00000	00000	00000	19	0	00000	00000
Business & Technology Support	00091	00001	00005	00000	00029	00000	125	1	00002	00001
Call Centres & Collections	00147	00003	00011	00000	00066	00004	224	7	00006	00000
Service Delivery Renewal	00026	00000	00000	00000	00000	00000	26	0	00000	00000
Marketing Services	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Pricing & Energy Forecasting	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Customer Development & Support	00021	00000	00002	00000	00002	00001	25	1	00001	00000
Customer Services	00319	00004	00019	00000	00099	00005	437	9	00009	00001
NorthPoint Energy Solutions	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Electricity Trading	00017	00002	00002	00000	00000	00000	19	2	00000	00001
Energy & Risk Mgmt	00007	00000	00001	00000	00000	00000	8	0	00000	00001
Financial & Business Supp	00006	00000	00001	00000	00000	00000	7	0	00000	00001
Gas Management	00004	00001	00002	00000	00000	00000	6	1	00000	00001
Power Mktg & Contract Mgt	00004	00000	00000	00000	00000	00000	4	0	00000	00000
Business Solutions	00001	00000	00001	00000	00000	00000	2	0	00000	00001
NorthPoint Energy Solutions	00043	00003	00007	00000	00000	00000	50	3	00000	00005
Plng, Envir & Reg Affairs	00004	00000	00000	00000	00000	00000	4	0	00000	00000
System Planning	00031	00001	00000	00000	00000	00000	31	1	00000	00000
Strategic Corporate Devt	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Environment	00019	00001	00001	00000	00000	00000	20	1	00000	00000
Plng, Envir & Reg Affairs	00055	00002	00001	00000	00000	00000	56	2	00000	00000
Power Production	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Boundary Dam Power Stn	00293	00004	00006	00000	00000	00000	299	4	00000	00000

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	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Northern Hydro	00070	00001	00002	00000	00000	00000	72	1	00000	00000
Poplar River Power Stn	00138	00002	00007	00000	00001	00001	146	3	00001	00000
Shand Power Station	00098	00004	00008	00000	00001	00000	107	4	00000	00000
Western Plants	00094	00000	00007	00000	00000	00000	101	0	00005	00000
Business Perf & Plng	00016	00000	00001	00000	00000	00000	17	0	00000	00001
Engineering Services	00056	00000	00006	00000	00001	00000	63	0	00001	00001
Fuel Supply	00009	00000	00000	00000	00001	00000	10	0	00000	00000
Human Resources PP	00004	00000	00000	00000	00001	00000	5	0	00000	00000
Operations Support	00044	00000	00005	00000	00000	00000	49	0	00000	00003
Wind & Flyash	00006	00000	00000	00000	00000	00000	6	0	00000	00000
Investments & Contracts	00007	00000	00000	00000	00000	00000	7	0	00000	00000
ower Production	00838	00011	00042	00000	00005	00001	885	12	00007	00005
ransmission & Distribution	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Regina Region T&D	00220	00002	00007	00000	00002	00000	229	2	00000	00002
Saskatoon Region T&D	00219	00003	00008	00000	00008	00000	235	3	00001	00002
Prince Albert Region T&D	00134	00000	00005	00000	00004	00000	143	0	00000	00000
Weyburn Region T&D	00174	00001	00012	00000	00003	00000	189	1	00002	00001
Business Support Services T&D	00030	00000	00004	00001	00000	00001	34	2	00000	00001
Comms, Protec & Scada	00026	00002	00001	00000	00000	00000	27	2	00000	00001
Electrical Inspections	00039	00000	00000	00000	00000	00000	39	0	00001	00000
Gas Inspections	00032	00000	00000	00000	00001	00000	33	0	00003	00000
Grid Control Centre	00058	00001	00001	00000	00001	00000	60	1	00002	00001
Materials & Engineering	00064	00000	00003	00000	00000	00000	67	0	00001	00000
Field Services	00035	00000	00005	00000	00000	00000	40	0	00000	00002
ransmission & Distribution	01034	00009	00046	00001	00019	00001	1099	11	00010	00010
lean Coal Technology	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Clean Coal Project	00010	00000	00001	00000	00000	00000	11	0	00000	00000
lean Coal Technology	00012	00000	00001	00000	00000	00000	13	0	00000	00000
orporate Relations	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Marketing & Communication Prod	00019	00000	00000	00000	00000	00000	19	0	00000	00000
Marketing & Communication Plan	00011	00000	00000	00000	00000	00000	11	0	00000	00000
Stakeholder Relations	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Aboriginal Relations	00003	00000	00000	00000	00000	00000	3	0	00000	00000
orporate Relations	00037	00000	00000	00000	00000	00000	37	0	00000	00000
aw, Land, Regulatory Affairs	00010	00000	00000	00000	00000	00000	10	0	00000	00000
Law Department	00021	00000	00002	00000	00000	00000	23	0	00000	00000
aw, Land, Regulatory Affairs	00031	00000	00002	00000	00000	00000	33	0	00000	00000
otal SaskPower 12-31-2009	02653	00042	00135	00001	00129	00007	2917	50	00039	00023

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
tal Managemen	00769	00013	00014	00001	00000	00000	783	14	00005	00000
tal CEP	00557	00010	00056	00000	00129	00007	744	17	00022	00010
tal IBEW	01327	00019	00063	00000	00000	00000	1390	19	00012	00013
tal SaskPower 12-31-2009	02653	00042	00135	00001	00129	00007	2917	50	00039	00023

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Secondments	00000	00001	00000	00000	00000	00000	0	1	00000	00000
Secondments	00000	00001	00000	00000	00000	00000	0	1	00000	00000
President's Office	00002	00000	00000	00000	00000	00000	2	0	00000	00000
President's Office Admin	00001	00000	00000	00000	00000	00000	1	0	00000	00000
President's Office	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Corp & Financial Services	00001	00000	00000	00000	00000	00000	1	0	00000	00000
C&FS Admin	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Corporate Planning	00010	00000	00000	00000	00000	00000	10	0	00000	00000
Bus Analy & Risk Mgmt	00011	00000	00000	00000	00000	00000	11	0	00000	00000
Corporate Accounting & Busines	00026	00000	00003	00000	00000	00000	29	0	00000	00001
Internal Audit	00010	00000	00000	00000	00000	00000	10	0	00000	00000
Treasury & Corporate Services	00038	00001	00004	00000	00001	00000	43	1	00000	00000
Procurement	00024	00001	00002	00000	00001	00000	27	1	00000	00000
Corp & Financial Services	00123	00002	00009	00000	00002	00000	134	2	00000	00001
Corp Infor & Technology	00001	00000	00000	00000	00000	00000	1	0	00000	00000
CI&T Administration	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Application Development & Supp	00012	00001	00000	00000	00000	00000	12	1	00000	00000
Portfolio Management Office	00008	00000	00000	00000	00000	00000	8	0	00000	00000
IT Business Services	00018	00002	00002	00000	00001	00000	21	2	00000	00000
Enterprise Programs	00003	00000	00001	00000	00000	00000	4	0	00000	00000
Infrastructure Services	00024	00000	00000	00000	00000	00000	24	0	00000	00000
Enterprise Arch Sec & Plng	00024	00000	00000	00000	00000	00000	24	0	00000	00000
Corp Infor & Technology	00093	00003	00003	00000	00001	00000	97	3	00000	00000
Customer Services	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Clerical Support	00006	00000	00000	00000	00001	00000	7	0	00000	00000
Demand Side Mgmt Program	00018	00001	00000	00000	00000	00000	18	1	00000	00000
Human Resources	00000	00001	00000	00000	00000	00000	0	1	00000	00000
Business & Technology Support	00080	00005	00023	00000	00026	00000	129	5	00003	00000
Call Centres & Collections	00141	00004	00030	00001	00065	00003	236	8	00007	00000
Service Delivery Renewal	00030	00000	00007	00000	00001	00000	38	0	00000	00000
Pricing & Energy Forecasting	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Customer Development & Support	00024	00002	00000	00000	00001	00000	25	2	00001	00000
Customer Services	00307	00013	00060	00001	00094	00003	461	17	00011	00000
NorthPoint Energy Solutions	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Energy Trading	00022	00002	00000	00000	00000	00000	22	2	00000	00000
Business Dev't & Contract Serv	00010	00000	00001	00000	00000	00000	11	0	00000	00001
NorthPoint Energy Solutions	00033	00002	00001	00000	00000	00000	34	2	00000	00001
Plng, Envir & Reg Affairs	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Support Services	00002	00000	00000	00000	00000	00000	2	0	00000	00000
System Planning	00027	00002	00000	00000	00000	00000	27	2	00000	00000
Strategic Corporate Devt	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Environment	00019	00001	00002	00000	00000	00000	21	1	00000	00000
Plng, Envir & Reg Affairs	00052	00003	00002	00000	00000	00000	54	3	00000	00000
Power Production	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Boundary Dam Power Stn	00277	00003	00006	00000	00000	00000	283	3	00001	00000
Northern Hydro	00064	00002	00003	00000	00001	00000	68	2	00001	00000
Poplar River Power Stn	00127	00003	00004	00000	00002	00000	133	3	00002	00000
Shand Power Station	00097	00004	00001	00000	00001	00000	99	4	00002	00000
Western Plants	00098	00000	00000	00000	00000	00000	98	0	00002	00000
Business Perf & Plng	00016	00000	00001	00000	00000	00000	17	0	00000	00001
Engineering Services	00061	00001	00002	00000	00000	00000	63	1	00002	00001

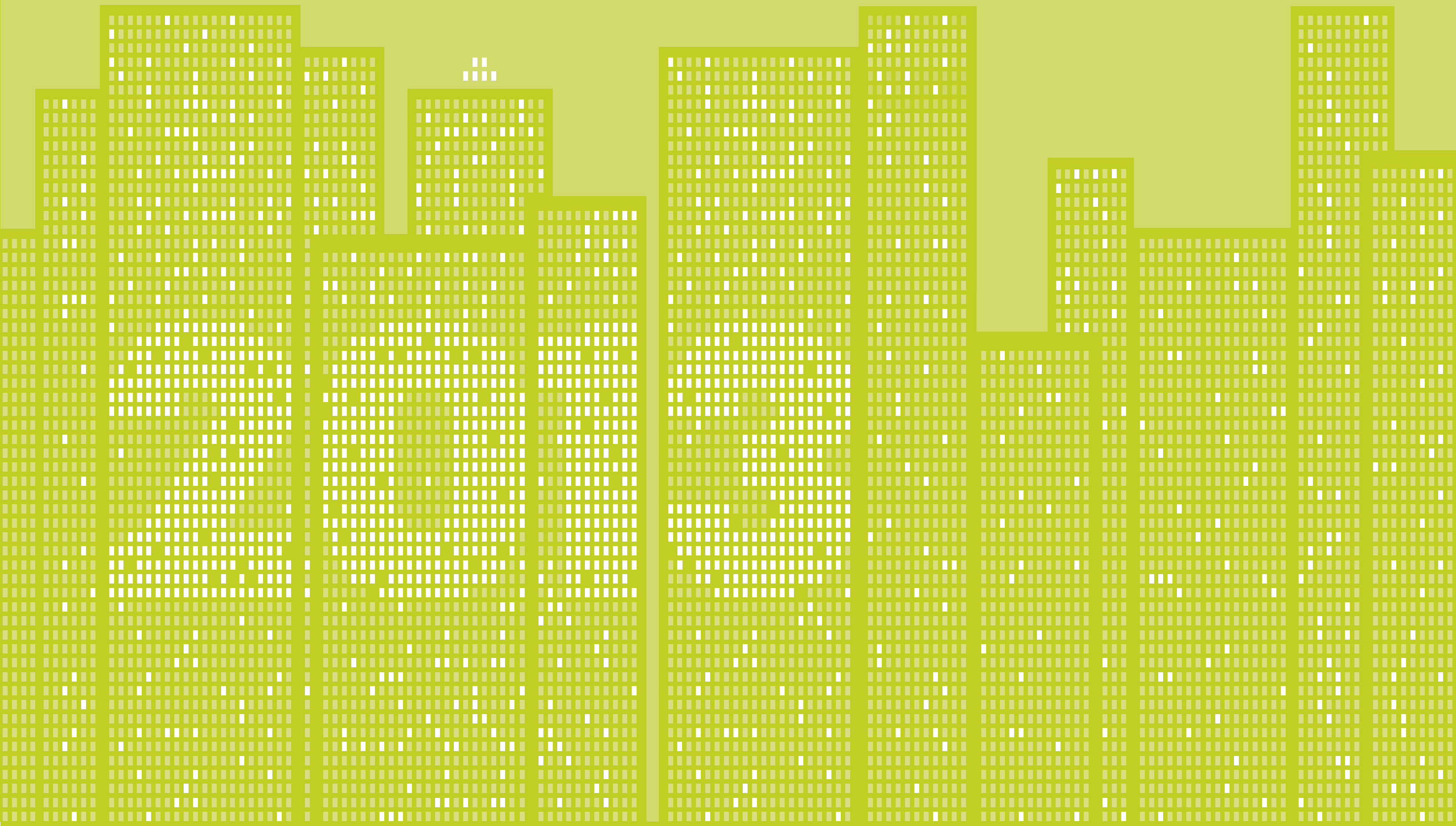
ZPRHRM02
AERHART
PRD

SaskPower
SaskPower Employee Inventory Summary

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Fuel Supply	00010	00000	00000	00000	00000	00001	10	1	00000	00000
Human Resources PP	00004	00000	00000	00000	00001	00000	5	0	00000	00000
Operations Support	00040	00002	00001	00000	00000	00000	41	2	00002	00000
Investments & Contracts	00013	00000	00000	00000	00000	00000	13	0	00000	00000
Power Production	00810	00015	00018	00000	00005	00001	833	16	00012	00002
Transmission & Distribution	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Technical Governance	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Distribution Services	00665	00004	00030	00001	00021	00000	716	5	00003	00001
Project Mgmt & Business Servic	00018	00000	00000	00000	00000	00000	18	0	00000	00000
Electrical Inspections	00045	00002	00000	00000	00001	00000	46	2	00000	00000
Gas Inspections	00037	00000	00000	00000	00001	00000	38	0	00002	00000
Grid Control Centre	00058	00000	00000	00000	00001	00000	59	0	00001	00000
Engineering & Construction - T	00065	00001	00001	00000	00000	00000	66	1	00001	00000
Asset Mgmt & Field Services	00042	00000	00008	00000	00000	00000	50	0	00000	00003
SAP Optimization	00005	00000	00000	00000	00000	00000	5	0	00000	00000
Transmission Services	00139	00000	00002	00000	00000	00000	141	0	00000	00001
Workplace Learning & Performan	00029	00001	00001	00000	00000	00000	30	1	00000	00000
Transmission & Distribution	01106	00008	00042	00001	00024	00000	1172	9	00007	00005
Clean Coal Technology	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Clean Coal Project	00012	00000	00000	00000	00000	00000	12	0	00000	00000
Clean Coal Technology	00014	00000	00000	00000	00000	00000	14	0	00000	00000
Corporate Relations	00002	00000	00000	00000	00000	00000	2	0	00000	00000
Corporate Communications	00025	00001	00001	00000	00000	00000	26	1	00001	00000
Stakeholder Relations	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Aboriginal Relations	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Corporate Relations	00033	00001	00001	00000	00000	00000	34	1	00001	00000
Law, Land, Regulatory Affairs	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Law & Privacy Department	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Governance, Reg Aff & Land	00025	00002	00001	00000	00000	00000	26	2	00000	00000
Law Department	00003	00000	00000	00000	00000	00000	3	0	00000	00000
Law, Land, Regulatory Affairs	00032	00002	00001	00000	00000	00000	33	2	00000	00000
Human Resources	00001	00000	00000	00000	00000	00000	1	0	00000	00000
Corporate Human Resources	00087	00002	00001	00000	00001	00000	89	2	00013	00000
Business Development	00007	00000	00000	00000	00000	00000	7	0	00000	00000
Human Resources	00095	00002	00001	00000	00001	00000	97	2	00013	00000
Total SaskPower 12-31-2011	02701	00052	00138	00002	00127	00004	2966	58	00044	00009

SaskPower
Management & In-Scope [illegible]

	Permanent Working	LOA	Temporary Working	LOA	Part Time Working	LOA	Total Working	LOA	DIP	SS
Total Management	00820	00017	00014	00000	00000	00000	834	17	00007	00000
Total CEP	00555	00020	00084	00002	00127	00004	766	26	00024	00004
Total IBEW	01326	00015	00040	00000	00000	00000	1366	15	00013	00005
Total SaskPower 12-31-2011	02701	00052	00138	00002	00127	00004	2966	58	00044	00009



COMPARISON OF ELECTRICITY PRICES IN MAJOR NORTH AMERICAN CITIES

Rates in effect April 1, 2013

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INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2013. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third section presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1] (IN ¢/kWh)[2]

1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2013.
2) In Canadian dollars.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1] (IN ¢/kWh)[2]

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2013.
2) In Canadian dollars.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the nine other Canadian provinces, and 10 utilities in as many American states. The results are based, in part, on a survey to which 15 utilities responded, and in part on estimates of bills calculated by Hydro-Québec and confirmed, for the most part, by the utilities concerned.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2013. The most recent rate adjustments applied by the utilities in the study between April 1, 2012, and April 1, 2013, are indicated in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the Detailed Tables.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists taxes applicable on April 1, 2013, by customer category; those which may be partially or fully refundable are also indicated.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes offer different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2013.

TIME-OF-USE RATES

The rates offered by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates which are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include adjustment clauses that allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2012, and April 1, 2013, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.9836 (CA$1 = US$0.9836), the rate in effect at noon on April 1, 2013. The Canadian dollar had thus depreciated by 2.5% relative to the U.S. dollar since April 1, 2012.

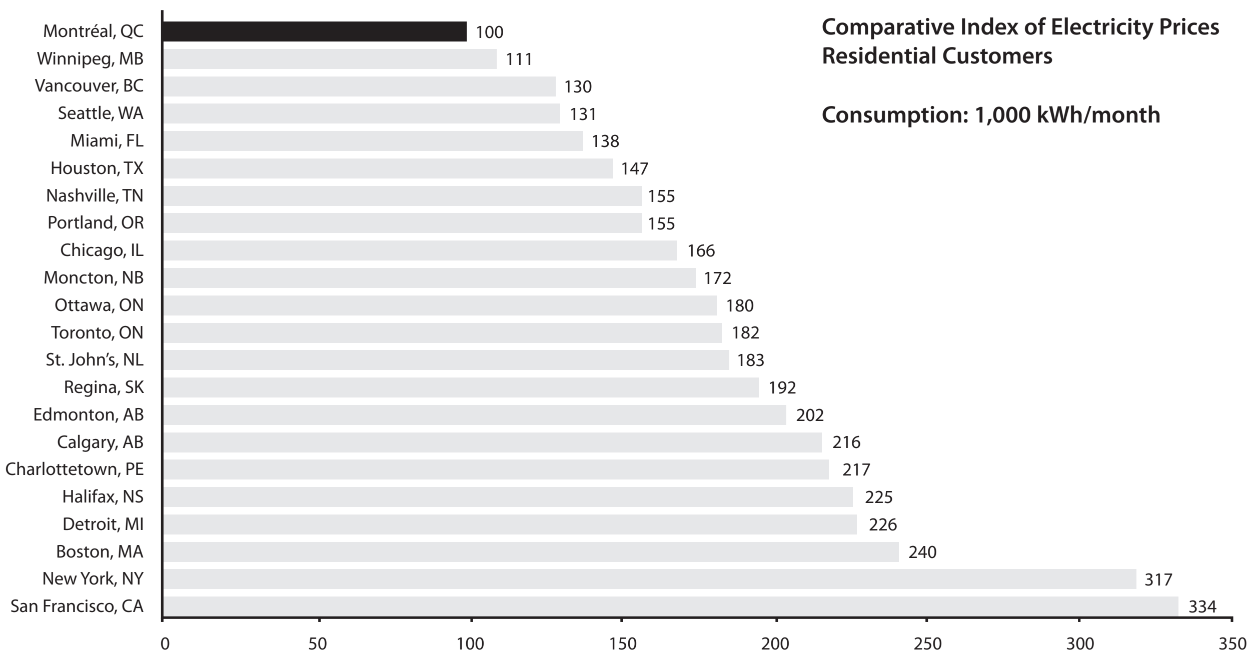
HIGHLIGHTS

The *Distribution Tariff* sets out Hydro-Québec's rates, as approved by the Régie de l'énergie (the Québec energy board) in accordance with Decision D-2013-043. Two types of rates are in effect: domestic rates, for residential customers, and general rates, for commercial, institutional and industrial customers. The last three customer categories are grouped according to their minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kWh, Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

FIGURE 1

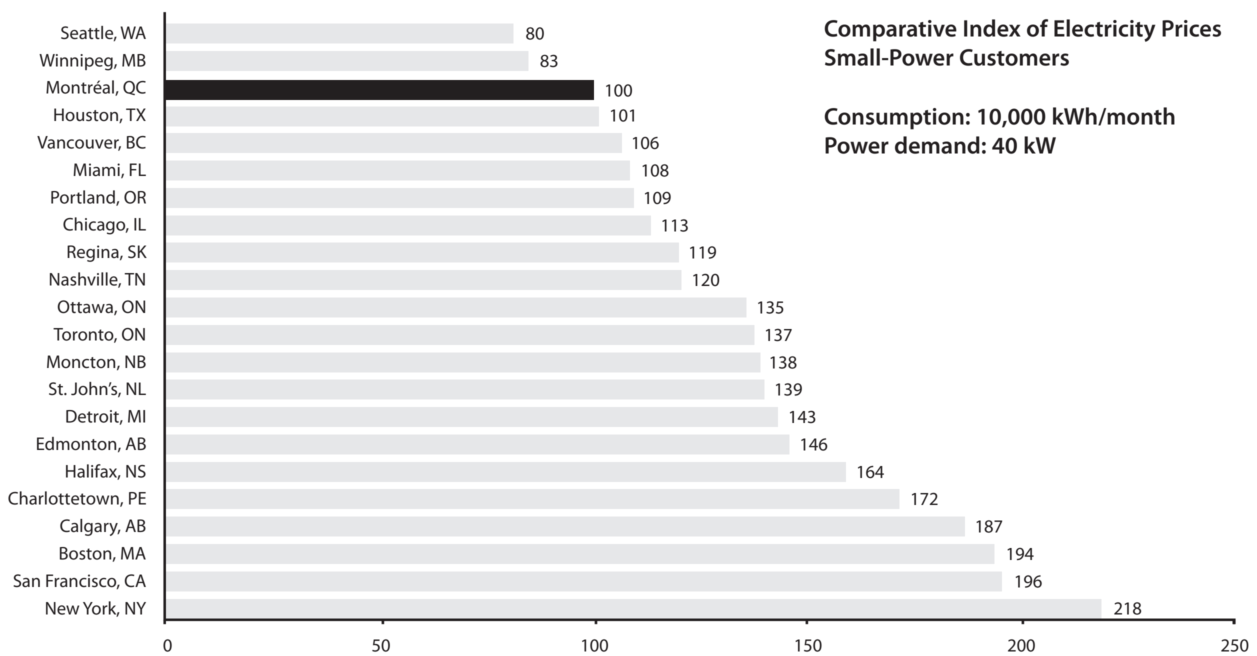


Hydro-Québec = 100
Monthly bill (excluding taxes)
Rates in effect April 1, 2013

SMALL-POWER CUSTOMERS (LESS THAN 100 kW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kW. Montréal is in *third* place, up from fourth place last year. Figure 2 shows the comparative index of electricity prices.

FIGURE 2



Hydro-Québec = 100

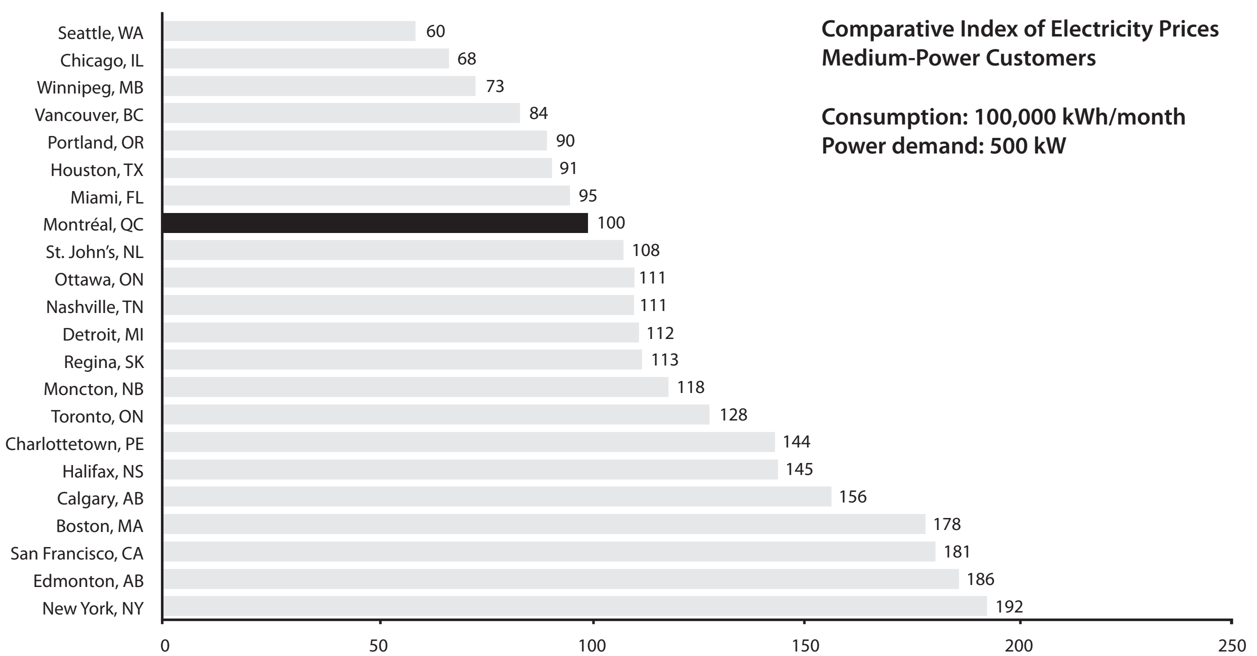
Monthly bill (excluding taxes)
Rates in effect April 1, 2013

MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average observed in the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal holds *eighth* place.

