YUKON ELECTRICAL
An *ATCO* Company

YUKON ENERGY

February 19, 2010

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. McLennan:

Re: Yukon Energy and Yukon Electrical 2009 Phase II Rate Application

This letter addresses two applications:

1) **Joint Phase II Rate Application:** The Yukon Energy Corporation ("YEC") and Yukon Electrical Company Limited ("YECL") (jointly, the "Companies") 2009 Phase II Rate Application (the "Application"). The filing consists of the Application and the Supporting Documents (comprising 8 Tabs of detailed materials, six of which are included herein and the remaining two of which will be filed by March 1, 2010).

2) **Rider D – Diesel Generation Energy Cost Recovery Rider:** This Rider is proposed by YECL to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted, which will be filed March 2010.

Joint Phase II Rate Application

Board Order 2009-8 directed the Companies to file a joint Phase II application, with stakeholder input, that provides:

- An up-to-date cost of service study (with electronic models attached) that provides accurate revenue to cost ratios ("R/C ratios") for all rate classes;
- Rate design recommendations that comply with previous Board directions and comply with current OICs; and
- Updated terms and conditions of service, including a review of investment levels.

In a letter to the YUB dated January 29, 2010, the Companies committed to file a complete Phase II Application by February 19, 2010. The attached Application provides an up to date cost of service study, and proposes adjustments to rates to be effective September 1, 2010. These rate adjustments include revising the manner of collecting the approved 2009 Consolidated Firm Rate Revenue requirement of $50.833 million with proposed rate design recommendations that comply with prior Board directions and current OICs. The Application also includes updates to the Terms and Conditions of Service (previously known as "Electric Service Regulations"). The Companies are able to include with this filing today all of the attached Supporting Document tabs, other than Tabs 4 and 5 which will be filed with the Board by March 1, 2010 (the Companies need this additional time to complete the necessary joint editing and review of these documents).

YECL Diesel Generation Energy Cost Recovery Rider D

YECL is separately seeking approval of a proposed Diesel Generation Energy Cost Recovery Rider to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted. This will be provided as a separate attachment to the cover letter when the remaining Tab 4 and Tab 5 are filed with the Board.

Proposed Process

The Companies propose that the Board establish a process to allow for interested parties to be identified and for a schedule to be developed for review of this Application. The Companies will arrange for publication of a Notice of the Board's process and a date for public hearing in the local press once plans are finalized.

Notifications of this filing are being sent to intervenors in the 2008/2009 GRA's for YEC and YECL. Copies of this letter, the Application and the Supporting Documents are being made available via Yukon Energy's and Yukon Electrical's websites in their entirety at the following addresses: www.yukonenergy.ca and http://www.yukonelectrical.com. Applications can also be provided, where requested by interested parties, in hard copy format.

If you have any questions regarding the above please call.

Yours truly,

YUKON ELECTRICAL COMPANY LIMITED	YUKON ENERGY CORPORATION
Nick Palladino	Ed Mollard
Manager Pricing	Chief Financial Officer

YUKON ELECTRICAL
An *ATCO* Company

YUKON ENERGY

March 1, 2010

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. McLennan:

Re: Yukon Energy and Yukon Electrical 2009 Phase II Rate Application

On February 19, Yukon Energy and Yukon Electrical (the "Companies") submitted their joint Phase II Rate Application. At that time, it was noted that three items remained outstanding – Tab 4 (Rate Design) and Tab 5 (Terms and Conditions of Service) for the Joint Phase II Rate Application, and the concurrent YECL Application for Rider D – Diesel Generation Energy Cost Recovery Rider. These items are attached to this letter.

The Companies will prepare and file consolidated electronic and print-ready version of the Applications, combining the materials filed on February 19, 2010 and those attached to this letter, as soon as possible this week. Paper copies will be delivered to the Board.

Joint Phase II Application

As set out in the Companies letter to the Board dated February 19, 2010, the Companies committed to file by March 1, 2010 the two remaining tabs of Supporting Material, as follows:

- **Tab 4 Rate Design:** The Companies have worked diligently in an effort to present a uniform and consistent approach to rate design. As set out in the Application filed February 19, 2010, this includes joint submission of two options (Option A and B) for the Board's review and consideration. However, the Companies were not able to arrive at common descriptions of the options or the underlying system conditions driving the need to re-establish efficiency-based price signals to customers. As a result, the Companies have provided herein two rate design discussions (Tab 4YEC and Tab 4YECL). Each Company will be prepared to speak to their discussion as part of this proceeding.

- **Tab 5 Terms and Conditions of Service:** The attached material provides a single joint description of the proposed changes to the Terms and Conditions of Service. However, as noted in Tab 5 there are two items on which the two utilities are not in agreement. These relate to the requirements for collecting the "minimum bill" before reconnecting large customers, and the level of Maximum Company Investment after 2011, including the approach to be used to determine these values.

In the Application document filed February 19, 2010, two typographical errors have been identified. On page 5 the value for Option B First Block Energy (Residential Government) should be 17.92 cents/kW.h (not 17.78 cents/kW.h). On page 6 in the last line of text, the value of the runoff rate for the Old Crow zone should be identified as 31.72 cents/kW.h (not 31.69 cents/kW.h). These errors will be corrected in the final consolidated version of the filing being prepared.

YECL Diesel Generation Energy Cost Recovery Rider D

YECL is separately seeking approval of a proposed Diesel Generation Energy Cost Recovery Rider to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted. This is provided herein under separate cover.

Electronic Materials

Also being filed at this time is electronic models of the Cost of Service Study and other electronic models providing backup to specific items noted in the supporting documents.

Notifications of this filing are being sent to intervenors in the 2008/2009 GRA's for YEC and YECL. Copies of this letter, the Application and the Supporting Documents are being made available via Yukon Energy's and Yukon Electrical's websites in their entirety at the following addresses: www.yukonenergy.ca and http://www.yukonelectrical.com. Applications can also be provided, where requested by interested parties, in hard copy format.

If you have any questions regarding the above please call.

Yours truly,

YUKON ELECTRICAL COMPANY LIMITED	YUKON ENERGY CORPORATION
N Palladino	E Mollard
Nick Palladino	Ed Mollard
Manager Pricing	Chief Financial Officer

2009 PHASE II RATE APPLICATION

TO THE YUKON UTILITIES BOARD (BOARD)

YUKON ENERGY CORPORATION & YUKON ELECTRICAL COMPANY

APPLICATION AND ORDERS REQUESTED

Yukon Energy and Yukon Electrical's (hereafter "the Companies'") joint 2009 Phase II Rate Application (the "Application") addresses cost of service, rates and changes to Terms and Conditions of Service (previously known as "Electric Service Regulations"). As directed by the Board in Order 2009-8, the Application specifically includes the following:[1]

- An up-to-date cost of service study (with electronic models attached) that provides accurate revenue to cost ratios ("R/C ratios") for all rate classes (provided as Appendix 3.1 of Tab 3);
- Rate design recommendations that comply with previous Board directions, and comply with current OICs (provided in Tab 4 with supporting tables); and
- Updated Electric Service Regulations including a review of investment levels provided in Tab 5.

OVERVIEW

Through the proceedings leading to Board Orders 2009-5 (YECL final revenue requirement) and 2009-10 (YEC final revenue requirement), the Board approved the revenue requirements for each Company and rate adjustments (through riders) to permit the Companies to fully collect their 2009 revenue requirements at test year forecast loads. Consequently, this Phase II Rate Application includes no net change to the overall level of rates in Yukon.

This joint Application proposes adjustments to rates, to be effective September 1, 2010 and to collect the approved 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million.[2] Rate design adjustments included in the Application are proposed in response to Directive 13 of Order 2009-8 (directing the Companies to provide rate design recommendations that comply with previous Board directions and current OICs).

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1 Although this Application is based on the 2009 test year, it will not apply approved Phase II rates on a retroactive basis.

2. See Tab 2, Table 2.2 and Table 2.3.

Two specific rate design matters have been identified for attention in this Application:

- Eliminate the current general purpose Rate Riders (Riders J and R) from customer bills and adjust retail base rates to fully reflect approved 2009 costs.
- Adjust rates within each retail customer class within the bounds permitted by OICs 2008/149 and 2007/94 to address economy and efficiency rate principles/directives, including the need to adjust runoff rates in light of approved 2009 incremental costs (based on 2009 incremental cost of diesel) in order to begin restoring efficient price signals to each customer class with a goal to send reasonable price signals to each customer class recognizing the existing cost structure. All proposed rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers, and therefore meet the requirements of the above noted OICs to prevent rate revenue rebalancing among retail customer classes.

The Application includes the following:

- Cost of Service Summary;
- Incremental Cost of Diesel Generation;
- Summary of Requested Orders; and
- Overview of Supporting Documents.

COST OF SERVICE SUMMARY

Cost of Service (COS) Revenue to Cost (R/C) Ratios by rate class are provided below in Table 1 for 1997 versus 2009. These R/C ratios compare, by firm customer class, the approved rate revenues for the class (for 2009, the class rate revenue cannot be changed due to OIC 2008/149) and the overall Yukon costs of service (i.e., approved Yukon Consolidated Firm Rate Revenue) allocated to the class for the same test year.

Table 1:
Revenue to Cost (R/C) Ratios by Rate Class – 1997 and 2009 (%)

Customer Class	1997 Final Approved	2009
Residential Government	100%	105%
Residential Non Government	81%	79%
General Service Government	143%	144%
General Service Non Government	110%	117%
Industrial	100%	109%
Street Lights	110%	69%
Sentinel Lights	110%	148%

The effective unit costs arising from the cost of service analysis reflect average embedded costs as follows:

- **Cost per customer:** Customer related costs for a distribution level customer (residential or general service) vary from approximately $453/year to $475/year ($37.76 to $39.63 per month).
- **Cost for demand service:** The demand related costs for distribution level customers (residential or general service, as well as lighting classes) vary from $228/kW-year to $243/kW-year ($19.02 to 20.26 per kW/month) for each unit of coincident peak demand at the customer meter. For transmission level customers (industrial) the cost is $158/kW-year ($13.16 per kW/month).
- **Embedded costs of energy:** The energy related costs for distribution level customers (residential or general service, as well as lighting classes) is 8.5 cents/kW.h at the customer meter, and for transmission level customers (industrial) the cost is 7.8 cents/kW.h.

INCREMENTAL COST OF DIESEL GENERATION

Table 2 summarizes the 2009 incremental cost of diesel generation, based on approved fuel price forecasts.

Table 2:
2009 Incremental Cost of Diesel Generation

Yukon Energy Corporation & Yukon Electrical Company Limited
2009 Incremental Cost of Diesel

2009 Incremental Rates

Incremental Rates	Hydro		Large Diesel	Old Crow
	WAF (Faro)	MD (Dawson)	Watson	
Forcast Cost of Fuel - (cent/L)	99.2	97.5	87.48	193.41
Approve Heat Rate - (KW.h/L)	3.55	3.71	3.82	3.56
Losses	8.46%	8.46%	5.82%	7.75%
Run-out Cost - (cent/KW.h)	30.31	28.50	24.23	58.54
Add O&M - (cent/KW.h)	3.00	3.00	3.00	3.00
Total	33.31	31.50	27.23	61.54
Generation (KW.h)	866,000	396,000	14,593,000	2,029,000
Weighting Factor	68.62%	31.38%	100.00%	100.00%
Blended Cost (cent/KW.h)	32.74		27.23	61.54
Blended Cost,WAF-Large Diesel (cent/KW.h)		27.67		

	Small Diesel			
	Destruction Bay	Beaver Creek	Swift River	
Forcast Cost of Fuel - (cent/L)	83.13	81.52	92.44	
Approve Heat Rate - (KW.h/L)	3.41	3.56	2.99	
Losses	8.48%	8.48%	8.48%	
Run-out Cost - (cent/KW.h)	26.45	24.84	33.54	
Add O&M - (cent/kW.h)	3.00	3.00	3.00	
Total	29.45	27.84	36.54	Blended Hydro, Large
Generation (KW.h)	1,741,000	2,115,000	326,000	Diesel and Small Diesel
Weighting Factor	41.63%	50.57%	7.80%	
Blended Cost (cent/KW.h)		29.19		27.99

SUMMARY OF REQUESTED ORDERS

Changes are sought in this Application to remove Rider J and Rider R, and to adjust various rate schedules effective September 1, 2010 (Appendix 4.1 presents tables reviewing rates and bill impacts for residential and general service Options A and B below; Appendix 4.2 provides all other adjusted rate schedules in blacklined form).

In addressing the relevant issues and options for adjusting residential and general service rates at this time, the Companies jointly recommend establishment of new rate blocks for each class (with a joint approach in this regard specifically for general service classes), as well as new base rates that allow for current removal of Rider J and Rider R along with inclining rates and an improved reflection of incremental diesel generation costs to provide a reasonable price signal to customers in the context of the current Yukon cost structure. In order to comply with the revised deadline for filing of the Application, the Companies have not been able to finalize one specific rate package to be recommended within this framework. To assist the Board and intervenors to review the new rate structures in the context of materially different degrees of rate change impact for different customer groups within each class, the Companies have provided two sets of options for residential and general service rate class 2009 rate adjustments as summarized below.

- **Option A** – Reflects runoff rates at 80% of 2009 incremental diesel generation costs, with resulting increased bill impacts for a minority of higher use customers and reduced bills for the majority of customers using only first block energy.
- **Option B –** Retains first block energy rates at approximately current levels (no material bill changes), and keeps runoff rate levels at 50% of 2009 incremental diesel generation costs.

In summary, approval of the Board is requested for the following Orders for rates effective September 1, 2010 (the Companies are not proposing to apply rates retroactive):

1. **2009 Rates:** Approval of rate adjustments, by class for all related customers of Yukon Energy and Yukon Electrical (these rate adjustments are described in detail in Tab 4):
   a. **Retail Rates:** for each retail rate class, rate adjustments without any rebalancing of overall rate revenues as between customer classes:
      i. Amend Rate Schedules for **Residential Non-Government** (1160, 1260, 1360, 1460 for the respective zones) and **Residential Government** (1180, 1280, 1380, 1480) to provide adjusted base rates and an adjusted rate design that includes a new equalized second energy block. Two options are provided for review and assessment (both options adjust the base **customer charge** to $14.65 per month

for non-government and $18.47 per month for government, reflecting the current charge after rider impacts):

1. **Option A:**
   (1) **First energy block** for use up to 1,000 kW.h per month (about 70% of residential non-government class annual bills do not exceed this level), with an adjusted base energy rate of 10.90 ¢/kW.h for non-government and 16.17 ¢/kW.h for government;
   (2) **A new equalized second energy block** for use from 1,001 to 1,500 kW.h per month (about 90% of non-government class annual bills do not exceed this level), with a base energy rate of 15.22 ¢/kW.h for non-government and government (reflects current Small Diesel zone run off rate after Rider J and Rider R); and
   (3) **An adjusted runoff energy block** for all use in excess of 1,500 kW.h per month, with runoff rates that reflect 80% of short term incremental generation costs (non-government and government blended rate of 22.39 ¢/kW.h for Hydro, Large Diesel and Small Diesel zones, and 49.23 ¢/kW.h for Old Crow zone, based on fuel price forecasts as approved for 2009).

2. **Option B:**
   (1) **First energy block** for use up to 1,000 kW.h per month (about 70% of residential non-government annual bills do not exceed this level), with an adjusted base energy rate of 12.14 ¢/kW.h for non-government and 17.92 ¢/kW.h for government;
   (2) **A new equalized second energy block** for use from 1,001 to 2,500 kW.h per month (about 98% of residential non-government annual bills do not exceed this level), with a base energy rate of 12.82 ¢/kW.h for non-government and government; and
   (3) **An adjusted runoff energy block** for all use in excess of 2,500 kW.h per month with runoff rates that reflect 50% of short term incremental generation costs (non-government and government blended rate of 13.99 ¢/kW.h for Hydro, Large Diesel and Small Diesel zones, and 30.77 ¢/kW.h for Old Crow zone, based on fuel price forecasts as approved for 2009).

ii. Amend Rate Schedules for **General Service Non-Government and Municipal Government** (2160, 2170, 2260, 2270, 2360, 2370, 2460, 2470) and **General Service Federal and Territorial Government** (2180, 2280, 2380, 2480) to provide adjusted base rates and an adjusted rate design that includes a new equalized second energy block for use from 2,000 to 15,000 kW.h per month, and a new equalized third energy block from 15,001 to 20,000 kW.h per month linked to the short term incremental generation costs for Hydro, Large Diesel and Small Diesel zones. This three block rate structure ensures that for all but approximately 109 of the largest GS customers who consume over 20 MW.h in a month (on the order of 3% of GS customers), the rate design in all practical respects parallels the residential three block rate design with the third block linked to either 50% (Option B) or 80% (Option A) of the incremental cost of diesel. For the large GS customers (>20,000 kW.h/month) an adjusted runoff energy block is established for all use in excess of 20,000 kW.h per month with a rate designed to address large users today prior to future consideration of a potential separate General Service Large User rate class. Two options are provided for review and assessment:

1. Option A:

(1) **Demand charge** of $6/kW per month for non-government and $10/kW per month for government (minimum bill of 5 kW/month);

(2) **First energy block** with a base energy rate of 8.31 ¢/kW.h for non-government and 18.81 ¢/kW.h for government (about 67% of general service non-government annual bills do not exceed this level);

(3) **Second energy block** with a base energy rate of 14.90 ¢/kW.h for non-government and 14.90 ¢/kW.h for government (about 96% of general service non-government annual bills do not exceed this level);

(4) **Third energy block** with a base energy rate of 22.39 ¢/kW.h for non-government and government that reflects 80% of the short term incremental generation costs for Hydro, Large Diesel and Small Diesel zones (about 98% of general service non-government annual bills do not exceed this level); and

(5) **Runoff energy block** with a fixed base energy rate for non-government and government of 12.86 c/kWh for Hydro and Large Diesel zones, 15.22 ¢/kW.h for Small Diesel zone and 31.72 ¢/kW.h

for Old Crow zone which are the present effective base rates in these zones (i.e., including Riders J and R).

2. **Option B:**

(1) **Demand charge** of $7.39/kW per month for non-government and $12.31/kW for government (minimum bill of 5 kW/month);

(2) **First energy block** with a base energy rate of 10.23 ¢/kW.h for non-government and 21.48 ¢/kW.h for government (about 67% of general service non-government annual bills do not exceed this level);

(3) **Second energy block** with a base energy rate of 12.88 ¢/kW.h for non-government and 12.97 ¢/kW.h for government (about 96% of general service non-government annual bills do not exceed this level);

(4) **Third energy block** with a base energy rate of 13.99 ¢/kW.h for non-government and government that reflects 50% of the short term incremental generation costs for Hydro, Large Diesel and Small Diesel zones (about 98% of general service non-government annual bills do not exceed this level); and

(5) **Runoff energy block** with a fixed base energy rate for non-government and government of 12.86 ¢/kW.h for Hydro and Large Diesel zones, 15.22 ¢/kW.h for Small Diesel zone and 31.72 ¢/kW.h for Old Crow zone which are the present effective base rates in these zones (i.e., including Riders J and R).

iii. Amend Rate Schedules for **Street Lighting (61, 66, 67)** and **Sentinel Lighting (75, 76)** to adjust base rates by an equal percentage of 23.123% to reflect the proposed elimination of Riders J and R from current customer bills.

b. **Industrial Rates**:

i. **Rate Schedule 39** to incorporate wording in the rate schedule to clarify the operation of Rider F to this customer class, as approved in Order 2009-10.

c. **Wholesale Rates**:

i. **Rate Schedule 42** (wholesale sales to Yukon Electrical) to adjust the base energy rate that applies throughout Yukon (as required to reflect adjusted retail base rates and removal of Rider J and R). In the event that an approach reasonably consistent with Option A above is not adopted by the Board to move the residential Hydro zone non-government run-out rate materially closer to the GRA incremental diesel cost, approval to incorporate the full incremental cost of diesel generation on the major systems (27.67 ¢/kW.h) as the Energy Reconciliation Adjustment rate.[3]

ii. **Rate Schedule 51** is revised to provide for a single energy-only rate of 8.290 ¢/kW.h for Option A and 8.299 ¢/kW.h for Option B that applies to all firm Yukon Energy purchases from Yukon Electrical throughout Yukon.

d. **Other Rate Matters**:

i. Cancellation of the earlier **Rate Schedules 33, 38 and 40**, each of which relates solely to unique circumstances of previous industrial customers, and do not have relevance today.

ii. Elimination of **Riders J and R** from current customer bills.

2. **Terms and Conditions of Service:** Approval of the revised terms under which the Companies provide service to customers, including Maximum Company Investment levels as detailed in Tab 5 of the Application.

No changes are proposed today to the Secondary Energy rate schedules (32 and 43) or to Riders A (Multiple Residence Service) or B (Unmetered General Service Flat Rate).

OVERVIEW OF SUPPORTING DOCUMENTS

Detailed schedules, analysis and documentation in support of the Application are presented in the attached supporting documents.The supporting documents address detailed information on the requested approvals, including Cost of Service ("COS") analyses. The supporting documents also provide other background information relevant to the Application, including review of past Board Orders and directives since the last major rate review in 1996/97, details on specific elements of the Application (e.g., specific proposals relating to rates), and copies of relevant Orders-in-Council.

The following is an outline of the specific supporting documents included with the Application:

- **Tab 1 Introduction and Background:** Provides an introduction to the supporting documents, addressing YUB review of Yukon Energy and Yukon Electrical joint rate applications and other cost of service and rate related issues.

- **Tab 2 Outcomes of YEC and YECL Revenue Requirement Reviews:** Summarizes the outcomes of each Company's respective GRA revenue requirement reviews.

[3] As noted in the concurrent YECL application for Rider D, YECL proposes that any amount charged for diesel generation on the margin that varies from forecast will be flowed through to customers in accordance with the proposed Rider D.

- **Tab 3 Cost of Service:** Provides an up to date cost of service (COS) study, with updated revenue/cost (R/C) ratios for all rate classes receiving firm service, based on the 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million for the Companies as set out in Tab 2.

- **Tab 4YEC Rate Design – Yukon Energy Discussion:** Provides rate design options and proposals to collect the approved 2009 Consolidated Firm Rate Revenue Requirement. This tab sets out Yukon Energy's discussion on the options presented.

- **Tab 4YECL Yukon Electrical's Proposed Rate Design:** Provides Yukon Electrical's rate design option and proposal to collect the approved 2009 Consolidated Firm Rate Revenue Requirement.

- **Tab 5 Terms and Conditions of Service:** Reviews and updates the Terms and Conditions of Service (previously known as "Electric Service Regulations") and Maximum Company Investment levels.

- **Tab 6 Board Directives:** Provides a review of past Board Orders and responses to outstanding directives since the last joint rate filing by the Companies in 1996/97.

- **Tab 7 Consultation:** Outlines and summarizes the stakeholder consultation process undertaken in advance of the preparing the final Application and provides in Appendix 7.1 the consultation materials provided to stakeholders and submissions received from stakeholders.

- **Tab 8 Orders in Council:** Provides the relevant Order in Council documents which guide the rate design.

YUKON ENERGY

YUKON ENERGY CORPORATION

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THE YUKON ELECTRICAL COMPANY LIMITED
An *ATCO* Company

2009 Phase II Rate Application

February 19, 2010

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TAB 1
INTRODUCTION AND BACKGROUND

1.0 INTRODUCTION AND BACKGROUND

Yukon Energy Corporation ("Yukon Energy") and Yukon Electrical Company Limited ("Yukon Electrical") (collectively the "Companies") 2009 Phase II Rate Application[1] (the "Application") to the Yukon Utilities Board (the "YUB" or "Board") includes eight tabs of supporting materials related to the Application.

Tab 1 provides an introduction to the supporting documents under the following headings:

- Board Directives re: 2009 Phase II Application;
- Previous Joint Applications by the Companies;
- Applications Since the 1996/97 GRA;
- Rate and Bill Changes Since 1996/97 GRA;
- Load and System Changes Since 1996/97 GRA; and
- Implications for 2009 Phase II Rate Application.

1.1 BOARD DIRECTIVES RE: 2009 PHASE II APPLICATION

In 2008, each Company separately filed a General Rate Application seeking Board approval for that Company's forecast revenue requirements for 2008 and 2009. The Board approved Yukon Electrical's revenue requirements in Orders 2009-2 and 2009-5, and approved Yukon Energy's revenue requirements in Orders 2009-8 and 2009-10. Aside from interim rate riders to reflect the approved revenue requirements, the Board directed that all rate matters be addressed in a separate joint Phase II application by the Companies based on their respective revenue requirements, as approved.

Board Order 2009-8 directed the Companies to file a joint Phase II application, with stakeholder input, that provides:

- An up-to-date cost of service study (with electronic models attached) that provides accurate revenue to cost ratios ("R/C ratios") for all rate classes;

[1] Although the Phase II Application is based on the 2009 test year, the Companies are not intending to apply the Phase II approved rates on a retroactive basis.

- Rate design recommendations that comply with previous Board directions and comply with current OICs; and
- Updated terms and conditions of service, including a review of investment levels.

1.2 PREVIOUS JOINT APPLICATIONS BY THE COMPANIES

Following the establishment of Yukon Energy in 1987, the Companies filed various joint applications during the next decade seeking Board approval of revenue requirements and rates. This joint approach reflected two factors:

- OIC rate directives to the YUB, starting with OIC 1988/150, which in effect required a joint filing by the Companies for cost of service and rate matters in order that the Board could implement the OIC rate directives, including:
  - Equalized rates for all non-government retail customers within each customer class, regardless of the company that served them;
  - Variations in non-government rates allowed in runoff blocks starting at no less than 1,000 kWh/month for residential and 2,000 kWh/month for general service;
  - Specific directives for major industrial rates; and
  - Wholesale rates sufficient to recover Yukon Energy's regulated costs not otherwise recovered from other Yukon Energy customers.
- Yukon Energy had retained Yukon Electrical as its manager, pursuant to a Management Agreement.

The first focused review of cost of service and rates occurred in 1992, initiated in response to OIC 1991/62 (which replaced OIC 1988/150).[2] The Companies provided a joint filing on cost of service and rate design and, pursuant to the OIC, the Board undertook a review and issued a report with recommendations to the Minister (1992 YUB Report on COS and Rate Design).[3] As part of the 1993/94 GRA, the Companies provided their response to the findings of the 1992 Report, and provided a cost of service study and rate design proposal consistent with the recommended principles.

[2] At that time, a COS was anticipated to be required for the Board to set rates for Major Industrial customers to ensure (after expiry of the then contract with the Faro mine owner) that such rates would be sufficient (as required by OIC 1991/62) to cover cost of service for this class determined on a Yukon wide basis with costs consolidated for both Companies.

[3] See Appendix 7.1 for a copy of the Report, as provided to interested parties following the December 15, 2009 consultations session.

The most recent joint application by the Companies to adjust rates was the 1996/97 General Rate Application ("1996/97 GRA"), filed in November 1995 after the reopening of the Faro mine. The 1996/97 GRA contained both revenue requirement and cost of service/rate design topics in a single filing. The 1996/97 GRA occurred subsequent to the issuance of OIC 1995/90 (which replaced OIC 1991/62) and provided, for the first time since the initiation of levelized rates, the opportunity for inter-class rate rebalancing. This was done in an attempt to bring individual customer classes closer to paying rates that represented a reasonable proportion of the measured costs of serving that class (Revenue/Cost ratio, or R/C). The 1996/97 GRA also included provision for retail runoff rates to be adjusted for all zones (rather than only for communities supplied primarily by generation other than hydro, as in OIC 1988/150 and OIC 1991/62) so as to ensure that they continued to reflect the short-run incremental cost of diesel. The Board's directives regarding the 1996/97 GRA were provided in Order 1996-6 (revenue requirements based on a negotiated settlement package), Order 1996-7 and Order 1996-8.

Table 1.1 summarizes 1996/97 GRA R/C ratios by customer class prior to the GRA and after rate rebalancing provided for in the 1996/97 GRA. The COS study filed in the 1996/97 GRA illustrated General Service classes paying above 100% R/C ratios and consequently, this class received a major rate decrease to lower its R/C to 110%. Residential Non-Government class rates were not adjusted to raise the R/C from 80.52% to the zone of reasonableness (90% to 110%) due to the effects of the Yukon Government subsidies which at that time would negate the impact of any rate rebalancing for that class.

Table 1.1:
1996/97 GRA Revenue/Cost Percentages by Rate Class

	Before GRA Adjustments	After GRA Adjustements
Res Non-Gov (before YG relief)	80.52%	80.52% (68% w/ gov rate relief)
Residential Gov	97.55%	100%
GS Non-Gov	131.79%	110%
GS Gov	153.93%	143.20%
Industrial	89.55%	100%
Streetlights	154.32%	110%
Spacelights	110.54%	110%

Board Order 1996-7 approved the revised rates and ordered the utilities to target all classes to 90-110% R/C within 10 years.

Subsequent to the 1996/97 GRA, Yukon Energy ended its Management Agreement with Yukon Electrical at the end of 1997. Thereafter, aside from joint reports filed at the direction of the Board, the Companies no longer filed joint applications for revenue requirements or rates, and (prior to the current Application) no joint COS, rate design, or Electric Service Regulations ("ESRs") applications have been prepared by the Companies.

1.3 APPLICATIONS SINCE THE 1996/97 GRA

After the 1996/97 GRA, there was not another full General Rate Application until 2008. Individual regulatory and rate matters were addressed in the intervening years through various reviews and rate riders.

- **Faro Mine closure and Rider J:** Subsequent to the 1996/97 GRA, the Faro mine (which comprised 40% of the load on the system) closed permanently in early 1998. After a limited scope[4] proceeding in 1998, involving Yukon Energy as sole applicant, Rider J was established for all retail rates of both Companies to recover specific identifiable and major adverse net rate revenue impacts on Yukon Energy from the Faro mine closing.
- **Yukon Energy 2005 Required Revenues and Related Matters proceeding:** The first full review of Yukon Energy's revenue requirements since the 1996/97 GRA occurred with Yukon Energy's 2005 Required Revenues and Related Matters application; however, aside from certain limited rate matters (e.g., Secondary Sales rate adjustment, and rates affecting the Faro mine shut down activities), no changes were made to retail rates and no new COS was developed.[5] The permanent closure of the Faro mine resulted in surplus hydro on the WAF system. As a result, Yukon Energy pursued new sales under the "Secondary Energy" rate schedule to develop a new market for this low-cost power. New Secondary Energy sales and higher related rate revenues approved in the 2005 application provided additional revenues that helped defer firm rate increases.

[4] The 1998 proceeding addressed only the YEC net revenue changes from its 1997 GRA revenue requirement forecast due to the Faro mine closure. The hearing did not address other ancillary impacts from the closure, such as reductions in retail electricity sales in the town of Faro or other communities, or to address any other cost pressures affecting Yukon Energy since the Board's 1996 hearing on the 1996/97 GRA.
[5] At the outset of the 2005 Required Revenues and Related Matters hearing for Yukon Energy, in response to a motion that the Board require both Yukon Energy and Yukon Electrical to file a general rate application (and a separate motion that the Board require Yukon Electrical to file a rate application as soon as possible to be heard in conjunction with Yukon Energy's application), the Board issued Order 2005-1 directing the Companies to jointly file a report with the Board by September 1, 2005 that provides information on the revenue to cost ratios by customer class for both companies using the most recent cost of service allocation study. The report jointly filed by the utilities referenced the 1996/97 GRA R/Cs as the last COS study and indicated no need for a new COS study to know where rates have to be adjusted at the outset if wanting to target 90-110 R/C, i.e., Residential Non-Gov't would need increased rates; and GS Gov would need decreased rates.

- **20-Year Resource Plan 2006-2025:** In 2006, the Board was requested by the Minister to review and report on Yukon Energy's 20-Year Resource Plan: 2006-2025, and the Board provided its Report to the Minister in January 2007. Yukon Energy's 20-Year Resource Plan addressed bulk power (generation and transmission) requirements and capital supply options for the WAF and Mayo Dawson grids, noting that current hydro generation surpluses on each grid might extend for at least 15 years absent new major industrial loads and reviewing renewable resource options to displace new baseload diesel generation requirements in the event that new major industrial loads were to be connected to the grids. The 20-Year Resource Plan also updated Yukon Energy's capacity planning criteria and addressed capacity resource shortfalls and options for the near term.
- **Minto PPA:** In 2007, Yukon Energy applied for approval of a Purchase Power Agreement ("PPA") for major industrial sales to the Minto mine. As a result, based on OIC 2007/94, the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to the adjusted Rate Schedule 39, Industrial Primary, which was attached as Schedule A to the OIC. In 2007 the Board was also requested by the Minister to review and report on Yukon Energy's Part III Application for the Carmacks-Stewart Transmission Project ("CSTP"), and the Board provided this report to the Minister at the end of May 2007.
- **2008/09 General Rate Applications:** In 2008, both Yukon Electrical and Yukon Energy filed separate 2008/09 GRAs addressing revenue requirements and other matters. The Board directed that all rate related matters be deferred to the current joint 2009 Phase II Application.

1.4 RATE AND BILL CHANGES SINCE THE 1996/97 GRA

Rate design and COS updates, which are typically relied upon, to guide ongoing adjustments to base rates for firm sales to each customer class, have been in abeyance since the 1996/97 GRA. Due to this long period without changes to base rates for firm sales, rate design and rate structure issues have not been addressed in a material fashion during this period. This has the following implications for the present Application:

- The Companies have continued since 1997 to rely upon across-the-board percentage rate riders (e.g., Rider J and Rider R) to recover approved rate revenue requirements needed beyond what is provided by the 1997 base rates, and there have been no changes since the

1996/97 GRA to base rates (i.e., the rates set out in the various rate schedules) for firm sales to all retail customers in Yukon;

- Current runoff base rates continue to be based on fuel prices approved in the 1996/97 GRA and do not reflect current GRA fuel prices that are over 2.5 times the levels in the 1996/97 GRA. Since the 1996/97 GRA, the Companies have typically relied upon Rider F to recover higher fuel costs – however, the 2008/2009 applications for each Company have resulted in approved new revenue requirements that reflect adjusted fuel prices; and
- There has been no opportunity to advance the rate rebalancing directives outlined by the Board in Order 1996-7, or (prior to this Application) to prepare an updated COS based on updated and approved revenue requirements for both Companies.

Whereas rate relief subsidies impeded rate rebalancing in the 1996/97 GRA, the Rate Stabilization Fund ("RSF") subsidy provided by the Yukon Government ended as at July 1, 2009. An Interim Energy Rebate ("IER") was implemented in 2009, as an interim measure, and it is currently understood that it may terminate in 2010 (subsequent to the Phase II proceeding). The IER provides for a 2.662 cents/kW.h rebate for up to first 1000 kW.h per month (first block) for residential non-government customers. With the termination of the RSF there is no longer any similar rate relief for general service or municipal customers.

Since the 1996/97 proceeding, rate policy OIC 1995/90 has been supplemented by OIC 2007/94 and OIC 2008/149, which provides the following guidance related to rate setting prior to 2013:

- **OIC 2007/94** - The Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary, Attached as Schedule A to the OIC. This rate schedule provides for Rider F fuel cost adjustments as well as inflation-related annual adjustments, but does not allow Major Industrial Customer rates to be adjusted based on COS until after 2012.
- **OIC 2008/149** - The Board must ensure that rate adjustments for retail customers prior to 2013 apply equally, when measured as percentages, to all classes of retail customers. This provision does not allow adjustments before 2013 to the overall firm rate revenue collected from each retail customer class based on COS.

1.5 LOAD AND SYSTEM CHANGES SINCE 1996/97 GRA

The 1996/97 GRA was based on continued operation of the Faro mine, with resulting material baseload diesel generation requirements on the WAF grid. The separate Mayo hydro system, in contrast, was forecast to have a material hydro generation surplus. Dawson was assumed to be in the Large Diesel rate zone, as a community relying only on local diesel generation.

Since the 1996/97 GRA, material load and system changes have occurred in Yukon. In summary, the approved 2009 GRA revenue requirements of the Companies include the following:

- **Closure of the Faro Mine** - Since the 1998 closure of the Faro mine, the WAF system has operated as a basically 100% hydro generation system, in sharp contrast to the 1996/97 system supply situation where nearly 100 GW.h of diesel generation was forecast for the WAF system.
- **Material Increases in Diesel Prices** - Diesel fuel price escalation since the 1996/97 GRA represents a material change reflected in the 2008/09 GRA revenue requirements of the Companies. Approved GRA diesel fuel prices for 2009 are well above the levels approved for 1997.[6]
- **Enhanced Diesel Generating Capacity** - Yukon Energy's 2006 20-Year Resource Plan proposed new generation capacity planning criteria, and forecast potential significant WAF generating winter peak capacity (MW) shortfalls based on these criteria as early as 2007 and 2008.[7] To address these winter peak generating capacity shortfalls Yukon Energy initiated a series of capital spending activities to enable 25.4 MW of cost effective WAF diesel capacity to be added, restored, or extended as required in the near term. The approved 2009 revenue requirements include forecast in-service costs for Mirrlees unit restoration or life extension at Faro and Whitehorse, but do not include any costs for Yukon Energy's acquisition of the Minto mine diesel units.

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[6] By way of example, Yukon Energy's approved average GRA fuel price for WAF is 99.2 ¢/litre for 2009, compared with 29.78 ¢/litre for 1997. Similarly, Yukon Electrical's approved GRA fuel price for Watson Lake in 2009 is approximately 3 times the price approved for 1997 (for other isolated diesel communities served by Yukon Electrical, the increase is at least 2.5 times from 1997 to 2009).

[7] Winter peak generation interruption impact related to a single major system risk event (Aishihik transmission interruption) was underlined by the January 29, 2006 Whitehorse-Aishihik-Faro ("WAF)" grid outage. On April 11, 2006 Yukon Energy provided a response to the Board regarding three questions related to this outage.

- **Grid extensions**
  - **Mayo Dawson (MD) Transmission Line** - Low-cost surplus hydraulic generation from the Mayo system now supplies Dawson (which was previously served only by high-cost diesel generation) via the Mayo-Dawson Transmission Line Project, and flexible debt financing was arranged (the Mayo Dawson Note) to ensure that ratepayers are not paying any more in any year of this project than the costs that would have been faced had Dawson remained on diesel generation. Taking Dawson out of the diesel zone (by MD project) reduced diesel usage by Yukon utilities at that time by approximately 40%.
  - **Carmacks-Stewart Transmission Project (CSTP) Stage One** - The completion of CSTP Stage 1 in 2008 allowed for grid service to be provided to the Minto mine and Pelly Crossing (reducing reliance on diesel generation on the system and reducing the hydro surplus on WAF). Completion of CSTP Stage 2 in 2010/11 will enable new renewable generation projects to help meet new load on both grids.

- **Diminishing WAF and MD Hydro Surpluses –** After the closure of the Faro Mine, YEC pursued secondary sales development to improve cost recovery from surplus hydro.[8] The 2007 PPA with Minto Explorations and 2008 Stage One CSTP development resulted in new firm sales of surplus WAF hydro generation to displace diesel generation at the Minto Mine as well as at Pelly Crossing. Yukon Energy's 2008/2009 GRA forecast surplus hydro generation is adequate to supply secondary sales in the test years; however, the WAF system is reaching a point where the material existing surplus hydro generation is becoming greatly diminished. Based on Yukon Energy's current forecasts, ongoing load growth and expressed interest from other future industrial customers will likely cause the existing hydro generation on both the WAF and MD grids to be basically fully utilized within the next few years[9].

Finally, it is also worth noting that annual variability in hydro generation due to water flow variations has not been an issue throughout most of the past decade, but will once again become a major consideration in the coming years:

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[8] In 2005, surplus hydro generation on WAF prior to secondary (interruptible) sales approximated 90 GW.h/yr at normal flows; absent new industrial loads, some surplus hydro was forecast to remain at normal flows on both the WAF and MD grids until at least around 2020.

[9] Yukon Energy is in the process of required reviews and permitting to proceed with the Mayo B near term hydro generation expansion opportunity to displace up to 38 GWh/year of baseload diesel generation starting in 2012.