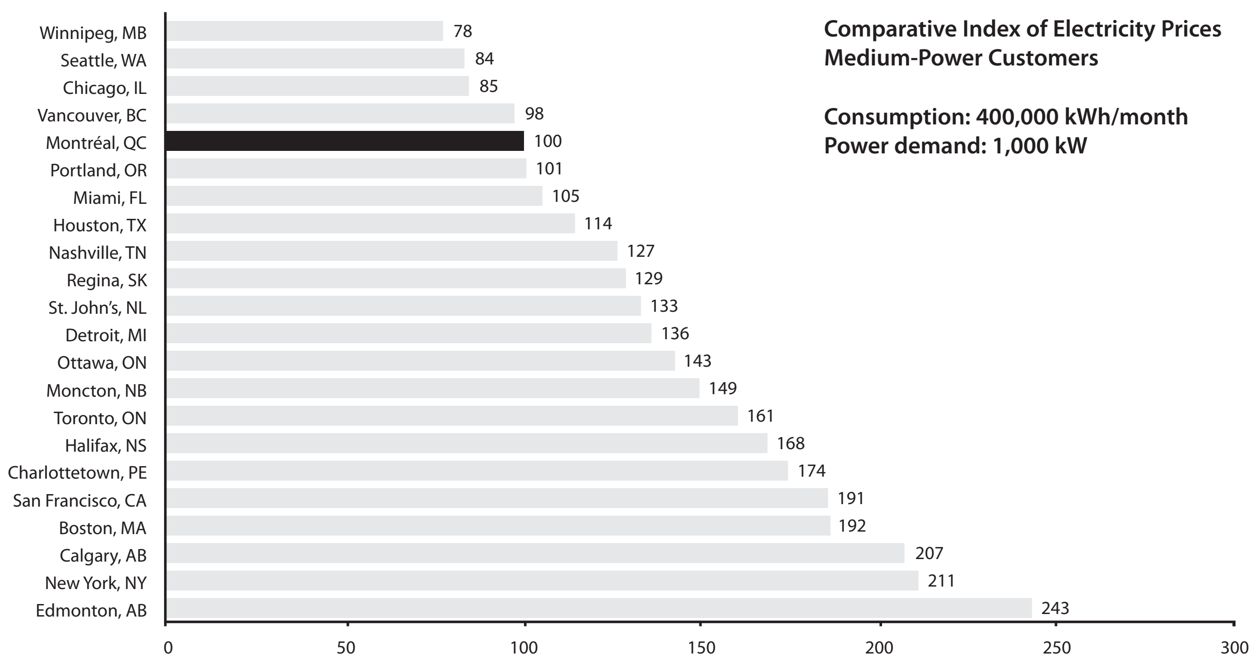
FIGURE 3



Hydro-Québec = 100
Monthly bill (excluding taxes)
Rates in effect April 1, 2013

For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal is in *fifth* place.

FIGURE 4

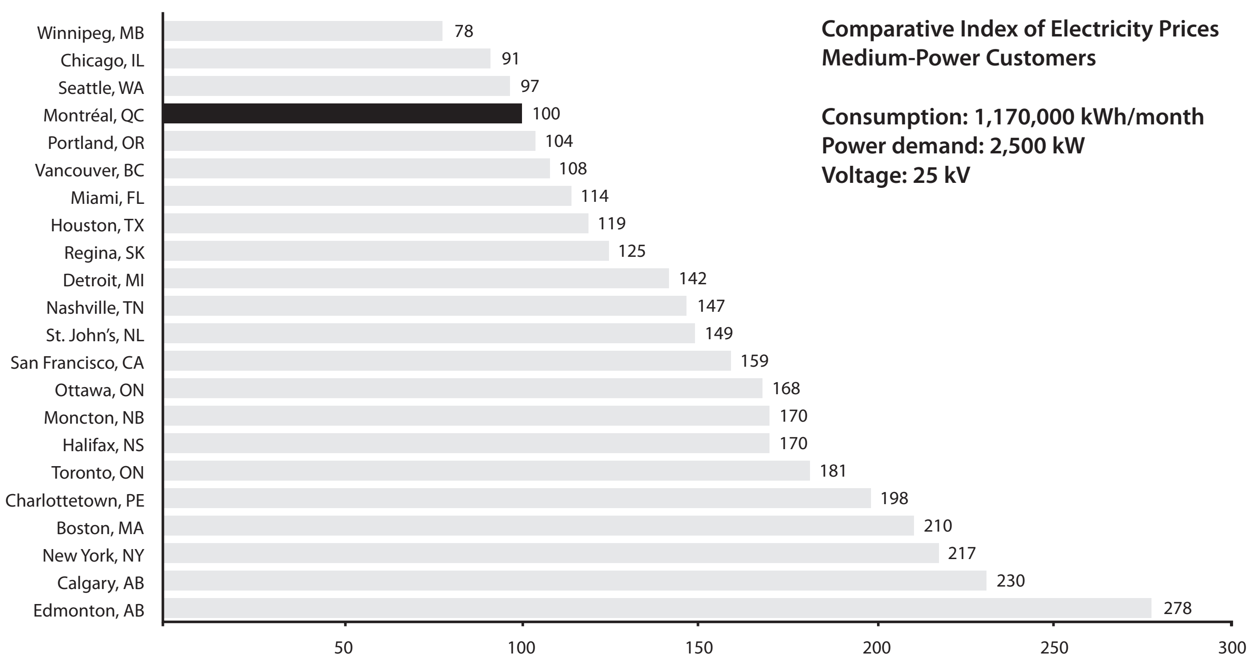


Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2013

In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal ranks *fourth*.

FIGURE 5



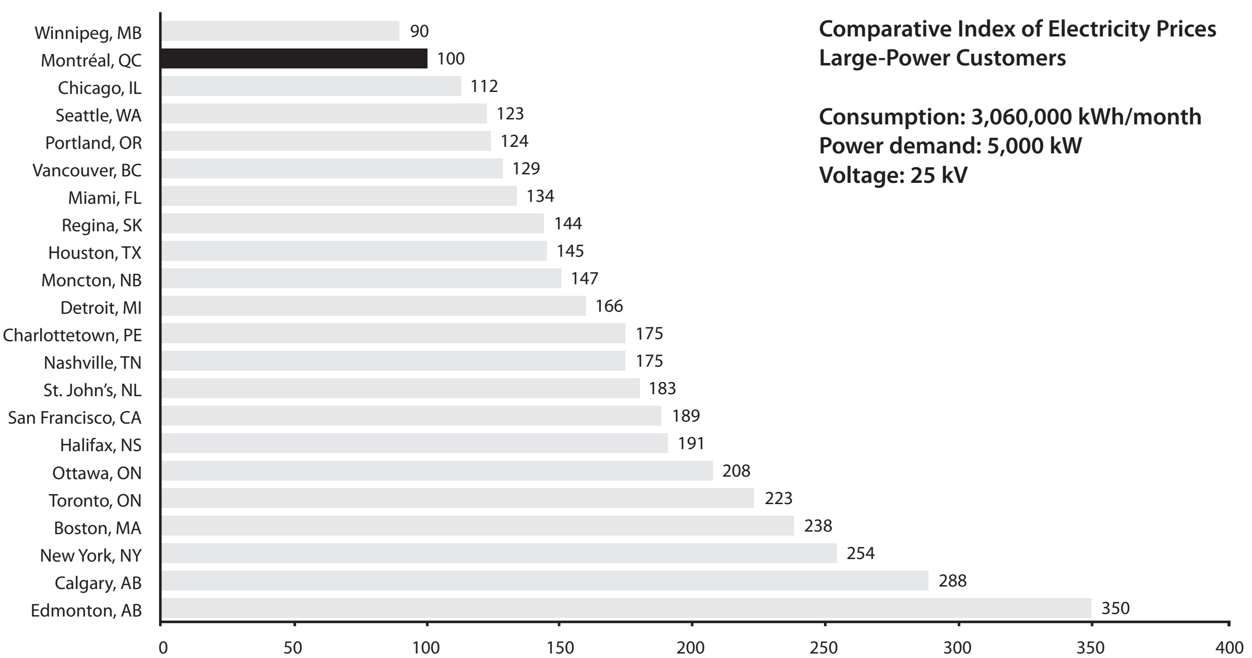
Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2013

LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. Montréal is in *second* place.

FIGURE 6

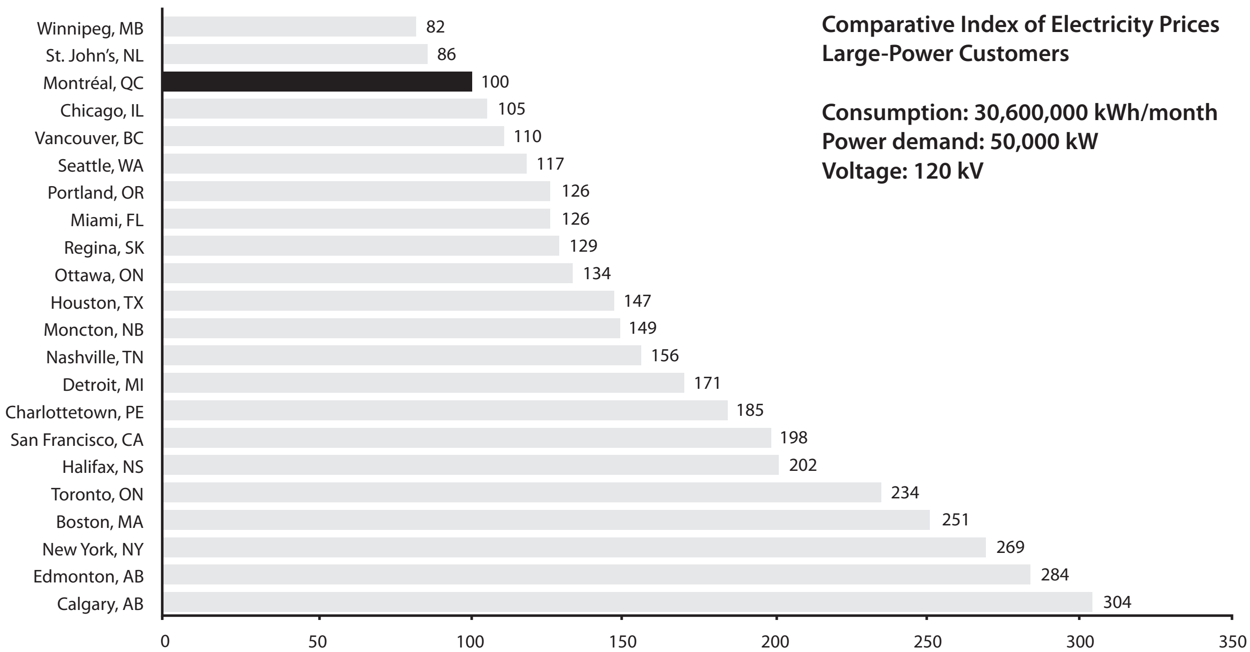


Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2013

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal now ranks *third*.

FIGURE 7



Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2013

DETAILED RESULTS

SUMMARY TABLES (EXCLUDING TAXES)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2013

(in CA$)

Summary Table (excluding taxes)

RESIDENTIAL SERVICE		GENERAL SERVICE					
		Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	68.66	905.33	11,325.00	29,523.00	73,215.00	149,334.00	1,412,340.00
Calgary, AB	148.11	1,692.51	17,654.99	61,079.67	168,448.22	429,548.36	4,290,648.90
Charlottetown, PE[3]	148.67	1,553.67	16,281.47	51,496.47	144,791.47	260,996.00	2,609,960.00
Edmonton, AB[4]	139.00	1,324.54	21,020.77	71,687.00	203,235.45	521,985.52	4,016,330.35
Halifax, NS	154.46	1,485.36	16,465.50	49,743.00	124,767.26	285,481.69	2,854,839.24
Moncton, NB	118.23	1,245.63	13,393.23	43,903.23	124,305.23	220,150.83	2,099,500.00
Ottawa, ON	123.91	1,226.46	12,515.25	42,364.48	123,214.65	310,002.05	1,896,290.98
Regina, SK	131.52	1,081.71	12,809.51	38,100.26	91,328.93	214,382.42	1,820,786.20
St. John's, NL[5]	125.48	1,258.03	12,242.80	39,291.36	109,407.32	273,474.72	1,218,646.00
Toronto, ON	124.75	1,239.63	14,440.64	47,413.57	132,733.39	333,306.03	3,307,566.21
Vancouver, BC	89.07	960.48	9,562.73	28,908.98	78,775.56	192,034.70	1,547,610.85
Winnipeg, MB	76.25	747.55	8,274.60	23,039.85	56,906.00	134,293.00	1,157,035.00
American Cities							
Boston, MA	165.01	1,756.61	20,119.48	56,599.02	153,703.67	354,881.85	3,546,649.23
Chicago, IL[3]	114.30	1,019.69	7,702.15	25,091.44	66,974.40	166,833.25	1,485,462.76
Detroit, MI[3]	155.35	1,290.99	12,676.52	40,005.19	103,729.17	248,434.96	2,417,421.60
Houston, TX[3]	100.97	917.66	10,361.78	33,675.00	87,439.28	215,842.94	2,075,123.32
Miami, FL[3]	94.62	974.41	10,814.64	31,053.07	83,698.10	199,765.69	1,781,441.28
Nashville, TN	106.18	1,087.76	12,567.55	37,519.40	107,430.71	261,129.92	2,203,756.90
New York, NY[3]	217.49	1,970.50	21,796.14	62,339.39	159,101.02	379,886.95	3,798,167.64
Portland, OR	106.32	982.53	10,159.31	29,835.90	76,265.30	185,498.73	1,781,123.04
San Francisco, CA[3]	229.40	1,778.95	20,448.84	56,378.52	116,148.06	281,559.86	2,797,561.02
Seattle, WA	89.69	727.96	6,837.31	24,850.56	70,900.03	183,616.05	1,653,225.94
AVERAGE	**128.52**	**1,237.63**	**13,612.28**	**41,995.38**	**111,659.92**	**263,747.25**	**2,353,249.38**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2013

(in ¢/kWh)[1]

Summary Table (excluding taxes)

RESIDENTIAL SERVICE		GENERAL SERVICE					
		Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	6.87	9.05	11.33	7.38	6.26	4.88	4.62
Calgary, AB	14.81	16.93	17.65	15.27	14.40	14.04	14.02
Charlottetown, PE[4]	14.87	15.54	16.28	12.87	12.38	8.53	8.53
Edmonton, AB[5]	13.90	13.25	21.02	17.92	17.37	17.06	13.13
Halifax, NS	15.45	14.85	16.47	12.44	10.66	9.33	9.33
Moncton, NB	11.82	12.46	13.39	10.98	10.62	7.19	6.86
Ottawa, ON	12.39	12.26	12.52	10.59	10.53	10.13	6.20
Regina, SK	13.15	10.82	12.81	9.53	7.81	7.01	5.95
St. John's, NL[6]	12.55	12.58	12.24	9.82	9.35	8.94	3.98
Toronto, ON	12.48	12.40	14.44	11.85	11.34	10.89	10.81
Vancouver, BC	8.91	9.60	9.56	7.23	6.73	6.28	5.06
Winnipeg, MB	7.63	7.48	8.27	5.76	4.86	4.39	3.78
American Cities							
Boston, MA	16.50	17.57	20.12	14.15	13.14	11.60	11.59
Chicago, IL[4]	11.43	10.20	7.70	6.27	5.72	5.45	4.85
Detroit, MI[4]	15.54	12.91	12.68	10.00	8.87	8.12	7.90
Houston, TX[4]	10.10	9.18	10.36	8.42	7.47	7.05	6.78
Miami, FL[4]	9.46	9.74	10.81	7.76	7.15	6.53	5.82
Nashville, TN	10.62	10.88	12.57	9.38	9.18	8.53	7.20
New York, NY[4]	21.75	19.70	21.80	15.58	13.60	12.41	12.41
Portland, OR	10.63	9.83	10.16	7.46	6.52	6.06	5.82
San Francisco, CA[4]	22.94	17.79	20.45	14.09	9.93	9.20	9.14
Seattle, WA	8.97	7.28	6.84	6.21	6.06	6.00	5.40
AVERAGE	**12.85**	**12.38**	**13.61**	**10.50**	**9.54**	**8.62**	**7.69**

1) In Canadian dollars.
2) Supply voltage of 25 kV.
3) Supply voltage of 120 kV.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2013

(Hydro-Québec = 100)

Summary Table (excluding taxes)

RESIDENTIAL SERVICE		GENERAL SERVICE						
		Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	216	187	156	207	230	288	304
Charlottetown, PE[3]	217	172	144	174	198	175	185
Edmonton, AB[4]	202	146	186	243	278	350	284
Halifax, NS	225	164	145	168	170	191	202
Moncton, NB	172	138	118	149	170	147	149
Ottawa, ON	180	135	111	143	168	208	134
Regina, SK	192	119	113	129	125	144	129
St. John's, NL[5]	183	139	108	133	149	183	86
Toronto, ON	182	137	128	161	181	223	234
Vancouver, BC	130	106	84	98	108	129	110
Winnipeg, MB	111	83	73	78	78	90	82
American Cities							
Boston, MA	240	194	178	192	210	238	251
Chicago, IL[3]	166	113	68	85	91	112	105
Detroit, MI[3]	226	143	112	136	142	166	171
Houston, TX[3]	147	101	91	114	119	145	147
Miami, FL[3]	138	108	95	105	114	134	126
Nashville, TN	155	120	111	127	147	175	156
New York, NY[3]	317	218	192	211	217	254	269
Portland, OR	155	109	90	101	104	124	126
San Francisco, CA[3]	334	196	181	191	159	189	198
Seattle, WA	131	80	60	84	97	123	117
AVERAGE	**187**	**137**	**120**	**142**	**153**	**177**	**167**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

DETAILED RESULTS

SUMMARY TABLES (INCLUDING TAXES)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2013

(in CA$)

Summary Table (including taxes)

RESIDENTIAL SERVICE		GENERAL SERVICE					
		Small Power	Medium Power			Large Power	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[1]	5,000 kW[1]	50,000 kW[2]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	78.94	1,040.91	13,020.92	33,944.07	84,178.95	171,696.77	1,623,837.92
Calgary, AB	155.52	1,777.14	18,537.73	64,133.66	176,870.63	451,025.78	4,505,181.34
Charlottetown, PE[3]	169.48	1,771.18	18,560.88	58,705.98	165,062.28	297,535.44	2,975,354.40
Edmonton, AB[4]	145.95	1,390.77	22,071.81	75,271.35	213,397.22	548,084.80	4,217,146.87
Halifax, NS	162.18	1,708.16	18,935.33	57,204.45	143,482.35	328,303.94	3,283,065.13
Moncton, NB	133.60	1,407.56	15,134.35	49,610.65	140,464.91	248,770.44	2,372,435.00
Ottawa, ON	140.02	1,385.90	14,142.23	47,871.87	139,232.55	350,302.32	2,142,808.81
Regina, SK	151.25	1,303.46	15,435.46	45,910.81	110,051.36	258,330.82	2,194,047.37
St. John's, NL[5]	131.75	1,421.57	13,834.36	44,399.24	123,630.27	309,026.43	1,377,069.98
Toronto, ON	143.04	1,421.31	16,317.93	53,577.34	149,988.73	376,635.81	3,737,549.82
Vancouver, BC	95.51	1,075.73	10,710.26	32,378.06	88,228.62	215,078.87	1,733,324.15
Winnipeg, MB	87.31	874.64	9,681.28	26,956.62	63,394.00	149,603.00	1,231,085.00
American Cities							
Boston, MA	165.01	1,833.99	21,052.88	58,840.16	159,518.49	367,145.33	3,669,148.44
Chicago, IL[3]	129.42	1,137.87	8,760.17	29,086.71	78,227.88	194,980.02	1,735,223.90
Detroit, MI[3]	172.44	1,432.99	14,070.94	44,405.76	115,139.38	275,762.80	2,683,337.98
Houston, TX[3]	101.98	992.50	11,107.97	36,056.50	94,546.07	233,602.75	2,245,892.84
Miami, FL[3]	108.62	1,198.76	13,332.27	38,003.38	102,243.53	243,376.92	2,151,310.82
Nashville, TN	106.18	1,163.91	13,447.28	40,145.76	114,950.86	279,409.02	2,358,019.88
New York, NY[3]	236.69	2,200.03	24,335.63	69,593.68	177,561.07	423,943.23	4,238,648.06
Portland, OR	107.95	997.71	10,316.84	30,294.85	77,466.11	188,427.48	1,809,293.85
San Francisco, CA[3]	246.90	1,915.32	22,011.99	60,724.85	125,204.13	303,579.07	3,016,400.30
Seattle, WA	89.69	727.96	6,837.31	24,850.56	70,900.03	183,616.05	1,653,225.94
AVERAGE	**139.07**	**1,371.79**	**15,075.26**	**46,453.01**	**123,351.79**	**290,828.96**	**2,588,791.26**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2013

(in ¢/kWh)[1]

Summary Table (including taxes)

RESIDENTIAL SERVICE		GENERAL SERVICE					
		Small Power	Medium Power			Large Power	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[2]	5,000 kW[2]	50,000 kW[3]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	7.89	10.41	13.02	8.49	7.19	5.61	5.31
Calgary, AB	15.55	17.77	18.54	16.03	15.12	14.74	14.72
Charlottetown, PE[4]	16.95	17.71	18.56	14.68	14.11	9.72	9.72
Edmonton, AB[5]	14.60	13.91	22.07	18.82	18.24	17.91	13.78
Halifax, NS	16.22	17.08	18.94	14.30	12.26	10.73	10.73
Moncton, NB	13.36	14.08	15.13	12.40	12.01	8.13	7.75
Ottawa, ON	14.00	13.86	14.14	11.97	11.90	11.45	7.00
Regina, SK	15.12	13.03	15.44	11.48	9.41	8.44	7.17
St. John's, NL[6]	13.17	14.22	13.83	11.10	10.57	10.10	4.50
Toronto, ON	14.30	14.21	16.32	13.39	12.82	12.31	12.21
Vancouver, BC	9.55	10.76	10.71	8.09	7.54	7.03	5.66
Winnipeg, MB	8.73	8.75	9.68	6.74	5.42	4.89	4.02
American Cities							
Boston, MA	16.50	18.34	21.05	14.71	13.63	12.00	11.99
Chicago, IL[4]	12.94	11.38	8.76	7.27	6.69	6.37	5.67
Detroit, MI[4]	17.24	14.33	14.07	11.10	9.84	9.01	8.77
Houston, TX[4]	10.20	9.92	11.11	9.01	8.08	7.63	7.34
Miami, FL[4]	10.86	11.99	13.33	9.50	8.74	7.95	7.03
Nashville, TN	10.62	11.64	13.45	10.04	9.82	9.13	7.71
New York, NY[4]	23.67	22.00	24.34	17.40	15.18	13.85	13.85
Portland, OR	10.80	9.98	10.32	7.57	6.62	6.16	5.91
San Francisco, CA[4]	24.69	19.15	22.01	15.18	10.70	9.92	9.86
Seattle, WA	8.97	7.28	6.84	6.21	6.06	6.00	5.40
AVERAGE	**13.91**	**13.72**	**15.08**	**11.61**	**10.54**	**9.50**	**8.46**

1) In Canadian dollars.
2) Supply voltage of 25 kV.
3) Supply voltage of 120 kV.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2013

(Hydro-Québec = 100)

Summary Table (including taxes)

RESIDENTIAL SERVICE		GENERAL SERVICE						
		Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	197	171	142	189	210	263	277
Charlottetown, PE[3]	215	170	143	173	196	173	183
Edmonton, AB[4]	185	134	170	222	254	319	260
Halifax, NS	205	164	145	169	170	191	202
Moncton, NB	169	135	116	146	167	145	146
Ottawa, ON	177	133	109	141	165	204	132
Regina, SK	192	125	119	135	131	150	135
St. John's, NL[5]	167	137	106	131	147	180	85
Toronto, ON	181	137	125	158	178	219	230
Vancouver, BC	121	103	82	95	105	125	107
Winnipeg, MB	111	84	74	79	75	87	76
American Cities							
Boston, MA	209	176	162	173	189	214	226
Chicago, IL[3]	164	109	67	86	93	114	107
Detroit, MI[3]	218	138	108	131	137	161	165
Houston, TX[3]	129	95	85	106	112	136	138
Miami, FL[3]	138	115	102	112	121	142	132
Nashville, TN	135	112	103	118	137	163	145
New York, NY[3]	300	211	187	205	211	247	261
Portland, OR	137	96	79	89	92	110	111
San Francisco, CA[3]	313	184	169	179	149	177	186
Seattle, WA	114	70	53	73	84	107	102
AVERAGE	**176**	**132**	**116**	**137**	**147**	**169**	**159**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

DETAILED RESULTS
RESIDENTIAL SERVICE

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2013
(in CA$)

Residential Service

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	46.00	52.77	68.66	146.46	224.26
Calgary, AB	99.59	115.76	148.11	277.51	406.91
Charlottetown, PE[1]	102.13	117.65	148.67	272.77	366.77
Edmonton, AB	94.64	109.43	139.00	257.30	375.60
Halifax, NS	100.60	118.55	154.46	298.09	441.72
Moncton, NB	81.29	93.61	118.23	216.73	315.23
Ottawa, ON	80.62	95.05	123.91	239.35	354.78
Regina, SK	89.78	103.70	131.52	242.82	354.12
St. John's, NL[2]	84.22	97.97	125.48	235.51	345.55
Toronto, ON	83.00	96.84	124.75	241.50	358.26
Vancouver, BC	50.16	61.92	89.07	197.64	306.21
Winnipeg, MB	50.23	58.90	76.25	145.65	215.05
American Cities					
Boston, MA	105.57	125.42	165.01	323.48	481.96
Chicago, IL[1]	77.52	89.78	114.30	166.07	239.55
Detroit, MI[1]	97.31	116.65	155.35	310.14	464.94
Houston, TX[1]	76.83	88.25	100.97	192.33	283.70
Miami, FL[1]	61.81	72.75	94.62	202.47	310.31
Nashville, TN	70.87	82.64	106.18	200.33	294.49
New York, NY[1]	141.91	167.11	217.49	419.04	620.58
Portland, OR	70.31	82.31	106.32	227.49	348.66
San Francisco, CA[1]	141.08	184.33	229.40	575.03	920.96
Seattle, WA	48.85	62.47	89.69	198.58	307.47
AVERAGE	**84.29**	**99.72**	**128.52**	**253.92**	**378.96**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

AVERAGE PRICES ON APRIL 1, 2013

(in ¢/kWh)[1]