- During recent years, effectively since the closure of the Faro Mine, Yukon Energy's WAF system has been at load levels that present very little risks of low water resulting in hydro generation shortfalls and costly requirements for diesel generation (though this situation did occur for a short part of 1999).
- When the Faro Mine was operating, a regulatory provision was adopted to address the financial risk of water flow variations resulting in more diesel being required than was forecast to meet firm loads (as of the 1996/97 GRA this was called the Diesel Contingency Fund, or "DCF"). The DCF enables the Companies' revenue requirements as regards WAF hydro generation (including Yukon Electrical Fish Lake hydro generation) to be based on long-term average generation (thus removing the risk of water flow variability, the impacts of which are addressed through the DCF in much the same way as fuel price variability is addressed through Rider F). Because of the DCF provisions, any diesel generation which only arises due to low water conditions is paid for by the DCF and consequently does not directly affect the utilities' revenue requirements or rates.[10]
- Starting in 2009, Yukon Energy's loads once again are reaching levels where very low flow conditions could cause financial impacts for the utilities. As noted in Yukon Energy's 2008/2009 GRA, there is also no provision in the DCF to address the possible financial implications on Yukon Energy of sustained interruption of secondary sales (and consequently secondary sales revenues) arising from low water conditions.[11]

1.6 IMPLICATIONS FOR 2009 PHASE II RATE APPLICATION

The focus of the 2009 Phase II Rate Application is to finalize rates on a "go forward" basis to reflect the approved 2009 GRA revenue requirements of the Companies (see Tab 2), and thereby complete the overall 2008/09 GRA process.

As part of the Application, an updated COS study is provided based on the approved consolidated revenue requirements for the Companies for 2009 (see Tab 3). Based on the methods set out, this updated COS shows the allocation of the approved consolidated 2009 GRA firm rate revenue requirement

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[10] At present grid loads, any such DCF which arises solely due to lower water is fully addressed by the DCF and as such will not drive the requirement for "diesel on the margin" to be recovered under Rate Schedule 42 Energy Reconciliation Adjustments.
[11] Review of the DCF provisions and terms will be warranted in the near term to ensure that current conditions and issues are fully addressed, including the need to integrate the Mayo Dawson grid into the DCF scope following completion of CSTP Stage Two.

among customer classes, and the R/C ratios for each customer class. The base rate component based on current rates and rate riders as approved as of January 1 2010 (excluding Rider F) are also shown.[12]

Notwithstanding the extent to which current OIC's limit the ability of the Board to change rates today based on an updated COS analysis, the 2009 Phase II Rate Application addresses rate adjustments that are feasible and appropriate today (see Tab 4). These rate adjustments reflect the implications of normal ratemaking principles and the current OIC rate directives (OIC 1995/90), as well as the fact that the current proceeding marks the first opportunity in over 12 years to review retail base rates for firm service in Yukon. In addressing rate changes, the Companies recognize the need to develop an orderly process for dealing with the various rate matters that have been outstanding for some time. This process should examine both the current situation and expected developments in the coming years. Two specific rate matters are noted in this regard:

- **End reliance on Rate Riders and adjust retail base rates to reflect approved 2009 costs:** It has been over 12 years since the Companies were jointly before the Board to adjust base rates to reflect current costs, and it is necessary to adjust base rates for firm service to reflect (to the extent feasible, given OIC 2008/149 and other considerations that temper the pace of major rate changes) the approved 2009 costs (including updated fuel costs) and end the reliance on non-fuel rate riders (i.e., Riders J and R).
- **Economy and efficiency rate principles/directives:** Promoting economy and efficiency by sending customers a price signal at higher levels of consumption in an increasing costing environment. The rate design proposal considers how best to adjust runoff rates to reflect 2009 incremental costs based on current fuel prices in the current costing environment. The need to adjust runoff rates to reflect approved 2009 incremental costs based on current fuel prices reflects the following considerations:
  - Since 1996/97 rate design and rate structure issues have not materially been addressed. Consequently, current runoff rates are based on fuel prices approved in 1996/97 and do not reflect current incremental fuel prices;
  - Yukon Energy's forecasts indicate that the grid systems are moving into a position of having diesel on the margin for substantial portions of the year in the very near future

[12] Rider F addresses diesel fuel price changes from the prices included in the utilities' revenue requirements, and as such is not included in test year forecasts, or in the 2009 Cost of Service analysis.

(this always is the case in the diesel rate zones). It is timely to re-establish price signals for consumers based on the actual incremental cost of diesel in 2009, as was last done in the 1996/97 GRA; and

- o While inter-class rate rebalancing (among the customer classes) cannot be undertaken at present due to OIC 2008/149, retail runoff block adjustments do not need to be deferred and can be undertaken now to ensure that consumers begin to receive appropriate efficiency price signals.

Similar to Canada's other hydro-based jurisdictions, Yukon's power system includes material assets with embedded costs well below the cost to bring on new generation today. Once the existing surplus hydro is fully utilized, ongoing increases in load will serve to be an upward rate driver for all customers. In this type of cost environment, it is important to develop rate structures for all customers that:

a) Reflect appropriate efficiency signals based on incremental costs (typically focused on "marginal" or incremental consumption); while

b) Still allowing for the fair apportionment of costs to customer classes, and a fair sharing of the benefits of the past resources (focused on ensuring that most consumption by any class is representative of the costs of "heritage" generating assets, such that each class see overall charges that closely represent embedded costs by rate class, where such embedded costs are on average well below the incremental costs of new supply).

OIC's in place since 1988, including the current OIC 1995/90, have provided key directions in this regard:

- To allocate throughout Yukon the benefits of lower cost heritage grid generation and transmission assets which the Board last implemented through first block rates approved in the 1996/97 General Rate Application; combined with
- Runoff rates to recover incremental costs of higher cost non-renewable generation.

The Board has sought to implement this balance in conjunction with a long-term goal of moving each class closer to paying a reasonable share of the overall allocated cost of the system.

Given diminishing hydro surpluses due to ongoing load growth, it once again becomes important that customers begin to receive appropriate incremental price signals through rates. Based on current OIC's and the 1996/97 GRA rate design, these incremental price signals are concentrated in the second block or "runoff" rates which apply to all non-government residential consumption over no less than 1,000 kW.h in a billing month, and all non-government general service customers over no less than 2,000 kW.h in a billing month. It is important to design rates with regard to firm loads that send the appropriate price signal based on the current costing environmental. Under the current pricing structure, the runoff second block rates have not been adjusted since the 1996/97 GRA. At the time of the last full GRA, incremental cost included in runoff rates was based on a fuel price averaging about 30 cents per litre and does not reflect current incremental costs.

TAB 2
OUTCOMES OF YEC AND YECL REVENUE REQUIREMENT REVIEWS

2.0 OUTCOMES OF YEC AND YECL REVENUE REQUIREMENT REVIEWS

The Companies' COS (Tab 3) reflects, and the Companies' proposed rates (Tab 4) are designed to recover, the approved 2009 revenue requirements for Yukon Energy and Yukon Electrical. These revenue requirements are the approved values consistent with the Board's review of each Company's forecast sales, generation, costs, and rate base.

This Tab summarizes the outcomes of these respective GRA revenue requirement reviews in the following sections:

- Revenue Requirement and Revenues at Existing Rates;
- Approved Sales Forecasts; and
- System Supply and Dispatch.

2.1 REVENUE REQUIREMENT AND REVENUES AT EXISTING RATES

The 2009 approved revenue requirements total $31.031 million for YEC (Board Order 2009-10) and $45.264 million for YECL (Board Order 2009-5). The individual revenue requirements include material cost items which are solely "intercompany transfers" and are not required to be a net recovery from customers. Consequently, the net Consolidated Revenue Requirement is $52.331 million, as set out in Table 2.1.

Table 2.1:
2009 Consolidated Revenue Requirement ($000s)

	YEC	YECL	Total
Fuel Expense	$ 443	$ 5,397	$ 5, 840
Purchase Power	$ 54	$23,910	$ 0
Purchase Power - cap. Fish Lake[1]		-$ 69	-$ 69
Other Operating & Maintenance	$13, 178	$ 9, 080	$22, 258
Depreciation expenses, net	$ 6, 869	$ 3, 060	$ 9, 929
Income Tax expense		$ 211	$ 211
Return on Rate Base-Debt	$ 5, 463	$ 1, 933	$ 7, 396
Return on Rate Base-Equity	$ 5, 025	$ 1, 742	$ 6, 767
Revenue Requirement	$31, 031	$45, 264	$52, 331

The Companies' currently approved rates are designed to recover $50.833 million from firm power rates. This firm rate revenue requirement is set out in Table 2.2 below:

Table 2.2:
Consolidated Firm Rate Revenue Requirements ($000s)[2]

Consolidated Revenue Requirement	$52,331
Less: YEC Revenue Offsets[3]	$ 125
Less: YECL Revenue Offsets	$ 827
Less Secondary Retail Sales[4]	$ 546
Total	$50,833

The present approved rates are designed to collect the consolidated firm revenue requirement,[5] as set out in Table 2.3:

Table 2.3:
Revenues at Existing Rates ($000s)

Retail Sales[6]	$38,684
Industrial Sales[7]	$ 3,203
Rider J[8]	$ 4,873
Rider R[9]	$ 4,072
Total	$50,833

[1] A unique item in the current 2009 YECL revenue requirement is the directive to capitalize $0.069 million of purchased power which is related to the capital work on Fish Lake hydro in 2009. This item does not have a corresponding entry on the Yukon Energy revenue requirement, and consequently does not net out on consolidation, in contrast to the other purchased power forecasts.
[2] The 2009 revenue requirements for YEC approved in Board Order 2009-10 and 2009 revenue requirement for YECL approved in Board Order 2009-5.
[3] "Revenue offsets" are other revenues derived from non-rate sources, such as revenues from joint use of the utility's poles by third parties, etc.
[4] This includes both the portion of secondary revenues collected by YECL, and by YEC, at the forecast secondary rates approved in each utilities Phase I Application.
[5] In preparing the Yukon Energy Compliance Fling, Yukon Energy was directed to use Yukon Electrical's sales forecast for the purposes of forecasting wholesale sales. This was incorporated into Yukon Energy's Compliance Filing for wholesale (Rate Schedule 42) sales, but was inadvertently not incorporated for wholesale Rider J collections. In forecasting Rider J collections, Yukon Energy used a wholesale rider recovery estimate that slightly overstated the recovery that should be forecast based on YECL's approved load forecast. Consequently, Yukon Energy's approved Rider J adjustment at forecast sales levels (to 12.46%) fails to collect $0.054 million of YEC's approved revenue requirement. The rates proposed in this filing (Tab 4) address this adjustment on a go forward basis (implies correct Rider J of 12.597%). No approvals are sought to adjust Rider J for this factor during the periods it was applicable.
[6] Revenues at 1997 GRA approved base rates for the approved 2009 forecast firm sales to government and non-government residential and general service customers, space light customers, and street light customers of YEC and YECL.
[7] Revenues at approved Rate Schedule 39 for approved 2009 forecast sales to the Minto mine, including Industrial fixed Rider F, the revenues from which were approved as part of Yukon Energy's Revenue Requirement GRA filing (Order 2009-10).
[8] Assumes corrected Rider J at 12.597% of 2009 firm retail sales revenues at base rates (see footnote #5 above).

A further breakdown of cost components is available in Tab 3 and the determination of class rates is discussed in Tab 4. As noted in Tab 4, this Application seeks to eliminate Riders J and R and incorporate the recovery of these amounts into base rates.

2.2 APPROVED SALES FORECASTS

The approved 2009 consolidated sales forecast for the Companies includes, on average, approximately 17,467 primary retail customers (excluding lights and industrial), of which 14,381 are residential and 3,086 are general service. Of the total number of primary retail customers (excluding lights and industrial), approximately 89% of the customers are served from Yukon Electrical, while the remaining 11% of customers are served from Yukon Energy. Total 2009 consolidated firm sales (including lights and industrial) are forecast at 338,175 MW.h, of which 278,133 MW.h are YECL sales (approximately 82%) and 60,042 MW.h are YEC sales (approximately 18%).[10] These approved firm sales forecasts are broken out as follows by major customer groups:

- **Retail - Residential** – 139,798 MW.h for 14,381 customers (average for year)
  - Non-government residential customers account for over 98% of these sales
  - Among non-government residential customers
    - Approximately 70% of the monthly bills in the year do not exceed 1,000 kW.h (the first rate block)
    - First rate block sales account for about 80% of forecast MW.h sales
- **Retail - General Service** – 164,908 MW.h for 3,086 customers (average for the year)
  - Non-government general service customers (including municipals) account for about 69% of these sales
  - Among non-government general service customers
    - Approximately 67% of the monthly bills in the year (excluding municipals) do not exceed 2,000 kW.h (the first rate block)
    - First rate block sales (including municipals) account for only about 29% of forecast MW.h sales
  - Among federal and territorial government general service customers, over 87% of sales are in the second rate block (i.e., over 2,000 kWh/month).

[9] Rider R of 10.526% of 2009 firm retail sales revenues at base rates, effective January 1, 2010 (Order 2009-5). This Rider R was set to collect the approved 2009 YECL revenue requirement over a full year based on approved 2009 forecast loads.
[10] An additional 7,584 MW.h of secondary sales are included in the approved YEC GRA forecast for 2009.

- **Retail - Space Lights and Street Lights –** 4,445 MW.h
- **Industrial –** 29,023 MW.h for one customer (the Minto mine)

In contrast, the 1997 GRA consolidated primary sales for the Companies was forecast at 441,750 MW.h, broken out as follows:

- **Retail – Residential** at 125,032 MW.h (97% non-government) and 12,191 average customers.
- **Retail – General Service** at 129,115 MW.h (59% non-government) and 2,736 average customers.
- **Retail – Street and Space Lights** at 3,574 MW.h.
- **Industrial** at 184,029 MW.h (of which 180,000 was for the Faro mine).

Since 1997, forecast retail primary customers (excluding lights) have grown by 16%, but the overall forecast primary sales load has declined by 103 GW.h or 23% during this 12 year period (due to the decline of 155 GW.h in forecast Industrial sales). Residential forecast load has grown 11.8% in this time period with the greatest growth occurring in 2006. General Service forecast load has grown 27.8% in this time period with the greatest growth occurring in 2002, 2004, 2006 and 2007 when such new loads as Klondike Motors, Walmart, Yukon Honda, Ricky's Restaurant, Superstore, Chilkoot Strip Mall, Copper Ridge Bigway, Canadian Tire and Mark's Work Warehouse were added.

2.3 SYSTEM SUPPLY AND DISPATCH

Yukon wide generation forecast for the Companies in 2009 approximates 392.2 GW.h of which 7.6 GW.h represents sales to secondary customers. On a seasonal basis, Yukon wide generation is forecast to vary from slightly less than 30 GW.h in summer months (May to September) to about 40 GW.h in peak winter months (December-January).

The 2009 Consolidated Firm Revenue Requirements are based on system supply dominated by hydro on the integrated systems (WAF and Mayo-Dawson hydro accounts for about 94% of total Yukon generation by the Companies) with only limited use of diesel generation for peaking and maintenance reasons on these grids.

In the three isolated system rate zones supply is entirely from local diesel generation:

- Large Diesel Rate Zone (today only Watson Lake, formerly included Dawson City);
- Small Diesel Rate Zone (today only Destruction Bay, Beaver Creek, and Swift River; formerly included Stewart Crossing and Pelly Crossing); and
- Old Crow Rate Zone.

While there remains surplus hydro at times of the year on the grid systems to supply secondary loads, the availability of secondary energy is diminishing in 2009, such that the forecast secondary supply quantities reflect material sustained interruptions to aid in avoiding diesel generation. The present system condition is such that secondary supplies are at times interrupted for peaking reasons (i.e., the grid demand at certain temperature ranges does not permit secondary loads to be supplied without having to turn on diesels to help meet the required system MW peak). With load growth, the WAF system in particular will soon achieve a state where the driver of winter diesel generation is not temperature or peak loads per se, but the availability of energy over the duration of the winter. In that situation, system operators preparing forecasts of energy supply will determine the need to interrupt secondary sales, and ultimately to turn on diesel units, to manage the drawdown of reservoirs which, absent these measures, would be forecast to approach or drop below their minimum elevations by the end of the winter. At these times, where diesel is actively "on the margin" of supply, there is no economic distinction between energy usage at peak versus off-peak times – all energy consumption serves to consume limited water availability regardless as to time-of-day or temperature and all winter firm power usage serves to drive either secondary sales interruptions or, ultimately, the need to use diesel generation.

System consolidated energy supply forecast generation as approved for 2009 is 392.2 GW.h, comprised of 28.6 GW.h of Yukon Electrical generation (primarily diesel) and 363.6 GW.h of Yukon Energy generation (primarily hydro, including hydro generation for the purposes of serving secondary customers). The consolidated forecast generation includes firm sales of 338.2 GW.h, secondary sales of 7.6 GW.h and Yukon-wide losses of 46.4 GW.h, or 13.4% of system sales. Based on ratios from the 1996/97 GRA, system energy losses are assumed to be split 41% to transmission and 59% to distribution.

Yukon-wide consolidated coincident peak demand totals 72.3 MW. This peak demand assumed secondary sales will be interrupted at the time of the system peak, which is consistent with the approved revenue forecasts for secondary sales in 2009.

The WAF system meets its required firm capacity (N-1) in 2009 with the contribution of 24 MW of Whitehorse winter hydro capacity, plus all installed YEC and YECL WAF diesel capacity, excluding the Minto diesels (which are not included in rate base per Order 2009-8). In Order 2009-8, at paragraph 206, the Board found that for this test period there is a surplus (3 MW) for WAF above the contingency (N-1 criteria for capacity planning) when the Faro and Whitehorse diesel units are included (before consideration of the Minto units).

TAB 3

COST OF SERVICE

3.0 COST OF SERVICE

This Tab provides an up to date cost of service (COS) study, with updated revenue/cost (R/C) ratios for all rate classes receiving firm service, based on the 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million for the Companies as set out in Tab 2.

This Tab consists of the following items:

- Overview;
- COS Methodology for 2009 Update;
- Summary Results for 2009 COS; and
- Overview of Detailed COS Schedules.

The full 2009 COS results are provided in Appendix 3.1 (electronic models are filed with the Application). Other supporting detailed information and analysis is provided in other appendices as required.

3.1 OVERVIEW

The COS study in this Application allocates approved 2009 firm rate revenue requirement consolidated costs for the Companies to each consumer firm rate class and compares these costs for each rate class against the respective approved revenues for 2009 from each rate class (based on current rates before any new rate adjustments).

As with other past COS studies, the analysis in Tab 3 assigns the revenue requirement to each of the customer classes in order to reflect the distinctive consumption characteristics of each class that contribute to cost causation on the overall system.

Cost of service methodology in Canada typically involves a fully distributed cost of service study that uses embedded costs as approved for the revenue requirement, evaluated in a 3 step process:

1. **Functionalization** of each capital item and expense item under three general headings: Generation, Transmission and Distribution. This step allows overall costs of the Companies to be examined by the separate three distinct functions involved in the supply of electric service.

2. **Classification** of functionalized costs into three parts that reflect the manner in which these costs are incurred by specific customers:
   a. Customer Cost (costs which primarily reflect the number of customers rather than the actual usage by each customer);
   b. Demand or Capacity (kW) Cost (costs which primarily reflect customer requirements to be supplied at peak times, such as the time of the system winter peak); and
   c. Energy Usage (kW.h) Cost (costs which primarily reflect customer energy usage).

3. **Allocation** of the classified customer, demand and energy usage costs among established customer classes using allocation methodologies.

Based on the above approach to rate setting and on past practice in Yukon, the cost of service for each customer class in 2009 is determined on a Yukon-wide basis with no differentiation between the utilities or between communities. This approach is also consistent with the requirements of Rate Policy OIC 1995/90 (which directs that firm rates for each class are to be set on a Yukon-wide basis).

The following customer classes are currently utilized for firm rate making purposes and have been adopted for the 2009 COS study:

- Residential Government;
- Residential Non-Government;
- General Service Government;
- General Service Non-Government;
- Major Industrial;

- Street Lights; and
- Sentinel Lights (previously named "Space Lights" in 1996/97 GRA).

The 2009 COS reviews, and where applicable, updates the COS principles and methods applicable in Yukon:

- **Section 3.2** provides COS methodology for 2009 Update.
- **Section 3.3** provides summary results for 2009 COS.

As reviewed in Tab 4, a cost of service study is one tool among a suite of rate design criteria for testing and determining final firm rates. However, in light of the specific near term framework for rate setting in Yukon (OIC 2007/94 and 2008/149), the 2009 Cost of Service cannot be used to adjust the current major industrial customer rates or to implement rebalancing today of rate revenues between retail rate classes until January 1, 2013.

3.2 COS METHODOLOGY FOR 2009 UPDATE

Except as otherwise noted below, the COS methodology used to prepare the 2009 Cost of Service study in Appendix 3.1 largely reflects past principles and methods adopted by the Companies and approved by the Board (see Appendix 3.4). Individual methodology changes are reviewed below first for bulk power cost classification (generation and transmission), and then for distribution cost classification. Cost allocation methods (i.e., methods to allocate classified costs to firm rate classes) are also separately reviewed. As in the case of all previous COS studies, wholesale customer class costs are not separately assessed in the COS analysis.

3.2.1 Bulk Power Classification Methods (Production and Transmission)

Bulk power classification methods address the treatment of Production function costs and Transmission function costs. The treatment of secondary sales in 2009 is also described (as such sales were not included in the previous COS studies of the Companies in any material way).

Classification methods for bulk power reflect consideration of a number of factors, such as:

- How any given asset or class of assets is used;

- What type of loads on the system increase the required level of investment in the particular type of asset (i.e., what is the basis for the investment); and
- What would be the alternative system cost profile absent the assets (i.e., what are the benefits of the asset to the system).

In this regard, the emphasis for utility cost changes since 1996/97 and continuing into the future focuses on the materially increased costs of generating the energy demands on each system, particularly as load growth increasingly drives towards diesel fuel being required for baseload purposes on the grid systems. Since 1996/97, the cost of supplying increased energy loads, using diesel, has nearly tripled. In the same time, the costs to ensure the ability to reliably meet short–term demand peaks (by increasing the installed reliable generating capacity of the system) is relatively low.

In short, in their purest form, the following cost profiles for load variations are noted:

- **Capacity:** In its purest form, the cost of capacity relates to the cost to ensure reliable firm service to accommodate an incremental very short-term increase in winter peak loads at the time of coincident peak (the moment of highest system load). At the present time the Board has determined that there is a capacity surplus on the system, and that there is additional low cost backup capacity. As such, the cost profile for pure capacity loads is relatively low.
- **Energy:** The cost profile of a pure energy use is that of a sustained consumption of kW.h throughout the year. At the present time, increases of this nature drive expensive diesel fuel consumption on the diesel systems, and similarly drive the WAF (Whitehorse-Aishihik-Faro) system and ultimately the interconnected WAF and MD (Mayo Dawson) systems inevitably towards the need to consume expensive diesel fuel generation for base load supply.

The determination of appropriate generation and transmission classification factors for 2009 takes the above relationship into account, by applying careful consideration of the relative energy benefit of each asset and ensuring there is no excessive focus on its capacity benefits.

Production – Classification methods are reviewed separately below as required for different generation assets:

- **Hydro - Whitehorse Unit #4 (WH4) – Classified 100% to Energy** - The Companies do not propose any change from the classification used since the 1992 cost of service review and subsequently during the 1996/97 GRA and adopted for the Minto PPA proceeding (based on recommendation #3 from the 1992 Report).[1]

  In Order 1996-7, the Board noted that the allocation was consistent with past practice and "continued to be appropriate" but stated that it "will consider the issue still subject to review at a later date when circumstances change." In 2009, unlike the 1996/97 GRA, Whitehorse Unit #4 is expected to make a positive net contribution to meeting customer demand under drought conditions at the time of the winter system peak. Absent Whitehorse Unit #4 the original three Whitehorse hydro plant units can only produce 20 MW; however, at the time of system peak in winter the full Whitehorse hydro plant (units 1-4) is now relied upon to produce 24 MW of firm capacity, as reviewed in Yukon Energy's 20-Year Resource Plan (under non-drought conditions, the Whitehorse plant routinely produces 24-28 MW). This is in contrast to previous firm capacity assessments which based the winter capacity of the Whitehorse plant at 19 MW. Overall, however, reliance during the winter peak on a net contribution of only 4 MW of the 20 MW total capacity of Whitehorse Unit #4 confirms that this unit continues to differ materially from other generation units for the purpose of cost classification. Accordingly, consistent with past practice and the purpose for which the unit was originally constructed and for simplicity, the Whitehorse Unit #4 continues to be classified 100% to energy.

- **Aishihik Plant (existing, excluding Aishihik 3rd Turbine) – Classified 100% to Energy -** Under the new capacity planning criteria recently adopted in Yukon Energy's 20-Year Resource Plan: 2006-2025 (driven by N-1 methods), Aishihik generation is considered to not contribute to the WAF system's ability to serve peak loads at critical times due to transmission constraints. As a result, there must be sufficient diesel generation installed (plus WH and Fish Lake winter capacity) to permit the full system loads to be carried. Consequently, Aishihik's contribution to system service is solely of an energy benefit

[1] Recommendation #3 from the 1992 Report states that the classification is based on the rationale that "...the unit was constructed solely for the purpose of displacing high cost diesel generation...", and "... did not increase the companies' ability to meet customers' demand at the time of system peak..."

(offsetting the use of the diesel plants to provide energy or peaking output). This methodology differs from the classification adopted in the 1996/97 GRA COS (before the new capacity planning criteria was adopted), when Aishihik plant costs were classified 60% energy and 40% demand. The Aishihik 3rd Turbine is excluded as this unit is not planned to be in service in 2009, and therefore its costs are not part of the 2009 Consolidated Firm Rate Revenue Requirement.

- **Mayo Hydro – Classified 100% to Energy** – The Companies in this Application propose to change the classification of hydro plant at Mayo (from that proposed by the Companies and recommended by the Board in 1992 and subsequently approved in Order 1993-8 and 1996-7) due to material changes in circumstances on the system since the 1996/97 GRA. In particular, the construction of Mayo Dawson transmission line and the upcoming CSTP (Carmacks-Stewart Transmission Project) connection of the two grids provides that the Mayo hydro facility will make a material net contribution in avoiding the need for expensive diesel generation. In 1992, Mayo Hydro was substantially underutilized, supplying only the local Mayo and Keno loads. At that time the plant was classified 60% energy and 40% demand. It is also noted that the loads on the MD system are able, if needed, to be supplied by resident diesel assets which are in the ratebase in each major community location (Mayo, Stewart Crossing, and Dawson). Consequently, the primary function for the Mayo hydro system is to provide energy to offset what would otherwise be the requirement to operate these diesel units. Further, looking beyond 2009 and the interconnection of WAF and MD through the completion of the CSTP, the same conclusion will generally apply for the integrated grid and hydro units outside Whitehorse, i.e., the loads on the integrated system will be able to be supplied by resident diesel in the respective community/mine location and the remaining sole function for the hydro system outside Whitehorse is to provide energy to offset what would otherwise be the requirement to operate these diesel units (e.g., Dawson, Pelly, or Faro).

- **Other Hydro (including Whitehorse Units #1, #2, and #3) - Classified 40% to Demand and 60% to Energy –** No change is proposed from the 1996/97 GRA. In 1992, the Companies used "cost causation" for the purpose of classifying the cost of facilities between demand and energy, and in determining the 40% demand/60% energy split; the Companies relied upon "classification of similar hydro facilities in British Columbia, Manitoba, Ontario and Quebec." The Board recommended this classification (Recommendation #2 of the 1992 Report) and subsequently accepted this classification during the 1996/97 GRA (Order 1996-7), noting "the Board considers this issue open and subject to review in a future proceeding." There has been no notable change to the use or function of these assets and consequently no proposed change in classification is proposed. Further, this classification is aligned with the current classification followed for hydro assets in other similar non-interconnected jurisdictions such as NWT and Newfoundland.[2]

The WH 1, 2 and 3 assets, along with providing an energy-serving function, also serve a separate and distinct function compared to any other hydro units in Yukon. In the case of nearly every major grid-served community in Yukon, there is a resident diesel installation capable of meeting the local loads (demand) in the event of transmission outages. However, this is not the case in Whitehorse, with only 25 MW of installed diesel as compared to a local peak on the order of 50 MW. In order to ensure a reasonable ability to meet the Whitehorse peak loads from local sources, it is necessary to recognize the capacity contribution of WH 1, 2 and 3.

- **Diesel Plant – Classified 100% to Demand** – No change is proposed from the 1996/97 GRA. In the 1992 review, the Companies noted that "...diesel generating plant was typically classified as demand-related in Canada". YEC/YECL acknowledged during the 1992 review that diesel generating plant was built not only for the purpose of meeting peak capacity but also for the provision of energy, however, due to the "...relatively minor cost of diesel generating plant an alternative classification process would not yield a materially different result...". There has been no notable change to the use or function of these assets and consequently no proposed change in classification is proposed.

- **Wind – Classified 100% to Energy** – No change is proposed from the 1996/97 GRA. Wind facilities were built to reduce fuel cost year round, and are consequently considered to be energy-related; further, these units are not assumed to provide reliable firm winter peak capacity.

Transmission – classified 100% to Energy (after all contributions) – The Companies propose to change the classifications used in the 1996/97 GRA for two reasons:

[2] NWT PUB Decision 5-95 directed NWTPC to classify the Snare Yellowknife Hydro plant in the basis of 60% energy 40% demand noting that a 60:40 energy:demand split is a reasonable basis for classification of Hydro plant costs, consistent with cost causation. NTPC continues to use this same classification, most recently in the cost of service summary filed in support of its 2006/08 Phase II Application. Newfoundland Labrador Hydro classifies hydro and thermal plant in its cost of service on the following basis :"that portion of hydraulic plant costs in the Island Interconnected System equal to the annual system coincident load factor be classified as energy related and the balance be classified as demand related" (per 1993 generic COS report pg 38). This has resulted in classification ratios of 43.59% to demand and 56.41% to energy in NLH's 2007 COS study (per Schedule 4.1 of the 2007 COS study updated November 2006).

1) The material changes on the system since the 1996/97 GRA, including the closure of Faro Mine, the construction of Mayo Dawson transmission line and the anticipated interconnection of the grid through the completion of the CSTP.

2) Relative importance of the transmission system in providing the benefit of avoiding expensive diesel generation.

In particular, absent the transmission interconnections to any given community today, there would be a requirement to operate the presently installed diesel generating plants to serve load. This would materially increase the cost of power in Yukon, and would drive what is entirely an energy-related cost item – diesel fuel. Consequently, the cost profile in terms of benefits of installed transmission relates almost entirely to avoided energy-related diesel fuel costs. In addition, transmission in Yukon is designed and sized to address considerations of length, voltage stability, and losses, and investment is not being driven to enhance existing transmission assets (e.g., twinning lines, or reconductoring) to serve growing peak loads. For this reason, the cost profile of transmission in Yukon is heavily oriented towards energy.

In 1992, it was recommended that the appropriate method of allocating transmission costs was to specifically assign 85% of the costs of Whitehorse-Faro line to the Faro mine, and then allocate all remaining transmission costs to all customer classes, including the Faro mine, on the basis of demand at the time of system peak. This treatment was based on the view that inasmuch as the Whitehorse-Faro line was constructed specifically for the purpose of serving the Faro mine, and no other load accounted for any material use of this line when the Faro mine is operating, almost all of the cost of the line should be allocated to the Faro mine when it is operating.

The recommended change to classify all current transmission to energy reflects the following considerations:

- As noted in Yukon Energy's Minto Mine PPA application (Schedule A), the Faro mine closure removes the basis for specifically assigning to the Industrial class (i.e., Faro mine) 85% of the Whitehorse-Faro transmission costs; furthermore, the Minto mine PPA effectively directly charged this customer all of the costs for the new spur line serving this mine plus at least $7.2 million of the CSTP Stage One costs (this contribution on behalf of the mine was augmented, as directed by the Board, through an added contribution by Yukon Development Corporation). In light of these current conditions, the Companies see no current basis for direct assignment (to any customer or customer rate class) of any specific transmission costs remaining to be addressed in the 2009 COS.

- Today, the Whitehorse-Faro line serves to provide grid access to diesel generation at Faro and (over the Whitehorse-Carmacks segment) to provide hydro energy grid access to supply the Minto mine and Pelly Crossing. Given that the Minto mine diesel costs are not included in the 2009 COS, no portion of this line (or of the CSTP Stage One line) serves to provide grid access to material ratebase diesel generation to meet overall WAF grid winter peak capacity.

- The remainder of the WAF 138 kV grid (from Aishihik to Whitehorse), as well as the new CSTP Stage One line to the Minto mine and Pelly Crossing, today play no role in contributing to WAF reliable winter peak capacity. In addition, nearly every major delivery point on the WAF and MD transmission systems are able to be supplied by resident diesel in the respective community/mine location, and therefore the current function for this transmission system is to provide energy to offset what would otherwise be the requirement to operate these diesel units (e.g., Dawson, Stewart Crossing, Pelly, or Faro), i.e., these lines exist solely to supply hydro energy to displace the need for diesel generation to supply loads in Whitehorse and elsewhere.

- If it was to be determined that some transmission does merit a capacity component (such as the portion of the old WAF system that provides access to winter peaking diesel capacity at Faro), there remains a strong argument that at least the Aishihik line, Mayo-Dawson, and potentially CSTP are properly now classified 100% energy, since under the current capacity planning criteria Aishihik does not contribute to the system firm load carrying capability (due to N-1) and MD and CSTP were built almost entirely to displace diesel generation. On an overall transmission cost basis, this would represent the dominant share of remaining annual transmission costs to be addressed in 2009.

Secondary Sales revenues – 100% as offset to energy costs - Secondary sales are not included in the COS as a separate rate class. Secondary sales are based solely on surplus hydro generation, and have terms and conditions that require interruption of these sales whenever surplus hydro is not available (or not expected to be available) to supply all of these sales. Customers using secondary sales are required to have fully operative alternative energy supply sources to meet their full needs in the event of interruption by the Companies. Accordingly, secondary sales are not a component of firm rate service – and the rates charged are determined on a quarterly basis to reflect customer savings relative to use of alternative oil or propane energy supplies. In short, secondary sales rates bear no relation to a cost-based standard in terms of the costs to the utilities to supply the service, but rather a "value of service" concept based on the customer's avoided costs of their alternative source of heat.[3] The Companies use these secondary sales revenues to reduce the firm rate revenues required to be collected from the retail and industrial customer classes.

Although there was a small amount of secondary sales available in Mayo in 1996, secondary sales revenues did not become material until a few years after the closure of the Faro mine. With the resulting surplus hydro electricity on WAF due to the closure of Faro there has been material revenues attributed to secondary sales in the 2009 revenue requirement submissions. Based on normal rate principles, these secondary sales revenues are assigned to reduce overall Consolidated Revenue Requirement costs (per Tab 2) in order to determine the costs to be recovered through rates from customers receiving firm power service. Further, based on normal COS principles, secondary sales revenues are allocated to offset generation energy function costs.[4] Accordingly, secondary sales are not to be analyzed or treated as a separate rate class in the COS (there is no "allocation of costs" to these customers) but are solely treated as incidental revenues.

3.2.2 Distribution Classification Methods

The Companies have reviewed and updated the customer/demand classification factors for Distribution plant using Yukon specific data and the same methodologies that were approved in ATCO Electric's 2010 Distribution Tariff Application as well as Northland Utilities (NUY) and Northland Utilities (NWT) 2008-2010 Phase II General Rate Applications.

The following Distribution classification factors are recommended as part of this Application. For comparison purposes, the Companies have provided the classification factors that were approved in Board Order 1996-7:

[3] This same rate design is used by other utilities who market surplus power to non-firm customers, including Northwest Territories Power Corporation.
[4] For simplicity, secondary revenues are applied in the COS study as an offset to fuel expenses, which is similarly a 100% energy classified line item.

Land and Land Rights, Substation Equipment	0% Customer, 100% Demand (no change)
Poles, towers and fixtures	56% Customer, 44% Demand (previously 75% Customer, 25% Demand)
OH Conductors/UG Conduits (Wires)	52% Customer, 48% Demand (previously 30% Customer, 70% Demand)
Line Transformers	28% Customer, 72% Demand (previously 30% Customer, 70% Demand)
Services	100% Customer, 0% Demand (no change)
Meters and Metering Equipments	100% Customer, 0% Demand (no change)
Streetlights/ Space Lights	Directly assigned to rate class (no change)

Distribution Land, Land Rights and Substation Equipment plant categories require no change to the customer/demand classification. This plant is normally built to serve a particular load and the size is not affected by the number of customers to be served. As such, these costs are 100% demand-related.

Services and Metering costs are generally classified as 100% customer-related since their costs are dependent on the number of customers served.

The costs for Street Lights and Space Lights are directly assigned to their respective rate classes, as was done and approved in previous Yukon rate applications.

The treatment of Yukon Electrical revenue offsets has been revised to use Distribution Plant to classify revenue offsets to match how revenue was derived.
The Companies view the above classifications to be consistent with the goals of identifying cost causation. These classifications are also supported by the National Association of Regulatory Utility Commissioners' (NARUC) Electric Utility Cost Allocation Manual and are consistent with the practices of other Canadian utilities.

The full distribution classification factor study is provided as Appendix 3.2.

3.2.3 Allocation Methods

Classified costs were allocated to each firm rate class using methods adopted in past COS studies and updated estimates for the number of customers, peak demand, and energy use for each rate class. Specific procedures are set in the COS study tables (Appendix 3.1) and noted in section 3.5. The updated Energy Demand and Loss Analysis (EDLA) is provided in Appendix 3.3.

The primary allocators derive directly from revenue billing determinants reviewed as part of the load forecast in the approved Revenue Requirements (energy sales, system losses, number of customers). The notable exception is the allocation of demand costs, which must be based on an estimate of each class' contribution to the overall system coincident peak ("CP"), and to the distribution system non-coincident peak ("NCP"). The EDLA analysis was used to determine a reasonable representation of load characteristics for each class for the purposes of estimating class aggregate demands. Based on the approaches adopted, the major demand load metrics applied are noted in Table 3.1 below.

Table 3.1:
Demand Load Characteristics at the Meter, By Class

		2009	1996/97
Residential Non-Government	CP load factor	56.5%	53.0%
	NCP load factor	48.2%	45.6%
Residential Government	CP load factor	56.5%	49.2%
	NCP load factor	48.2%	42.3%
General Service Non-Government	CP load factor	77.4%	61.5%
	NCP load factor	63.6%	49.2%
General Service Government	CP load factor	77.4%	66.5%
	NCP load factor	63.6%	53.2%
Industrial	CP load factor	77.4%	99.9%
	NCP load factor	N/A	N/A[5]
Streetlights	CP load factor	46.7%	48.0%
	NCP load factor	46.7%	48.0%
Space Lights	CP load factor	46.7%	47.7%
	NCP load factor	46.7%	47.7%

[5] NCP demands are used for allocating distribution system related costs, such as distribution poles and wires. These assets are largely not relevant to industrial customers.

Only three classes indicate a substantial (>10%) change since the 1996/97 GRA in their load characteristics in the updated EDLA – industrial, and both government and non-government general service:

- The changes in industrial coincident peak load factor relate to the particular characteristics of the individual customers. The Faro mine operated with a high individual load factor, which is one input to the overall CP load factor for the class. The Minto mine is forecast in the 2009 load forecast to be of a lower load factor and a much smaller size relative to the overall system.
- With respect to General Service (both government and non-government), there is a notable increase in the calculated CP and NCP load factors. The effect of this increase is to reduce the estimated coincident peak demand for this class compared to the 1996/97 ratios, and consequently less demand-related costs are allocated to the class. It is important to note that no Yukon specific load studies have been conducted, and consequently the new load factors are derived from recent load studies on ATCO Electric customers in Alberta (the 1996/97 load factors were based on earlier analyses of ATCO Electric customers in Alberta as well).

3.3 SUMMARY RESULTS FOR 2009 COS

As reviewed in Tab 2, the 2009 Consolidated Firm Rate Revenue Requirement for the Companies ($50.833 million) provides the foundation for the 2009 COS. The 2009 COS study is provided in Appendix 3.1.

In summary, the COS Revenue to Cost (R/C) Ratios by rate class are provided below in Table 3.2 for 1997 versus 2009.