Residential Service

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	7.36	7.04	6.87	7.32	7.48
Calgary, AB	15.93	15.44	14.81	13.88	13.56
Charlottetown, PE[2]	16.34	15.69	14.87	13.64	12.23
Edmonton, AB	15.14	14.59	13.90	12.87	12.52
Halifax, NS	16.10	15.81	15.45	14.90	14.72
Moncton, NB	13.01	12.48	11.82	10.84	10.51
Ottawa, ON	12.90	12.67	12.39	11.97	11.83
Regina, SK	14.37	13.83	13.15	12.14	11.80
St. John's, NL[3]	13.47	13.06	12.55	11.78	11.52
Toronto, ON	13.28	12.91	12.48	12.08	11.94
Vancouver, BC	8.03	8.26	8.91	9.88	10.21
Winnipeg, MB	8.04	7.85	7.63	7.28	7.17
American Cities					
Boston, MA	16.89	16.72	16.50	16.17	16.07
Chicago, IL[2]	12.40	11.97	11.43	8.30	7.98
Detroit, MI[2]	15.57	15.55	15.54	15.51	15.50
Houston, TX[2]	12.29	11.77	10.10	9.62	9.46
Miami, FL[2]	9.89	9.70	9.46	10.12	10.34
Nashville, TN	11.34	11.02	10.62	10.02	9.82
New York, NY[2]	22.71	22.28	21.75	20.95	20.69
Portland, OR	11.25	10.98	10.63	11.37	11.62
San Francisco, CA[2]	22.57	24.58	22.94	28.75	30.70
Seattle, WA	7.82	8.33	8.97	9.93	10.25
AVERAGE	**13.49**	**13.30**	**12.85**	**12.70**	**12.63**

1) In Canadian dollars.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

COMPARATIVE INDEX ON APRIL 1, 2013

(Hydro-Québec = 100)

Residential Service

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	216	219	216	189	181
Charlottetown, PE[1]	222	223	217	186	164
Edmonton, AB	206	207	202	176	167
Halifax, NS	219	225	225	204	197
Moncton, NB	177	177	172	148	141
Ottawa, ON	175	180	180	163	158
Regina, SK	195	197	192	166	158
St. John's, NL[2]	183	186	183	161	154
Toronto, ON	180	184	182	165	160
Vancouver, BC	109	117	130	135	137
Winnipeg, MB	109	112	111	99	96
American Cities					
Boston, MA	230	238	240	221	215
Chicago, IL[1]	169	170	166	113	107
Detroit, MI[1]	212	221	226	212	207
Houston, TX[1]	167	167	147	131	127
Miami, FL[1]	134	138	138	138	138
Nashville, TN	154	157	155	137	131
New York, NY[1]	309	317	317	286	277
Portland, OR	153	156	155	155	155
San Francisco, CA[1]	307	349	334	393	411
Seattle, WA	106	118	131	136	137
AVERAGE	**183**	**189**	**187**	**173**	**169**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

DETAILED RESULTS

GENERAL SERVICE – SMALL POWER

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2013
(in CA$)

General Service – Small Power

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	79.31	190.93	905.33	1,707.00	2,493.50
Calgary, AB	126.84	282.06	1,692.51	2,554.13	4,005.71
Charlottetown, PE[1]	142.40	338.77	1,553.67	2,739.47	3,784.47
Edmonton, AB	112.34	276.14	1,324.54	2,227.32	3,362.08
Halifax, NS	121.70	297.72	1,485.36	2,602.80	3,713.40
Moncton, NB	111.46	262.33	1,245.63	2,167.63	3,109.23
Ottawa, ON	98.98	239.52	1,226.46	2,178.55	3,145.88
Regina, SK	104.73	236.75	1,081.71	2,083.80	2,857.76
St. John's, NL[2]	113.33	331.94	1,258.03	2,237.92	3,167.52
Toronto, ON	106.24	259.40	1,239.63	2,345.79	3,389.87
Vancouver, BC	79.32	201.12	960.48	1,632.06	2,294.38
Winnipeg, MB	73.23	164.35	747.55	1,493.80	1,955.80
American Cities					
Boston, MA	130.38	335.76	1,756.61	3,506.79	4,662.70
Chicago, IL[1]	93.01	222.10	1,019.69	1,634.80	2,511.27
Detroit, MI[1]	110.63	278.94	1,290.99	1,797.01	3,188.57
Houston, TX[1]	75.87	257.26	917.66	1,586.10	2,236.50
Miami, FL[1]	76.70	192.86	974.41	1,835.51	2,408.56
Nashville, TN	105.87	238.56	1,087.76	2,253.07	2,988.46
New York, NY[1]	182.70	569.78	1,970.50	3,843.02	4,877.41
Portland, OR	93.65	218.42	982.53	1,667.04	2,408.47
San Francisco, CA[1]	145.21	370.53	1,778.95	2,842.11	4,236.93
Seattle, WA	54.60	145.59	727.96	1,022.19	1,655.19
AVERAGE	**106.30**	**268.67**	**1,237.63**	**2,179.91**	**3,111.53**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

AVERAGE PRICES ON APRIL 1, 2013

(in ¢/kWh)[1]

General Service – Small Power

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	10.57	9.55	9.05	12.19	9.97
Calgary, AB	16.91	14.10	16.93	18.24	16.02
Charlottetown, PE[2]	18.99	16.94	15.54	19.57	15.14
Edmonton, AB	14.98	13.81	13.25	15.91	13.45
Halifax, NS	16.23	14.89	14.85	18.59	14.85
Moncton, NB	14.86	13.12	12.46	15.48	12.44
Ottawa, ON	13.20	11.98	12.26	15.56	12.58
Regina, SK	13.96	11.84	10.82	14.88	11.43
St. John's, NL[3]	15.11	16.60	12.58	15.99	12.67
Toronto, ON	14.17	12.97	12.40	16.76	13.56
Vancouver, BC	10.58	10.06	9.60	11.66	9.18
Winnipeg, MB	9.76	8.22	7.48	10.67	7.82
American Cities					
Boston, MA	17.38	16.79	17.57	25.05	18.65
Chicago, IL[2]	12.40	11.10	10.20	11.68	10.05
Detroit, MI[2]	14.75	13.95	12.91	12.84	12.75
Houston, TX[2]	10.12	12.86	9.18	11.33	8.95
Miami, FL[2]	10.23	9.64	9.74	13.11	9.63
Nashville, TN	14.12	11.93	10.88	16.09	11.95
New York, NY[2]	24.36	28.49	19.70	27.45	19.51
Portland, OR	12.49	10.92	9.83	11.91	9.63
San Francisco, CA[2]	19.36	18.53	17.79	20.30	16.95
Seattle, WA	7.28	7.28	7.28	7.30	6.62
AVERAGE	**14.17**	**13.43**	**12.38**	**15.57**	**12.45**

1) In Canadian dollars.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

COMPARATIVE INDEX ON APRIL 1, 2013

(Hydro-Québec = 100)

General Service – Small Power

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	160	148	187	150	161
Charlottetown, PE[1]	180	177	172	160	152
Edmonton, AB	142	145	146	130	135
Halifax, NS	153	156	164	152	149
Moncton, NB	141	137	138	127	125
Ottawa, ON	125	125	135	128	126
Regina, SK	132	124	119	122	115
St. John’s, NL[2]	143	174	139	131	127
Toronto, ON	134	136	137	137	136
Vancouver, BC	100	105	106	96	92
Winnipeg, MB	92	86	83	88	78
American Cities					
Boston, MA	164	176	194	205	187
Chicago, IL[1]	117	116	113	96	101
Detroit, MI[1]	139	146	143	105	128
Houston, TX[1]	96	135	101	93	90
Miami, FL[1]	97	101	108	108	97
Nashville, TN	133	125	120	132	120
New York, NY[1]	230	298	218	225	196
Portland, OR	118	114	109	98	97
San Francisco, CA[1]	183	194	196	166	170
Seattle, WA	69	76	80	60	66
AVERAGE	**134**	**141**	**137**	**128**	**125**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

DETAILED RESULTS

GENERAL SERVICE – MEDIUM POWER

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MONTHLY BILLS ON APRIL 1, 2013

(in CA$)

General Service – Medium Power

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	11,325.00	15,835.00	22,650.00	29,523.00	73,215.00
Calgary, AB	17,654.99	30,768.86	34,851.92	61,079.67	168,448.22
Charlottetown, PE[2]	16,281.47	25,781.47	32,496.47	51,496.47	144,791.47
Edmonton, AB[3]	21,020.77	36,751.73	40,225.13	71,687.00	203,235.45
Halifax, NS	16,465.50	24,871.50	32,931.00	49,743.00	124,767.26
Moncton, NB	13,393.23	21,953.23	26,783.23	43,903.23	124,305.23
Ottawa, ON	12,515.25	21,309.20	24,776.57	42,364.48	123,214.65
Regina, SK	12,809.51	19,047.51	25,624.26	38,100.26	91,328.93
St. John's, NL[4]	12,242.80	20,121.82	23,564.51	39,291.36	109,407.32
Toronto, ON	14,440.64	23,970.94	28,557.58	47,413.57	132,733.39
Vancouver, BC	9,562.73	14,413.73	19,206.98	28,908.98	78,775.56
Winnipeg, MB	8,274.60	11,614.60	16,359.85	23,039.85	56,906.00
American Cities					
Boston, MA	20,119.48	28,384.23	40,069.51	56,599.02	153,703.67
Chicago, IL[2]	7,702.15	12,404.63	15,781.41	25,091.44	66,974.40
Detroit, MI[2]	12,676.52	20,258.39	25,327.12	40,005.19	103,729.17
Houston, TX[2]	10,361.78	16,274.50	21,849.56	33,675.00	87,439.28
Miami, FL[2]	10,814.64	15,554.49	21,573.36	31,053.07	83,698.10
Nashville, TN	12,567.55	18,859.91	24,934.69	37,519.40	107,430.71
New York, NY[2]	21,796.14	31,199.70	43,532.27	62,339.39	159,101.02
Portland, OR	10,159.31	15,649.77	19,394.73	29,835.90	76,265.30
San Francisco, CA[2]	20,448.84	29,383.26	39,408.13	56,378.52	116,148.06
Seattle, WA	6,837.31	12,591.83	13,197.97	24,850.56	70,900.03
AVERAGE	**13,612.28**	**21,227.29**	**26,958.92**	**41,995.38**	**111,659.92**

1) Supply voltage of 25 kV.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

AVERAGE PRICES ON APRIL 1, 2013

(in ¢/kWh)[1]

General Service – Medium Power

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[2] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	11.33	7.92	11.33	7.38	6.26
Calgary, AB	17.65	15.38	17.43	15.27	14.40
Charlottetown, PE[3]	16.28	12.89	16.25	12.87	12.38
Edmonton, AB[4]	21.02	18.38	20.11	17.92	17.37
Halifax, NS	16.47	12.44	16.47	12.44	10.66
Moncton, NB	13.39	10.98	13.39	10.98	10.62
Ottawa, ON	12.52	10.65	12.39	10.59	10.53
Regina, SK	12.81	9.52	12.81	9.53	7.81
St. John's, NL[5]	12.24	10.06	11.78	9.82	9.35
Toronto, ON	14.44	11.99	14.28	11.85	11.34
Vancouver, BC	9.56	7.21	9.60	7.23	6.73
Winnipeg, MB	8.27	5.81	8.18	5.76	4.86
American Cities					
Boston, MA	20.12	14.19	20.03	14.15	13.14
Chicago, IL[3]	7.70	6.20	7.89	6.27	5.72
Detroit, MI[3]	12.68	10.13	12.66	10.00	8.87
Houston, TX[3]	10.36	8.14	10.92	8.42	7.47
Miami, FL[3]	10.81	7.78	10.79	7.76	7.15
Nashville, TN	12.57	9.43	12.47	9.38	9.18
New York, NY[3]	21.80	15.60	21.77	15.58	13.60
Portland, OR	10.16	7.82	9.70	7.46	6.52
San Francisco, CA[3]	20.45	14.69	19.70	14.09	9.93
Seattle, WA	6.84	6.30	6.60	6.21	6.06
AVERAGE	**13.61**	**10.61**	**13.48**	**10.50**	**9.54**

1) In Canadian dollars.
2) Supply voltage of 25 kV.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

COMPARATIVE INDEX ON APRIL 1, 2013
(Hydro-Québec = 100)

General Service – Medium Power

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	156	194	154	207	230
Charlottetown, PE[2]	144	163	143	174	198
Edmonton, AB[3]	186	232	178	243	278
Halifax, NS	145	157	145	168	170
Moncton, NB	118	139	118	149	170
Ottawa, ON	111	135	109	143	168
Regina, SK	113	120	113	129	125
St. John's, NL[4]	108	127	104	133	149
Toronto, ON	128	151	126	161	181
Vancouver, BC	84	91	85	98	108
Winnipeg, MB	73	73	72	78	78
American Cities					
Boston, MA	178	179	177	192	210
Chicago, IL[2]	68	78	70	85	91
Detroit, MI[2]	112	128	112	136	142
Houston, TX[2]	91	103	96	114	119
Miami, FL[2]	95	98	95	105	114
Nashville, TN	111	119	110	127	147
New York, NY[2]	192	197	192	211	217
Portland, OR	90	99	86	101	104
San Francisco, CA[2]	181	186	174	191	159
Seattle, WA	60	80	58	84	97
AVERAGE	**120**	**134**	**119**	**142**	**153**

1) Supply voltage of 25 kV.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

DETAILED RESULTS

GENERAL SERVICE – LARGE POWER

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MONTHLY BILLS ON APRIL 1, 2013

(in CA$)

General Service – Large Power

Power demand Consumption Voltage Load factor	5,000 kW 2,340,000 kWh 25 kV 65%	5,000 kW 3,060,000 kWh 25 kV 85%	10,000 kW 5,760,000 kWh 120 kV 80%	30,000 kW 17,520,000 kWh 120 kV 81%	50,000 kW 23,400,000 kWh 120 kV 65%	50,000 kW 30,600,000 kWh 120 kV 85%
Canadian Cities						
Montréal, QC	127,446.00	149,334.00	271,524.00	821,868.00	1,193,460.00	1,412,340.00
Calgary, AB	334,874.65	429,548.36	811,221.55	2,464,150.99	3,343,911.80	4,290,648.90
Charlottetown, PE[1]	216,644.00	260,996.00	499,816.00	1,514,232.00	2,166,440.00	2,609,960.00
Edmonton, AB[2]	407,541.35	521,985.52	766,693.06	2,312,010.47	3,127,449.69	4,016,330.35
Halifax, NS	232,172.89	285,481.69	544,308.97	1,650,707.71	2,321,751.24	2,854,839.24
Moncton, NB	185,437.83	220,150.83	402,800.00	1,219,800.00	1,757,500.00	2,099,500.00
Ottawa, ON	248,362.72	310,002.05	598,079.37	1,219,750.05	1,596,998.69	1,896,290.98
Regina, SK	174,883.22	214,382.42	351,996.00	1,054,189.70	1,469,498.20	1,820,786.20
St. John's, NL[3]	216,349.92	273,474.72	512,323.56	706,903.20	1,010,494.00	1,218,646.00
Toronto, ON	263,587.47	333,306.03	630,569.90	1,907,480.11	2,635,697.71	3,307,566.21
Vancouver, BC	157,631.41	192,034.70	295,442.78	895,719.50	1,266,076.45	1,547,610.85
Winnipeg, MB	111,685.00	134,293.00	221,217.00	670,448.00	953,275.00	1,157,035.00
American Cities						
Boston, MA	296,495.62	354,881.85	680,329.55	2,059,968.68	2,962,786.89	3,546,649.23
Chicago, IL[1]	133,317.10	166,833.25	301,084.95	852,534.23	1,150,301.34	1,485,462.76
Detroit, MI[1]	206,946.76	248,434.96	463,332.50	1,402,681.72	2,006,199.80	2,417,421.60
Houston, TX[1]	173,283.80	215,842.94	395,071.13	1,196,090.04	1,649,590.45	2,075,123.32
Miami, FL[1]	167,197.94	199,765.69	342,919.37	1,035,520.62	1,490,608.15	1,781,441.28
Nashville, TN	216,007.96	261,129.92	430,713.16	1,289,914.13	1,919,585.18	2,203,756.90
New York, NY[1]	318,124.07	379,886.95	728,814.47	2,206,875.08	3,180,538.86	3,798,167.64
Portland, OR	151,645.25	185,498.73	342,481.31	1,033,126.65	1,468,299.17	1,781,123.04
San Francisco, CA[1]	229,697.17	281,559.86	535,184.20	1,618,831.81	2,278,934.14	2,797,561.02
Seattle, WA	141,887.82	183,616.05	312,263.62	948,831.30	1,278,696.87	1,653,225.94
AVERAGE	**214,146.36**	**263,747.25**	**474,463.02**	**1,367,347.00**	**1,919,458.80**	**2,353,249.38**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2013

(in ¢/kWh)[1]

General Service – Large Power

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	5.45	4.88	4.71	4.69	5.10	4.62
Calgary, AB	14.31	14.04	14.08	14.06	14.29	14.02
Charlottetown, PE[2]	9.26	8.53	8.68	8.64	9.26	8.53
Edmonton, AB[3]	17.42	17.06	13.31	13.20	13.37	13.13
Halifax, NS	9.92	9.33	9.45	9.42	9.92	9.33
Moncton, NB	7.92	7.19	6.99	6.96	7.51	6.86
Ottawa, ON	10.61	10.13	10.38	6.96	6.82	6.20
Regina, SK	7.47	7.01	6.11	6.02	6.28	5.95
St. John's, NL[4]	9.25	8.94	8.89	4.03	4.32	3.98
Toronto, ON	11.26	10.89	10.95	10.89	11.26	10.81
Vancouver, BC	6.74	6.28	5.13	5.11	5.41	5.06
Winnipeg, MB	4.77	4.39	3.84	3.83	4.07	3.78
American Cities						
Boston, MA	12.67	11.60	11.81	11.76	12.66	11.59
Chicago, IL[2]	5.70	5.45	5.23	4.87	4.92	4.85
Detroit, MI[2]	8.84	8.12	8.04	8.01	8.57	7.90
Houston, TX[2]	7.41	7.05	6.86	6.83	7.05	6.78
Miami, FL[2]	7.15	6.53	5.95	5.91	6.37	5.82
Nashville, TN	9.23	8.53	7.48	7.36	8.20	7.20
New York, NY[2]	13.60	12.41	12.65	12.60	13.59	12.41
Portland, OR	6.48	6.06	5.95	5.90	6.27	5.82
San Francisco, CA[2]	9.82	9.20	9.29	9.24	9.74	9.14
Seattle, WA	6.06	6.00	5.42	5.42	5.46	5.40
AVERAGE	**9.15**	**8.62**	**8.24**	**7.80**	**8.20**	**7.69**

1) In Canadian dollars.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2013

(Hydro-Québec = 100)

General Service – Large Power

Power demand **Consumption** **Voltage** **Load factor**	**5,000 kW** **2,340,000 kWh** **25 kV** **65%**	**5,000 kW** **3,060,000 kWh** **25 kV** **85%**	**10,000 kW** **5,760,000 kWh** **120 kV** **80%**	**30,000 kW** **17,520,000 kWh** **120 kV** **81%**	**50,000 kW** **23,400,000 kWh** **120 kV** **65%**	**50,000 kW** **30,600,000 kWh** **120 kV** **85%**
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	263	288	299	300	280	304
Charlottetown, PE[1]	170	175	184	184	182	185
Edmonton, AB[2]	320	350	282	281	262	284
Halifax, NS	182	191	200	201	195	202
Moncton, NB	146	147	148	148	147	149
Ottawa, ON	195	208	220	148	134	134
Regina, SK	137	144	130	128	123	129
St. John's, NL[3]	170	183	189	86	85	86
Toronto, ON	207	223	232	232	221	234
Vancouver, BC	124	129	109	109	106	110
Winnipeg, MB	88	90	81	82	80	82
American Cities						
Boston, MA	233	238	251	251	248	251
Chicago, IL[1]	105	112	111	104	96	105
Detroit, MI[1]	162	166	171	171	168	171
Houston, TX[1]	136	145	146	146	138	147
Miami, FL[1]	131	134	126	126	125	126
Nashville, TN	169	175	159	157	161	156
New York, NY[1]	250	254	268	269	266	269
Portland, OR	119	124	126	126	123	126
San Francisco, CA[1]	180	189	197	197	191	198
Seattle, WA	111	123	115	115	107	117
AVERAGE	**168**	**177**	**175**	**166**	**161**	**167**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

APPENDIX
RATE ADJUSTMENTS

Average Adjustments

Adjustments by Customer Category

RATE ADJUSTMENTS

All Categories

	Before April 2012		Between April 1, 2012 and April 1, 2013		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2012	-0.45	April 1, 2013	2.41	
ENMAX, AB	2011	n.a.	April 1, 2013	n.a.	
Maritime Electric, PE	2011	-14.00	March 1, 2013	2.20	
EPCOR, AB	n.a.	n.a.	April 1, 2013	n.a.	
Nova Scotia Power, NS	2012	8.60	January 1, 2013	3.00	
NB Power, NB	2010	3.00	—	—	
Hydro Ottawa, ON	2011	n.a.	January 1, 2013	n.a.	
SaskPower, SK	2010	4.50	January 1, 2013	4.90	
Newfoundland Power, NL[1]	2011	7.70	July 1, 2012	6.64	
Newfoundland and Labrador Hydro, NL[1]	2007	-18.30	—	—	
Toronto Hydro, ON	2011	n.a.	—	—	
BC Hydro, BC	2012	3.91	April 1, 2013	1.44	
Manitoba Hydro, MB	2012	2.00	September 1, 2012	2.40	
American Utilities					
NSTAR Electric & Gas, MA	2012 2011	1.80 n.a.	April 1, 2013 2013	3.30 n.a.	Delivery charge Default service
Commonwealth Edison, IL	n.a.	n.a.	n.a.	n.a.	
DTE Electric, MI	n.a.	n.a.	—	—	
CenterPoint Energy, TX	n.a.	n.a.	n.a.	n.a.	
Florida Power and Light, FL	2012	n.a.	n.a.	n.a.	
Nashville Electric Service, TN	n.a.	n.a.	n.a.	n.a.	
Consolidated Edison, NY	n.a.	n.a.	n.a.	n.a.	
Pacific Power and Light, OR	n.a.	n.a.	May 23, 2012 January 1, 2013 February 1, 2013	-1.3 0.9 0.3	
Pacific Gas and Electric, CA	n.a.	n.a.	January 1, 2013	n.a.	
Seattle City Light, WA	2012	3.20	January 1, 2013	4.40	

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more, Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (between April 1, 2012 and April 1, 2013)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2013	2.41	2.41	2.41	2.41
ENMAX, AB	April 1, 2013	n.a.	n.a.	n.a.	n.a.
Maritime Electric, PE	March 1, 2013	n.a.	n.a.	n.a.	2.20
EPCOR, AB	April 1, 2013	n.a.	n.a.	n.a.	n.a.
Nova Scotia Power, NS	January 1, 2013	3.00	3.00	3.00	3.00
NB Power, NB	—	—	—	—	—
Hydro Ottawa, ON	May 1, 2012 November 1, 2012 January 1, 2013	3.79 -0.94 0.60	3.80 -0.97 -1.93	0.58 — 9.83	n.a. n.a. n.a.
SaskPower, SK	January 1, 2013	4.90	4.90	4.90	4.90
Newfoundland Power, NL[1]	July 1, 2012	6.55	7.23	8.65	6.64
Newfoundland and Labrador Hydro, NL[1]	—	—	—	—	—
Toronto Hydro, ON	—	—	—	—	—
BC Hydro, BC	April 1, 2013	1.44	1.44	1.44	1.44
Manitoba Hydro, MB	September 1, 2012	2.30	2.40[2] 2.50[3]	2.50	2.40
American Utilities					
NSTAR Electric & Gas, MA	April 1, 2013 2013	n.a. n.a.	n.a. n.a.	n.a. n.a.	3.30[4] n.a.[5]
Commonwealth Edison, IL	n.a.	n.a.	n.a.	n.a.	n.a.
DTE Electric, MI	—	—	—	—	—
CenterPoint Energy, TX	n.a.	n.a.	n.a.	n.a.	n.a.
Florida Power and Light, FL	n.a.	n.a.	n.a.	n.a.	n.a.
Nashville Electric Service, TN	n.a.	n.a.	n.a.	n.a.	n.a.
Consolidated Edison, NY	n.a.	n.a.	n.a.	n.a.	n.a.
Pacific Power and Light, OR	May 23, 2012 January 1, 2013 February 1, 2013	-1.1 1.7 0.3	-1.5 0.3 0.3	-1.5 0.3 0.3	-1.3 0.9 0.3
Pacific Gas and Electric, CA	January 1, 2013	n.a.	n.a.	n.a.	n.a.
Seattle City Light, WA	January 1, 2013	6.80	0.2 to 12	-4.10	4.40

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.
2) General Service Small.
3) General Service Medium.
4) Delivery Charge.
5) Default Service.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

APPENDIX

TIME-OF-USE RATES
ADJUSTMENT CLAUSES

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2013 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	14–10,000 kW
NSTAR Electric & Gas, MA	General: All levels
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	All levels
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account Rate Rider
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Advanced Metering System Surcharge Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge System Benefit Fund Charge Transition Charges Transmission Cost Recovery Factor
Commonwealth Edison, IL	Advanced Metering Program Adjustment Capacity Charge Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund Energy Efficiency and Demand Response Adjustments Environmental Cost Recovery Adjustment Hourly Purchased Electricity Adjustment Factor PJM Services Charges Purchased Electricity Adjustment Factor Purchased Electricity Charges Renewable Energy Resources and Coal Technology Development Assistance Charge Residential Real Time Pricing Program Cost Recovery Charges Uncollectible Cost Factors
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Market Supply Charge Merchant Function Charge Monthly Adjustment Clause Renewable Portfolio Standard Program Revenue Decoupling Mechanism Adjustment System Benefits Charge Surcharge to collect PSL Section 18-a Assessments
DTE Electric, MI	2011 Choice Incentive Mechanism Energy Optimization Surcharge Nuclear Decommissioning Surcharge Power Supply Cost Recovery Clause Rate Realignment Adjustment (U-16472 RRA) Renewable Energy Plan Surcharge Securitization Bond Charge and Securitization Bond Tax Charge Vulnerable Household Warmth Fund Credit
ENMAX, AB	Balancing Pool Allocation Refund Rider Local Access Fee Transmission Access Charge Deferral Account Rider

EPCOR, AB	Balancing Pool Rider Local Access Fee Transmission Charge Deferral Account True-Up Rider
Florida Power and Light, FL	Conservation Charge Capacity Payment Charge Environmental Charge Fuel Charge Storm Charge
Hydro Ottawa, ON	Debt Retirement Charge Deferral/Variance Account Disposition Rate Rider Disposition of Global Adjustment Sub-Accounts Rate Rider Ontario Clean Energy Benefit
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Newfoundland and Labrador Hydro, NL	Residential Energy Rebate
Newfoundland Power, NL	Municipal Tax Adjustment Rate Stabilization Adjustment
Nova Scotia Power, NS	Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism
NSTAR Electric & Gas, MA	Default Service Adjustment Demand-Side Management Charge Energy Efficiency Reconciliation Factor Miscellaneous Charges Net Metering Recovery Surcharge Pension Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Transition Cost Adjustment Transmission Service Cost Adjustment
Pacific Gas and Electric, CA	Competition Transition Charge DWR Bond Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments

Pacific Power and Light, OR	Adjustment associated with the Pacific Northwest Electric Power Planning Conservation Act Base Supply Service Energy Conservation Charge Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Klamath Dam Removal Surcharges Low Income Bill Payment Assistance Fund Oregon Solar Incentive Program Deferral Supply Service Adjustment Property Sales Balancing Account Adjustment Public Purpose Charge Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral Adjustment TAM Adjustment for Other Revenues UE 246 Generation Credit
Toronto Hydro, ON	Debt Retirement Charge Ontario Clean Energy Benefit Recovery of Late Payment Litigation Costs Rate Rider Smart Meter Funding Adder

APPENDIX
TAXES APPLICABLE

Residential Service

General Service

Industrial Service

TAXES APPLICABLE TO RESIDENTIAL SERVICE

On April 1, 2013

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax (GST)	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	13	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional Transit Levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + Regional Transit Levy
Winnipeg, MB	Provincial sales tax	7	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3.75	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	5.1326	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.16	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission surcharge	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL SERVICE

On April 1, 2013

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax (GST)	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	13	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	5	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	7	To base amount of bill (industries other than mining and manufacturing)
		1.4	To base amount of bill (mining and manufacturing industries)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3.75	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	7	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL SERVICE (cont'd)

On April 1, 2013

	Tax	% (or other)	Applicable
Nashville, TN	State sales tax	7	To base amount of bill
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.6316	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.16	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission surcharge	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL SERVICE

On April 1, 2013

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax (GST)	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	13	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	5	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	7	To base amount of bill (industries other than mining and manufacturing)
		1.4	To base amount of bill (mining and manufacturing industries)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3.75	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	7	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL SERVICE (cont'd)

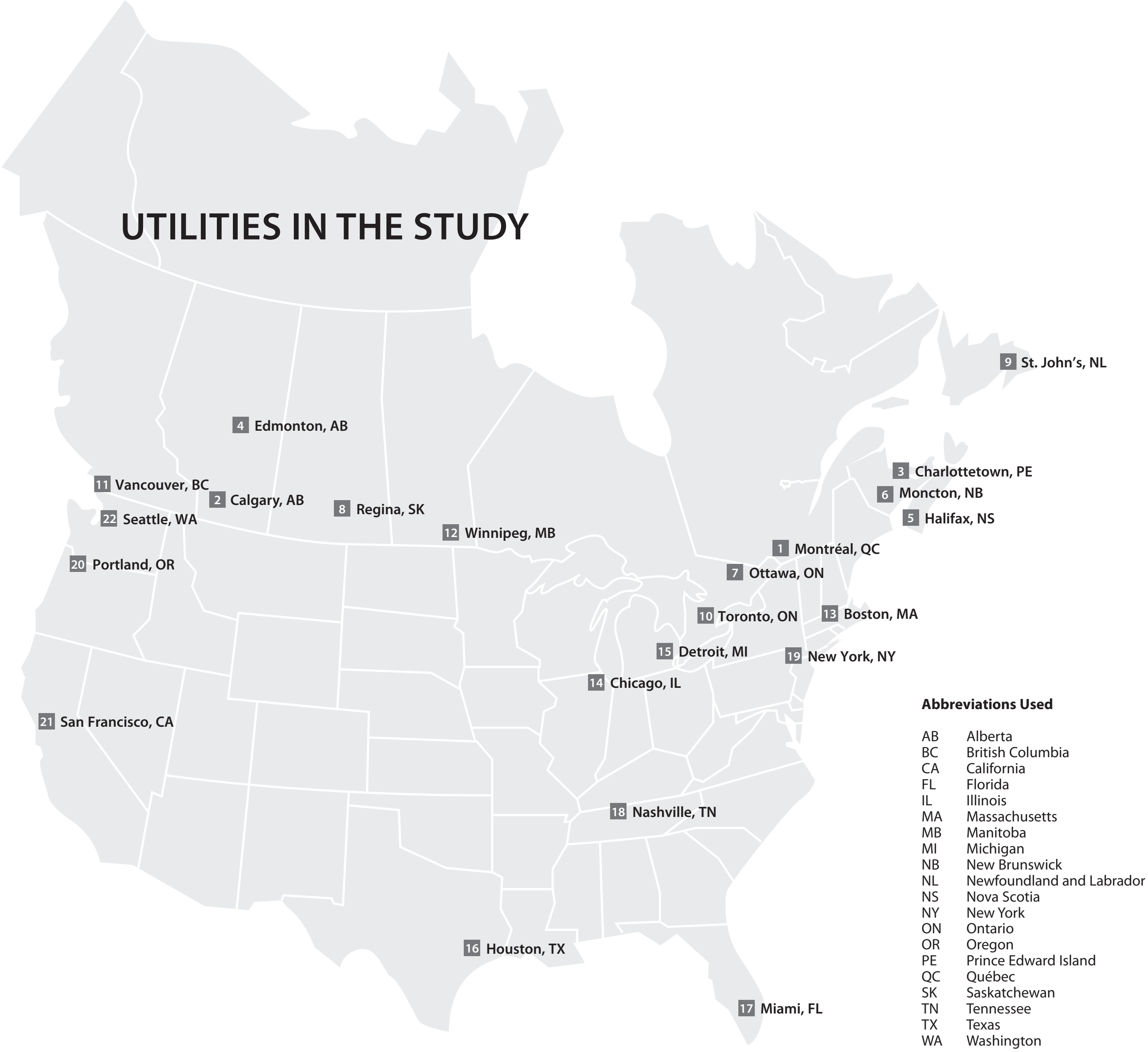
On April 1, 2012

	Tax	% (or other)	Applicable
Nashville, TN	State sales tax	7	To base amount of bill (companies other than manufacturing)
	State sales tax	1.5	To base amount of bill (manufacturing companies)
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.6316	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.16	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission surcharge	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

APPENDIX

UTILITIES IN THE STUDY

UTILITIES IN THE STUDY



CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro (customers with a power demand of 30,000 kW or more)
Newfoundland Power (all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- NSTAR Electric & Gas
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

A government-owned company whose lines of business have been unbundled, Hydro-Québec is one of the largest electric utilities in North America, with an installed capacity of 35,829 MW; 98% of electricity is generated using waterpower. Its transmission and distribution activities are regulated. The utility distributes electricity to nearly 4 million residential, commercial, institutional and industrial customer accounts throughout Québec and delivers electricity to nine municipal systems and one regional cooperative. Hydro-Québec also does business with many electric utilities in the Northeastern United States, Ontario and New Brunswick.

The *Act respecting the Régie de l'énergie* (Québec energy board) established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution at an average cost of 2.79¢/kWh. Above that volume, needs have to be met through tender calls. The Régie de l'énergie approved a 2.41% increase in the rates of Hydro-Québec Distribution, which took effect on April 1, 2013.

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

A subsidiary of Fortis Inc., Maritime Electric is the principal supplier of electricity on Prince Edward Island, with some 76,000 customers. Since its two power plants (with a total capacity of 150 MW) are operated strictly for reserve purposes, it purchases most of its electricity from NB Power, with which it has long-term contracts, and through additional short-term contracts on the New England wholesale market. Maritime Electric also purchases nearly 52 MW of wind-generated electricity from private producers.

Since the adoption of the *Electric Power Act* on January 1, 2004, Maritime Electric has had to submit all requests for rate increases to the Island Regulatory and Appeals Commission.

ENMAX
EPCOR
Calgary, Alberta
Edmonton, Alberta

ENMAX Corporation is a wholly owned subsidiary of the City of Calgary. It generates, transmits and distributes electricity to approximately 836,000 customers throughout the province. In addition to its active participation in Alberta's restructured electricity industry, ENMAX serves customers who are eligible for the City of Calgary's regulated rate option tariff.

EPCOR Utilities, whose sole shareholder is the City of Edmonton, transmits and distributes electricity to more than 350,000 residential and business customers in Edmonton. It also supplies to more than 600,000 customers throughout the province who are eligible for a regulated rate option tariff.

Since July 1, 2010, prices under the regulated rate option tariff have fluctuated monthly with market forecasts, so customers' electricity bills have varied more.

NOVA SCOTIA POWER
Halifax, Nova Scotia

Nova Scotia Power, a subsidiary of Emera, is the principal supplier of electricity in Nova Scotia, meeting most of the province's needs for electricity generation, transmission and distribution. It supplies electricity to 490,000 customers. Its generating facilities have an installed capacity of almost 2,400 MW.

The open access transmission tariff came into effect on November 1, 2005. Under the province's energy policy, eligible customers have nondiscriminatory access to the utility's transmission system.

NB POWER
Moncton, New Brunswick

A subsidiary of provincial Crown corporation NB Power Group, NB Power Distribution and Customer Service Corporation directly serves more than 349,000 customers and sells electricity to the province's municipal systems, which supply nearly 42,000 customers. NB Power has a generating capacity of about 3,500 MW under the management of NB Power Generation and NB Power Nuclear.

The New Brunswick electricity market has been partially open to competition since October 1, 2004. Large industrial customers and three municipal electricity distribution utilities are free to choose their supplier. However, other retail market customers continue to be served by NB Power.

SASKPOWER

Regina, Saskatchewan

Crown utility SaskPower directly serves more than 490,000 customers and sells wholesale electricity to municipal systems in Saskatchewan. The utility operates 18 power plants, with a net generating capacity of some 3,500 MW.

In Saskatchewan, the wholesale electricity market has been open to competition since 2001. In October 2009, SaskPower adopted a supply strategy that calls for the rehabilitation or replacement of some of its power plants or the construction of new facilities, with a view to increasing its generating capability by 4,100 MW by 2032.

NEWFOUNDLAND AND LABRADOR HYDRO

(customers with a power demand of 30,000 kW or more)

NEWFOUNDLAND POWER (all other customer categories)

St. John's, Newfoundland and Labrador

Newfoundland Power, a subsidiary of Fortis Inc., serves about 251,000 customers on the island of Newfoundland. Since it operates only small generating stations with a total installed capacity of less than 140 MW, it purchases 90% of its electricity from Newfoundland and Labrador Hydro (NLH), a subsidiary of Nalcor Energy that operates generating facilities with an installed capacity of more than 1,600 MW and a transmission system that serves the whole province. NLH also supplies remote regions, Labrador and large industrial customers. Aside from Newfoundland and Labrador Hydro, Nalcor Energy operates generating facilities with an installed capacity in excess of 5,600 MW.

In November 2005, the Newfoundland and Labrador government made public a discussion paper that serves as the basis for the province's energy policy. Security of supply and the regulatory framework are among the topics covered in the section on electricity. In 2007, the government released its long-term energy plan, which aims to achieve economic self-reliance and environmental sustainability.

TORONTO HYDRO
HYDRO OTTAWA

Toronto, Ontario
Ottawa, Ontario

A subsidiary of Hydro Ottawa Holding, whose sole shareholder is the City of Ottawa, Hydro Ottawa serves some 300,000 customers. Toronto Hydro-Electric System is a subsidiary of city-owned Toronto Hydro Corporation and serves about 709,000 customers, or 18% of Ontario electricity consumers.

In Ontario, the wholesale and retail markets have been open to competition since May 2002. Electricity generation is the responsibility of Ontario Power Generation while transmission service is supplied by Hydro One.

Following the adoption of the *Electricity Restructuring Act* in December 2004, the Ontario Energy Board was mandated to establish a regulated price plan. Prices have been reviewed on May 1 each year since 2006 and adjusted six months later, if necessary. Two new rates came into effect on April 1, 2005: a seasonally variable two-tier rate for consumers with a standard meter, and an optional time-of-use rate for consumers under the Ontario Energy Board Smart Metering Initiative. The Government of Ontario plans to have smart meters installed in all homes throughout the province.

BC HYDRO

Vancouver, British Columbia

Provincial Crown corporation BC Hydro operates generating facilities with a total capacity of more than 12,000 MW; nearly 95% of electricity is generated using waterpower. It distributes electricity to about 1.9 million customers.

The wholesale market in British Columbia is open to competition, as is the retail market for some large industrial companies. When the market was opened up, generation, transmission and distribution were made into separate entities. The *Clean Energy Act* grouped transmission and distribution in July 2010 to ensure coordinated supply planning for the province.

MANITOBA HYDRO

Winnipeg, Manitoba

Manitoba Hydro is a Crown utility serving nearly 542,000 customers throughout the province. Virtually all the electricity it generates and distributes comes from its 15 hydropower plants, which have a total capacity of 5,600 MW.

The wholesale electricity market has been open to competition since 1997 and Manitoba Hydro joined Midwest ISO, a regional transmission organization, in 2001.

AMERICAN UTILITIES

NSTAR ELECTRIC & GAS

Boston, Massachusetts

NSTAR serves 1.1 million residential and commercial customers in Boston and elsewhere in the state of Massachusetts. The utility purchases electricity on the market and concentrates on transmission and distribution.

Since March 1, 2005, NSTAR has applied basic service rates to the electricity commodity component for customers who have chosen not to purchase electricity from a competitor. These rates are adjusted every six months, or every three months in the case of large industrial customers. The rates reflect the average market price of electricity.

COMMONWEALTH EDISON (ComEd)

Chicago, Illinois

ComEd, a subsidiary of Exelon Corporation, purchases, transmits and distributes electricity on the wholesale and retail markets. On the retail market, it serves more than 3.8 million customers in northern Illinois, or 70% of the state's population.

Since May 1, 2002, the retail market has been fully open for residential, commercial and industrial customers. On January 2, 2007, ComEd raised its electricity rates for the first time since 1997. On the same date, energy supply charges based on the September 2006 auction in the State of Illinois came into effect for residential and commercial customers. In 2007, the Illinois Commerce Commission opened the market to free competition for medium- and large-power customers.

DTE ELECTRIC

Detroit, Michigan

DTE Electric operates generating facilities with a total installed capacity of almost 11,100 MW. A subsidiary of DTE Energy, it serves 2.1 million customers in southeastern Michigan.

Under the June 2000 legislation restructuring the electricity industry, all retail market customers in Michigan have been able to choose their electricity supplier since January 1, 2002.

CENTERPOINT ENERGY

Houston, Texas

CenterPoint Energy concentrates on electricity transmission and distribution and delivering natural gas. It sells electricity to approximately 2.1 million customers in the Houston area.

The majority of Texas consumers have had access to an open retail market since January 1, 2002. As of January 2007, electricity distributors with effective monopolies are no longer obliged to maintain their rates above the "price to beat" designed to encourage new market entrants. Customers who have opted to continue doing business with the same distributor pay a monthly rate that varies according to the market price.

The Texas transmission market was restructured in early 2011, moving from a zonal to nodal system.

FLORIDA POWER AND LIGHT (FPL)

Miami, Florida

FPL's vast transmission and distribution system supplies more than 4.6 million customers. A subsidiary of NextEra Energy, the utility operates generating facilities with an installed capacity of 24,100 MW.

In May 2006, the Florida Public Service Commission concluded that it was not in the best interests of consumers to set up a regional transmission organization. On April 1, 2010, FPL released its 2010–2019 strategic plan, in which it proposes to upgrade some of its nuclear plants and add new generating facilities using thermal and renewable energy. It will also rely on energy efficiency measures to meet the demand for power during the strategic plan time frame.

NASHVILLE ELECTRIC SERVICE

Nashville, Tennessee

Nashville Electric Service, whose sole shareholder is the City of Nashville, distributes the electricity that it purchases from the Tennessee Valley Authority (TVA) to more than 360,000 customers. A federal agency, the TVA supplies 155 distributors and nearly 60 large industrial and federal customers.

Close to half the electricity produced by the TVA comes from its 11 coal-fired plants, with the rest from gas, nuclear and hydro plants. Since 2000, the TVA has also included renewables, including solar, wind and biomass energy.

CONSOLIDATED EDISON (ConEd)

New York, New York

ConEd of New York delivers electricity to 3.3 million customers and natural gas to nearly 1.1 million customers in and around New York City and Westchester County. This ConEd subsidiary operates the largest underground system in the world, which represents 72% of its distribution system.

When the electricity market was opened to competition in 1998, ConEd had to dispose of a large part of its generating capacity, which is now limited to about 700 MW. Rates, which continue to be regulated by the New York State Public Service Commission, are adjusted monthly to reflect the market price of electricity.

PACIFIC POWER AND LIGHT

Portland, Oregon

Pacific Power and Light, a subsidiary of PacifiCorp, serves some 730,000 customers across three states, including more than 555,000 in Oregon. PacifiCorp operates generating facilities with an installed capacity of over 10,500 MW.

On March 1, 2002, the Oregon state government opened its retail market to competition for large commercial and industrial customers. Residential and small commercial customers have fewer suppliers to choose from, but they do have a range of options, including market-based rates, regulated rates or rates applicable to green energy.

PACIFIC GAS AND ELECTRIC (PG&E)

San Francisco, California

Pacific Gas and Electric concentrates on the transmission and distribution of electricity and natural gas. A subsidiary of PG&E Corporation, it has 5.1 million electric customer accounts.

In 2001, California adopted emergency measures to mitigate the price volatility that followed the opening of the electricity market. Those measures allowed it to reinstate regulatory authority over production costs and to give responsibility for electricity purchases to the California Department of Water and Resources. Since January 1, 2003, PG&E has been authorized to again purchase energy and directly supply its customers.

SEATTLE CITY LIGHT

Seattle, Washington

Seattle City Light, whose shareholder is the City of Seattle, serves about 400,000 customers. It produces 45% of the electricity it needs and purchases the rest from the Bonneville Power Administration (BPA), a northwestern U.S. federal agency that wholesales electricity produced by some 30 hydropower stations.

Six electric utilities in the Pacific Northwestern states, including Seattle City Light and BPA, got together in early 2006 to form the nonprofit ColumbiaGrid. The group's objective is to develop an integrated approach to the use and expansion of the region's interconnected transmission system.

Sources:
Annual reports and Web sites of the Canadian and American utilities in the study.

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Review of Cost Allocation and Rate Design Methodologies

A Report Prepared by
Elenchus Research Associates Inc.
John Todd, Michael Roger

On Behalf of
SaskPower

January 25, 2013

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1 OVERVIEW

SaskPower retained Elenchus Research Associates (Elenchus) to:

1. review its cost allocation methodology,
2. compare the SaskPower methodology with practices in Canada and the US with particular emphasis on Canadian electric utilities,
3. make recommendations to SaskPower on possible improvements to the cost allocation methodology
4. review SaskPower's current rate design approach, and
5. make recommendations for possible changes to its approach to rate design for SaskPower's consideration.

This report consists of 5 additional sections.

Section 2 provides a very brief overview of the standard approach to cost allocation that is widely accepted by regulators across Canada and internationally. Section 3 extends the discussion of the principles on which the Elenchus review is based by summarizing generally accepted rate making (Bonbright) principles, as the tailored version of those general principles that guide SaskPower approach to rate making.

Section 4 provides an overview of SaskPower's cost allocation methodology, recognizing that this methodology is fully documented in "2010 Base IFRS Embedded Cost of Service Results" which has been prepared by SaskPower. Elenchus has reviewed this documentation to confirm that the SaskPower model is consistent with the documentation of the methodology.

Section 5 presents the results of Elenchus survey of the cost allocation methodologies currently used by selected (major) Canadian and U.S. electric utilities.

Section 6 contains Elenchus comments and recommendations based on our review of the SaskPower cost allocation model and its approach to rate design in light of generally accepted regulatory principles, current standard practices across jurisdictions and the specific operational circumstances of SaskPower.

Section 7 includes the comments received from stakeholders on Elenchus' recommendations in this report and provides Elenchus' responses to the comments.

Appendix A includes the documentation of SaskPower's Cost Allocation Methodology.

Appendix B provides a list of the utilities surveyed and the responses to the cost allocation survey.

Appendix C includes the qualifications of the Elenchus' team that conducted the study and prepared this report.

2 COST ALLOCATION

It is standard practice in Canada in many jurisdictions internationally to rely on cost allocation studies to apportion utility assets and expenses to a utility's customer classes.[1] Because most of the assets and expenses of an electrical power system are used jointly by multiple customer classes, cost allocation studies are used to apportion a utility's revenue requirement among customer classes on a fair and equitable basis as guided by the principle of cost causality.

Traditionally there are three steps that are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, transmission, distribution, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, each account in the utility's system of accounts is functionalized. That is, the function(s)

[1] A standard reference document for cost allocation methodologies continues to be the "Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992. A subsequent NARUC publication, "Cost Allocation for Electric Utility Conservation and Load Management Programs" (1993) extends the application of the basic principles to conservation and demand side management (DSM) programs.

served by the assets or expenses contained in each account is identified so that the costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as demand, energy and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of system demand, energy throughput or the number of customers.

Allocation, which is the final step, is the process of attributing the demand, energy and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to demand, energy, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class. For example, if the necessary investment in a particular class of asset (e.g., certain transmission lines) is caused strictly by the single peak in annual demand, then the relevant costs would be allocated using the 1-coincident peak (1-CP) method. The actual application of these broad principles in the context of SaskPower is explained in section 4.

In some instances assets and/or costs can be related directly to a particular customer class and are then directly assigned to the customer class, for example streetlight assets and expenses, by-passing the categorization step.

Cost allocation studies can be done using historical actual data or using future test year data. The information needed is the utilities' financial data related to assets and expenses as well as sales data. The financial data is usually based on the accounting system used by the utility. The sales data used is by customer class and includes for example number of customers, energy (kWh) and demand (kW) consumption.

Cost allocation studies are conducted periodically by utilities to compare the costs attributable to the various customer classes with the revenues being collected from the customer classes. The comparison of costs and revenues is done to determine to what extent the customer class is paying their fair share of the costs imposed on the utility.

The ratio of revenue to cost illustrates to what extent the class is paying for their share of costs. A revenue to cost ratio of 1 or above 1 means that the class is paying their fair share of cost or even more than their fair share. A revenue to cost ratio below 1 means that the class is not paying for their fair share of costs.

Since the allocation of shared costs amongst various customer classes can't be done in an accurate way and parameters or allocators are used to split shared costs, in many jurisdictions, a range of revenue to cost ratio is accepted as reflecting the fair allocation of costs to customer classes instead of thriving to achieve a revenue to cost ratio of 1 for all customer classes. Many jurisdiction use a range of 0.95 to 1.05 as acceptable revenue to cost ratios when establishing revenue responsibilities by customer class.

3 GENERALLY ACCEPTED RATE MAKING PRINCIPLES

It is generally accepted by regulators and regulated utilities that any utility's cost allocation methodology and approach to rate design should be based on a set of clearly enunciated principles. These principles then guide the work that is undertaken to allocate assets and expenses to customer groups appropriately and establish rates that recover those costs from customers in a manner that is consistent with the principles.

The most commonly used reference for defining the objectives in utilities' cost allocation and rate design is the seminal work of James Bonbright.[2] Chapter 16 of the Second Edition sets out ten "attributes of a sound rate structure":

Revenue-related Attributes:

> • *Effectiveness in yielding the utility's 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 utility companies.*

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[2] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

- *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.*

Cost-related Attributes:

- *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.*

Practical-related Attributes

- *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*
- *Freedom from controversies as to proper interpretation.*

It is inevitable that in applying these principles, conflicts arise in trying to apply all of the principles simultaneously. An allocation that is more equitable may well compromise economic efficiency or simplicity. Determining the optimal trade-offs between the principles in developing rates therefore requires judgment. For this reason, cost allocation and rate design are often referred to as being as much art as science.

SaskPower's six stated key objectives[3] for its cost of service study and resulting rate design are consistent with the Bonbright principles and appear to encompass all ten of the principles set out by Bonbright in 1988. The SaskPower objectives are:

1. Meeting revenue requirement
2. Fairness and equity
3. Economic efficiency
4. Conservation of resources

[3] 2010 Base IFRS Embedded Cost of Service Results Document

5. Simplicity and administrative ease
6. Stability and gradualism

The flowing sub-sections set out our interpretation of SaskPower's objectives.

3.1 MEETING REVENUE REQUIREMENT

Meeting SaskPower's revenue requirement implies that customer rates should be set so as to yield sufficient revenues for the utility to recover its approved costs. The recoverable costs that make up the company's revenue requirement include all operating, maintenance and administration expenses, including amortization, as well as the cost of capital. The cost of capital includes both the interest on outstanding debt and a return on equity (or interest coverage) that enables the utility to be financially sound.

3.2 FAIRNESS AND EQUITY

Fairness and equity are understood to mean that the utility's assets and expenses have been apportioned to the customer classes in a manner that has cost causality as the main criteria. The methodologies used to apportion costs follow criteria that can be measured in a fair way and can be understood and accepted by stakeholders. Most of the utilities assets and expenses are shared by all or most of the utility's customers and cost causality parameters are developed to assign the assets and expenses to customer groups.

3.3 ECONOMIC EFFICIENCY

Economic efficiency means that the utility's assets and expenses are being utilized effectively (operational efficiency) and, to the extent practical, the rates charged customers provide reasonable price signals that allow the utility to develop the power system in a manner that is efficient through time (dynamic efficiency).

3.4 Conservation of Resources

Conservation of resources is further dimension of economic efficiency in that the design of rates should result in price signals that encourage consumers the use power in a manner that maintains a reasonable balance between cost of supplying power to consumers and the value of that power to consumers.

3.5 Simplicity and Administrative Ease

Simplicity and administrative ease are criteria that address the need to use cost allocation and rate design methods that are understandable by stakeholders and customers and are implementable by the utility given its available capabilities and resources.

3.6 Stability and Gradualism

Stability and gradualism are criteria that deal with the need to use cost allocation and rate design approaches that produce stable results over time and manageable/gradual changes as a result of changing circumstances. The purpose of the criteria is to avoid as much as possible approaches that produce sudden and significant changes in cost allocation and rate design as a result of changing circumstances. This is not intended as an impediment to appropriate changes, but rather a recognition that significant changes in the level of charges can be difficult for consumers to absorb in their daily lives. Hence, when circumstances justify changes that may have a significant impact on customer bills, it is desirable to phase in the changes in a manner that mitigates bill impacts without unduly compromising the other objectives of SaskPower's cost allocation and rate design.

4 SaskPower Cost Allocation Methodology

SaskPower cost allocation methodology[4] follows the standard industry approach of Functionalization, Classification and Allocation of assets and costs to customer classes.