Table 3.2:
Revenue to Cost (R/C) Ratios by Rate Class – 1997 and 2009 (%)

Customer Class	1997 Final Approved	2009
Residential Government	100%	105%
Residential Non Government	81%	79%
General Service Government	143%	144%
General Service Non Government	110%	117%
Industrial	100%	109%
Street Lights	110%	69%
Sentinel Lights	110%	148%

The COS in Appendix 3.1 includes a summary of consolidated property plant and equipment, ratebase and costs for the Companies, and a summarized fully allocated 2009 Cost of Service and schedules for each rate class. A detailed index in the Appendix 3.1 identifies the page numbers of the various schedules. A summary of COS results is provided below, followed by an overview of the more detailed schedules provided in Appendix 3.1.

3.3.1 Summary of Cost of Service Study Results

The 2009 Cost of Service results are summarized in Table 3.3.

Table 3.3:
Summary 2009 Cost of Service by Function, Classification and Rate Class ($000)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	8,357	19,079	27,436
Transmission - Transmission Line	0	0	9,063	9,063
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	1,420	1,215	0	2,635
Carrying Costs (Excluding Return and Income Tax)	2,512	2,091	0	4,603
Operating & Maintenance Costs	1,709	1,436	0	3,145
Customer Accounting & Public information	2,557	0	365	2,921
Insurance	195	162	0	358
Revenue Offsets	(610)	(342)	0	(952)
Administrative & General	1,808	1,013	0	2,821
Amortization of Contributions	(687)	(509)	0	(1,196)
	------	------	------	------
Total	8,904	13,423	28,506	50,833

The effective unit costs arising from the cost of service analysis reflect average embedded costs as follows:

- **Cost per customer:** Customer related costs for a distribution level customer (residential or general service) vary from approximately $453/year to $475/year.
- **Cost for demand service:** The demand related costs for distribution level customers (residential or general service, as well as lighting classes) vary from $228/kW-year to $243/kW-year for each unit of coincident peak demand at the customer meter. For transmission level customers (industrial) the cost is $158/kW-year.

- **Embedded costs of energy:** The energy related costs for distribution level customers (residential or general service, as well as lighting classes) is 8.5 cents/kW.h at the customer meter, and for transmission level customers (industrial) the cost is 7.8 cents/kW.h.

3.4 OVERVIEW OF DETAILED COS SCHEDULES

The basic methodology employed by the Companies to functionalize, classify and allocate costs to rate classes is reviewed above. As noted, this methodology is largely the same as what was used in the previous COS completed for the 1997 GRA only certain limited exceptions.

3.4.1 Mid-year Balance of Gross Property Plant & Equipment

The Companies have provided the forecast 2009 mid-year balance of gross property plant and equipment in Schedule 4-T-1 (the mid-year balance of opening 2009 gross property plant and equipment and closing balance of 2009 gross property plant and equipment).

3.4.2 Mid-year Net Rate Base

Forecast 2009 mid-year net rate base (mid-year net Property Plant & Equipment plus reserves, deferred items, working capital and special regulatory items less mid-year net contributions) by function have been provided in Schedule 4-T-2.

3.4.3 Classification of Assets as Being Customer, Demand or Energy Related

In order to allocate costs to each rate class in regards to cost causation, assets were classified as either being customer, demand or energy related. In the 2009 forecast COS Study:

Customer costs are those costs that vary with the number of customers served and are not affected by demand or energy considerations. These costs include customer costs related to distribution poles, overhead/underground line and line transformers, meters, services, customer accounting, public information, and administrative and general costs.

Demand costs are those costs which vary with kilowatt (kW) of demand and include investment charges and expenses made in connection with the provision of generating plants, transmission lines, substations and that part of the distribution system not included as customer costs.

Energy costs vary with the amount of kilowatt-hour (kW.h) of energy used and are largely fuel expenses, purchase power and production O&M expenses, offset by secondary sales revenues. They also include a share of transmission and administrative and general costs.

Classification factors are as noted above.

3.4.4 General Plant Asset Classification

As in the past, general plant assets exist to support the production, transmission and distribution functions and therefore were classified in the same proportion as gross production, transmission and distribution assets.

3.4.5 Classification of Costs to Customer, Demand and Energy

Once the gross asset and rate base balances have been classified as being customer, demand or energy related; the various components of the revenue requirement are then classified according to the applicable balance.

Classification of Revenue Requirement

Schedule 4-T-3 summarizes the service costs.

Depreciation expense was classified based on the mid-year balance of gross property plant and equipment in Schedule 4-T-4.

The classification of Municipal taxes is based on the mid-year balance of gross property, plant and equipment (Schedule 4-T-5).

The classification of both return and income tax was based on the mid-year net rate base balances in Schedules 4-T-6 and 4-T-7.

The carrying costs and O&M associated with the general functions were classified based on the mid-year balance of gross property, plant and equipment excluding general plant in Schedules 4-T-8.

The carrying costs of working capital were classified based on the mid-year balance of gross property, plant and equipment without general plant in Schedule 4-T-11.

The carrying costs of rate case expense were classified based on the mid-year balance of gross property, plant and equipment without general plant in Schedule 4-T-12.

The classification of operation & maintenance costs is shown in Schedule 4-T-13.

Classifying insurance expense costs to customer, demand, and energy was done based on mid-year balance of gross property, plant and equipment without general plant in Schedule 4-T-14.

The classification of revenue offsets (e.g., pole rentals) is based on the sum of all service costs (excluding production and transmission costs, administrative & general (A&G), credit to expense, amortization of contributions, and franchise fee) and is provided in Schedule 4-T-15. This change to the allocation of revenue offsets more appropriately reflects how the majority of the offsets were derived.

The classification of A&G expenses are based on the sum of all service costs (including revenue offsets but excluding purchase power and amortization of contributions) and are provided in Schedule 4-T-16.

Amortization expenses, related to transmission and distribution contributions, were classified based on depreciation expense in Schedule 4-T-17.

3.4.6 Allocation of Classified Costs to Rate Class

Once each cost component has been classified into its customer, demand and energy components, they are then allocated to the various rate classes.

Production Costs

A summary illustrating a) the classification of production costs as being either customer, demand or energy related, and b) the allocation of production costs to the various rate classes has been provided in Schedule 4-T-18.

Transmission Costs

A summary schedule that illustrates a) the classification of transmission costs, by cost component, and b) the allocation of transmission related costs to rate class has been provided in Schedule 4-T-19.

Distribution Costs

With respect to distribution costs, the allocation methods employed are those that were used in the previous GRA. Both return and income tax associated with distribution assets have been allocated to the rate classes based on the mid-year balance of distribution net rate base allocated to each rate class (Schedule 4-T-20). All other carrying costs associated with distribution assets have been allocated to each rate class based on the mid-year balance of gross distribution property, plant and equipment allocated to each rate class (Schedule 4-T-21).

Distribution O&M has been allocated to each rate class based on the mid-year balance of gross distribution property plant and equipment allocated to each rate class as shown in Schedule 4-T-22.

Customer Accounting and Public Information costs are allocated based on the average number of customers and energy sales ratio and is found in Schedule 4-T-23.

The allocation of the distribution-related portion of insurance expense to each rate class was based on the mid-year gross distribution plant allocated to each rate class in Schedule 4-T-24.

Distribution-related revenue offsets were allocated to each rate class based on the sum of all service costs allocated to rate class excluding A&G expenses, Credits, Amortization of Contributions and Purchase Power (Schedule 4-T-25).

Distribution related A&G expenses were allocated to each rate class based on the sum of all service costs excluding A&G expenses, credits, and amortization of contributions, purchase power, and franchise fee but includes revenue offsets (Schedule 4-T-26).

3.4.7 Cost of Service Summary by Rate Class

A summary of the costs allocated by rate class has been provided. The costs by rate class are in Schedules 4-T-27 to 4-T-33.

3.4.8 Summary of Customers, Demand and Energy

A summary of the customer counts, demand and energy by rate class is in Schedule 4-T-34.

A summary of the costs allocated and the Total Service Cost is provided in Schedule 4-T-35.

APPENDIX 3.1

Yukon Electric and Yukon Energy
2008-10 GRA
Cost of Service Study

Table of Contents

Yukon
2009 GRA
Combined YECL and YEC
Mid-year Balance of Gross Plant, Property & Equipment
2009

Total		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	81,427	81,427
Plant	- Other Hydro	0	16,392	24,589	40,981
Production	- Diesel	0	40,662	0	40,662
Plant	- Wind	0	0	3,150	3,150
	Production Total	0	57,055	109,166	166,220
		------	------	------	------
Transmission	- Transmission Line	0	0	99,823	99,823
	Transmission Total	0	0	99,823	99,823
		------	------	------	------
Distribution Plant [1]		61,942	51,553	0	113,495
General Plant		4,836	8,970	19,026	32,832
	Gross PP & E Total	66,778	117,578	228,015	412,370
		======	======	======	======

Notes

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[1] Distribution Plant by Rate Class

	Customer	Demand	Energy	Total
Residential	763	390	0	1,153
Residential - Non Government	42,683	25,340	0	68,023
General Service	1,638	7,009	0	8,647
General Service - Non Government	7,572	15,662	0	23,234
Industrial	3	2,302	0	2,305
Street Lights	8,968	724	0	9,692
Sentinel Lights	315	126	0	440
	======	======	======	======
Total	61,942	51,553	0	113,495

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Yukon
2009 GRA
Combined YECL and YEC
Summary of Mid-Year Rate Base
2009

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Mid-year Net Rate Base					
Production	- Hydro Energy Only	0	0	48,236	48,236
Plant	- Other Hydro	0	6,657	9,986	16,643
Production	- Diesel	0	18,799	0	18,799
Plant	- Wind	0	0	1,782	1,782
	Production Total	0	25,456	60,004	85,460
Transmission	- Transmission Line	0	0	40,444	40,444
	Transmission Total	0	0	40,444	40,444
Distribution Plant [1]		19,509	16,695	0	36,204
General Plant		2,641	5,283	12,512	20,436
		======	======	======	======
Fixed Assets	Total	22,150	47,435	112,960	182,545
Reserves and Deferred Items					
Miscellaneous Reserves					(754)
Deferred Expenses - Other					8,332
Reserves and Deferred Total					7,578
					======
Working Capital &					
Special Regulatory Items					
Working Capital					5,820
Deferred Charges / Credits					1,484
					======
	Total				7,303
					======
MID-YEAR NET RATE BASE					197,426
					======

Notes

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[1] Distribution Plant by Rate Class	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Residential	244	126	0	370
Residential - Non Government	13,639	8,208	0	21,847
General Service	543	2,270	0	2,813
General Service - Non Government	2,528	5,073	0	7,601
Industrial	0	743	0	743
Street Lights	2,491	235	0	2,725
Sentinel Lights	63	41	0	104
	======	======	======	======
Total	19,509	16,695	0	36,204

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Page 3

Yukon
2009 GRA
Combined YECL and YEC
Summary of Service Costs

	Forecast Cost ($000)
Carrying Cost of Investment	
Depreciation	10,184
Municipal Taxes	510
Franchise Taxes	0
Return on Ratebase	14,163
Income Taxes	211
Amortization of Contribution	(2,389)

Total Carrying Cost	22,680

Operating Expenses	
Production Cost (Wind)	62
Production Cost Excluding Fuel	5,503
Fuel & Purchased Power, less secondary sales revenues	5,225
Transmission	1,226
Distribution	3,145
Administrative General	8,705
Customer Accounting	2,492
Public Information	429
General Expense	1,123
Insurance	1,196

Total Operating Expense	29,105

Credit to Expense	
Service Revenue	(115)
Rental & Misc. Revenue	(837)
Penalty	0

Total Credit	(952)

Total Service Cost	50,833
	======

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Page 4

Yukon
2009 GRA
Combined YECL and YEC
(Based on Mid-year Balance of Gross Plant, Property & Equipment)
Classifying Depreciation to Customer, Demand and Energy

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	1,639	1,639
Plant	- Other Hydro	0	349	523	872
Production	- Diesel	0	898	0	898
Plant	- Wind	0	0	95	95
	Production Total	0	1,247	2,257	3,504
Transmission	- Transmission Line	0	0	2,101	2,101
	Transmission Total	0	0	2,101	2,101
Distribution Plant		1,538	1,280	0	2,819
General Plant		259	481	1,020	1,761
	Depreciation Provision	1,798	3,008	5,378	10,184
		======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
(Based on Mid-year Balance of Gross Plant, Property & Equipment)
Classifying Municipal and Franchise Taxes to Customer, Demand and Energy

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	101	101
Plant	- Other Hydro	0	20	30	51
Production	- Diesel	0	50	0	50
Plant	- Wind	0	0	4	4
	Production Total	0	71	135	206
		------	------	------	------
Transmission	- Transmission Line	0	0	124	124
	Transmission Total	0	0	124	124
		------	------	------	------
Distribution Plant		77	64	0	140
General Plant		6	11	24	41
	Municipal Taxes	83	145	282	510
		======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
2009
(Based on Mid-year Rate Base)
Classifying Return to Customer, Demand and Energy

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	3,460	3,460
Plant	- Other Hydro	0	478	716	1,194
Production	- Diesel	0	1,349	0	1,349
Plant	- Wind	0	0	128	128
	Production Total	0	1,826	4,305	6,131
		------	------	------	------
Transmission	- Transmission Line	0	0	2,901	2,901
	Transmission Total	0	0	2,901	2,901
		------	------	------	------
Distribution Plant		1,400	1,198	0	2,597
General Plant		189	379	898	1,466
		------	------	------	------
Fixed Assets	Total	1,589	3,403	8,104	13,095
		======	======	======	======
Reserves and Deferred Items					
Miscellaneous Reserves					(54)
Deferred Expenses - Other					598
	Reserves and Deferred Total				544

Working Capital & Special Regulatory Items					
Working Capital					417
Rate Case Expense (mid-year)					106
	Total				524

Return Total					14,163

Yukon
2009 GRA
Combined YECL and YEC
Classifying Income Tax to Customer, Demand and Energy - 2009
(Based on Mid-year Rate Base)

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	52	52
Plant	- Other Hydro	0	7	11	18
Production	- Diesel	0	20	0	20
Plant	- Wind	0	0	2	2
	Production Total	0	27	64	91
		------	------	------	------
Transmission	- Transmission Line	0	0	43	43
	Transmission Total	0	0	43	43
		------	------	------	------
Distribution Plant		21	18	0	39
General Plant		3	6	13	22
		------	------	------	------
Fixed Assets	Total	24	51	121	195
		======	======	======	======
Reserves and Deferred Items					
Miscellaneous Reserves					(1)
Deferred Expenses - Other					9
	Reserves and Deferred Total				8
					======
Working Capital &					
Special Regulatory Items					
Working Capital					6
Rate Case Expense (mid-year)					2
	Total				8
					======
Income Tax Total					211
					======

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Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Carrying Cost of General Plant to Customer, Demand and Energy
(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

	($000)
Depreciation	1,761
Municipal Tax	41
Return	1,466
Income Tax	22
O & M	1,123

Total	4,412
	======

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	947	947
Plant	- Other Hydro	0	191	286	476
Production	- Diesel	0	473	0	473
Plant	- Wind	0	0	37	37
	Production Total	0	663	1,269	1,932
		------	------	------	------
Transmission	- Transmission Line	0	0	1,160	1,160
	Transmission Total	0	0	1,160	1,160
		------	------	------	------
Distribution Plant		720	599	0	1,319
	General Plant Carrying Cost	720	1,263	2,429	4,412
		======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Carrying Cost of Miscellaneous Reserves to Customer, Demand and Energy
(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

	($000)
Return	(54)
Income Tax	(1)
	------
	(55)
	======

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	(12)	(12)
Plant	- Other Hydro	0	(2)	(4)	(6)
Production	- Diesel	0	(6)	0	(6)
Plant	- Wind	0	0	(0)	(0)
	Production Total	0	(8)	(16)	(24)
		------	------	------	------
Transmission	- Transmission Line	0	0	(14)	(14)
Plant	Transmission Total	0	0	(14)	(14)
		------	------	------	------
Distribution Plant		(9)	(7)	0	(16)
	Miscellaneous Reserve Carrying Cost	(9)	(16)	(30)	(55)
		======	======	======	======

Yukon
2009 GRA
Combined YECL and YEC
Classifying Carrying Cost of "Other" Deferred Expenses
to Customer, Demand and Energy

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(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

	"Other" Deferred ($000)
Return	598
Income Tax	9

	607
	======

Hay River		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	130	130
Plant	- Other Hydro	0	26	39	65
Production	- Diesel	0	65	0	65
Plant	- Wind	0	0	5	5
	Production Total	0	91	174	266
		------	------	------	------
Transmission	- Transmission Line	0	0	160	160
	Transmission Total	0	0	160	160
		------	------	------	------
Distribution Plant		99	82	0	181
		------	------	------	------
	"Other" Deferred Expense Carrying Cost	99	174	334	607
		======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Carrying Cost of Working Capital to Customer, Demand and Energy
(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

	($000)
Return	417
Income Tax	6

	424
	======

Combined		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	91	91
Plant	- Other Hydro	0	18	27	46
Production	- Diesel	0	45	0	45
Plant	- Wind	0	0	4	4
	Production Total	0	64	122	186
		------	------	------	------
Transmission	- Transmission Line	0	0	111	111
	Transmission Total	0	0	111	111
		------	------	------	------
Distribution Plant		69	58	0	127
	Working Capital Carrying Cost	69	121	233	424
		======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Carrying Cost of Rate Case Expense to Customer, Demand and Energy
(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

	($000)
Return	106
Income Tax	2

	109
	======

Combined		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	23	23
Plant	- Other Hydro	0	5	7	12
Production	- Diesel	0	12	0	12
Plant	- Wind	0	0	1	1
	Production Total	0	16	31	48
		------	------	------	------
Transmission	- Transmission Line	0	0	29	29
	Transmission Total	0	0	29	29
		------	------	------	------
Distribution Plant		18	15	0	32
	Rate Case Expense Carrying Cost	18	31	60	109
		======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Operation and Maintenance Expenses

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production O&M (Wind)	0	0	62	62
Production O&M (Excl Fuel & Pur Pwr)	0	2,751	2,751	5,503
Fuel & Purchased Power	0	0	5,225	5,225
Transmission - Transmission Line	0	0	1,226	1,226
Transmission - Other Lines	0	0	0	0
Transmission - Spare Line	0	0	0	0
Distribution (Excl Lights and Brushing)	1,264	1,215	0	2,478
Distribution (Brushing)	198	221	0	419
Distribution (Street and Sentinel Lights)	248	0	0	248
Administrative General	0	0	0	8,705
Customer Accounting	2,492	0	0	2,492
Public Information	429	0	0	429
General Plant	0	0	0	1,123
Insurance	0	0	0	1,196

Total O & M				29,105
				======

Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Risk Insurance Expense
(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Hydro Energy Only	0	0	257	257
Plant	- Other Hydro	0	52	77	129
Production	- Diesel	0	128	0	128
Plant	- Wind	0	0	10	10
	Production Total	0	180	344	524
		------	------	------	------
Transmission	- Transmission Line	0	0	315	315
	Transmission Total	0	0	315	315
		------	------	------	------
Distribution Plant		195	162	0	358
		------	------	------	------
	Insurance Expenses	195	342	659	1,196
		======	======	======	======

Yukon
2009 GRA
Combined YECL and YEC
Classifying Revenue Offsets
to Customer, Demand and Energy
(Based on Sum of All Service Costs Excluding Administrative & General)

Sum of Service Costs (Excl A&G, Revenue Offsets) Yukon	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution Plant	8,776	4,919	0	13,695
	------	------	------	------
Sum of Service Costs Excluding A&G	8,776	4,919	0	13,695
	======	======	======	======

Classified Revenue Offsets Yukon	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution Plant	(610)	(342)	0	(952)
	------	------	------	------
Revenue Offsets	(608)	(344)	0	(952)
	======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
2009
Classifying Administrative & General Expenses
(Based on Sum of All Service Costs Including Revenue Offsets)

Sum of Service Costs (Incl Revenue Offset, Excl Purch Power, A&G)	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production Total	0	6,928	11,499	18,427
Transmission - Transmission Line	0	0	8,155	8,155
Transmission Total	0	0	8,155	8,155
Distribution Plant	8,166	4,577	0	12,743
Sum of Service Costs Incl Rev Offsets Excl Purch Power	8,166	11,505	19,654	39,325