4.1 Functionalization

The asset and expense functions utilized by SaskPower to group assets and costs of a similar nature include the following:

1. Generation:
   i. Load
   ii. Losses
   iii. Scheduling and Dispatch
   iv. Regulation and Frequency Response
   v. Spinning Reserve
   vi. Supplementary Reserve
   vii. Planning Reserve
   viii. Reactive Power
   ix. Grants in Lieu of Taxes
   x. Interruptible Adjustment
2. Transmission
   i. Main Grid
   ii. 138 kV Lines Radials
   iii. 138/72 kV Substations
   iv. 72 kV Lines Radials
3. Distribution
   i. Area Substations

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[4] ibid

ii. Distribution Mains
iii. Urban Laterals
iv. Rural Laterals
v. Transformers
vi. Service Customer
vii. Meters
viii. Streetlights

4. Customer Service
   i. Metering Services
   ii. Meter Reading
   iii. Billing and Customer Service
   iv. Customer Collecting
   v. Customer service
   vi. Marketing

The functions used by SaskPower provide enough differentiation of assets and costs by grouping assets and costs of a similar nature in the cost allocation methodology to enable the classification and allocation of assets and costs to customer classes using cost causality principles. The extent of the breakdown onto functions is consistent with other Canadian power utilities.

Additional details on the functionalization step followed by SaskPower in its cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

4.2 CLASSIFICATION

SaskPower classifies assets and costs into demand related, energy related and customer related as it is the standard practice of other Canadian power utilities. Classifying assets and costs into these three categories allow for the subsequent proper allocation of these assets and costs to customer groups.

The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Equivalent Peaker method. This method is based on the ratio of the unit cost of new peaking capacity to the new cost of base load capacity by generation types to classify rate base and depreciation into demand and energy related.

The fuel expense for SaskPower units is classified as 100% energy-related as is common practice in the cost allocation studies of other Canadian power utilities with rate regulated generation functions.

Transmission facilities are classified by SaskPower as 100% demand-related. This also is the usual approach for these types of assets and costs.

Distribution substations and three phase feeders are classified 100% demand-related. Urban and rural single-phase primary lines are classified 65% demand-related and 35% customer-related. Line transformers are classified 70% demand-related and 30% to customer-related.

All secondary lines, services, and meters are classified 100% customer-related.

Customer related assets and costs are classified 100% to customer.

More details on the classification of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

4.3 ALLOCATION

The last step in SaskPower's cost allocation study allocates the demand, energy and customer related assets and costs to SaskPower's customer classes. Having classified assets and costs into demand, energy and customer related, allows for the allocation of these assets and costs using the appropriate parameters (i.e., allocators) that reflect cost causality. For example, it allows for energy consumed by customer class to be used to allocate energy related assets and costs, and for using the number of customers to allocate customer related assets and costs that are driven by the number of customers.

Demand related generation assets and costs and transmission assets and costs are allocated to customer classes using the one coincident peak (1-CP) method based on demand adjusted for the estimated associated transmission and distribution losses. Energy related generation assets and costs are allocated to customer classes based on the energy consumed by customer classes, adjusted to include estimated losses.

Distribution demand related assets and costs are allocated to customer classes based on a combination of one coincident peak method or one class non-coincident peak method.

Customer related assets and costs are allocated to customer classes based on a combination of methods based on the number of customer by customer class or weighted number of customer by customer class, depending on the assets or costs being allocated.

4.3.1 Customer classes

The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expenses are allocated. Each rate class may have multiple rate codes.

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

More details on the allocation of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

SaskPower also conducted studies to develop appropriate customer class load profiles based on valid sampling of customers and SaskPower also utilizes a study of losses to determine the losses incurred in providing electricity to its various customer groups.

More details on the customer load profiles and loss study conducted by SaskPower are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

5 SURVEY OF COST ALLOCATION METHODOLOGIES

Elenchus conducted a survey of Canadian and US utilities with respect to the Cost Allocation methodologies currently being used in the industry. Special emphasis was placed on obtaining information from Canadian utilities.

Classification of assets and expenses and allocation methodologies were surveyed and the results of the survey are included in this report and more details of the survey responses are provided in Appendix B.

As a result of deregulation in the electricity sector, some generators no longer follow a cost allocation approach to determine how to allocate their assets and costs to customer classes and to develop appropriate rates. Instead generators bid their supply to electricity system market operators, or have bi-lateral agreements that have specified prices. Revenues are based on market prices for electricity.

5.1 GENERATION CLASSIFICATION

There are a variety of methodologies used in the utility industry to classify generation between demand and energy related. The methodologies range from classifying all generation as energy related to classifying all generation as demand related. The choice of methodology would usually reflect the utility's circumstances. Some utilities may consider also a 50/50 split as a compromise method.

In the Average and Excess method of classifying generation, assets and costs are allocated using factors that combine each class's average demands over the test period with its non-coincident peak demands. The average demand is the ratio of each class average demand to total average demand. The excess demand is the difference between the class non-coincident peak and the average demand.

In the Equivalent Peaker method, generation assets and costs are separated into those deemed to serve peak demands and those that are deemed to be incurred to provide energy. The peaker assets and costs are allocated on a demand basis and the remaining assets and costs, deemed to be energy related, are allocated on an energy basis. The peaker assets and costs are the generation assets and costs of the units used to satisfy all demands.

In the Peak and Average method a combination of the class contribution to 12 CP and class contribution to average energy usage is used to allocate generation.

SaskPower uses the Equivalent Peaker method outlined in the NARUC Electric Utility Cost Allocation manual by taking the ratio of the unit costs of new peaking capacity to the unit cost of new base load capacity in order to determine the demand related portion of generation by fuel type.

5.1.1 HYDROELECTRIC

Based on the survey results, Canadian utilities appear to favour the load factor approach to classify hydroelectric generation.

Other methodologies for classifying some hydroelectric generation assets and expenses to energy are based on the:

- purpose of hydroelectric generation, base or peaking
- ratio of energy produced in an average year compared to extreme year
- ratio between hydroelectric capacity factor and total system capacity factor

Based on the responses to the survey the percentages of demand related classification of hydroelectric generation costs are summarized in the following Table.

Classification of Hydroelectric generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	2	17
70 - 90	0	0
50 - 70	1	8
35 - 50	3	25
Below 35	1	8
NA	5	42
Totals	12	

5.1.2 BASE LOAD STEAM

Based on the responses to the survey the percentages of demand related classification of base load steam generation (coal, oil, or gas) costs are summarized in the following Table.

Classification of Base Load Steam generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	3	25
70 - 90	0	0
50 - 70	0	0
35 - 50	2	17
Below 35	1	8
NA	6	50
Totals	12	

5.1.3 Base Load Combined Cycle

Based on the responses to the survey the percentages of demand related classification of base load combined cycle generation costs are summarized in the following Table.

Classification of Base Load combined cycle generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	3	25
70 - 90	0	0
50 - 70	0	0
35 - 50	1	8
Below 35	1	8
NA	7	58
Totals	12	

5.1.4 Combustion Turbine

Based on the responses to the survey the percentages of demand related classification of combustion turbine generation costs are summarized in the following Table.

Classification of combustion turbine generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	4	33
70 - 90	0	0
50 - 70	0	0
35 - 50	2	17
Below 35	1	8
NA	5	42
Totals	12	

5.2 TRANSMISSION CLASSIFICATION

Based on the responses to the survey the percentages of demand related transmission costs are summarized in the following Table.

Classification of transmission costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	7	58
70 - 90	0	0
50 - 70	0	0
35 - 50	3	25
Below 35	0	0
NA	2	17
Totals	12	

Transmission costs are usually classified as 100% demand related since transmission is planned in order to transport electricity at the time of maximum demand in the system. Transmission includes the operation of the grid at different voltages as a single function that transports power from generating stations to the distribution system. Transmission also provides reliability to the electricity system by connecting multiple generation sources.

In some cases transmission is considered and extension of generation, when it is connecting remote generators, and is therefore, classified into demand and energy in the same proportion as the generation it is connecting.

5.3 SUB-TRANSMISSION CLASSIFICATION

Some utilities may have an additional asset and expense function, sub-transmission system, which connects the transmission system to the distribution system. The definition of sub-transmission depends on the definition of Transmission. If Transmission assets are defined as 115kV and above, then 69 kV assets would be defined as Sub-transmission. In Ontario where Transmission is defined as assets above 50 kV, Sub-transmission is usually defined as 27.6 kV and 44 kV, or as in the case of one distributor it includes voltages between 13.8 kV and below 50 kV.

The sub-transmission assets and expenses are usually classified in the same proportion as the transmission system is classified. Based on the responses to the survey the percentage of demand related costs for sub-transmission costs are summarized in the following Table.

Classification of Sub-transmission costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	8	67
70 - 90	0	0
50 - 70	0	0
35 - 50	1	8
Below 35	2	17
NA	1	8
Totals	12	

5.4 DISTRIBUTION CLASSIFICATION

Distribution assets connect the transmission assets to the customer. The closer the distribution assets are to the transmission system and further away from the customers, the classification of these assets will be similar to the classification of the transmission assets.

The closer the distribution assets are to the customer connections, then these costs are more and more classified as customer related. For example meter assets and costs are classified as 100% customer related, since these assets and costs have to be incurred by the utility regardless of how much power the customer consumes.

In order to determine what proportion of distribution costs are customer related and what proportion are demand related, there are two generally accepted methodologies being used by utilities: Minimum System method and Zero Intercept method.

The Minimum System method calculates the proportion of distribution asset costs that are customer related by taking the ratio of the costs of the smallest distribution assets, e.g. shortest poles, to the costs of all similar assets, e.g. all poles. This process is used to determine the customer components for transformers and line conductors. A common critique of this method is that the customer related portion of the distribution system is able to carry some electricity, therefore, some demand related costs would be included in the customer component.

The Zero Intercept method calculates the customer related component of a distribution asset type by plotting a graph of the unit costs of different size similar assets and using the value at the zero intercept in the graph to represent to customer component of the asset costs. A common critique of this method is that a utility may not have enough data to plot a proper graph, or in some instances may result in a negative value at zero intercept. Based on the responses to the survey the classification methods used for line and transformers are shown in the following Table.

Classification Method for Distribution Lines and Transformers		
Method	Number of respondents	Percent of Respondents
Minimum System	2	17
Zero Intercept	1	8
Both Minimum and Zero Intercept	3	25
Other	5	42
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of distribution stations costs classified as demand related is shown in the Table below.

Classification of Distribution Substation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	11	92
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Primary Lines costs classified as demand related is shown in the Table below.

Classification of Primary Lines costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	5	42
70 - 90	2	17
50 - 70	3	25
35 - 50	1	8
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Distribution Transformer costs classified as demand related is shown in the Table below.

Classification of Distribution Transformers costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	7	58
70 - 90	2	17
50 - 70	1	8
35 - 50	1	8
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Line Transformer costs classified as demand related is shown in the Table below.

Classification of Line Transformers costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	4	33
70 - 90	4	33
50 - 70	1	8
35 - 50	1	8
NA	2	17
Totals	12	

Based on the responses to the survey the proportion of Secondary Line costs classified as demand related is shown in the Table below.

Classification of Secondary Line costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	2	17
70 - 90	2	17
50 - 70	4	33
35 - 50	1	8
Below 35	2	17
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Services costs classified as customer related is shown in the Table below.

Classification of Services costs to customer		
Percent Classified as customer	Number of respondents	Percent of Respondents
90 - 100	11	92
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Meter costs classified as customer related is shown in the Table below.

Classification of Meter costs to customer		
Percent Classified as customer	Number of respondents	Percent of Respondents
90 - 100	11	92
NA	1	8
Totals	12	

5.5 ALLOCATION

5.5.1 GENERATION AND TRANSMISSION ALLOCATORS

1 COINCIDENT PEAK METHOD

The 1 CP allocation method allocates demand related costs to a customer class in proportion to the contribution of that customer class to the utility's maximum system peak. This method is based on the assumption that system capacity requirements are determined by the maximum demand imposed by customers on the system.

The advantage of this method is that it reflects cost causality and customers that impose costs on the system are responsible for those costs.

The disadvantage of this method is that customers that do not use the system at the time of the system peak, or can reduce their consumption during the peak could end up using the system for free, or not paying their fair share of costs. Another disadvantage is that if there are major system changes and the peak shifts to a different time, it could result in changes to class allocation factors.

12 COINCIDENT PEAK METHOD

The 12 CP method is similar to the 1 CP method but instead of using only one value for the year, it is based on each months maximum peak times. This method assumes that each monthly peak is important and not just the single annual peak.

The advantage of this method is that it addresses the disadvantage of the 1 CP method by reducing or eliminating entirely the possibility of using the system for free. The disadvantage of this method is that if the system had seasonal characteristics, using only one value for each month may not track costs properly.

VARIOUS COINCIDENT PEAK VARIATIONS

A variation on the 1 CP and 12 CP methods is that more than 1 and less than 12 values are used in the derivation of the coincident peak allocator.

Another variation is that the coincident peak value may not necessarily be one per month, but could be for example, the higher 5 coincident peak values regardless of when they occur in the year.

1 CLASS-NON-COINCIDENT PEAK METHOD

The 1 Non-Coincident peak method is based on the maximum demand by customer class, regardless of when they occur. It is very likely that the maximum demands occur at different times and may not all be at the time of the system maximum demand. A ratio is developed by customer class based on the class maximum demand compared to the sum of all classes' maximum demands.

The advantage of this method is that it reflects cost causality for assets that are the closest to the customer, or serve only similar type of customers.

The disadvantage of this method is that it does not take into account the benefits derived though diversity and that not all customers' maximum demand occur at the same time, allowing for the assets to be built to serve less than the sum of all customers maximum demand.

Another disadvantage of this method is that a customer class can increase consumption up to its maximum demand and not be charged more costs.

12-NON-COINCIDENT PEAK

The 12 NCP allocation method is similar to the 1 NCP method, but instead of using just one maximum demand for the year, 12 monthly values are used. The ratios of class maximum demand to the sum of each class maximum demands are calculated for each month.

The advantage of this method over the 1 NCP is that if a class increases consumption, it would be allocated more costs.

AVERAGE AND EXCESS METHOD

This method develops allocation factors taking into account average and excess demand. Average demand factors are the ratio of the average demand by customer class to the total system average demand. The excess demand is the difference between the maximum demand by class to the average demand. The excess demand factor is the ratio of each class excess demand to the total system excess demand.

The allocation factors for each class are determined by weighting the average demand factor for each class by the system average load factor. The excess demand factor is weighted by one minus the load factor. The two ratios are added together to determine the average and excess allocation factor.

The advantage of this method is that takes into account load factors, how the system is being utilized and also addresses allocation of costs at times other than the maximum system demand.

The disadvantage of this method is that it allocates costs equally to classes, regardless if the consumption is during the peak of the system or not.

Other disadvantages of this method are that it assumes a linear relationship between load factor and coincidence factor and that it does not reflect diversity between customer classes.

EQUIVALENT PEAKER METHOD

This method is based on charging the marginal energy cost in each hour plus the annual cost of peaking capacity equal to the peak kW. The assumption is that all peak demand costs should equal the cost of peaking capacity and the excess of cost of base load generation over peaking capacity should be energy related costs.

The advantage of this method is that it reflects marginal costs, so from economic theory perspective it is efficient.

The disadvantage of this method is that it is complex and uses marginal costs which may introduce variability over time to the results.

Based on the responses to the survey the allocation method for generation demand related costs is shown in the Table below.

Allocation Method for Generation Demand Costs		
Method	Number of respondents	Percent of Respondents
1 CP	2	17
4 CP	2	17
12 CP	2	17
Highest 300 Hours	1	8
3 Winter CP	1	8
NA	4	33
Totals	12	

Based on the responses to the survey the allocation method for transmission demand related costs is shown in the Table below.

Allocation Method for Transmission Demand Costs		
Method	Number of respondents	Percent of Respondents
1 CP	4	33
2 CP	1	8
4 CP	1	8
12 CP	2	17
Other	3	25
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for sub-transmission demand related costs is shown in the Table below.

Allocation Method for Sub-transmission Demand Costs		
Method	Number of respondents	Percent of Respondents
1 CP	2	17
4 CP	2	17
12 CP	3	25
NCP	2	17
Other	2	17
NA	1	8
Totals	12	

5.5.2 Interruptible Load

Interruptible load reflects a type of service that is curtailed at time of system maximum demand or other emergencies. Because of the possibility of curtailment, customers served under this condition pay less for electricity than customers supplied on a firm basis. Usually the amount of the discount customer receives is tied to the savings to the utility of not building peak capacity to serve the customer. Having this type of service allows for better utilization of the electricity system.

SaskPower has implemented a demand response program[5] that is based on the same principle as interruptible rates, better utilization of the electricity system in return for a discount. In the program, at times of capacity constraints customers participating in the program that shift load, receive financial compensation.

SaskPower accounts for the costs of the demand response program as Fuel expenses. This treatment is acceptable since in the absence of the program, the utility would have to supply the shifted demand by utilizing marginal plants burning marginal fuel and these avoided expenses would have been included as Fuel expenses.

5.5.3 Distribution Costs Allocators

Demand

The demand allocation methods for distribution costs are related to the proximity of the distribution asset to the end-use customer. Distribution assets that are further away from the customer and closer to the sub-transmission or transmission system are allocated to customer classes based on coincident demand allocators. The closer the distribution assets are to the customers, then the demand allocation method would reflect the customer class' maximum demand, that is, non-coincident maximum demand.

Customer

Distribution costs that do not vary with customer consumption are classified as customer related and are allocated to customer classes based on number of customers by class or based on weighted number of customers. The weights are related to the type of assets or costs being considered and reflect cost causality. For example meter reading assets and costs would be weighted by the number of times the meter is read by customer class, e.g. monthly, by-monthly.

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[5] http://www.saskpower.com/save_power/business/programs_offers/demand_response/

Based on the responses to the survey the allocation method for distribution station demand related costs is shown in the Table below.

Allocation Method for Distribution Station Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	5	42
4 NCP	1	8
12 NCP	2	17
Other	3	25
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution Primary Lines demand related costs is shown in the Table below.

Allocation Method for Distribution Primary Lines Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	6	50
4 NCP	1	8
12 NCP	2	17
Other	2	17
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution transformers demand related costs is shown in the Table below.

Allocation Method for Distribution Transformers Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	6	50
4 NCP	1	8
12 NCP	2	17
Other	2	17
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution secondary lines demand related costs is shown in the Table below.

Allocation Method for Distribution Secondary Lines Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	5	42
4 NCP	1	8
12 NCP	2	17
Other	3	25
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution station customer costs is shown in the Table below.

Allocation Method for Distribution Station Customer Costs		
Method	Number of respondents	Percent of Respondents
# of Customers	3	25
NA	9	75
Totals	12	

Based on the responses to the survey the allocation method for distribution primary lines customer costs is shown in the Table below.

Allocation Method for Distribution Primary Lines Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	7	58
Other	2	17
NA	3	25
Totals	12	

Based on the responses to the survey the allocation method for distribution transformer customer costs is shown in the Table below.

Allocation Method for Distribution Transformers Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	5	42
Other	4	33
NA	3	25
Totals	12	

Based on the responses to the survey the allocation method for distribution secondary line customer costs is shown in the Table below.

Allocation Method for Distribution Secondary Lines Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	7	58
Other	3	25
NA	2	17
Totals	12	

Based on the responses to the survey the allocation method for services customer costs is shown in the Table below.

Allocation Method for Services Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	3	25
Weighted # of customers	4	33
Other	4	33
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for meter costs is shown in the Table below.

Allocation Method for Meter Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	2	17
Weighted # of customers	5	42
Other	4	33
NA	1	8
Totals	12	

5.6 RATE DESIGN

There are various alternatives for rate design being used for different customer classes in the industry. They include:

- End use – Purpose of electricity use, for example residential, commercial, pumping load
- Energy or demand billed – How the customer is being billed: based on energy (kilowatt hours) or demand (kilowatts)
- Density – Where the customer is located: in an urban (high density) area or a rural (low density) area
- Seasonal – When the customer consumes power: year-round or only during a specific season (e.g. summer cottages)
- Voltage of supply – Voltage that the customer is supplied electricity: transmission or high voltage, sub-transmission, primary, secondary or low voltage
- Size – Amount of demand (kilowatts) or capacity that the customer consumes: e.g. above 50 kW, above 5 MW
- Load factor – Consumption pattern of electricity over time reflecting the costs that this pattern of consumption imposes on the utility, e.g. high load factor customers consume almost the same amount of electricity in all hours
- Quality of supply – Assurances of electricity supply, e.g. firm, interruptible
- Time-of-use – How electricity is charged to the customer, prices may vary by season, (e.g. winter summer), and by period (e.g. peak, off-peak)
- Unmetered – If electricity consumption is uniform then it does not need to be metered e.g. streetlight, cable TV

More than one rate design is usually used by utilities in order to properly reflect the differences across customer classes and the individual utility's operations.

6 ELENCHUS COMMENTS AND RECOMMENDATIONS

Based on our review of SaskPower's cost allocation methodology, our knowledge of standard practices in other jurisdictions across Canada and our survey of the cost allocation practices of other electric utilities undertaken for this report, we are of the view that the methodology currently used by SaskPower in its cost allocation methodology is generally consistent with generally accepted rate making principles and practices as well as the methodologies commonly used by other electric utilities. Furthermore, SaskPower's cost allocation methodology is consistent with, and reflective of, SaskPower's operational circumstances.

The following sub-sections outline observations on notable issues and recommended refinements that in our view merit consideration. As noted earlier, cost allocation is more of an art than a science; hence, adoption of any recommended changes to SaskPower's methodology should be dependent on the cost and/or availability of the required data, as well as the potential impact on the complexity of rates and the impact on customers. No changes should be implemented without due consideration and balancing of all of the Bonbright principles of rate making and SaskPower's objectives and operational circumstances.

6.1 CLASSIFICATION OF GENERATION COSTS

Based on the results of the survey, six out of seven utilities classify hydroelectric generation as at least 35% demand related. The seventh utility classifies hydroelectric generation as 100% energy related. In SaskPower case, using the peaker method results in 31% of hydroelectric generation being classified as demand related. Elenchus therefore notes that the proportion of demand-related costs used by SaskPower is at the lower end of the range compared to other utilities that classify a portion of hydroelectric generation as demand related, but Elenchus does not recommend a change in the classification methodology used by SaskPower. SaskPower's classification results reflect the way hydroelectric generation is being used by the utility.

For baseload steam generation, combined cycle generation, and combustion turbine generation five out of six utilities surveyed classify at least 35% as demand related, compared to SaskPower's baseload steam generation value of 52% demand related, combined cycle value of 83% demand related and peaking generation of 100% demand related. SaskPower result's for these types of generation are within the range for other utilities surveyed.

Given the mix of type of generation used by SaskPower to meet electricity demand in its territory, the use of the peaker method to classify generation costs is appropriate in Elenchus' opinion.

Elenchus understands that SaskPower is having difficulties in obtaining the data needed in order to update the Equivalent Peaker method of classifying generation assets and costs between demand and energy related. Standard costing data for fossil plants is no longer available and historical data are being used. Even when using historical data, the results for SaskPower are not out of line with the results for other utilities.

Elenchus suggests that as long as the results of the survey of other electric utilities shows that SaskPower's classification percentages are not out of line, the current percentages should continue to be used by SaskPower. If SaskPower results start to deviate from other utilities, SaskPower should consider changing the classification methodology, or updating the values used to reflect the results of the survey. Another alternative would be to use inflation indices to update the historical costs that SaskPower has available.

Elenchus does not see a compelling reason to suggest changing the SaskPower classification methodology. The survey results and Elenchus experience do not suggest that there is a consensus in the industry of what is considered a right or wrong methodology. The various classification methodologies used in the industry are the result of utilities' past practices, utilities' circumstances and are determined through the regulatory process as providing appropriate results that reflect local circumstances.

6.2 CLASSIFICATION OF DISTRIBUTION COSTS

Lines and transformers are the largest cost items in the distribution of electricity to customers. Five of the twelve utilities surveyed use the minimum system to classify some component of the distribution system as customer related.

Currently SaskPower uses survey results to classify distribution costs between demand and customer related for lines and transformers. SaskPower tried to use the Zero Intercept method, but was unable to obtain the necessary supporting data.

An alternative for SaskPower's consideration is to use the Minimum System method to classify lines and transformer assets and costs between demand and energy. The data required for the Minimum System method reflects the current minimum size transformers and lines used by the utility in serving customers and uses replacement assets and costs to estimate the value of this the minimum system. The ratio of the cost of the minimum system to the cost of replacing all transformers and lines would represent the customer component percentage. The data needed for the minimum system method may be easier to obtain since it is based on current values of assets.

6.3 CLASSIFICATION AND ALLOCATION OF OVERHEAD COSTS

SaskPower requested that Elenchus review its classification and allocation of overhead assets and costs.

In general, other utilities classify overhead assets and costs in the same proportion as other assets and costs. Using this approach ensures that the effect of the classification of overhead costs is neutral and it does not alter the overall classification of assets and costs. Similarly, the allocation of overhead assets and costs is based on the allocation of other assets and costs to customer classes. It is Elenchus' understanding that SaskPower's classification and allocation of overhead costs follows the same approach, it is classified and allocated in the same manner as other assets and costs.

Elenchus endorses this approach. There is a very loose causal relationship to support the allocation of overhead costs to customer classes. There is significant merit in allocating these costs in direct proportion to all other costs, where there is a more directly discernible causal relationship.

6.4 ALLOCATION OF COSTS

6.4.1 LOAD FORECAST DATA

SaskPower currently uses a forecast of the potential maximum demand in its sales forecast when estimating the peak system demand. This demand only occurs under extreme weather conditions. The rationale for this approach is that the system is designed to handle extreme weather conditions. Hence, from an engineering perspective, the costs incurred in ensuring that the system has sufficient capacity under extreme weather conditions are based on the forecast demand under those extreme conditions.

Elenchus notes, however, that other utilities commonly use a forecast of system demand based on the class load profiles under normal weather conditions and not on design (i.e., most extreme) weather; hence, the peak demands can be characterized as the “typical” rather than “extreme”. The concept underlying this approach is that it is more equitable to allocate capacity costs based on the typical usage of the system, rather than design considerations.

Since this approach allocates cost to classes based on peak demands in a normal year, it results in a lower allocation of costs to classes with weather sensitive load. Over time, deviations from normal weather patterns even out. Using a normal forecast based on the last 30 years (or the last 10 years) of observations is an alternative that many utilities consider to be consistent with the fairness principle since it reflects actual typical usage rather than extreme demands that are rarely experienced.

The determination of the normal peak demands of the classes is typically determined by calculating the average annual (or monthly) maximum degree-days and then forecasting the peak demands using that average maximum degree-day value. The time period used to determine the average maximum degree-days is most commonly 10 years, although some utilities use as much as a 30-year average and other use as little as a five-year average. Given the apparent warming trend in recent years, the rationale for using a shorter time frame for calculating the average is that recent experience is probably the best indicator of current “normal” weather and therefore the best forecast of the “most likely” weather and demand peaks in the test year.

Elenchus recommends that SaskPower consider basing the demand allocators on peak demand under “normal”, rather than extreme, weather conditions.