Classified A & G	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production Total	0	1,534	2,546	4,079
Transmission - Transmission Line	0	0	1,805	1,805
Transmission Total	0	0	1,805	1,805
Distribution Plant	1,808	1,013	0	2,821
Administrative & General Expenses	1,808	2,547	4,351	8,705

Yukon
2009 GRA
Combined YECL and YEC
Classifying Amortization of Transmission & Distribution Contributions
2009
(Based on Mid-year Depreciation)

	Total ($000)
Amortization of Production Contributions	
Production	(295)
Total	(295)
Amortization of Distribution Contributions	
Residential	(14)
Residential - Non Government	(917)
General Service	(74)
General Service - Non Government	(147)
Industrial	0
Street Lights	(43)
Sentinel Lights	(1)
Total	(1,196)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Mid-year Depreciation (based on Gross PP&E)				
Total Production	0	1,247	2,257	3,504
Allocated Amortization of Contributions				
Total Production	0	(105)	(190)	(295)
Transmission				
Mid-year Depreciation (based on Gross PP&E)				
	0	0	2,101	2,101
Allocated Amortization of Contributions				
	0	0	(897)	(897)
Distribution				
Mid-year Depreciation (based on Gross PP&E)				
Residential	19	10	0	29
Residential - Non Government	1,060	629	0	1,689
General Service	41	174	0	215
General Service - Non Government	188	389	0	577
Industrial (distribution level)	0	57	0	57
Street Lights	223	18	0	241
Sentinel Lights	8	3	0	11
Total	1,538	1,281	0	2,819
Allocated Amortization of Contributions				
Residential	(9)	(5)	0	(14)
Residential - Non Government	(575)	(342)	0	(917)
General Service	(14)	(60)	0	(74)
General Service - Non Government	(48)	(99)	0	(147)
Industrial (distribution level)	0	0	0	0
Street Lights	(40)	(3)	0	(43)
Sentinel Lights	(0)	(0)	0	(1)
Total Distribution	(698)	(498)	0	(1,196)

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Yukon
2009 GRA
Combined YECL and YEC
2009
Allocation of Direct Production Costs

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Depreciation	0	1,247	2,257	3,504
Municipal and Franchise Taxes	0	71	135	206
Return on Ratebase	0	1,826	4,305	6,131
Income Taxes	0	27	64	91
General Plant Carrying Costs	0	663	1,269	1,932
Miscellaneous Reserve Carrying Costs	0	(8)	(16)	(24)
Maintenance Reserves Carrying Costs	0	0	0	0
Deferred Expenses (Production) Carrying Costs	0	0	0	0
Deferred Expenses (Other) Carrying Costs	0	91	174	266
Working Capital Carrying Costs	0	64	122	186
Rate Case Expense Carrying Costs	0	16	31	48
Unamortized Bad Debt & Land Gains	0	0	0	0
Unamortized DSM Costs	0	0	0	0
Unamortized Overhaul Costs	0	0	0	0
Production, Fuel & Purchase Power	0	2,751	8,038	10,790
Insurance Expense	0	180	344	524
Revenue Offsets	0	0	0	0
Administrative General	0	1,534	2,546	4,079
Amortization of Contribution to Prod. Facilities	0	(105)	(190)	(295)
Total	0	8,357	19,079	27,436

Allocated Costs	Demand Cost Allocator: Coincidental Peak (kW)	Share of Demand Cost ($000)	Energy Cost Allocator: Energy Sent Out (MWh)	Share of Energy Cost ($000)	Total Cost ($000)
Residential	549	63	2,467	123	186
Residential - Non Government	34,979	4,045	157,172	7,819	11,863
General Service	9,534	1,103	58,707	2,920	4,023
General Service - Non Government	21,049	2,434	129,606	6,447	8,881
Industrial	4,789	554	30,504	1,517	2,071
Street Lights	1,168	135	4,339	216	351
Sentinel Lights	198	23	737	37	60
Total	72,266	8,357	383,532	19,079	27,436

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Yukon
2009 GRA
Combined YECL and YEC
2009
Allocation of Direct Transmission Line Costs

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Depreciation	0	0	2,101	2,101
Municipal and Franchise Taxes	0	0	124	124
Return on Ratebase	0	0	2,901	2,901
Income Taxes	0	0	43	43
General Plant Carrying Costs	0	0	1,160	1,160
Miscellaneous Reserve Carrying Costs	0	0	(14)	(14)
Maintenance Reserves Carrying Costs	0	0	0	0
Deferred Expenses (Transmission) Carrying Costs	0	0	0	0
Deferred Expenses (Other) Carrying Costs	0	0	160	160
Working Capital Carrying Costs	0	0	111	111
Rate Case Expense Carrying Costs	0	0	29	29
Unamortized Bad Debt & Land Gains	0	0	0	0
Unamortized DSM Costs	0	0	0	0
Unamortized Overhaul Costs	0	0	0	0
Transmission O&M	0	0	1,226	1,226
Insurance	0	0	315	315
Administrative General	0	0	1,805	1,805
Amortization of Contributions	0	0	(897)	(897)
	------	------	------	------
Total	0	0	9,063	9,063
	======	======	======	======

Allocated Costs	Energy Cost Allocator:	0% Specific Costs ($000)	Demand Cost Allocator: Coincidental Peak (kW)	100% Specific Costs ($000)	Total Costs ($000)
Residential	2,467,306	58	549	0	58
Residential - Non Government	157,171,605	3,714	34,979	0	3,714
General Service	58,706,926	1,387	9,534	0	1,387
General Service - Non Government	129,606,367	3,063	21,049	0	3,063
Industrial	30,503,678	721	4,789	0	721
Street Lights	4,338,813	103	1,168	0	103
Sentinel Lights	737,295	17	198	0	17
	------	------	------	------	------------
Total	383,531,990	9,063	72,266	0	9,063
	======	======	======	======	============

Yukon
2009 GRA
Combined YECL and YEC
Allocation of Distribution Return and Income Tax to Rate Class
(Based on Mid-year Balance of Net Distribution Rate Base)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution Carrying Costs				
Return	1,400	1,198	0	2,597
Income Tax	21	18	0	39
	------	------	------	------
Total	1,420	1,216	0	2,636
	======	======	======	======
Allocated Costs				
Residential	18	10	0	27
Residential - Non Government	993	625	0	1,618
General Service	40	173	0	213
General Service - Non Government	184	387	0	571
Industrial	0	0	0	0
Street Lights	181	18	0	199
Sentinel Lights	5	3	0	8
	------	------	------	------
Total	1,420	1,216	0	2,636
	======	======	======	======

Yukon
2009 GRA
Combined YECL and YEC
Allocation of Distribution Carrying Costs (Excluding Return and Income Tax)
2009
(Based on Mid-year Balance of Gross Distribution Plant, Property & Equipment)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution Carrying Costs				
Depreciation	1,538	1,280	0	2,819
Municipal Taxes	77	64	0	140
General Plant Carrying Costs	720	599	0	1,319
Miscellaneous Reserve Carrying Costs	(9)	(7)	0	(16)
Maintenance Reserves Carrying Costs	0	0	0	0
Deferred Expenses (Prod &Trans) Carrying Costs	0	0	0	0
Deferred Expenses (Other) Carrying Costs	99	82	0	181
Working Capital Carrying Costs	69	58	0	127
Rate Case Expense Carrying Costs	18	15	0	32
Unamortized Bad Debt & Land Gains	0	0	0	0
Unamortized DSM Costs	0	0	0	0
Unamortized Overhaul Costs	0	0	0	0
	------	------	------	------
Total	2,512	2,091	0	4,603
	======	======	======	======

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Total Allocated Carrying Costs				
Residential	31	16	0	47
Residential - Non Government	1,731	1,057	0	2,788
General Service	66	292	0	359
General Service - Non Government	307	653	0	960
Industrial	0	36	0	36
Street Lights	364	30	0	394
Sentinel Lights	13	5	0	18
	------	------	------	------
Total	2,512	2,091	0	4,603
	======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
Allocation of Distribution Operating & Maintenance Costs
2009

(Based on Mid-year Balance of Gross Distribution Plant, Property & Equipment)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution O&M (Excl Lights and Brushing)	1,264	1,215	0	2,478
Distribution O&M (Brushing)	198	221	0	419
Distribution (Street and Sentinel Lights)	248	0	0	248
	------	------	------	------
Total	1,709	1,436	0	3,145
	======	======	======	======
Allocated O&M (Excl Lights and Brushing)				
Residential	18	9		27
Residential - Non Government	1,024	597		1,621
General Service	39	165		204
General Service - Large	182	369		551
Industrial	0	54		54
Street Lights		17		17
Space Lights		3		3
	1,264	1,215		2,478
Allocated O&M (Brushing)	------	------	------	------
Residential	3	2		5
Residential - Non Government	155	109		264
General Service	9	30		39
General Service - Large	30	67		97
Industrial	0	10		10
Street Lights		3		419
Space Lights		1		1
	198	221		834
	------	------	------	------
Allocated Distribution O&M				
Residential	21	11	0	32
Residential - Non Government	1,180	706	0	1,885
General Service	48	195	0	243
General Service - Non Government	212	436	0	648
Industrial	0	64	0	64
Street Lights	248	20	0	268
Sentinel Lights	0	3	0	3
	------	------	------	------
Total	1,709	1,436	0	3,145
	======	======	======	======

Yukon
2009 GRA
Combined YECL and YEC
Allocation of Customer Accounting and Public Information Costs
2009

(Based on Average Number of Customers Excluding Street Lights and Sentinel Lights and Energy Sales)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Customer Accounting	2,492	0	0	2,492
Public Information	429	0	0	429
	------	------	------	------
Total	2,921	0	0	2,921
	======	======	======	======

Customer Accounting: 100% of Cost Allocated Based on Avg No. of Customers; 0% of Cost Allocated Based on Energy Sale

	Avg No. of Customers	100% of Cost	Energy Sales	0% of Cost	Total Cost
Residential	252	36	2,161	0	36
Residential - Non Government	14,128	2,016	137,637	0	2,016
General Service	547	78	51,410	0	78
General Service - Non Government	2,539	362	113,498	0	362
Industrial	1	0	29,023	0	0
Street Lights	0	0	3,800	0	0
Sentinel Lights	0	0	646	0	0
	------	------	------	------	------------
2009 Total	17,468	2,492	338,175	0	2,492
	======	======	======	======	============

Public Information: 15% of Cost Allocated Based on Avg No. of Customers; 85% of Cost Allocated Based on Energy Sale

	Avg No. of Customers	15% of Cost	Energy Sales	85% of Cost	Total Cost
Residential	252	1	2,161	2	3
Residential - Non Government	14,128	52	137,637	148	200
General Service	547	2	51,410	55	57
General Service - Non Government	2,539	9	113,498	122	132
Industrial	1	0	29,023	31	31
Street Lights	0	0	3,800	4	4
Sentinel Lights	0	0	646	1	1
	------	------	------	------	------------
2009 Total	17,468	64	338,175	365	429
	======	======	======	======	============

Allocated Customer Accounting and Public Information Costs

	Customer	Demand	Energy	Total
Residential	37	0	2	39
Residential - Non Government	2,068	0	148	2,216
General Service	80	0	55	136
General Service - Non Government	372	0	122	494
Industrial	0	0	31	31
Street Lights	0	0	4	4
Sentinel Lights	0	0	1	1
	------	------	------	------
Total	2,557	0	365	2,921
	======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
Allocation of Insurance Expenses
2009

(Insurance Based on Mid-year Gross Distribution Plant, Property and Equipment)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Insurance	195	162	0	358
	------	------	------	------
Total	195	162	0	358
	======	======	======	======
Allocated Insurance Expense				
Residential	2	1	0	4
Residential - Non Government	135	80	0	214
General Service	5	22	0	27
General Service - Large	24	49	0	73
Industrial	0	7	0	7
Street Lights	28	2	0	31
Space Lights	1	0	0	1
	------	------	------	------
Total	195	162	0	358
	======	======	======	======
Allocated Insurance Costs				
Residential	2	1	0	4
Residential - Non Government	135	80	0	214
General Service	5	22	0	27
General Service - Non Government	24	49	0	73
Industrial	0	7	0	7
Street Lights	28	2	0	31
Sentinel Lights	1	0	0	1
	------	------	------	------
Total	195	162	0	358
	======	======	======	======

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Yukon
2009 GRA
Combined YECL and YEC
Allocation of Revenue Offsets
2009

(Based on Sum of All Service Costs Excluding Administrative & General)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Revenue Offsets	(610)	(342)	0	(952)
	------	------	------	------
Total	(610)	(342)	0	(952)
	======	======	======	======
Allocated Sum of Service Costs Excluding A&G				
Residential	109	38	2	150
Residential - Non Government	6,106	2,468	148	8,723
General Service	239	683	55	977
General Service - Non Government	1,099	1,525	122	2,746
Industrial	0	108	31	139
Street Lights	821	71	4	896
Sentinel Lights	18	12	1	31
	------	------	------	------
Total	8,393	4,904	365	13,662
	======	======	======	======
Allocated Revenue Offsets				
Residential	(8)	(3)	0	(11)
Residential - Non Government	(444)	(172)	0	(616)
General Service	(17)	(48)	0	(65)
General Service - Non Government	(80)	(106)	0	(186)
Industrial	(0)	(7)	0	(8)
Street Lights	(60)	(5)	0	(65)
Sentinel Lights	(1)	(1)	0	(2)
	------	------	------	------
Total	(610)	(342)	0	(952)
	======	======	======	======

Yukon
2009 GRA
Combined YECL and YEC
Allocation of Administrative & General Expenses
2009

(Based on Sum of All Service Costs Excluding Administrative & General and but Including Revenue Offsets)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Administrative & General Expenses	1,808	1,013	0	2,821
	------	------	------	------
Total	1,808	1,013	0	2,821
	======	======	======	======
Allocated Sum of Service Costs Excl A&G but Incl Revenue Offset				
Residential	102	35	2	139
Residential - Non Government	5,662	2,296	148	8,107
General Service	222	635	55	912
General Service - Non Government	1,019	1,419	122	2,560
Industrial	0	100	31	132
Street Lights	761	66	4	831
Sentinel Lights	17	11	1	29
	------	------	------	------
Total	7,783	4,562	365	12,710
	======	======	======	======
Allocated Administrative & General Expenses				
Residential	24	8	0	31
Residential - Non Government	1,315	510	0	1,825
General Service	52	141	0	193
General Service - Non Government	237	315	0	552
Industrial	0	22	0	22
Street Lights	177	15	0	191
Sentinel Lights	4	3	0	6
	------	------	------	------
Total	1,808	1,013	0	2,821
	======	======	======	======

Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: Residential Government
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	63	123	186
Transmission - Transmission Line	0	0	58	58
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	18	10	0	27
Carrying Costs (Excluding Return and Income Tax)	31	16	0	47
Operating & Maintenance Costs	21	11	0	32
Customer Accounting & Public Information	37	0	2	39
Insurance	2	1	0	4
Revenue Offsets	(8)	(3)	0	(11)
Administrative & General	24	8	0	31
Amortization of Contributions	(9)	(5)	0	(14)
	------	------	------	------
Total	116	102	183	401
	======	======	======	======
Unit Cost	458.5	233.3	8.5	

$/customer $/kW c/kWh

Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: Residential Non-Government
2009

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	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	4,045	7,819	11,863
Transmission - Transmission Line	0	0	3,714	3,714
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	993	625	0	1,618
Carrying Costs (Excluding Return	1,731	1,057	0	2,788
Operating & Maintenance Costs	1,180	706	0	1,885
Customer Accounting & Public Information	2,068	0	148	2,216
Insurance	135	80	0	214
Revenue Offsets	(444)	(172)	0	(616)
Administrative & General	1,315	510	0	1,825
Amortization of Contributions	(575)	(342)	0	(917)
	------	------	------	------
Total	6,402	6,509	11,681	24,592
	======	======	======	======
Unit Cost	453.1	234.0	8.5	
	$/customer	$/kW	c/kWh	

Schedule 4-T-29
Page 29

Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: General Service Government
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	1,103	2,920	4,023
Transmission - Transmission Line	0	0	1,387	1,387
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	40	173	0	213
Carrying Costs (Excluding Return and Income Tax)	66	292	0	359
Operating & Maintenance Costs	48	195	0	243
Customer Accounting & Public Information	80	0	55	136
Insurance	5	22	0	27
Revenue Offsets	(17)	(48)	0	(65)
Administrative & General	52	141	0	193
Amortization of Contributions	(14)	(60)	0	(74)
	------	------	------	------
Total	260	1,819	4,363	6,442
	======	======	======	======
Unit Cost	474.3	239.9	8.5	
	$/customer	$/kW	c/kWh	

Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: General Service - Non Government
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	2,434	6,447	8,881
Transmission - Transmission Line	0	0	3,063	3,063
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	184	387	0	571
Carrying Costs (Excluding Return and Income Tax)	307	653	0	960
Operating & Maintenance Costs	212	436	0	648
Customer Accounting & Public information	372	0	122	494
Insurance	24	49	0	73
Revenue Offsets	(80)	(106)	0	(186)
Administrative & General	237	315	0	552
Amortization of Contributions	(48)	(99)	0	(147)
Total	1,207	4,069	9,632	14,909
Unit Cost	475.5	243.1	8.5	

$/customer $/kW c/kWh

Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: Industrial
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	554	1,517	2,071
Transmission - Transmission Line	0	0	721	721
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	0	0	0	0
Carrying Costs (Excluding Return and Income Tax)	0	36	0	36
Operating & Maintenance Costs	0	64	0	64
Customer Accounting & Public Information	0	0	31	31
Insurance Expense	0	7	0	7
Revenue Offsets	(0)	(7)	0	(8)
Administrative & General	0	22	0	22
Amortization of Contributions	0	0	0	0
	------	------	------	------
Total	0	676	2,270	2,946
	======	======	======	======
Unit Cost	0.0	157.9	7.8	
	$/customer	$/kW	c/kWh	

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Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: Street Lights
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	135	216	351
Transmission - Transmission Line	0	0	103	103
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	181	18	0	199
Carrying Costs (Excluding Return and Income Tax)	364	30	0	394
Operating & Maintenance Costs	248	20	0	268
Customer Accounting & Public information	0	0	4	4
Insurance	28	2	0	31
Revenue Offsets	(60)	(5)	0	(65)
Administrative & General	177	15	0	191
Amortization of Contributions	(40)	(3)	0	(43)
	------	------	------	------
Total	898	212	322	1,432
	======	======	======	======
Unit Cost		228.3 $/kW	8.5 c/kWh	

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Yukon
2009 GRA
Combined YECL and YEC
Summary of Fully Allocated Costs by Rate Class: Sentinel Lights
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	23	37	60
Transmission - Transmission Line	0	0	17	17
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	5	3	0	8
Carrying Costs (Excluding Return and Income Tax)	13	5	0	18
Operating & Maintenance Costs	0	3	0	3
Customer Accounting & Public information	0	0	1	1
Insurance	1	0	0	1
Revenue Offsets	(1)	(1)	0	(2)
Administrative & General	4	3	0	6
Amortization of Contributions	(0)	(0)	0	(1)
	------	------	------	------
Total	21	37	55	112
	======	======	======	======
Unit Cost		232.5 $/kW	8.5 c/kWh	

Yukon
2009 GRA
Combined YECL and YEC
Summary of Customers, Demand, and Energy for Allocation Purposes
2009

	Number of Customers
Residential	252
Residential Non Government	14,128
General Service	547
General Service Non Government	2,539
Industrial	1
Street Lights	NA
Sentinel Lights	NA

Total	17,468

	Distribution Level Demand Sales(kW)
Residential	437
Residential Non Government	27,816
General Service	7,582
General Service Non Government	16,739
Industrial	0
Street Lights	929
Sentinel Lights	158

Total	53,661

	Distribution Level Energy Sales (KW.h)
Residential	2,160,655
Residential Non Government	137,637,409
General Service	51,410,490
General Service Non Government	113,498,139
Industrial	0
Street Lights	3,799,560
Sentinel Lights	645,660

Total	309,151,913

Yukon
2009 GRA
Combined YECL and YEC
Summary of Costs
2009

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	0	8,357	19,079	27,436
Transmission - Transmission Line	0	0	9,063	9,063
Transmission - Other	0	0	0	0
Distribution				
Return and Income Tax	1,420	1,215	0	2,635
Carrying Costs (Excluding Return and Income Tax)	2,512	2,091	0	4,603
Operating & Maintenance Costs	1,709	1,436	0	3,145
Customer Accounting & Public information	2,557	0	365	2,921
Insurance	195	162	0	358
Revenue Offsets	(610)	(342)	0	(952)
Administrative & General	1,808	1,013	0	2,821
Amortization of Contributions	(687)	(509)	0	(1,196)
	------	------	------	------
Total	8,904	13,423	28,506	50,833

Total Service Cost				50,833

				0

APPENDIX 3.2

APPENDIX 3.2 – DISTRIBUTION CLASSIFICATION STUDY

The distribution plant categories of Poles, Transformers, and Wires were studied by utilizing a minimum-size methodology and a zero-intercept methodology applied to Yukon Electrical records.