6.4.2 COINCIDENT PEAK

In jurisdictions where electricity markets have been opened up to competition, such as Ontario and Alberta, generation costs are bid to the system market operator by generators and are not classified and allocated to customers using a traditional cost allocation methodology. Transmission companies in these competitive markets are also usually not allowed to own generation assets. This is the situation in which four of the utilities surveyed operate.

The survey results show that the method used to allocated demand-related generation assets and costs by five out of seven utilities involves using more than one coincident peak as allocator: three, four or twelve coincident peak values are used.

For transmission demand related assets and costs four out of eleven utilities use the one coincident peak method as allocator and seven out of eleven utilities use more than one coincident peak as an allocator: two, three, four or twelve peaks are used.

SaskPower uses the 1 CP allocation method to allocate both generation and transmission demand related assets and costs to customer classes in order to reflect cost causality. For Distribution demand related assets and costs SaskPower uses a combination of one coincident peak method or one class non-coincident peak method.

Although SaskPower’s methodology is consistent with the approach taken by several other electric utilities included in the survey, Elenchus considers it important to consider the extent to which SaskPower's cost are actually caused by the single annual coincident demand peak.

Based on information from SaskPower staff it was determined that it is not only the maximum demand for the year that is of importance to system planners, but also the maximum demand in the spring and fall when most of the maintenance of equipment is scheduled, reducing available capacity. From this perspective, it may be that the spring and fall peaks are critical causal drivers of certain system costs.

In addition the capacity of network equipment in the summer can be reduced by as much as 25% of the winter capacity due to the effect of higher summer temperatures on the actual loads that the facilities can handle. As a result, for some facilities, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities.

An analysis of the last 10 years of system data (2002-2011) in SaskPower's service territory shows that the ratio of summer to winter maximum demand is 91%. The same data for the last 3 year shows a ratio of 90% between summer and winter maximum demand. It is therefore evident that SaskPower is a winter peaking utility. Nevertheless, it is also evident that if the seasonal peak is assessed as a percentage of seasonal capacity, it is the summer peaks that place the greatest demands on the network relative to the actual operating capacity during those peak periods. On this basis, it may be more appropriate to view the summer peaks as the prime driver that causes capacity costs to be incurred, at least for those facilities that are most affected by the higher summer temperatures.

In Ontario, which used to be a winter peaking system, but is now a summer peaking system, the ratio of winter to summer maximum demand, using 2010 and 2011 data, was 89%[6]. In Ontario, the allocation factor used by Hydro One Networks (Hydro One Networks has over 95% of transmission capacity in Ontario) to allocate a large portion

[6] Ontario maximum demand: December 2010, 22,114 MW, July 2010, 25,075 MW, January 2011, 22,733 MW July 2011, 25,450 MW. IESO Market Summaries
http://www.ieso.ca/imoweb/marketdata/marketSummary.asp

of its transmission costs, (network costs represent over 60% of Hydro One's Transmission Revenue Requirement), is based on the higher of the monthly coincident demand during the peak period or 85% of the monthly maximum customer demand, also during the peak period.

Based on the results of the survey where the majority of applicable utilities use more than one peak as allocator, taking into consideration the information from SaskPower's system planners, Elenchus recommends that SaskPower explore the implications of using as demand allocation methodology for generation and transmission a coincident peak method that incorporates more months. This change would allow for seasonal capacity and seasonal demand to also be taken into consideration in the allocation factors.

Elenchus would recommend using two or four CP as an allocation method for demand related generation and transmission assets and costs to take into account system planning considerations and as a first step of moving away from using the 1 CP allocation method. While it is conceivable that through detailed analysis it would be possible to determine which facilities experience peak demand, relative to their seasonal capacity, in summer (reduced capacity), winter (highest demand) and the spring/fall (maintenance outages), with different peak allocators being used for each category of assets, it may be more straightforward to simply transition over time to a 4-CP allocator and possibly eventually to a 12-CP allocator.

In order to capture SaskPower circumstances, Elenchus recommends that the coincident peak allocators be split in equal numbers between winter and summer. For example if SaskPower implements 2 CP as an allocator, one should be for the winter months and the other should be for the summer months.

For Distribution demand related costs, Elenchus recommends that if SaskPower changes the 1 CP allocation for Generation and Transmission and uses more than one CP, a similar change should be done for those distribution related demand assets and costs that are currently allocated to customer classes using 1 CP. This would result in consistent change for the allocators and would reflect SaskPower's circumstances. For the distribution assets and costs that SaskPower currently uses 1 NCP, Elenchus is not recommending changes.

6.4.3 Customer Classes

The number of customer classes in a utility is usually determined by regulation or past utility history. The number of customer classes reflects a balancing act between trying to group customers with similar cost causality characteristics and maintaining a manageable level of different customer classes. The larger the number of customer classes, the better the cost allocation will reflect cost causality characteristics for individual customers, but the more expensive it is to maintain by the utility and the more complicated the regime is for customers. It is inevitable that any grouping of customers results in winners and losers within the group. The trade-off is that the fewer the number of customer classes, the less expensive it is to maintain by the utility and also it is easier to understand by customers and stakeholders.

SaskPower customer classes consist of 10 groups, but each customer class has multiple rate codes, making the administration of the multiple rate codes a challenge for SaskPower staff. Elenchus recommends that a review of the rates code should be undertaken by SaskPower and rates codes that are found to contain no customers should be eliminated, unless the rate code is required to support Government or SaskPower initiatives (for example encouraging time-of-use rates). Also, there may be circumstances where a rate code contains customers, but in order to simplify customer classification, these customers could be combined with another rate code that exhibits similar cost causality characteristics and would not result in undue customer impact from the elimination of the rate code.

As an example, small farm customers that are energy billed and that show similar cost causality characteristics as residential customers could be merged with the Residential rate code. Larger farms that are demand billed and show similar costs causality characteristics as commercial customers could be moved to the applicable commercial rate code.

6.4.4 RATE DESIGN TIME-OF-USE RATES

SaskPower requested that Elenchus comment on the implications of establishing time-of-use rates.

Time-of-use rates are implemented by utilities in order to send a more refined price signal to customers on the costs of consuming electricity at different times of the day. Generation costs are normally the largest component of electricity supply costs and reducing generation costs could provide benefits to the utility and consumers in the form of lower utility costs and therefore lower customer bills. The intent of time-of-use rates is that if customers have the proper price signals with enough incentives to modify behaviour, customers would change consumption patterns and reduce or eliminate consumption during high cost periods and increase consumption during low cost periods. Reducing consumption in high cost periods would allow the utility to reduce its total costs by reducing the requirement for peak capacity or for purchasing expensive imported power at times of high electricity demand.

Implementing time-of-use rates (TOU rates) requires that the proper infrastructure be in place in the form of “smart” meters that are capable of recording, for example, hourly consumption. Implementing TOU rates also requires meter reading and billing systems capabilities that enable the processing of the required data. The assets and software required in order to implement time-of-use rates are such that it may be justifiable in locations with very high electricity supply costs during peak periods. TOU rates may also provide some benefits to larger electricity consumers, but it may not be a financially sound investments in instances of low electricity consumption, for example seasonal customers or where the capacity and fuel cost savings are not large enough to offset the infrastructure costs required to implement time-of-use rates. As with any other investment, a decision on implementation should be based on a sound business case. The business case for TOU rates can be approached either by considering only the utility’s generation and network costs and savings, or by also building into it external costs, such as environmental and health benefits. The goal of TOU rates should not be to benefit “free-riders” who are not on-peak users of power in any case, but to shift demand and reduce the average cost of power.

In order for time-of-use to achieve the goal of changing consumption patterns, the differential in prices between high and low cost periods should provide incentive for customers to modify behaviour without resulting in undue sacrifices. Is also should reflect the utility’s characteristics that would result in savings as a result of lower consumption during high cost periods. For example, if the period of high costs lasts for many hours, it would be difficult for consumers to reduce or shift load away from the high costs period and into lower costs periods.

In SaskPower’s case, it is Elenchus’ understanding that reduction in customers’ electricity consumption during high cost periods would not result in cost savings to SaskPower. Currently gas is the fuel used at the margin in order to supply capacity at times of high electricity demands and if consumption is shifted to periods of low electricity consumption, gas is still the fuel at the margin that is used to supply power at the margin during periods of low electricity consumption.

Time-of-use for transmission costs may make sense in instances when there is capacity constraint in the transmission system, but transmission costs are not a large component of customers’ electricity bill. Time differentiated transmission rates may be implemented to complement time differentiated generation rates and thus provide a consistent price signal to customers.

Distribution costs are for the most part fixed for a utility and are not dependent on customer’s electricity consumption, therefore time differentiated distribution rates may not be appropriate from a cost causality perspective, although they may be implemented to provide a consistent price signal to customers in support of time differentiated generation rates.

If SaskPower is to consider implementing time differentiated rates that could provide benefits to SaskPower in the form of reducing the need to build new capacity, or achieve fuel cost savings during peak demand periods, or in order to foster a culture of conservation in consumers, Elenchus recommends that pilot studies be conducted by

SaskPower in order to evaluate the potential results in consumption shift by customers in response to time differentiated price signals. Analyzing the load shifting and quantifying the related system benefits compared to the costs of implementing time differentiated rates would provide SaskPower with the information necessary to make a decision if implementing time differentiated rates makes financial sense for SaskPower. Different levels of differentials between high price and low price periods should be tested as well as different length of high price periods in order to evaluate customers' response to time differentiated prices.

It is Elenchus' understanding that SaskPower operates an electricity system that is already high load factor and is projected to become even higher by the addition of new load that is for the most part flat consumption load. Operating a system with high load factor limits the expected benefits of implementing time differentiated rates and the benefits of the potential load shifting. Under this circumstance Elenchus recommends that pilot time-of-use studies should be undertaken only if there is a reasonable expectation of implementing time differentiated rates in Saskatchewan. If circumstances change in Saskatchewan, for example marginal costs change, or what fuel type is at the margin providing peak capacity, consideration should be given to implementing time-of-use rates as one possible demand management tool available to the utility to be considered, instead of building new capacity to meet increased demand for electricity.

6.4.5 CP Allocation Method

SaskPower applies an adjustment in its rate design to take into consideration the relationship between load factor and coincidence factors. High load factor customers tend to have higher coincidence factors. That is, the higher the load factor for a customer the higher the chances are that it will consume electricity at the time of the utility's maximum system demand. In order to better reflect cost causality, energy rates are increased and demand rates are decreased by applying this adjustment. At a class level the revenue collected from customers before and after the rate design adjustment remains unchanged. This adjustment, which is referred to as the coincident peak allocation method by SaskPower, results in customers within a class with different load profiles having a revenue to cost ratio that is closer to the customer class average revenue to cost ratio than if no adjustment is made to the rates.

Based on Elenchus' experience the adjustment made by SaskPower is not widely applied in utilities, but it makes theoretical sense.

7 STAKEHOLDERS COMMENTS

Stakeholders provided the following comments on Elenchus' report.

7.1 GREATER SASKATOON CHAMBER OF COMMERCE

The Chamber of Commerce is of the view that the Reseller revenue to revenue requirement ratio be set at a value of 1.00. The Chamber of Commerce suggests that a value higher than 1.0 would deter alternate suppliers and a rate lower than 1.0 could result in cross-subsidization between SaskPower's customers and resellers' customers.

Elenchus' Response

Conducting a cost allocation study involves utilizing the best available, yet nevertheless imprecise, information with respect to how shared assets are used by various customer groups. For example:

- The allocators used to apportion assets and expenses to customer groups based on cost causality principles reflect the key drivers of costs;
- Sample load data is used in order to determine customer class consumptions for smaller customers;
- Simplifying assumptions are used in order to classify some distribution-related assets and expenses as demand and customer related.

A range of values around a revenue to revenue requirement ratio value of 1.0 is therefore analogous to adding statistical significance (standard deviation) to a statistical analysis. That is, ratios close to 1.0 are deemed not to represent cross-subsidization, just as small statistical variances are not considered to be "statistically significant". A range of acceptable revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs. Hence, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes.

Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

A cost allocation study is a “zero-sum” exercise. The utility’s revenue requirements and assets are apportioned amongst its customer groups in a fair and reasonable manner using cost causality principles. Any changes to the methodology in order to improve it will result in winner and losers when compared to the results of the previous methodology. Hence, rate stability is an important principle in setting rates and relative rates are typically not altered on the basis of deviations from a ratio of 1.0 that is not significant. The proposed changes, in Elenchus views, improve the cost causality and fairness of SaskPowers’ cost allocation methodology.

7.2 CITY OF SWIFT CURRENT

The City of Swift Current questions the results of the proposed changes to the demand allocators from using a winter peak to using a combination of winter and summer peaks. The City of Swift Current requests that Elenchus review the results of the proposed changes. The City of Swift Current draws the following conclusions from the results:

> *“1. The peak loads for the Urban Residential and Urban Commercial customer classes are under estimated.*
>
> *2. The Reseller customer class has been specifically targeted for a larger rate increase by design*.”

Elenchus’ Response

Elenchus’ has no reason to believe that SaskPower is specifically targeting the Reseller customer class for large rate increases or that the peak loads used by SaskPower for Urban Residential and Commercial customer classes are not a fair representation of their consumption characteristics. Elenchus understands that SaskPower is now using their own load research in order to determine the consumption characteristics of the mass market customers, (residential, farm, commercial and oilfield), as opposed to the previous methodology of using ATCO's load research.

Elenchus' review and recommendations are based on best industry practices and are not biased in favour or against any particular customer group. Cost causality is the main criteria used by Elenchus in its recommendation to include more values in the demand allocators. It is also a reflection on how the electricity system built by SaskPower is being operated.

7.3 CITY OF SASKATOON

The City of Saskatoon opposes changing the demand allocators from winter peak to a combination of winter and summer peaks because in its view the change impacts only the Reseller customer class and the change would impact the City of Saskatoon financially.

The City of Saskatoon mentions, in its comments on Elenchus' recommendations, that City Council made the decision to have electricity retail rates in the City of Saskatoon equal to the SaskPower's rates and asked if Elenchus has encountered a similar situation like the one described for the City of Saskatoon.

Elenchus' Response

Elenchus recommendation with respect to demand allocation method is based on cost causality principles and SaskPower system operations.

As stated in Section 6.4.2 of this report, SaskPower staff described to Elenchus that it is not only the maximum demand for the year that is of importance to SaskPower's system planners, but also the maximum demand in the spring and fall when most of the maintenance of equipment is scheduled, reducing available capacity. This means that the spring and fall peaks are critical causal drivers of certain system costs and should be considered when selecting the proper allocation methodology in order to reflect cost causality principles.

Additionally the capacity of network equipment in the summer can be reduced by as much as 25% of the winter capacity due to the effect of higher summer temperatures on the actual loads that the facilities can handle. As a result, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities.

In its submission, the City of Saskatoon mentions that Saskatoon Light and Power annual peak generally occurs in July or August. In this case, the City's load profile is such that its contribution to SaskPower's winter peak is not as critical and has less of an impact in cost allocation than its contribution to SaskPower's summer peak. Using an allocation method that includes more values than just the winter peak will still reflect the lower winter than summer consumption of Saskatoon Light and Power and provide some benefit to Saskatoon Light and Power. As mentioned above, summer available capacity reductions due to temperature and summer loads are taken into account by system planners in building and maintaining the SaskPower electricity system. It is Elenchus' opinion that the choice of an appropriate allocation method should be reflective of cost causality and how the electricity system is designed and operated.

The issue raised by the City of Saskatoon on the setting of rates in other jurisdiction is not directly related to the work undertaken by Elenchus in this report for SaskPower.

Nevertheless, with respect to Elenchus' experience in other jurisdiction where companies purchase electricity for distribution inside their territories, the rate approach followed by the City of Saskatoon is unique. In other jurisdiction with similar arrangements as exist between SaskPower and the City of Saskatoon, the distributors establish the rates they charge their customers reflecting the cost they incur in purchasing electricity and adding their own distribution costs. The distributors' rates are commonly reviewed and approved by regulators and allow the distributors to earn an approved return on their investments. The regulatory review level can be at a high level or can also be very detailed. Distributors' rates are not set equal to other distributors' rates in jurisdictions that Elenchus is familiar with.

As an example, in Ontario there are over 70 distributors that serve mostly urban centers and each distributor has its rates reviewed and approved by the Ontario Energy Board, reflecting their own costs. There are situations in Ontario where one side of the street is served by one distributor and the other side of the street is served by another distributor. Customers on each side of the street pay different rates depending on which distributor is serving them and the rates reflect the costs incurred by the serving utility distributor. Similarly, the rates for municipal electric utilities are based on their costs and not the rates charged by the primary integrated electric utilities in other Canadian jurisdictions that have municipal electric distributors, namely, Nova Scotia, New Brunswick, Quebec and British Columbia.

7.4 CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

The Canadian Association of Petroleum Producers agrees with Elenchus' proposed changes to SaskPower's Cost Allocation and Rate Design methodologies but is concerned with the level of cross-subsidization that may occur if the ratio of revenue to revenue requirement is not set at 1.0 and encourages SaskPower to move all customer classes to a ratio of 1.0.

Elenchus Response

As explained above in our response to the Grater Saskatoon Chamber of Commerce comments, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes. Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

A range of acceptable revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs.

APPENDIX A: SASKPOWER COST ALLOCATION METHODOLOGY DOCUMENTATION

The information below was extracted from a document titled: "2010 Base IFRS Embedded Cost of Service Results" prepared by SaskPower.

Functionalization

1. Rate Base Items
1.01 - Plant in Service & Accumulated Depreciation

SaskPower Generation, Transmission, and Distribution:

All of the rate base accounts are functionalized on the basis of the plant designation; generation plant is functionalized entirely to the generation function, transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for the Centennial Wind Project are included with SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.

Coal Reserves:

SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

Shand Greenhouse:

The Shand Greenhouse assets are functionalized to generation. The subfunctionalization is the same as the total for all SaskPower generation.

Cory Cogeneration Project:

The SaskPower International assets associated with the Cory Cogeneration Station are functionalized to generation.

Meters:

Meters are included in the meters sub-function within distribution.

General Plant - Unused Land:

The functionalization and sub-functionalization of Unused land is done using operations, maintenance and administration expense.

General Plant – Buildings:

The functionalization of the SaskPower head office building is based on floor space analysis. All other buildings are functionalized using cost center charge backs. The asset values for buildings are then prorated to sub-functions within each function using operations, maintenance and administration expense.

General Plant - Office Furniture & Equipment:

The functionalization and sub-functionalization is the same as for buildings.

General Plant - Vehicles & Equipment:

The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit center. The asset values for vehicles and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

General Plant - Computer Development & Equipment:

The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) is functionalized on an application by application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

General Plant - Communication, Protection & Control Equipment:

Communication, protection & control equipment is functionalized to generation, transmission, distribution and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

General Plant - Tools & Equipment:

The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

1.02 - Allowance for Working Capital

The allowance for working capital is consistent with Cost of Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working is calculated as 12.5% of the sum of operations, maintenance and administration expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.03 - Inventories

SaskPower accounting records summarizes inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-

functions within the generation, transmission and distribution functions using operations, maintenance and administration expense.

1.04 - Other Assets

Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

· Natural gas / coal related:

Functionalized to generation.

· Employee related:

Functionalized using head count by Business Unit / Support Group.

· Insurance expense related:

Functionalized using advice from SaskPower Risk management staff.

· Miscellaneous:

Prorated to sub-functions within each function using operations, maintenance and administration expense.

2. Revenue Requirement Items

A summary of the functionalization methodology for expense plus the return on rate base items is provided below.

2.01 - Fuel Expense SaskPower Units

The fuel expense for SaskPower units is functionalized 100% to generation.

2.02 - Purchased Power and Import

The purchased power expense is functionalized 100% to generation.

2.03 - Export & Net Electricity Trading Revenue

Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.04 - Operating, Maintenance & Administration (O M & A) Expense

Power Production Business Unit:

The O M & A expense for the Power Production Business Unit is functionalized to generation. The O M & A expense for the Cory Cogeneration Station, flyash sales and the Centennial Wind Power Facility (credit) is functionalized to Generation.

Shand Greenhouse:

The O M & A expense for the Shand Greenhouse is functionalized to Generation.

NorthPoint:

The O M & A expense for NorthPoint is functionalized to Generation.

Transmission & Distribution Business Unit:

A small amount of the Transmission and Distribution Business Unit's O M & A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation.

The remainder of the O M & A expense for the Business Unit is split to transmission and distribution using cost centre reports. The transmission O M & A is sub-functionalized by separating transmission O M & A expense into line and station related. The line related O M & A is sub-functionalized to main grid,138 & 72 kV radials using line lengths by sub-function. The station related O M & A expense is sub-functionalized using station assets plant in service by subfunction.

Distribution O M & A is functionalized to distribution and customer services using a combination of staff advice and detailed cost centre O M & A reports.

The same analysis provides the sub-functionalization within the distribution and customer services functions. The Electrical and Gas inspections O M & A is functionalized to customer services.

Customer Services Business Unit:

The O M & A for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre operation, maintenance and administration reports.

Customer Services - Bad Debt Expense:

The bad debt expense is assigned to the customer collections sub-function with the Customer Services function.

President / Board:

Assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

Corporate & Financial Services:

Functionalized based on employee head count by Business Unit and Support Group.

Corporate & Financial Services - Insurance Premiums & Insurable Losses:

Functionalized based on Breakdown from SaskPower Risk Management & Insurance department staff.

Planning, Environment & Regulatory Affairs:

There are two major cost centres: Planning and Regulatory Affairs, and Environment. The Planning cost center is assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups. The Environment cost center is allocated based on an employee analysis which was done by SaskPower Environment department staff. Sub-functionalization is completed using O M & A sub-functionalization within each function.

People & Processes - General Council / Land:

Assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

People & Processes - Communication & Public Affairs:

Assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

People & Processes – Safety:

Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the O M & A subfunctionalization within each function.

People & Processes - Corporate Information & Technology (CI & T):

C I & T operations, maintenance and administration expense is separated into personal computer related and Business Unit related. The personal computer related is functionalized using employee headcount. The Business Unit related is functionalized using information from the cost centre report. Subfunctionalization is completed using O M & A within each function.

People & Processes - Human Resources:

Functionalized based on the employee head count by Business Unit and then subfunctionalized using the O M & A sub-functionalization within each function.

Service Delivery Renewal:

Functionalized based on costs being evenly allocated between T&D and Customer Services and then sub-functionalized using the O M & A sub-functionalization within each function.

2.05 - Depreciation & Depletion

The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.06 - Corporate Capital Tax

Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.07 - Grants in Lieu of Taxes

Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.08 - Miscellaneous Tax

The miscellaneous tax expenses have been grouped into the following categories using cost center reports:

- *Power production related:*

  Functionalized to generation.

- *Fuel supply related:*

  Functionalized to generation.

- *Gas & electric inspections related:*

  Functionalized to customer services.

- *Vehicles and equipment related:*

  Functionalized using the vehicles and equipment plant functionalization above.

- *Buildings related:*

  Functionalized using the buildings plant functionalization above.

- *Corporate related:*

  Functionalized using total O M & A expense.

2.09 - Other Income

Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.

- *Customer services payment income:*

  Assigned to the billing and customer accounts and customer collections subfunctions within customer services.

- *Meter reading income:*

  Assigned to the meter reading sub-function within the customer services function.

- *Gas & electric inspections income:*

  Assigned to the meter reading sub-function within the customer services function.

- *Transmission related income:*

  Assigned to sub-function within the transmission function using transmission OM & A expense.

- *Distribution related income:*

  Assigned to sub-function within the distribution function using distribution O M& A expense.

- *Clean Coal Project Credits:*

  Assigned to sub-function within the generation function using power production OM&A expense

- *Customer Contribution Revenue*

  As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.

- *Green power premium:*

  Functionalized to generation.

- *NorthPoint:*

  Functionalized to generation.

- *Flyash Sales:*

  Functionalized to generation.

2.10 - Return on Rate Base

The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

Classification

SaskPower generation rate base and expense is classified as either demand or energy related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Equivalent Peaker method, based on the NARUC Electric Utility Cost Allocation manual. This approach uses the ratio of the unit cost of new peaking capacity to the new cost of base load capacity for different generation types to classify rate base and depreciation to demand and energy.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The assets and expenses associated with the Cory Cogeneration Station are classified to demand and energy using the purchased power capacity / energy payments for this plant.

The expenses and income associated with fly-ash sales are classified as energy related.

The classification of all wind power rate base and expense are classified 80% to energy based on the results of SaskPower's most recent planning study regarding the capacity value of wind generation. This is a change from previous years, when SaskPower planning staff did not attach any capacity value to wind generation.

Coal Reserves:

SaskPower coal reserves are classified energy related.

Shand Greenhouse:

The Shand Greenhouse assets, O M & A and depreciation expenses are classified using the classification of all SaskPower generation.

NorthPoint:

The O M & A expense and other revenue associated with NorthPoint are classified 100% to energy related.

Transmission:

Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% to demand.

Distribution:

Substations are classified 100% to demand-related cost. Three phase feeders are classified 100% to demand-related cost. Both urban and rural single-phase primary lines are classified 65% to demand-related and 35% to customer-related cost. Line transformers are classified 70% to demand-related and 30% to customer-related cost based upon industry data. All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as customer-related.

Customer:

Customer related costs are classified 100% to customer.

Allocation

Generation:

The energy related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses.

The demand related rate base and expenses are allocated by the single coincident peak (1CP) method, plus an estimate of losses. The 1CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the system peak. The system peak load is SaskPower's largest demand calculated on an hourly interval basis. Allocation factors are developed as the ratio of the class load at the time of the system peak to the total load.

Interruptible Credit:

This interruptible credit (benefit) is allocated to the interruptible customer's class using the 1CP method. The cost of the interruptible credit is allocated to all other (non-interruptible) customers using the 1CP allocator.

Transmission:

All of the transmission functions are classified as demand and are allocated using the single coincident peak (1CP) method as aforementioned.

Distribution:

The demand functions within distribution use a combination of the 1CP method and the Non Coincident Peak (NCP) method. The NCP method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occur, to the sum of all the class peaks, similarly determined. Only the transformers function uses the NCP methodology, all other functions use the 1CP methodology.

The customer functions within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter.

Streetlight related rate base and expenses are allocated directly to streetlights.

Customer Services:

The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

Customer Contributions:

These contributions are allocated back directly to the customer classes which made the contribution.

Load Data

Customer load patterns were obtained for each class from the best available sources.

Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The typical load shapes for the customer types in each of these classes was then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.

Power and Reseller loads were analyzed based on hourly meter readings from actual customer's interval metered sites.

Loss Study

The purpose of a loss study is to properly quantify and assign to the appropriate customer class the electrical energy and demand losses in the various segments of the system. The starting point is the total energy loss in GWH, calculated as the *difference between input to the system measured at the generator and output measured at the customer's meter.*

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

Appendix B Utilities Surveyed

Canadian

BC Hydro

ATCO

Manitoba Hydro

Hydro One Networks Inc.[7]

Ontario Power Generation (OPG)

Hydro Quebec

Newfoundland Power

New Brunswick Power

Nova Scotia Power

US Utilities

AVISTA Corp.

Georgia Power

PECO

Many more utilities were contacted, but did not respond.

[7] In Ontario the electricity market was deregulated in April 1999. OPG generates electricity and Hydro One transmits and distributes electricity

	Hydroelectric	Baseload Steam	Combined Cycle	CTU	Transmission	Sub-transmission
BC Hydro	50% demand/50% energy	100% demand	100% demand	100% demand	100% demand	100% demand
ATCO	NA	NA	NA	NA	AESO bill into demand/customer	30% to 35%
Manitoba Hydro	100% weighted energy/0% demand	100% weighted energy/0% demand	100% weighted energy/0% demand	100% weighted energy/0% demand	100% demand	100% demand
Hydro One	NA	NA	NA	NA	100% demand	100% demand
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	NA	NA	NA	NA	42.7% demand	100% demand
NL Power	System load factor 45.6% demand	NA	NA	NA	100% demand	100% demand
NB Power	40% demand	40% demand	NA	40% demand	100% demand	Same as TX
NS Power	Not easily available	Not tracked for all costs by type	As Baseload Steam	100% demand	Currently 43% demand	Currently 43% demand
Avista	34.2% demand	34.2% demand	34.2% demand	34.2% demand	34.2% Wash. 100% Idaho	34.2% Wash. 100% Idaho
Georgia Power	100% demand	100% demand	100% demand	100% demand	100% demand	100% demand
PECO	95% demand+ Excl Fuel	95% demand+ Excl Fuel	95% demand+ Excl Fuel	95% demand+ Excl Fuel	100% demand	100% demand

	Distribution Substations	Primary Lines	Distribution Transformers	Line Transformers	Secondary Lines	Services Fixed costs
BC Hydro	100% demand	100% demand	38% demand/62% customer	NA	3% demand/97% customer	100% customer
ATCO	100% demand	100% demand	40% to 60% demand	40% to 60% demand	30% to 35% demand	100% customer
Manitoba Hydro	100% demand	60% demand	100% demand	100% demand	60% demand	100% customer
Hydro One	100% demand	45% demand related	100% demand	38% demand related	45% demand related	100% customer
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	100% demand	100% demand	100% demand	77% demand	77% demand	100% customer
NL Power	100% demand	64%	73%	73%	64%	100% customer
NB Power	100% demand	50% demand	75% demand	75% demand	50% demand	100% customer
NS power	100% demand	73% demand	100% demand	100% demand	50% demand	100% customer
Avista	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer
Georgia Power	100% demand	84% demand	100% demand	85% demand	77% demand	100% customer
PECO	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer

	Meters	Method used to determine distribution customer related	Method used to allocate generation demand costs	Method used to allocated transmission demand costs	Method used to allocated sub-transmission demand costs	Method used to allocated distribution stations demand costs
BC Hydro	100% customer	Zero Intercept for transformers. Minimum System for secondary system	4CP	4CP	4CP	Class NCP
ATCO	100% customer	Average of Zero intercept and Minimum system	NA	Allocated POD Capacity Demand and AEIS 1 CP Summary Demand	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)
Manitoba Hydro	100% customer	Fixed 60% demand/40% customer	NA	2 CP (average of Summer and Winter)	Class NCP	Class NCP
Hydro One	100% customer	Minimum System	NA	Highest 12 CP or 85% 12 NCP during peak hours for Networks	12 CP	4NCP
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	100% customer	Minimum System	Highest 300 hours	1CP	1CP	1NCP
NL Power	100% customer	Minimum System Analysis or Zero Intercept Method	1 CP	1 CP	1 CP	NCP
NB Power	100% customer	Historical	1 CP	12 CP	12 CP	12 CP

NS Power	100% customer	Judgement 50/50	3 winter CP	3 winter CP	3 winter CP	1 NCP
Avista	100% customer	Basic Customer Only Services and Meters (and directly assigned Street Lighting apparatus) is Customer-Related, all other Distribution plant is Demand-Related.	12 CP	12 CP	12 CP	12 NCP
Georgia Power	100% customer	most frequently used and smaller, Zero intercept	12 CP	Bulk power transmission: Step-up substations - 12 MCP 115 kV to 500 kV lines and subs - 80% 4-CP & 20% 12-CP (4-CP is June - Sept) Sub-transmission Levels (69 kV to 46 kV) - 4-CP Primary and Secondary - NCP (Non-coincident peak)	4 CP	69 kV to 46 kV - 4-CP (4-CP is June - Sept) Primary and Secondary - NCP
PECO	100% customer	Assumed secondary plant is customer related and primary is demand related	4 CP Average of 4 summer peaks	1 CP	NCP	NCP

	Method used to allocated distribution primary lines demand costs	Method used to allocated distribution transformers demand costs	Method used to allocated distribution secondary lines demand costs	Method used to allocated distribution stations customer costs	Method used to allocated distribution primary lines customer costs	Method used to allocated distribution transformers customer costs
BC Hydro	NCP class	NCP class	NCP class	# of customers	# of customers	# of customers
ATCO	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	Weighted Property Plant & Equipment (Transformers)	Weighted Property Plant & Equipment (Poles & Conductor)	NA	NA	Property Plant & Equipment (Transformers) weightings depending on customer counts
Manitoba Hydro	Class NCP	Class NCP	Class NCP	NA	Customer count	NA
Hydro One	4NCP	4NCP	4NCP	NA	Customer count Primary	Customer count
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	1NCP	1NCP	1NCP	# of customers	# of customers	# of customers
NL Power	NCP	NCP	NCP	N/A	Equal Weighting	Equal Weighting
NB Power	12 NCP	12 NCP	12 NCP	N/A	# of customers	# of customers
NS Power	1 NCP	1 NCP	1 NCP	N/A	Weighted # of customer	NA
Avista	12 NCP	12 NCP	12 NCP	NA	NA	NA
Georgia Power	NCP	NCP	Average # of Customers	NA	Average # of Customers	NA
PECO	NCP	NCP	NCP	# of customers	# of customers	# of customers

	Method used to allocated distribution secondary lines customer costs	Method used to allocated services customer costs	Method used to allocated Meter customer costs
BC Hydro	# of customers	# of customers	# of customers
ATCO	Property Plant & Equipment (Transformers) weightings depending on customer counts	Weighted Customer Count	Weighted Customer Count
Manitoba Hydro	Customer Count	Weighted Customer Count	Weighted Customer Count
Hydro One	Customer Count Secondary	Weighted Customer Count	Weighted Customer Count
OPG	NA	NA	NA
Hydro Quebec	# of customers	Weighted # of customers	Weighted # of customers
NL Power	Equal Weighting	Based on typical costs to provide drops to customers within each class	Based on typical costs to provide drops to customers within each class
NB Power	# of customers	Overhead allocation study	Direct Assignment
NS power	Weighted number of customers	# of customers	Weighted # of customers
Avista	NA	Unweighted # of customers	Weighted # of customers
Georgia Power	Average # of customers	Average # of customers	Average # of customers
PECO	# of customers	Direct Assignment	Direct Assignment

APPENDIX C ELENCHUS TEAM QUALIFICATIONS

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for over 35 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 200 regulatory proceedings and provided expert evidence in over 100 hearings. His clients include regulated companies, producers and generators, competitors, customers groups, regulators and government.

PROFESSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (ERAI) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Keith Bryan, Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc., (ECS) **1980**

- ECS was divested as a separate company in 2003.
- There are presently four ECS consultants: Bill Harper, Roger Higgin and James Wightman. Web address: www.econalysis.ca

PRIOR EMPLOYMENT

Ontario Economic Council **1978 - 1980**
Research Officer (Government Regulation)

Research Assistant **1973 - 1978**
Univ. of Toronto, Faculty of Management Studies

Bell Canada **1972 - 1973**
Western Area Engineering

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant for:

Before the Ontario Energy Board

2011
- Cost Allocation evidence for several Ontario electricity distributors (2012 Cost of Service)

2010
- Natural Resource Gas Rate Case
  (Evidence: Proposed Incentive Regulation Mechanism
- Cost Allocation evidence for several Ontario electricity distributors (2011 Cost of Service)

2009
- Hydro One Distribution Rate Case
  (Evidence: Principles for Density Based Rates)
- Cost Allocation evidence for several Ontario electricity distributors (2010 Cost of Service)

2008
- Provided technical and strategic assistance to eight second tranche electricity distribution companies in preparing their rebasing applications for rates for 2009.
  (Evidence: Cost allocation model updates (for two LDCs))

2007
- Third generation Incentive Regulation
  (Evidence: Inclusion of a capital expenditure factor)
- Provided technical and strategic assistance to six first tranche electricity distribution companies in preparing their rebasing applications for rates for 2008.

2006
- Cost Allocation Review (EB-2005-0252)
- Transmission Revenue Requirement Adjustment Mechanism (EB-2005-0501)
- Second Generation Incentive Regulation Mechanism (EB-2006-0088-0089)
  (Evidence: Capital Investment Factor)
  Sub-metering Review (EB-2005-0317)
  (Evidence: Comments on Staff Discussion Paper on Sub-metering)

2005
- Union Gas Rate Hearing
  (Evidence: Evaluation of Avoided Cost Methodology)

2004
- Enbridge Gas Distribution 2005 Rates (RP-2003-0203)

(Evidence: Determining the Fair Rate of Return for a 15-Month Period)
(Evidence: Stand-alone System Supply Costs)

2003
- Generic Proceeding on Electricity Distributor Boundary Changes (RP-2003-0044)
  (Evidence: The Benefits of Competition in the Electrical Distribution Sector)
- Union Gas Limited, 2004 Rates (RP-2003-0063)
  (Evidence: Monthly Demand Charge for Brighton Beach Power Station (with Paula Zarnett))

2002
- Union Gas Limited, 2003 Rates (RP-2002-0130/EB-2002-0363)
  (Evidence: Review of Union's Delivery Commitment Credit (with Joyce Poon))

2001
- Union Gas, Further Unbundling of Rates (RP-2000-0078)
  (Evidence: Regulatory Framework and Cost Responsibility)
- Hydro One Networks, Cost Allocation and Rate Design for RP-2000-0023
  (Evidence: Cost Allocation Model (with Bruce Bacon))

1999
- Propose Electric Distribution Rate Handbook
  (Evidence: Comments on Staff Proposals)
- Standard Supply Service Code, (RP-1999-0040)
- (Evidence: Comments and Alternate Proposal)
- Enbridge, Year 2000 Rate Application (RP 1999-0001)
- Enbridge, Performance Based Regulation Application (EBRO 497-01)
- Enbridge, Ancillary Service Separation & Rental Wind Down (EBO 179-14/15)

1998
- Consumers Gas, 1999 Test Year Rates Application (EBRO 497)
- Union Gas, Separation of Ancillary Services (EBO 177-17)
- Town of Aurora, Franchise Renewal (EBA 795)
- Union Gas, Customer Information System (EBO 177-15)
- Legislative Change (EBO 202)
- System Expansion Generic Hearing (EBO 188)

1997
- Consumers Gas, 1998 Test Year Rates Application (EBRO 495)

1997
- Ten Year Market Review Working Group
- Union Gas/Centra Gas Amalgamation Application

1996
- Union Gas/Centra Gas, 1997 Rates Application (EBRO 493/494)
- Consumers Gas, 1997 Test Year Rates Application (EBRO 492)
- Ontario Hydro, Review of 1997 Rates (HR-24)

1995
- Ontario Hydro, Review of 1996 Rates (HR-23)
- Consumers Gas, 1996 Test Year Rates Application (EBRO 490)
- Union Gas, 1996 Test Year Rates Application (EBRO 486)
- Union Gas/Centra Gas, Shared Services Hearing (EBRO 486/489)

1994
- Centra Gas, 1995 Test Year Rates Application (EBRO 489)
- Ontario Hydro International Hearing (EBRLG - 36)
- Ontario Hydro Corporate Restructuring and 1995 Rates (HR-22)
- Consumers' Gas, 1995 Test Year Rate Case (EBRO 487)

1993
- Joint Hearing on Direct Purchase Issues (EBRO 474-B/476/483/484/485)
- (Evidence: Return-to-System Policies for Ontario LDCs)
- Centra Gas, 1994 Test Year Rates Application (EBRO 483/484)
- Consumers' Gas, 1994 Test Year Rate Case (EBRO 485)

- Union Gas, 1994 Test Year Rate Case (EBRO 476-03)
- (Evidence: Equity Effects of Union's Depreciation Study)

1992
- Consumers' Gas, 1993 Test Year Rate Case (EBRO 479)
- Union Gas, 1993 Test Year Interim Rate Increase (EBRO 476)

1991
- Consumers' Gas, 1992 Test Year Rate Case (EBRO 473)
  (Evidence: Direct Purchase Issues)
- Union Gas, Application for Rates and Cost of Gas (EBRO 462)
- Centra Gas, 1992 Test Year Rates Application (EBRO 474)
  (Evidence: Direct Purchase Issues)

Before the Public Utilities Board of Manitoba

2005
- Manitoba Public Insurance, 2006 General Rates Application
  (Evidence: Rate Stabilization Reserve and Related Issues)

2003
- Centra Gas Manitoba, 2003/04 General Rate Application,
  (Evidence: Comments on the Future Regulatory Methodology)
- Manitoba Hydro, Rate Status Update
  (Evidence: Manitoba Hydro's Financial Requirements and Proposed Curtailable Rate Program, with William Harper)

2002
- Manitoba Hydro, Integration Proceeding
  (Evidence: Assessment of Manitoba Hydro/Centra Manitoba Integration, with William Harper)

2001
- Manitoba Public Insurance, 2002 General Rate Application
  (Evidence: Rate Stabilization Issues)
- Centra Gas Manitoba, Primary Gas Rates
  (Evidence: Centra Gas Manitoba's Rate Setting Methodology)

2000
- Centra Gas Manitoba, Rate Management
- Manitoba Public Insurance, 2001 General Rate Application
  (Evidence: MPI's Rate Stabilization Reserve Surplus)
- Manitoba Hydro, Surplus Energy Program

1999
- Centra Gas Manitoba, Western T-Service and Agency Billing and Collection Service
  (Evidence: Assessment of the Proposals of the Company)
- Manitoba Public Insurance, 2000 General Rate Application
  (Evidence: Rate Stabilization Reserve Risk Analysis)

1999
- Manitoba Hydro Purchase of Centra Manitoba
  (Evidence: Implications for Rates and the Regulatory Regime)

1998
- Centra Gas Manitoba, Rates Flowing from Board Order 79/98
- Manitoba Public Insurance, 1999 General Rate Application
  (Evidence: Rate Stabilization Reserve, Allocation of Costs and IT Expenditures)
- Centra Gas Manitoba, Feasibility Cost Assumptions Application
  (Evidence: Comments on Centra's Proposed Changes to the Feasibility Test)
- Centra Gas Manitoba, 1998 Test Year General Rate Application
  (Evidence: Comments on Centra's Proposed Customer Information System)

1997
- Centra Gas Manitoba, Ste. Agathe Franchise Application
- Manitoba Hydro, Review of ISE/DFH/SESS Programs
- Manitoba Public Insurance, 1998 General Rate Application
- Centra Gas Manitoba, Continuation of Shared Services Application

1996
- Centra Gas Manitoba, 1997 General Rate Application
- Centra Gas Manitoba, Cost of Service and Rate Design Review
- Generic Hearing on the Role of the LDC in Manitoba
  (Evidence: The Future Role of Centra Manitoba in the Supply of Natural Gas)
- Manitoba Hydro, General Rate Application, 1996 and 1997
- Centra Gas Manitoba, Price Management and Direct Purchase Issues

1995
- Application of the Gladstone, Austin Natural Gas Co-op Ltd.
- Manitoba Hydro, Review of Prospective Cost of Service Study (GRA)
  (Evidence: Comments on the Prospective COSS Methodology)
- Manitoba Hydro, Dual Fuel Heating and Industrial Surplus Energy Rates
- Centra Gas Manitoba, Rural Expansion/Brandon Facilities Upgrade Hearings
- Centra Gas Manitoba, 1995 General Rate Application
  (Evidence: Review of Centra's Weather Normalization Methodology)
- Centra Gas Manitoba, Rural Expansion Hearing
  (Evidence: Rural Mains Expansion Feasibility Test)

1994
- Centra Gas Manitoba, Future Test Year Application
  (Evidence: Comparison of the Future and Historic Test Year methods of RB-ROR regulation)
- Manitoba Hydro, General Rate Application, 1994 and 1995

1993
- Centra Gas Manitoba, Inc. 1994 General Rate Application
- Manitoba Telephone System, Interconnect Hearing
- Manitoba Telephone System, 1993 General Rate Application

1992
- Manitoba Telephone System, 1992 General Rate Application
  (Evidence: The appropriate debt ratio for a crown corporation)
- Manitoba Hydro, General Rate Application, 1992
- Centra Gas Manitoba, Inc. General Rate Application

1991
- Manitoba Telephone System, General Rate Application, 1991
- Centra Gas Manitoba, Inc. Application for Interim Refundable Rate Increase

1990
- Manitoba Hydro, Major Capital Projects
  (Evidence: Hydro's 1000MW Ontario Sale and system planning risks)
- ICG Utilities (Manitoba) Ltd., Generic Hearing on Rate Setting
  (Evidence: Implications of using a future versus historic test year)

Before the British Columbia Utilities Commission

2006
- British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement

2005
- Insurance Corporation of British Columbia, Financial Allocation Workshop
- FortisBC, General Rates Application
  (Evidence: Review of FortisBC Performance under PBR, 1996 to 2004) w. S. Motluk

2004	• Insurance Corporation of British Columbia, Financial Allocation Methodology (Evidence: Review of ICBC's Financial Allocation Methodology, with ICBC)
2002	• Pacific Northern Gas West and Northeast, General Rate Application
2001	• Utilicorp Networks Canada (formerly West Kootenay Power), Annual Review, 2001
2000	• Pacific Northern Gas, 2000-01 General Rate Application (negotiated) • West Kootenay Power, Annual Review, 2000
1999	• Centra Gas BC, 2000-02 Rates Application (negotiated) • BC Gas, Market Unbundling Group (Report to the BCUC) • West Kootenay Power, 2000-02 Rate Application (negotiated) • Pacific Northern Gas, 1999-00 General Rate Application (negotiated) • Annual Reviews of WKP and BC Gas • West Kootenay Power, Transmission Access Application
1998	• BC Gas, Southern Crossing Pipeline Application (Revised) • Pacific Northern Gas, 1998-99 Revenue Requirement/Rate Design (Evidence on PNG's Cost of Service Methodology)
1997	• BC Gas, Southern Crossing Pipeline Application (Evidence on the impact of ratepayer risks related to the SCP due to developments in the competitive environment in the natural gas sector) • Annual Reviews of WKP and BC Gas. • West Kootenay Power, Cost of Service and Rate Design (negotiated settlement)
1997	• Pacific Northern Gas Shared Services • Retail Access and Unbundling Tariff Hearing (suspended) (Evidence on the impact of market restructuring on costs and rates)
1996	• BC Gas - 1996 Rate Design (negotiated settlement) (Evidence: Alternative Methods for Allocating Distribution Mains Costs to Customer Classes) • BC Gas - 1996-1997, Revenue Requirement & IRP (negotiated settlement) • West Kootenay Power - Brilliant Generating Station Transactions • West Kootenay Power - General Rate Application/IRP (negotiated settlement)
1995	• Generic System Expansion Hearing • BC Gas - General Rate Application (negotiated settlement)
1994	• BC Hydro, 1994 Rate Increase Application • West Kootenay Power, 1994/95 Rates and Integrated Resource Plan (Evidence: Review of WKP's Integrated Resource Plan)
1993	• BC Hydro, 1993 Rate Increase Application • BC Gas, Rate Design Hearing (Evidence: Analysis of BC Gas' cost studies and their use in setting rates) • BC Gas - General Rate Application (settled and withdrawn prior to hearing) • Generic Hearing into the New Provincial Domestic Natural Gas Supply Policy

Before the Régie de l'énergie

2001
- Hydro Québec, Transmission Rates (R-3401-98)
  (Evidence: HQT's Transmission Tariff Rate Design Methodology, with B. Bacon)
- Inclusion of Operating Costs in the Gasoline Price Floor Set By the Régie
  (Evidence: Review of Principles) (Régie File R-3457-2000)

2000
- SCGM Unbundling of Tariffs (R-3443-2000)
  (Evidence: SCGM's Unbundling Tariff Proposal, with R. Higgin)
- Gazifère, Rates (R-3446-2000)
  (Evidence: Cash Working Capital and Other Issues, with G. Morrison)

1999
- Operating Costs Borne by Gasoline or Diesel Fuel Retailers (R-3399-98)
  (Evidence: Methodology for Determining Operating Costs)
- Small Hydro Within Hydro Quebec's Resource Plan (R-3410-98)
  (Evidence: Determining the Purchase Price for Small Hydro)

1999
- Gazifère, Year 2000 Rate Case
  (Evidence: Assessment of Cost Allocation and Revenue Sharing Proposals)

1998
- Hydro Québec, Rate-Setting Methodology Under s. 167 of the Régie de l'énergie Act.
  (Evidence: Recommendations on Regulatory Framework)
- Hydro Québec,The Role of Wind Power in the Quebec Energy Portfolio
  (Evidence: Issues Related to Establishing a Set-Aside)

Before the Alberta Energy and Utilities Board

2001
- Generic, Gas Rate Unbundling (2001-093)
  (Evidence: Canadian Experience and Approaches)
- Generic, Gas Cost Recovery Rate Methodology (2001-040)

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

2009
- Newfoundland Power, 2010 General Rate Application
  (Evidence: Assessment of five hearing issues)

2007
- Newfoundland Power, 2008 General Rate Application
  (Evidence: Regulatory instruments and other issues)

2006
- Newfoundland Power, 2007 Amortization and Cost Deferrals Application

2005
- Newfoundland Power, 2006 Accounting Policy Application
  (Evidence: Assessment of Newfoundland Power's Proposals)

Before the New Brunswick Energy and Utilities Board

2010
- New Brunswick Power Distribution Corp, 2010 Rate Review

2009
- EGNB, Development Period hearing
- New Brunswick Power Distribution Corp, 2009 Rate Review

2008
- New Brunswick Power Distribution Corporation, PDVSA Deferral Account

2007
- New Brunswick Power Distribution Corporation, PDVSA Deferral Account

(Evidence: Treatment of the Petroleos De Venezuela, S.A. (PDVSA) Settlement in Setting Rates)

Before the Nova Scotia Utility and Review Board

2011
- Nova Scotia Power, 2011 Annual Capital Expenditure Plan
- Nova Scotia Power, Load Retention Tariff (Evidence: Load Retention Tariff Methodology)
- Heritage Gas, 2012 General Tariff Application
- Efficiency Nova Scotia, Compliance Filing (Cost Allocation Methodology Report)

2008
- Town of Antigonish Electric Utility rate process (Evidence: Comments on the Town of Antigonish Electric Utility Revised Cost of Service Study)

Before the National Energy Board

1999
- BC Gas, Southern Crossing Project

Before the Canadian Radio television and Telecommunications Commission

2010
- Obligation to Serve and Other Matters (NC 2010-43) (Evidence: Analysis of Issues Related to Local Service Subsidy)

2006
- Review of Price Cap Framework (PN 06-5)

2001
- Implementation of Price Cap Regulation for Québec-Téléphone & Télébec (PN 01-36) (Evidence: Designing a Consistent Price Cap Regime)
- Price Cap Review (PN 01-37) (Evidence: The Second Generation Price Cap Regime)
- Recovery of 2000 and 2001 Income Tax Expense (PN 00-108) (Evidence: Appropriate Recovery of MTS Income Tax Expense)

2000
- Scope of Price Cap Review (PN 00-99)
- Sunset Rule for Near-Essential Facilities (PN 00-96)
- Access to Municipal Property in the City of Vancouver (PN 99-25)
- Review of Contribution Collection Mechanism (PN 99-6) (Evidence: Review of Contribution Collection Mechanism)
- Review of Direct Connection Charges

1999
- Review of Frozen Contribution Rate Policy (PN 99-5) (Evidence: Comments on the Frozen Contribution Rates Policy)
- High Cost of Serving Areas (PN 97-42)

1998
- Local Number Portability Start-up Costs (PN 98-10)
- Competition in the Provision of International Telecommunications Services (PN 97-34)

1997
- Implementation of Price Caps (PN 97-11)

- Review of Joint Marketing Restrictions (PN 97-14/97-21)
- Forbearance from Regulation of Toll Services Provided by Dominant Carriers (96-26)
- Regulation of Telecom Services Offered by Broadcast Carriers (PN 96-36)

1996
- Scope of Contribution (PN 96-19)
- Bell Canada, Business Rate Restructuring (PN 96-13)
- Price Cap Regulation and Related Issues (PN 96-8)
(Evidence: Evidence addressing the design of the price cap system)
- Interconnection and Network Component Unbundling (PN 95-36)
(Evidence: Mechanisms for Collecting Contribution)
- AGT, General Rate Application
- Local Services Pricing Options (PN 95-49/95-56)
(Evidence: Mechanisms for Pursuing the Goal of Universally Available Basic
- Telephone Service in Low-Penetration Exchanges)
- Review of Phase II (PN 95-19)
- Regulatory Framework for Ontario Independent Telephone Cos. (PN 95-15)
- Split Rate Base Hearing (PN 94-52, 94-56 and 94-58)
(Evidence: Applicability of the Decision 94-19 Regulatory Framework to MTS)

1995
- Review of the Regulatory Framework of Teleglobe Canada Inc. (PN 95-11)
- Review of the Quality of Service Indicators (PN 94-50)
- Bell SYGMA Hearing (PN 94-53)

1994
- Regulatory Framework
(Evidence: A Proposed Regulatory/Structural Alternative)
- Maritime Tel, General Rate Increase
- Island Tel, General Rate Increase
- BC Tel, General Rate Increase
- AGT, General Rate Increase
- Northwestel, General Rate Increase (paper hearing)
- Bell Canada, General Rate Increase
- Teleglobe, Annual Construction Program Review (paper hearing)
- New Brunswick Tel, Annual Construction Program Review (paper hearing)

1992
- Bell Canada - 1992 Annual Construction Program Review
- AGT - 1992 Annual Construction Program Review

1991
- Bell Canada - 1991 Construction Program Review

1990
- Maritime Telegraph & Telephone, Review of Revenue Requirement 1990-91
- (Evidence on the impact of modernization)
- Island Telephone Company, Review of Revenue Requirement 1990-91
(Evidence on the impact of modernization)
- Review of Cable Television Regulations
(Evidence on alternative forms of regulation)

Before the Ontario Telephone Services Commission

1992 • Review of Rate-of-Return Regulation for Public Utility Telephone Companies.
(Evidence: The need for OTSC regulation of municipal public utility telcos)

Before the Ontario Securities Commission

1985 • Securities Industry Review
(Evidence: Industry structure and the form of regulation)

1983 • Role of Financial Institutions in the Securities Industry
(Evidence: Discount Brokerage and the Role of Financial Institutions)

1982 • Institutional Ownership of, and Diversification by, Securities Dealers
(Evidence: The impact of foreign and institutional entry)

1981 • The Unfixing of Brokerage Commission Rates
(Evidence: The impact of price competition on the securities industry)

Before the Ontario Municipal Board

1995 • Appeal of Boundary Expansion by Lincoln Hydro Electric Commission
(Affidavit prepared on the tests for boundary expansions)

1992 • Evidence dealing with the *Rental Housing Protection Act, 1989*

Before the Supreme Court of Ontario

1990 • Challenge of the Residential Rent Regulation Act (1986) under the *Canadian Charter of Rights and Freedoms*
(Evidence: The impact of rent regulation on Ontario's rental housing market)

Before the Saskatchewan Court of Queen's Bench

1993 • Evidence regarding market dynamics and competition policy.