Data

The scope of the study examined quantities and cost records for the period of 1995 to 2008. Twenty-nine types of poles, sixty-eight types of transformers, and twenty-eight different types of wires were analyzed in the classification study. The installed quantities of each of these types of equipment were obtained from YECL's historical records for the period of 1995 to 2008. The material costs used represents YECL's 2008 average inventory issue amounts. Labour rates also represent YECL's 2008 forecasted amounts. Yukon Energy's distribution plant was not used in the classification study as it represents a small portion of the Yukon's overall distribution plant.

Methodology Overview

In classifying the distribution function, the customer and demand split is based on the distinct purposes of the distribution system. From a cost perspective, attaching customers to the system is identified as customer-related costs, while meeting existing customers' demand beyond their minimum load is considered demand-related costs.

In order to account for the varying equipment installed in the distribution system, an estimate of the volume split between three and single phase transformers, and wires was determined based on YECL equipment specifications and internal engineering personnel. A three phase versus single phase split was incorporated in the development of the "minimum system" cost for the transformers plant category. This volume split is used as a volume modifier in determining the "total as-built" costs for wires.

Minimum System Method[6]

Classifying distribution plant with the minimum-size method assumes that a hypothetical minimum size distribution system can be built to serve the minimum loading requirement of a customer. This method first involves determining the minimum cost pole, transformer, or wire that is currently installed in the distribution system. Page one of each of the schedules outlines the cost data collected for the different types of each equipment category, while page two contains the quantities of plant from the period of

[6] National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual Chapter 6, page 90 to 96.

1995-2008. The identified minimum cost is then applied to the total volume of each specific type of equipment and these results were then summed as the "minimum system" cost. Next, the total volume of the equipment is then applied to the actual pole cost and these results were then summed to form the "total as-built" cost. The ratio of the sums of the "minimum system" to the "total as built" cost was calculated and the result is an estimate of the customer portion of the Minimum System study.

Zero-Intercept Method[7]

The zero-intercept method seeks to identify that portion of the plant related to a hypothetical no-load or presumed zero-intercept situation. The zero-intercept (or the "B" value in the regression equation Y = AX + B) is assumed to be the minimum installed cost for each of the plant categories. Page three of the schedules lists the data points that were used in the regression analysis. All of the poles were included in the analysis. The transformers and wire used only the most common sizes. Computerized regression results from the Zero-Intercept Study are shown on page five, while a visual graph of this same information is illustrated on page six of each of the schedules. The zero-intercept value compared to the weighted average installed cost of each plant category is classified as customer related costs.

Analysis of the regression calculation (zero-intercept study) and the minimum system study are shown on page four, along with the calculated customer-related cost classification for the two methods used.

Poles, Towers, and Fixtures

The analysis of poles, towers, and fixtures utilized an independent variable known as the resistive moment at the ground line, measured in foot-pounds for Lodgepole pine wood poles[8], which represents 95% of YECL's distribution poles. Pole strength data was available for all pole types except for 65 foot class 2 and 70 foot class 2, where the strength data was extrapolated using linear regression.

The minimum installed cost for all poles, towers, and fixtures was determined to be a 35 foot class 5 pole that had a total installed cost of $938. This minimum cost is then applied to the quantities of each pole type. These amounts are then summed to form the aggregate minimum system cost of $7,310,068. The total as-built system cost is calculated to be $8,919,692 determined by multiplying the actual cost of each pole type with the actual quantities installed. The aggregate minimum system cost as a percentage of the aggregate total as-built cost is calculated to be 82%, representing the customer-related cost classification while the remainder of 18% is deemed to be demand-related.

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[7] National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual Chapter 6, page 90 to 96.

A regression analysis, as described above, was performed to reveal the installed cost for a minimum sized (a hypothetical zero-strength) pole at $350. This cost is deemed to be the minimum customer-related cost component. The minimum cost pole as a percentage of the weighted average installed cost for all poles represents the customer-related classification of approximately 31%. The portion of demand-related classification would represent the remaining 69%.

The twenty-nine pole sample selected for the inclusion in the regression analysis included all poles installed which resulted in a high R-Squared statistic[9] of 83%. As seen on page four of Schedule A (which is provided in the excel spreadsheet 'Regression YECL.xls' in the COS model CD) the results for the customer–related cost classifications are 82% under the minimum system study and 31% under the zero-intercept study. An average of the results from the two studies yields a customer-related classification factor of 56% with the remainder 44% being the demand-related classification.

Transformers

The independent variable used in the analysis of the transformers plant category is the transformer kVA size. The sample selected for inclusion in the regression analysis contained six uniquely sized single phase transformers which represent transformers up to and including 75kVA. The material cost is a weighted composite of all transformers in the same kVA size.

The minimum installed cost for all transformers is $1,323 which correlates to a 5 kVA single phase overhead transformer (TKVA 5 OH 24.9GY/14.4/120/240). This minimum was applied to the quantities of each transformer type and then summed to form the aggregate minimum system cost of $3,485,492. Comparing this minimum system cost to the total as-built system cost of $11,049,279 resulted in a customer-related classification of 32%. The remaining 68% is deemed to be the demand-related classification. The zero-intercept result of $1,024 resulted in a customer-related classification of 24% with a demand-related classification of 76%.

A volume modifier was applied to the minimum system study costs. The quantity of transformer types identified as three-phase was divided by three, resulting in a calculated proxy for a single-phase transformer (three single phase transformers are commonly used on 3 phase lines to make a 3 phase transformer). This provided the data to calculate a minimum system cost on a consistent single phase

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[8] Bulletin 1724E-150, US Department of Agriculture Rural Utilities Service, June 30, 2003, Exhibit A, Table 2 "Permitted Moments at Ground Line of Wood Poles", pg. 14.

[9] R-square (R^2) is a statistic that gives information about the goodness of fit of a model. In regression, the R^2 coefficient of determination is a statistical measure of how well the regression line approximates the real data points.

basis. Page four of Schedule B (which is provided in the excel spreadsheet 'Regression YECL.xls' in the COS model CD) details the derivation of the results for the classification of the customer-related and demand-related costs for transformers. An average of the results from the two studies yields a customer-related classification of 28% with the remaining 72% being demand-related. Regression results shown on page 5 of the same schedule reveals the R-squared statistic of 93% suggesting a strong linear relationship.

Overhead Conductors / Underground Conduits (Wires)

The independent variable used in the analysis of wires is the ampacity of each particular type of wire.[10] The sample selected for the regression analysis contains sixteen distinctive types of wires representing the most common type of wire by size. The cost per meter is a weighted average of all the conductor of the same size.

Using the same calculations as noted above, the minimum system study shows the customer-related classification to be 66% when the aggregate minimum-system cost is divided into the aggregate total-as built system cost. The remaining 34% is deemed to the demand-related classification. The zero-intercept results show a customer-related classification of 37% while the remaining 63% is deemed to be demand-related.

The volume modifier applied to the total-as built costs was calculated by determining the weighted average number of wires contained within the single and three phase system. The distribution system uses two wires for single phase installations and four wires for three phase installations, the YECL system is comprised of 58% single phase line and 42% three phase line. The result is a "total weighted average number of wires" in the system, calculated to be 2.84. A ratio of the "weighted average number of wires" (i.e. 2.84) over the number wires required under the minimum system (i.e. 2) resulted in a value of 142%. This value indicated that the total-as built system wire length contains 142% more wire than a minimum system. As a result, the total-as built costs were adjusted upwards to reflect the additional wire.

Schedule C (which is provided in the excel spreadsheet 'Regression YECL.xls' in the COS model CD) details the results for the analysis of wires. The customer-related classifications is calculated to be 37% under the zero-intercept study and 66% under the minimum plant study, while an average of the two

[10] General Cable Manufacturer's Standards: Complete Canadian Utility Catalogue September 2004 and Northern Telecom Electrical Conductors Handbook 1977.

methods reveals a 52% customer versus a 48% demand-related classification. The R-square statistic is 90%, showing a strong measure of the linear function.

Results

YECL studied the results of the zero-intercept and minimum plant studies and consider an average of the two methodologies to be the most appropriate and accurate. The zero-intercept method can produce results that allocate more costs to demand rate classes (large consumer) and the minimum plant method can produce results that allocate more costs to the customer (residential) rate classes. An average of the two methods helps mitigate these biases. This approach is consistent with the approved methodology of ATCO Electric Ltd. (Decision 2009-231) as well as Northland Utilities (NUY) (Decision 1-2009) and Northland Utilities (NWT) (Decision 2-2009). The following table summarizes the results from the above classification study for the plant categories of poles, transformers, and wires.

Table 1: CUSTOMER / DEMAND CLASSIFICATION SPLIT

(PERCENT CUSTOMER – RELATED)					
	2008 Study				Used in 1996/97 GRA
	Zero-Intercept Results	Minimum System Results	Average	**Recommend**	
Poles, Towers, & Fixtures	31%	82%	56%	**56%**	75%
Transformers	24%	32%	28%	**28%**	30%
Wires	37%	66%	52%	**52%**	30%
(PERCENT DEMAND RELATED)					
Poles, Towers, & Fixtures	69%	18%	44%	**44%**	25%
Transformers	76%	68%	72%	**72%**	70%
Wires	63%	34%	48%	**48%**	70%

APPENDIX 3.3

APPENDIX 3.3 – ENERGY DEMAND AND LOSS ANALYSIS (EDLA) STUDY

The Energy, Demand and Loss Analysis (EDLA) for the combined Yukon Energy (YEC) and Yukon Electrical Company Limited (YECL) systems was conducted to allocate annual energy loss and demand costs by rate class consumption for the forecast year. This analysis determined demand loss and coincident peak (CP) and non-coincident peak (NCP) demands at the customer level for each rate class. The analysis process is described as follows:

RATE CLASS ENERGY LOSS

The forecast total energy loss of the combined YEC and YECL systems was allocated to each rate class in proportion to the forecasted annual energy sales for each rate class. The Industrial Rate Class was only allocated transmission losses and the other Rate Classes were allocated both transmission and distribution losses.

RATE CLASS CP DEMAND AND DEMAND LOSS

For the forecast year, the customer level CP demand and demand loss were determined for each rate class as follows:

- Residential, commercial and industrial coincident load factors were calculated based on ATCO Electric load research conducted in 2003 to 2007 and were adjusted for differences in average customer sales. ATCO Electric lighting load factor was also used for Yukon lighting.
- Rate class coincident load factors were applied to annual energy sales for the class to estimate customer level CP demand.
- The total demand loss was estimated based on the difference of total supply demand and the customer level CP demand.
- The total distribution demand loss was allocated to each rate class in proportion to the estimated customer level CP demand.

- The total transmission demand loss was allocated to each rate class in proportion to the estimated distribution level CP demand.

RATE CLASS NCP DEMAND AND DEMAND LOSS

For the forecast year, the customer level NCP demand and demand loss were determined for each rate class as follows:

- Residential, commercial and industrial non-coincident load factors were calculated based on ATCO Electric load research conducted in 2003 to 2007 and were adjusted for differences in average customer sales. ATCO Electric lighting load factor was also used for Yukon lighting.
- Rate class non-coincident load factors were applied to annual energy sales for the class to estimate total customer level NCP demand.
- The total distribution demand loss was allocated to each rate class in proportion to the estimated customer level NCP demand.
- The total transmission demand loss was allocated to each rate class in proportion to the estimated distribution level NCP demand.

EDLA changes from 1995 study

The Energy, Demand and Loss Analysis (EDLA) completed in 1995 for the combined Yukon Energy Company (YEC) and Yukon Electrical Company Limited (YECL) Cost of Service Study was based on an analysis of hydro and diesel system losses. These losses were allocated to specific community rate classes and mining companies from YEC and YECL based on:

- Community rate class consumption; and
- System functional levels serving the community rate class (transmission level and primary/secondary distribution level).

System losses were forecasted for each hydro system (e.g. WAF and Mayo), large diesel system and small diesel system. The losses incurred to serve each community were then allocated by the consumption of the different rate classes in the community. The 1995 EDLA analysis subdivided system loss into different components or functional levels of the electric systems. These loss components consisted of station service and both copper and iron loss in the different sections of transmission and distribution (primary and secondary) systems. Also in the 1995 study, government and non-government splits of commercial and residential classes were calculated based on the customers and energy of each community.

In contrast, the 2009 EDLA was based on a simplified model providing results over a composite Yukon system. Unlike the 1995 EDLA, the 2009 EDLA does not attempt to evaluate or allocate losses based on a functional level analysis to specific communities because of the unavailability of specific component results for the Yukon systems and the amount of time and cost required to prepare a more detailed level of study. The quality and usefulness of the EDLA results were not minimized by these changes. The 2009 EDLA does break up percentage losses into transmission and distribution losses but does not break out primary and secondary distribution losses. Using this simplified model provides equally allocated Distribution losses to all classes (except Industrial) and Transmission losses to all classes including the Industrial rate class. In addition, the 2009 study splits government and non-government commercial and residential rate classes based on the customers and energy of each company.

The EDLA completed in 1995 and in 2009 use adjusted ATCO Electric Alberta load factors to calculate both NCP and CP demands.

The AE load factor for each rate class is adjusted to arrive at the Yukon load factor for the same rate class. The adjustment is based on Demand Tables, REA Bulletin 45-2, June 1963, U.S. Department of Agriculture. First, an adjustment factor to the tables is calculated by dividing the actual ATCO Electric load factor from load studies into one based on the Demand Tables. Next, a load factor is calculated for Yukon based on the Demand Tables. Finally, this load factor is multiplied by the adjustment factor to arrive at the preliminary load factor for Yukon.

$$F_{ADJ} = .005925\left[E_{AE}/12\right]^{.885} \frac{LF_{AE}}{E_{AE}/H}$$

$$LF_N = \frac{F_{ADJ}\, E_N/H}{.005925\left[E_N/12\right]^{.885}}$$

The 2 equations simplified equal:

$$LF_N = LF_{AE}\left[\frac{E_N}{E_{AE}}\right]^{.115}$$

Where:

LF_N – preliminary load factor or coincident load factor for the Yukon rate class

E_N – annual energy sales per customer for the Yukon rate class

LF_{AE} – load factor or coincident load factor for the ATCO Electric rate class

Based on load studies

E_{AE} – Annual energy sales per customer for the ATCO Electric rate class

H – Number of hours in a year

F_{ADJ} – Demand Table adjustment factor the ATCO Electric rate class

These tables were developed over 40 years ago by an independent organization. They have been used to allocate costs in all previous combined Yukon Energy Corporation – Yukon Electric Company Limited; Northland Utilities Limited (NWT); and Northland Utilities Limited Yellowknife filings since the 1970's. They were developed for systems with a small numbers of customers that require a cost effective solution for EDLA studies.

APPENDIX 3.4

APPENDIX 3.4 – BACKGROUND AND PAST PRACTICE

1.0 BACKGROUND

In past reviews, the Board has reviewed COS principles and methods in Yukon in the following YUB Reports and Board Orders:

- Board report dated June 1, 1992 to Commissioner in Executive Council following a hearing on COS and rate design pursuant to OIC 1991/62. The report and recommendations continue to form the foundational principles for cost of service and rate design in Yukon.
- Board Orders related to GRAs and rates following the 1992 review process (i.e., Order 1993-8 following the 1993/94 GRA and Order 1996-7 regarding the 1996/97 GRA, each filed jointly by YEC and YECL). The principles established by the 1992 Report were subsequently affirmed in Order 1993-8[11] and 1996-7[12] following YUB reviews of YEC/YECL revenue requirements, cost of service and rate design filings.
- Board Orders in 1998 following a hearing related to rate changes following closure of the Faro mine (Board Oder 1998-5); this Order addressed a Yukon Energy filing which adopted principles and methods for determining COS for the Major Industrial Customer class after closure of the Faro mine for the purpose of assigning costs to the Faro mine, based on the 1997 GRA and actual operation of this mine in 1997 and 1998.[13]
- Board Order 2007-5 and 2007-6 related to the Board approval of the Power Purchase Agreement for the Minto mine. In general, the Board deferred addressing COS issues until the next GRA.

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[11] In Order 1993-8, notwithstanding the closure of the Faro mine, the Board held that there were no changes in circumstances that warrant changes to cost of service or rate design principles for those established in 1992 cost of service and rate design review, and that the cost of service methodology and rate design proposed by the companies was appropriate.

[12] The 1996/97 Negotiated Settlement noted that "the rate design philosophy of the Companies is accepted subject to review at the hearing of Issue No. 11 (Cost of service allocations). YECL and YEC are to commit to provide a preliminary cost assessment of each community in the four zones based upon the same methodology that was used in the 1992 study, updated to use 1995 data. The cost assessment is to be filed with the Board by July 1, 1996." The COS issues reviewed at the hearing generally related to costs to serve the Faro mine.

[13] The 1998 YUB hearing resulted in Board review of Faro Mine COS for partial years of service in 1997 and 1998 (Exhibit 83 in that hearing set out the relevant final assessments relied upon by the Board). As part of the analysis prepared by YEC at that time, the 1997 COS estimate for the Industrial class was in effect modified as required based on approved COS principles and methods, to reflect the specific adjustments identified regarding Industrial loads, changes to WAF system costs tied to changes in Faro mine loads, and other specific changes set out in the filings regarding YEC's allowed return and amortizations.

One specific requirement in the past in utilizing the COS to set rates related to major industrial customers. Per section 6(1) of OIC 1995/90, the Board must ensure that rates charged to major industrial power customers (whether pursuant to contracts or otherwise) are sufficient to recover the costs of service to that customer class. The OIC directs that these costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

2.1 PAST PRACTICE

2.1.1 Overview - 1992 Methods as Previously Reviewed and Approved

COS studies in Yukon involving the Companies have followed generally accepted Canadian practice in functionalization, classification and allocation of costs,[14] with exceptions specific to the Yukon system previously reviewed and approved by the YUB. An overview is provided below:

Functionalization - Plant and operating expenses of the Companies (consolidated rate revenue requirement) are functionalized among four basic functions: generation, transmission, distribution and general, according to generally accepted practices. The "general" function separates out general administration costs that are not specific to generation, transmission or distribution functions.

Classification - The 1992 methodology for the classification of functionalized plant as well as for operating and maintenance expenses was as follows:

- **Classification of Plant**
  - **Hydro Plant** - Classified cost of general hydro assets 40% to demand and 60% to energy based on review of classification practices of other Canadian hydro utilities,[15] with the following exception:
    - **Whitehorse Unit #4** – Classified 100% to energy on the basis that the unit was constructed for the sole purpose of displacing diesel generation and did not serve to increase capacity during system peak. The unit was placed into service in 1984 to provide energy (rather than demand or capacity) benefits by displacing diesel generation during the non-winter season)[16] and did not result in an increase in the

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[14] Based on past reviews of practices of other electric generating utilities in Canada with predominantly hydro based generation (including B.C. Hydro, Manitoba Hydro and Ontario Hydro).
[15] Based on a review of practices in predominately hydro based jurisdiction it was concluded that utilities classified from 56.5% to 71% of hydro generation costs as energy. In 1992 the Companies concluded and the YUB recommended that it would be appropriate to classify hydro assets (excluding Whitehorse Unit #4) 60% to energy.
[16] See YEC and YECL's 1992 COS and Rate Design Application Section 7.1 (Section D).

ability to meet peak winter demand. The YUB accepted this treatment in the 1992 report, but recommended a study of the impact of Whitehorse Unit #4 on the capacity of Aishihik at the time of system peak.[17] In the 1993/94 GRA application (response to directives Page 5.2-12 to 5.2-13) the Companies noted that capacity at system peak was reviewed for each plant during the 1992 Capital Hearing; the utilities concluded that while Aishihik is operated as a peaking plant, and the capability of the plant to store water during the year can be enhanced by the addition of other hydro units on the WAF system, such as Whitehorse Unit #4, this additional storage enhances the long term average annual energy that can be generated at Aishihik and does not enhance the Aishihik unit's capacity at the time of system peak.[18]

  - **Diesel plant** – Classified 100% to demand on the basis that diesel plants are constructed to provide winter peak capacity; diesel plant is also generally classified to 100% demand in other Canadian jurisdictions.
  - **Transmission Plant** – Classified 100% to demand on the premise that transmission assets were sized to meet expected coincident peak demand of system.
  - **Distribution Assets** – Classified to customer and demand based on commonly accepted utilities practice.