Non-Hearing Processes (Task Forces, Lawsuits and Arbitrations)

2011 • Developing a regulatory training course for Ontario electricity distributors

2010 • Expert Advisor to the Ontario Energy Board for the Cost Allocation Review

2009 • Expert Advisor to New Brunswick Department of Energy on regulatory matters related to the proposed purchase of NB Power assets by Hydro Quebec
• Benchmarking for Regulatory Purposes (CAMPUT)

2008 • Expert Advisor to Ontario Energy Board for the Rate Design Review

2007	• Workshop on Electricity Market Design for the Electricity Regulatory Authority of Vietnam
2006	• Workshop on Regulatory Methodology for the Government of Vietnam (electricity regulator, Ministry of Energy and state-owned enterprises) with Marie Rounding
2004	• Vitamin Price Fixing
	• Allocation of debt related to separation of electric utilities
2001	• BC Gas, Second Generation Performance Based Regulation Negotiation
	• Telecommunications Industry, Price Cap Review Negotiation
1999	• PBR Task Force (Electricity), Ontario Energy Board
	• Market Unbundling Group (BC Gas), British Columbia Utilities Commission
	• Western Supply Transportation Service (Centra Gas Manitoba), Manitoba PUB
1998	• Market Design Task Force, Ontario Energy Board
1997	• Ten Year Market Review, Ontario Energy Board

Commercial Arbitrations

Current: Two arbitrations in Alberta

2006	• Disputed Power Purchase Agreement (PPA)
2004	• Evidence on the interpretation of a Gas Purchase Agreement (GPA)

Facilitation Activities

2010	• Three Strategic Planning Process for the Boards of Directors of an Ontario electricity distributor
2008	• Three Strategic Planning Processes for the Boards of Directors of electricity distributors
2007	• Stakeholder facilitation for Ontario Power Generation in relation to its Regulated Payment Amounts
2004	• Ontario Energy Board, Review of Further Efficiencies in the Electricity Distribution Sector (RP-2004-0020) (with IBM Consulting)
	• Visioning Session: Structural Review of an association of Ontario electric LDCs
	• Business Plan Visioning Session with the Board of Directors of an Ontario electric LDC
2000	• Ontario Energy Board, Distribution Access Rule Task Force

Other Regulatory Issues Researched for Clients

- "Benchmarking for Regulatory Purposes" (with First Quartile Consulting) for the Canadian Association of members of Regulatory Tribunals (CAMPUT)
- "Review of Potential Regulatory Cost Measures" (a Report for the OEB)
- "Survey of Regulatory Cost Measures" (a Report for the Ontario Energy Board)
- OEA Working Dialogue on OEB Regulating Efficiency and Effectiveness (2007)
- Regulatory Cost Measures for the Ontario Energy Industry (2007)
- "Designing an Appropriate Lost Revenue Adjustment Mechanism (LRAM) for Electricity CDM Programs In Ontario"
- Small Hydro PPA Terms and Conditions
- Ontario Electricity Supply Mix
- Mitigation of Regulatory Risk for Utilities
- Regulatory Benchmarking
- Cross-jurisdictional Survey of Regulatory Efficiency
- Renegotiation of Municipal Franchise Agreement

Regulated Industries:
Papers and Research Projects

- *Report on the Effects of Separating Hydro One's Transmission and Distribution Functions.*
- *Report on Hydro One Privatization Options.*
- *The Impact of Complete Deregulation on Market Efficiency of the Gas and Electric Industry in Alberta Post-2005 Assuming Current Market Dominance.*
- *Analysis of a Possible Equity Infusion for Ontario Hydro: Potential Implications for Financing Costs.*
- *Volatility in the Ontario Electricity Market, by ECS with Snelson International Energy.*
- *An Assessment of Price Volatility in the Ontario Electricity Market.*
- *Analysis of MTS Privatization Plan.*
- *Comments on the Issues Identified in the December 1995 Working Paper of the Advisory Committee on Competition in Ontario's Electricity System, A submission on behalf of The Power Workers'Union.*
- *Telecommunications Municipal/Franchise Tax Design Options (with Dr. E. Slack).*
- The Implications of Phase III Costing for the Rates and Toll Settlements of Independent Telephone Companies (with Andrew Roman).
- Submission to the Department of Communications (Canada) (August 1990): *Towards Competition in Telecommunication and Cable TV Services: A Single Switched Broadband Distribution Facility* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).

- Submission to the Department of Communications (Canada) (May 1990): *Fibre Optic Networks: Facilitating Competition in Telecommunication and Television Services for the Benefit of All Users* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).
- Submission to the CRTC concerning cable television regulation on behalf of the Public Interest Advocacy Centre (with Carmen Baggaley).
- Analysis of financing alternatives for Toronto Hydro's 13.8 kV conversion program for the City of Toronto Parks and Recreation Department.
- Analysis of the MacEachen White Paper on "Inflation and the Taxation of Personal Investment Income" for the Ontario Economic Council.
- Submission to the Parliamentary Committee commenting on the April 1985 Finance Green Paper, "The Regulation of Financial Institutions: Proposals for Discussion" prepared on behalf of the Public Interest Research Centre.

Financial Markets:
Papers and Research Projects

- Analysis of the potential consumer benefits from insurance retailing by financial institutions in Canada for the Public Interest Research Centre.
- Development of a financial model for projecting the financial implications of alternative corporate structures.
- Developed model for projecting cash flows for a major land development project.
- Analysis of the impact on the capital markets of changes to the investment rules for public sector pension funds for the Task Force on the Investment of Public Sector Pension Funds (with Prof. John Bossons).
- Review of the OSC proposals and alternatives for relaxing ownership restrictions in the securities industry prepared for the Ontario Securities Commission for submission to the Premier's Office (with Prof. Tom Courchene).
- Analysis of the Impact of Opening the Ontario Securities Market on the Economy of Toronto for a major Canadian securities dealer.
- Response to the December 1984 "Interim Report of the Ontario Task Force on Financial Institutions" for Consumer and Corporate Affairs (Canada).
- Report on functional integration in the Canadian financial services sector for the Australian Merchant Bankers' Association.
- Analysis of the Canadian and American Experience with Partially Negotiable Brokerage Commission Rates for the Australian Merchant Bankers Assoc.
- Served as a North American contact for the Office of Fair Trading (United Kingdom) providing information on developments in the debate over unfixing of brokerage fees, entry of banks into securities dealing and related matters.

- Development of a computerized package for analyzing the effects of alternative tax systems on business investment. Prepared for the Ontario Government reference to the Ontario Economic Council to study a separate personal income tax for Ontario.
- "An Analysis of the Use of Component Internal Rates of Return for Fund Performance Measurement" for Canadian National Investments.
- Analysis of Canadian Stock Market Data (development of a computer package for evaluating investment portfolio efficiency).
- Redesign and periodic updating of the financial, analysis methodology for Alfred Bunting and Co.
- Developed an APL computer package for teaching Business Finance concepts.

Housing:
Papers and Research Projects

- Potential Impact of Rent De-Control on Selected Markets in Ontario
- Review of the Ontario Auditors analysis of the cost of social housing.
- *Future Social Housing Delivery Opportunities in Metro Toronto*.
- Development of a model for projecting core need households to 2011.
- Analysis of the City of Toronto's approach to the valuation of certain properties developed under the *Rental Housing Protection Act, 1989*.
- *Security of Tenure Issues Pertaining to Co-operative Housing*.
- *Rent Regulation in Ontario*, a report prepared as expert Evidence for a Charter of Rights challenge of Ontario's system of rent regulation (with W.T. Stanbury).
- Feasibility study of enhancements to long term housing forecasting models (demographic factors) with David Foot.
- Feasibility study of enhancements to long term housing forecasting models (economic factors).
- Review of the housing situation in the Greater (Toronto) Metropolitan Region in 1988 and the next decade for the Ontario Ministry of Housing.
- Treatment of the Assisted Rental Program under rent regulation for the Ontario Ministry of Housing.
- Alternatives for implementing of the chronically depressed rent provision of the Residential Rent Regulation Act, 1986.
- Projected rental housing requirements to 1996, by unit rent level for Ontario Ministry of Housing.
- Analysis of the effects of the Canadian Home Ownership Stimulation Program on housing starts for Canada Mortgage and Housing Corporation.
- Energy Efficiency of New Housing (with Peat, Marwick and Partners and Scanada Consultants Limited) for Canada Mortgage and Housing Corporation.
- A Model of Supply and Demand in the Market for Housing for the Ontario Ministry of Housing.
- Several publications and presentations shown in the Academic Profile (see below).

Other Areas:
Papers and Research Projects

- Economic analysis of the market impact of the merger of two Canadian trucking companies in the context of the Competition Act.
- Assisted a Joint Task Force of the Ontario Ministries of Social Services and Health to develop a cost project model of alternative long term health care delivery systems.
- Study of Tax Incentives for Film and Television (joint project with Dr. E. Slack) for the Canadian Film and Television Association.
- Economic Analysis of Tax Incentives for the Film Industry (joint project with Dr. E. Slack) for the Department of Communications.
- Economic Impact of Cultural Institutions for Ontario Association of Art Galleries with the Ontario Federation of Symphony Orchestras and the Toronto Theatre Alliance.
- Economic Impact of Art Galleries' Expenditures on their Local Communities for the Ontario Association of Art Galleries.
- Developed a case study of the potash pro-rationing scheme invoked by the Saskatchewan government for the Faculty of Management Studies, Univ. of Toronto.
- Analysis of Regional Municipality of Niagara financial information for the Niagara Region Review Commission.
- Analysis of Ottawa/Carleton regional government's financial information, and comparison with other regional governments, using the MARS database (with Dr. E. Slack).
- A Dynamic Simulation Model of the North York Secondary School System for Planning for Declining Enrolment for the Ontario Institute for Studies in Education, Department of Educational Planning (with Dr. S. Padro).
- Development of an extension to the Limits to Growth World III Model incorporating commodity prices, technology, disaggregated regions and energy resources into the model.
- Development of a computer program for solving the Dynamic Transportation Problem (with Professors Sethi and Bookbinder at the Faculty of Management Studies, University of Toronto).

PRESENTATIONS

- “Innovations in Rate Design”, 2010 CAMPUT Training Session
- “Cost of Service Filing Requirements” (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- “Green Energy Act” (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- “Rate Design”, 2009 CAMPUT Training Session
- “How To Build Transmission and Distribution to Enable FiT: The Role of Distributors”, EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009

- “Distributor Mergers and Acquisitions: Potential Savings”, 2007 Electricity Distributors Ass
- “Beyond Borders” Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.
- “Low-Income Energy Plan for Peterborough City & County”, 2006 LIEN-AHAC Conference
- “The “Deregulated Retail Energy Sector in Ontario”, Toronto Association of Business Economists, Oct. 2003.
- “Other Approaches to Rate Regulation”, CAMPUT Annual Meeting, Sept. 2003.
- “Price Projection: Will the Rate Freeze be Revenue Neutral?” at Canadian Institute Conf., The Impact of Ontario’s New Electricity Market on Large Power Consumers Jan. 2003.
- “Managing Energy Price Risk: Impact of Market & Regulatory Developments on Price Risk Management”, Canadian institute Conference, Toronto, October 21, 2002.
- “Location Based Marginal Pricing: Will it Happen?” Ontario Energy Contracts, Insight Conference, Toronto, October 1, 2002.
- “The Evolution of the North American Energy Market” Canadian Gas Association Executive Conference, Vancouver, June 2002.
- “Alternate Dispute Resolution: Can Everyone Win?” Canadian Gas Association Breakfast, Whistler, British Columbia, May 7, 2002.
- “Incentive Regulation and Commodity Competition Impacts on Quality of Service & Rates”, CAMPUT Regulatory Educational Conference, Whistler, BC, May 7, 2002.
- “Energy Deregulation Developments and Impacts on the HVACR Industry”, HRAI’s 33rd Annual Meeting, August 23-25, 2001 Huntsville, Ontario.
- “Natural Gas Delivery Regulation in Canada”, HRAC Conference on Natural Gas in Nova Scotia, Halifax, Nova Scotia, August 25, 1999.
- “Licensing as a Regulatory Approach” Thirteenth Annual CAMPUT Regulatory Educational Conference, Saint John, New Brunswick, May 4, 1999.
- “The Impact of Restructuring Electricity Markets on Customers”, West Kootenay Power 1998 Annual Conference, The Dawn of Customer Choice, Kelowna, B.C., Dec. 2, 1998.
- “Gaining Access to the Retail Customer”, *Electricity Competition in Ontario, New Rule, New Opportunities, New Players* (Canadian Institute Conference), Toronto, Oct. 1998.
- “The Future: Mega-BTU Inc.?” (Plenary session) Twelfth Annual CAMPUT Regulatory Educational Conference, Banff, Alberta, April 27, 1998.
- “Protecting Low Income Consumers’ Access: Lessons Learned From Other Countries,” Twelfth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 26-27, 1998.
- “Competition: What happens downstream of the meter?” (Plenary) Eleventh Annual CAMPUT Regulatory Educ. Conference, Whistler, B.C., May 6, 1997.
- “Brokers, Marketers and the Public Interest” Eleventh Annual CAMPUT Regulatory Educational Conference, Whistler, B.C., May 6, 1997.
- “Separation of Gas Supply, Merchant Functions & Other Alternatives,” Tenth Annual CAMPUT Regulatory Educ. Conf., Niagara-on-the Lake, May 1, 1996.

- “The Impact of Deregulation on the Public Interest,” Tenth Annual CAMPUT Regulatory Educational Conference, Niagara-on-the Lake, April 30, 1996.
- “Marketing to Low and Moderate Income Consumers in the New Competitive Market: Lessons Learned From Other Industries,” Tenth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 22, 1996.
- “Where Should We be Going?” OEB Ten Year Market Review Workshop, Jan. 31, 1996.
- “Restructuring the Electrical Power Industry in Ontario” for the Board of Directors of Ontario Hydro on behalf of the Power Workers’ Union, August, 1995.
- "A New Vision for Ontario's Electric Demand/Supply Future" panel presentation, Opening Plenary Session of the Canadian Independent Power Conference, Toronto, Dec. 1993.
- "Trends in Rental Housing Affordability by Income Level in Ontario" presented at the 1992 meetings of the Canadian Economics Assoc., Charlottetown, PEI.
- "An Evaluation of Rent Regulation as an Instrument for Meeting the Housing Needs of Renters in Ontario," presented to the Ontario Standing Committee on General Government, August, 1991.
- with S.W. Hamilton (Sept 1990) "Housing and the Regulatory Environment", a paper presented at the Housing Young Families Affordability Symposium, (Vancouver: Canadian Housing and Renewal Association/Canada Mortgage and Housing Corp.)
- "New Telecommunications Technologies: Who Pays? Who Benefits?" presented at the 1990 (June) meetings of the Canadian Economics Assoc., Victoria, B.C.
- with W.T. Stanbury, (1989) "Rent Controls as a Prisoner of War Game", Canadian Real Estate Research Bureau, Faculty of Commerce and Business Administration, University of British Columbia, #89-ULE-019.
- "The Implications of Rent Regulation for Housing Market Models" presented at 1989 (June) meetings of the Canadian Economics Association, Quebec City.
- "Price Caps - An Alternative to Rate of Return Regulation?" at the Canadian Association of Members of Public Utility Tribunals/Centre for the Study of Regulated Industries, Annual Regulatory Studies Training Programme, McGill University, May 14-18, 1989.
- "Living with Rent Regulation in Ontario" at the 35th North American meetings of the Regional Sciences Association, Toronto, November 1988.
- "A Survey of the Research of the Thom Commission," at *Rent Control: The International Experience*, John Deutsch Institute Roundtable, Queen's University, September, 1987.
- Invited address on "Forecasting the Regulatory Environment of Financial Institutions" sponsored by the University of Michigan - Flint as the 1985 paper for their annual *Lectures on the American Economy and the Business Community* series.
- "Collapsing Barriers Between Banking and Other Financial Institutions" at the 1984 Canadian MBA Conference, McMaster University.
- The economic impact of cultural activities for conferences of National Museums of Canada, Canadian Conference on Heritage Resources, Canadian Museums Association, Ontario Association of Art Galleries, and Ontario Federation of Symphony Orchestras.

PUBLICATIONS

Refereed Books and Monographs:

- with W.T. Stanbury (February 1990) *Rent Regulation: The Ontario Experience*, (Vancouver: The Canadian Real Estate Research Bureau).
- with W.T. Stanbury (January 1990) *The Housing Crisis: The Effects of Local Government Regulation*, (Vancouver: The Laurier Institute).
- with T. Courchene and L. Schwartz (October 1986) *Ontario's Proposals for the Canadian Securities Industry*, Observation No. 29, (Toronto: C.D. Howe Inst.).
- (1983) *Price Competition in the Canadian Securities Industry: A Test Case of Deregulation*, (Toronto: Ontario Economic Council).
- with G.F. Mathewson (1982) *Information Entry and Regulation in Markets for Life Insurance - Part II Overview and Policy Implications*, (Toronto: Ontario Economic Council).

Refereed Articles:

- with W.T.Stanbury (1990) "Landlords as Economic Prisoners of War", *Canadian Public Policy*, XVI no.4.
- with G.D. Quirin and S.P. Sethi (1977) "Market Feedbacks and the Limits to Growth", *INFOR*, Vol. 15, No. 1.

Other Publications:

- (1992) *Technology, Competition and Cross-subsidization in the Canadian Telecommunications Industry*, (Ottawa: Public Interest Advocacy Centre).
- (April 1990) *Paying for What You Need: Technological Advances and Competition in Telecommunications*, (Ottawa: Public Interest Advocacy Centre).
- with Andrew Roman and Robert Horwood, (1989) *Insurance Retailing by Financial Institutions in Canada*, (Ottawa: Public Interest Research Centre).
- with Douglas G. Hartle (1983) "The TAX-2 Model and Results" in *A Separate Personal Income Tax for Ontario: An Economic Analysis*, Special Research Report, (Toronto: Ontario Economic Council).
- (1982) "Commentary" in *Inflation and the Taxation of Personal Investment Income: An Analysis and Evaluation of the Canadian 1982 Reform Proposals* (edit. D.W. Conklin), Special Research Report (Toronto: Ontario Economic Council).

TEACHING

1989	Economics of Housing, Scarborough College, University of Toronto
1979 – 1985	Engineering Economy, Faculty of Engineering, University of Toronto

1982 – 1985	Computerized Business Systems (B.A. Program), and Management Information Systems (M.B.A.), Canadian School of Management
1979	Introductory Economics at St. George Campus, University of Toronto
1977 – 1979	Economic Principles at Erindale College, University of Toronto
1980 – 1985	Scuba diving instruction for Basic Diver, Sport Diver, Assistant Instructor and Instructor courses (National Association of Underwater Instructors).

RESEARCH MANAGEMENT

1983 –1987

- Research Director: Commission of Inquiry Into Residential Tenancies.
- Directing a staff of four in house researchers on various background studies on Ontario's housing market and the literature related to rent regulation. Managed thirty external projects on topics related to the housing market and rent regulation.

1978 –1980

- Research Officer: Ontario Economic Council.
- Research was conducted in the areas of regulation of the securities industry, mineral resource taxation policy, and Federal Provincial energy policy.
- Other duties included managing ten external research contracts on topics in regulation and directing the work of research assistants.

OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board’s External Advisory Committee.
- Panelist for “Administrative Tribunals and ADR”, Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Participation on behalf of OCAP in consultative processes related to direct purchase and integrated resource planning in the Ontario natural gas industry.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Former Chairman of the Board of Directors of the Festival of Canadian Theatre.
- Articles in the editorial section of the Financial Times of Canada on policies for reforming Ontario's system of rent regulation (June 1990) and federal proposals regarding bank directorships (February 1991).
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.
- Refereed articles and research studies for *Canadian Public Policy*, *Queen's Quarterly* and Consumer and Corporate Affairs, Canada.

- Several organizations have been assisted in developing their research agendas, writing submissions to government on economic issue, or in other advisory capacities. Clients include the Public Interest Research Centre (topics include airline deregulation, Via Rail, telephone solicitation, Bell Canada's rate structure, frequent flyer programs, price cap regulation, and home equity conversion), Ontario Association of Art Galleries (arts funding and economic impact), Public Affairs Management, Inc., City of Toronto, Parks and Recreation Department, and Goldfarb Consultants.

CLIENTS

Private Sector Companies

Alfred Bunting & Co.
BC Gas Utilities Limited
Buttcon Ltd.
Canadian National Investments
Comdisco Canada Inc.
Devon Canada
EnCana
Enbridge Gas Distribution
Enron Trade and Capital Canada
Fine Line Communications Ltd.
Fuji Electric (Tokyo)
Great West Life Assurance Co.
Hydro One Networks Inc.
Insurance Corp. of British Columbia
New Brunswick Power (Disco)
Ontario Power Generation
Sithe Canada
Terasen Gas
Union Gas Limited
Over 30 Ontario electricity distributors
Auto Haulaway Inc.
BC Rail
Canavest House Ltd.
Entergrus (Chatham-Kent Energy)
Coral Energy
Direct Energy
ENERconnect
EnCana Corporation
Financial Times of Canada
FortisBC
Goldfarb Consultants
Highmark Properties
Hydro Québec
McLeod Young Weir
Ontario Hydro Services
Shulman Communications Inc.
Star Produce
The Morassutti Group
Wirebury Connections Inc.

Industry and Other Associations

Association for Furthering Ontario's Rental Development
Australian Merchant Bankers' Association
Canadian Association of Members of Public Utilities Tribunals (CAMPUT)
Canadian Business Telecommunications Alliance
Canadian Film and Television Association
Canadian Independent Telephone Association
Canadian Museums Association
Cornerstone Hydro Electric Concepts
Electricity Distributors Association

Manitoba Keewatinowi Okimakanak
Ontario Association of Art Galleries
Ontario Energy Association
Ontario Federation of Symphony Orchestras
Power Workers' Union (CUPE 1000)
Toronto Theatre Alliance

Consumers' Associations

Alberta Council on Aging
Alert on Welfare
British Columbia Old Age Pensioners' Association
Canadian Pensioners Concerned
(Nova Scotia Division)
Consumers Association Of Canada
(National)
(Manitoba Branch)
(Alberta Branch)
(Northwest Territories Branch)
Consumers Fight Back Association
Council of Senior Citizens' Organizations
Co-operative Housing Association of Ontario
Federated Anti-Poverty Groups of British Columbia
Action réseau consommateurs (formerly La Fédération
Nationale des Associations de Consommateurs du Québec)
Manitoba Society for Seniors
The National Anti-Poverty Organization
Nova Scotia League for Equal Opportunities
Ontario Coalition Against Poverty
Option Consommateurs
PEI Council for the Disabled
PEI Senior Citizens Federation
People on Welfare for Equal Rights
Public Interest Research Centre
Rural Dignity of Canada
Rural Dignity, PEI Chapter
Senior Citizen' Association
Social Action Commission

Counsel for Consumers' Associations

British Columbia Public Interest Advocacy Centre
Legal Aid Manitoba, Public Interest Law Centre
Newfoundland Consumer Advocate
Public Interest Advocacy Centre (Ottawa)

Government

Federal
Canada Mortgage and Housing Corporation
Canadian Conference on Heritage Resources
Consumer and Corporate Affairs (Canada)
Department of Communications (Canada)
Director of Investigation and Research, Combines Investigation Act
St. Lawrence Seaway Authority

Provincial
Alberta Department of Energy
Commission of Inquiry into Residential Tenancies
New Brunswick, Department of Energy
Niagara Region Review Commission
Ontario Economic Council
Ontario Energy Board
Ontario Institute for Studies in Education, Department of Educational Planning
Ontario Ministry of Community and Social Services
Ontario Ministry of Health
Ontario Ministry of Housing (Corporate Policy and Planning; Rent Review Policy, Housing Field Operations)
Ontario Securities Commission
Ontario Task Force on the Investment of Public Sector Pension Funds
Ottawa/Carleton Region Review Commission
University of Toronto

Other
City of Calgary Electrical System
City of Peterborough
City of Toronto, (Telecom; Housing; Parks and Recreation)
Halifax Regional Municipality
Manitoba NDP Caucus
Office of Fair Trading (United Kingdom)

St. Francis Xavier University
Toronto Harbour Commissioners
Four municipally operated public utility telephone system

ACADEMIC ACHIEVEMENTS

1975	Masters in Business Administration in Economics and Management Science, University of Toronto
1972	Bachelors of Science in Electrical Engineering, University of Toronto

MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

ASSOCIATE CONSULTANT, RATES AND REGULATION

Michael has over 33 years experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors, with particular emphasis in electricity rates in Ontario and the regulatory review and approval process for cost allocation and rate design. Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, and Hydro 2000.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system. Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB). Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design. Keep up to date on Cost Allocation and Rate Design issues in the industry. Ensure deliverables are of high quality, defensible and meet all deadlines. Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- In charge of producing weekly, monthly, quarterly and annual internal financial reporting products. Input to and coordination of senior management reporting and performance assessment activities. Expert line of business knowledge in support of financial and business planning processes. Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature. Provide support to other units as necessary. Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- In charge of the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company. Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting , Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy. Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company. Supervise professional staff supporting the function. Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- In charge of pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- The section was also responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head, (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers. Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro. Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates. Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant.
- Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity. Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System. Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board. Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecasting Analyst, Financial Forecasts **1980 - 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget. Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 - 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.