- **Classification of Operating and Maintenance Expenses** – following principles of cost causation were adopted:
  - **Fuel** - Classified 100% to energy following generally accepted practice
  - **Other Generating O&M** – Classified 50% to demand and 50% to energy based on experience in Alberta.[19]

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[17] At page 24 of the 1992 Report the Board notes that it considers the use of Whitehorse Unit #4 during the off-peak may increase the capacity available at Aishihik during system peak.

[18]It was noted that historically, Whitehorse Unit #4 was not associated with any increase in Aishihik capacity available at time of system peak, that each of Whitehorse Unit #4 and Aishihik are operated during winter to yield the maximum capacity contribution during the system peak hours, based on water available and other local relevant conditions within each independent watershed, and that for planning purposes relevant to COS the dependable capacity of each plant is based on dependable low flow water conditions in each of these independent watersheds. In sum, the use of Whitehorse #4 did not add to the dependable capacity available at Aishihik to meet demand at system peak times. It was noted that while Aishihik is operated as a peaking plant, and while the capability of the plant to store water during the year can be enhanced by the addition of other hydro units on the WAF system, such as Whitehorse Unit #4, such additional storage does not enhance the Aishihik unit's capacity at the time of system peak, but does enhance the long term average annual energy that can be generated at Aishihik.

[19] The Board in its 1992 report recommended the utilities perform a study to determine a more appropriate method of classifying generation O&M expenses. In response to recommendations (provided in the 1993/94 GRA), it was noted by the Companies that for the "average" plant factor, the ratio of the maximum demand to average demand of generating units is a commonly used guide to the allocation of operation and maintenance expenses between demand and energy. Plant factors are averaged over a number of years to smooth out period variations associated with load changes and expansion of generation capacity. The seven year rolling average of generating units in the Hydro, large diesel and small diesel zones suggest that an allocation very close to 50% is appropriate. A similar result was obtained for YECL's sister company in the NWT".

- **Transmission O&M** – Classified 100% to demand consistent with Transmission Plant.
- **Distribution O&M, Marketing O&M, Customer Accounting, General Plant O&M and Administrative and General O&M** were classified on an account by account basis to reflect cost causation of the various components.
- **Depreciation** was classified on the basis of corresponding gross plant, and **return and income taxes** were classified on the basis of rate base less customer contributions. **Municipal taxes and all-risk insurance** were classified on the basis of gross assets.

Allocation

Generation and Transmission plant and O&M demand costs were allocated on the basis of coincident peak of the various customer classes, and energy related generating costs were allocated to the customer classes on the basis of energy produced to serve the customer classes. In dealing with transmission, there was one exception related to the Whitehorse – Faro transmission line.

- **Allocation of Whitehorse-Faro Line** – For the Whitehorse-Faro Line, 85% of the cost was assigned specifically to the Faro mine customer (Curragh Resources) with remaining costs assigned to all customer classes on the basis of coincident peak.[20] In determining the proportion of this asset to be assigned specifically to the industrial class (i.e., the Faro mine) the Companies relied upon the decision of the National Energy Board related to the Northern Canada Power Commission (June, 1985). It was noted during the 1992 review that "inasmuch as the Whitehorse/Faro transmission line was constructed specifically for the purpose of servicing the Faro mine operated by Cyprus Anvil, a substantial portion of the cost of the line should be allocated to the industrial class."

[20] The record indicated that this 138 kW transmission line was built in 1969 as a consequence of an agreement between the Government of Canada and Cyprus Anvil Mining Corporation; it was noted by the NEB in its 1985 report that in the absence of government direction NCPC would not likely have built the line in question to serve that mine, and that when the mine was operating NCP had assigned in excess of 95% of the annual costs of this transmission line to the Faro mine. The NEB recommended that this line be treated as a specific asset, and that 85 % of costs associated with the line be directly assigned to the Faro mine with the remaining 15% of costs assigned to all customer classes in the hydro rate zone (including the mine) on the basis of their respective demands. The NEB review that recommended this allocation (subsequently accepted and recommended by the YUB in 1992) noted the need to "consider carefully the specific circumstances surrounding planning, development and use of various generation and transmission facilities in Yukon." In 1996/97 GRA, the then current Faro mine owner (Anvil Range Mining or ARM) argued that as a new company, it should not be subject to the specific cost allocations applied in the past, noting the transmission line was not designed specifically for ARM, is fully depreciated and the rate level should therefore reflect the current cost of the line. The Companies at that time argued that the vintage of the customer was irrelevant to the COSS and that there were no changes in circumstances to justify a review or revision of the methodology from that established in the 1992 Report. The Board in 1996 agreed that this allocation conforms to similar practices in Canada and the assignment of 85% specifically to the industrial rate class was based on usage and not related to the vintage of the customer since in the absence of the mine load the line would not have been built.

Distribution Plant and O&M expenses were allocated as follows:

- Demand related costs were allocated on the basis of non-coincident peak demand of the customer classes at the distribution level of service.
- Customer classes and customer related costs were generally allocated on the basis of average number of customers in each customer class.

2.1.2 Summary of 1996/97 COS

The 1996/97 COS study is the last full COS involving both Companies. It did not seek to materially change the methodology reviewed in 1992 as applied by the Companies and approved by the Board after the 1993/94 GRA (in Order 1993-8). The Board provided comment on the following issues in Order 1996-7:

- **Treatment of Yukon as single rate zone** – The Board affirmed the direction provided in OIC 1995/90 (section 6(1)) that "the entire Yukon must be treated as one rate zone and costs must be pooled in order to develop a rate that is equal for both utilities.[21]
- **Classification of Whitehorse #4 –** The Board noted that the results of the study provided to the Board in 1993/94 GRA Volume 1, Tab 5, pages 5.2 – 12/13 (YUB-YECL-1-53) confirmed the conclusions provided in the 1992 COS and Rate Design proceeding, and noted that "the Board finds the allocation factor used is appropriate and is consistent with past practice, and is appropriate at this time. However, the Board makes no comment on the conclusions of the Company study and will consider the issue still subject to review at a later date if circumstances change". [22]
- **Classification of other Hydro Facilities –** The Board in Order 1996-7 accepted the proposed allocation noting that there was no new evidence to support changing this. The Order considered the issue open to review at a future proceeding.[23]
- **Allocation of Aishihik-Faro Transmission Line** – The Board reiterated that "the allocation of specific transmission costs to the Faro mine customer (ARM) conforms to similar practices in Canada. The assignment of 85% of costs to the Faro transmission line to the industrial rate class is based on usage and is not related to the status of old or new

[21] At that time, ARM raised arguments concerning the legal basis for pooling tax costs where one utility pays income tax and the other does not, disputed the argument that the same class of customers must pay the same rates whether they are customers of YEC or YECL and argued that customers on WAF subsidize the diesel generation component of the system with the result that the cost of diesel in outlying communities did not reflect actual costs.
[22] At page 6 of Order 1996-7.
[23] At page 7 of Order 1996-7.

customers. In the absence of the mine load, the transmission line would not have been built. The current cost of service was provided in accordance with the Board's recommendations in 1992 and subsequently reaffirmed in its Decision 1993-8 (Section 6.1 page 99)."[24] The Board determined that the vintage of a customer was not appropriate to the development of cost of service studies in Yukon.

2.1.3 2007 Industrial COS for Minto mine PPA

The Minto PPA Application filed by Yukon Energy with the YUB for approval in 2007 included a proposal for a 2008 Firm Mine Rate (revised Rate Schedule 39, Industrial Primary) based on Yukon costs and regulatory principles.[25] To determine the 2008 Firm Mine Rate included in the PPA, it was necessary to determine the 2008 COS for the Major Industrial Customer class within the overall consolidated Yukon rate revenue COS for 2008, based on established Yukon COS principles and methods.[26]

General principles and methods applied in Yukon Energy's PPA application to determine the Firm Mine rate reflected in most instances OIC 1995/90, past COS filings of YEC/YECL, and previous Board COS rulings on such COS filings and related Major Industrial class rates. The following additional general COS principles and methods were proposed by Yukon Energy in Schedule E of the PPA application to determine the Firm Mine Rate (as then applied for) to reflect the 2008 forecast conditions that differ from the 1996/97 GRA conditions (when the last full COS was prepared based on YEC/YECL GRA filings):

1. **Faro mine closure changes:** It was noted that the Faro mine closure affected the following general COS principles and methods:
   a. **Specific assignment of transmission costs:** The Faro mine closure removes the basis for specifically assigning to the Industrial class (Faro mine) 85% of the WAF transmission costs for the Whitehorse to Faro line. The Minto PPA application classified 100% of these specific WAF transmission costs to energy (rather than demand) to reflect the approach adopted for other new transmission projects designed to displace diesel energy generation (rather than to meet system winter peak demands).
   b. **Secondary sales:** Due to this closure and resulting surplus hydro electricity on WAF, forecast 2008 secondary sales revenues (which were not forecast in 1996/97) were

[24] At page 5 of Order 1996-7.
[25] Pursuant to OIC 1995/90 YUB approval of any firm rate applicable Minto Mine was required to recover the cost of service to that customer class based on treating all of Yukon as one rate zone and pooling costs for both YEC and YECL.
[26] Cost of service principles and methods applied were determined based upon review of the 1992 Report to the Commissioner in Executive Council, past Board Orders related to GRAs and rates, including Order 1996-7 arising from the 1996/97 GRA and Board Orders arising subsequent related to the closure of the Faro mine.

assigned to offset 2008 forecast generation function costs (YEC sales revenues) and distribution function costs (YECL sales revenues).

c. **Flexible Term Note (FTN) added interest:** Due to the Faro mine closure, the FTN interest costs (as well as principal payments) were sensitive to changes in YEC's WAF sales. The Minto PPA application specified the principle that added FTN costs (interest) due to adding Minto mine loads on WAF are assigned to generation function costs for the purpose of estimating 2008 Yukon Industrial COS.[27]

2. **New Projects:** The Minto PPA application addressed the classification of two new transmission projects that were not in service in 1996/97, namely the Mayo-Dawson **(MD)** Transmission Project and the CSTP[28] and specified that 100% of such costs not offset by customer or other contributions were to be classified to energy (rather than demand). This approach was adopted to reflect the extent to which each of these transmission projects had been designed and planned almost entirely to displace diesel energy generation (rather than to meet system winter peak demands).[29]

3. In the case of Minto Spur (MS) and CSTP transmission capital costs, the following COS principles were applied:[30]

   a. **MS transmission**: All MS capital costs were directly assigned to the Minto mine as a capital contribution required through the PPA, reflecting the fact that, for all practical purposes, the MS facilities were being planned solely to supply WAF grid power to the Minto mine.[31]

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[27] In previous COS, FTN costs were allocated as part of Return allocations (generally tied to rate base allocations among functions); accordingly, only a portion of such costs would be assigned to the generation function. The principle for 2008 COS addresses the specific circumstance where new WAF loads related to this Minto mine are responsible for a specific increase in these costs.

[28] For the PPA COS assessment, Stage One of the CS project was assumed to be in service all of 2008.

[29] Excluding specific assignment to the Faro mine, transmission costs in previous COS were classified 100% to demand at the time of the system peak, without any consideration as to assigning any share to energy. In contrast, most of YEC's hydro generation assets were classified 60% to energy and 40% to demand, approximately reflecting average system load factors and practice in other jurisdictions; however, the Whitehorse #4 unit costs are classified 100% to energy to reflect this unit's planned use to displace diesel energy generation and not to contribute to meeting winter peak demands. The approach adopted in the Minto PPA would tend to assign more, rather than less, of the affected costs to the Major Industrial class (given the relatively high annual load factors displayed by this class).

[30] The PPA provides that new YEC Industrial Customers will be required by YEC to pay customer contributions for their appropriate share of capital costs for the CSTP and any new spur lines on a similar basis to the Capital Cost Contribution under the PPA, "*including a contribution to the capital costs incurred by YEC for the CS Project based on the segment and voltage level of transmission line that each New YEC Industrial Customer would require to receive Electricity through in absence of the Transmission Project or the CS Project.*"

[31] YEC's September 2006 CS/MS Project Proposal Submission to the Yukon Environmental and Socio-economic Assessment Board (YESAB) notes that, once built, the MS facilities on the east side of the Yukon River are expected to be retained after closure of the Minto mine to provide service to local area residents and businesses.

b. **CSTP transmission (Stage One)**: The Minto mine's then planned $7.2 million capital contribution to the CSTP transmission line (as provided for in the PPA) in effect constituted a direct assignment of these capital costs to the mine, based on the mine's segment of the line and voltage required to receive WAF grid power.

The Board did not accept the Firm Mine Rate as applied for in the Minto PPA (see Order 2007-5), noting concern regarding the lack of a complete updated COS study. The Board directed the Companies to provide a complete COS and rate design with their next GRA that included an update on allocators. Specifically, the Board noted that the study should review the following concerns identified by the Board at that time:

- Consider feasibility of direct assigning assets, where applicable to certain rate classes;
- Provide the justification on the allocation of transmission assets; and
- Explore the rationale of defining the CSTP as one of diesel displacement in light of Yukon Energy's comments that the project is to serve system requirements (the Board indicated that it would like to explore COS evidence in this regard).

The current approved Rate Schedule 39 applicable to the Minto mine (and other Major Industrial Customers), as directed by OIC 2007/94 and approved by Board Order 2008-13, is the same rate schedule as proposed in the Minto PPA application (except for the provisions in OIC 2007/94 to apply Rider F for ongoing fuel price adjustments and to escalate the base rates for inflation starting January 2010).

TAB 4YEC

RATE DESIGN – YUKON ENERGY DISCUSSION

4.0 TAB 4YEC - RATE DESIGN – YUKON ENERGY DISCUSSION

This Tab provides rate design options and proposals to collect the approved 2009 Consolidated Firm Rate Revenue Requirement. While the Companies jointly filed two rate design options on February 19, 2010 for review by the Board (Option A and Option B), the Companies were not able to arrive at common descriptions of the options, the relative merits or drawbacks of each of the options, or the underlying system conditions driving the need to re-establish efficiency-based price signals to customers. This tab (Tab 4YEC) sets out Yukon Energy's discussion on the options presented.

Tab 4YEC consists of the following items:

- Overview;
- Rate Design Approach;
- Incremental Costs;
- Residential and General Service 2009 Rate Options and Proposals; and
- Other 2009 Rate Proposals.

Changes are sought in this joint YEC/YECL Application to remove Rider J and Rider R, and to adjust the following rate schedules effective September 1, 2010 (Appendices to this Tab present tables reviewing rates and bill impacts for residential and general service Options A and B below respectively, as summarized in Table 4.1 and 4.2):

- Rate Schedules for **Residential Non-Government** (1160, 1260, 1360, 1460 for the respective zones) and **Residential Government** (1180, 1280, 1380, 1480) to provide adjusted base rates and an adjusted rate design that includes a new equalized second energy block. Two options are provided for review and assessment (both options adjust the base **customer charge** to $14.65 per month for non-government and $18.47 per month for government residential classes, reflecting the current charge after rider impacts):

- **Option A**:
  - **First energy block** for use up to 1,000 kW.h per month (about 70% of non-government class annual bills do not exceed this level), with an adjusted base energy rate of 10.90 ¢/kW.h for non-government and 16.17 ¢/kW.h for government;
  - **A new equalized second energy block** for use from 1,001 to 1,500 kW.h per month (about 90% of non-government class annual bills do not exceed this level), with a base energy rate of 15.22 ¢/kW.h for non-government and government (reflects current Small Diesel zone run off rate after Rider J and Rider R); and
  - **An adjusted runoff energy block** for all use in excess of 1,500 kW.h per month, with runoff rates that reflect 80% of short term incremental generation costs (non-government and government blended rate of 22.39 ¢/kW.h for Hydro, Large Diesel and Small Diesel zones, and 49.23 ¢/kW.h for Old Crow zone, based on fuel price forecasts as approved for 2009).
- **Option B**:
  - **First energy block** for use up to 1,000 kW.h per month (about 70% of residential non-government annual bills do not exceed this level), with an adjusted base energy rate of 12.14 ¢/kW.h for non-government and 17.92 ¢/kW.h for government;
  - **A new equalized second energy block** for use from 1,001 to 2,500 kW.h per month (about 98% of residential non-government annual bills do not exceed this level), with a base energy rate of 12.82 ¢/kW.h for non-government and government; and
  - **An adjusted runoff energy block** for all use in excess of 2,500 kW.h per month with runoff rates that reflect 50% of short term incremental generation costs (non-government and government blended rate of 13.99 ¢/kW.h for Hydro, Large Diesel and Small Diesel zones, and 30.77 ¢/kW.h for Old Crow zone, based on fuel price forecasts as approved for 2009.

Table 4.1 – Summary of Residential Rate Options A and B

RATE CLASS		OPTION A			OPTION B		
	Customer Charge per month	Energy 1 0-1000 kWh	Energy 2 1001-1500 kWh	Energy 3 > 1500 kWh	Energy 1 0-1000 kWh	Energy 2 1001-2500 kWh	Energy 3 > 2500 kWh
1160 Hydro Non-Gov	$14.65	$0.1090	$0.1522	$0.2239	$0.1214	$0.1282	$0.1399
1260 Sm Diesel Non-Gov	$14.65	$0.1090	$0.1522	$0.2239	$0.1214	$0.1282	$0.1399
1360 Lg Diesel Non-Gov	$14.65	$0.1090	$0.1522	$0.2239	$0.1214	$0.1282	$0.1399
1460 Old Crow Non-Gov	$14.65	$0.1090	$0.1522	$0.4923	$0.1214	$0.1282	$0.3077
1180 Hydro Gov	$18.47	$0.1617	$0.1522	$0.2239	$0.1792	$0.1282	$0.1399
1280 Sm Diesel Gov	$18.47	$0.1617	$0.1522	$0.2239	$0.1792	$0.1282	$0.1399
1380 Lg Diesel Gov	$18.47	$0.1617	$0.1522	$0.2239	$0.1792	$0.1282	$0.1399
1480 Old Crow Gov	$18.47	$0.1617	$0.1522	$0.4923	$0.1792	$0.1282	$0.3077

- Rate Schedules for **General Service Non-Government and Municipal Government** (2160, 2170, 2260, 2270, 2360, 2370, 2460, 2470) and **General Service Federal and Territorial Government** (2180, 2280, 2380, 2480) to provide adjusted base rates and an adjusted rate design that includes a new equalized second energy block for use from 2,001 to 15,000 kW.h per month, a new equalized third energy block from 15,001 to 20,000 kW.h per month, and an adjusted runoff energy block for all use in excess of 20,000 kW.h per month designed to address large users prior to future consideration of a separate General Service Large User rate class. Two options are provided for review and assessment (as summarized in Table 4.2):
    - **Option A**:
        - **Demand charge** of $6/kW per month for non-government and $10/kW per month for government (minimum bill of 5 kW/month);
        - **First energy block** with a base energy rate of 8.31 ¢/kW.h for non-government and 18.81 ¢/kW.h for government (about 67% of general service non-government annual bills do not exceed this level);
        - **Second energy block** with a base energy rate of 14.90 ¢/kW.h for non-government and government (about 96% of general service non-government annual bills do not exceed this level);

- **Third energy block** with a base energy rate of 22.39 ¢/kW.h for non-government and government (about 98% of general service non-government annual bills do not exceed this level); and
- **Runoff energy block** with a fixed base energy rate for non-government and government of 12.86 ¢/kW.h for Hydro and Large Diesel zones, 15.22 ¢/kW.h for Small Diesel zone and 31.72 ¢/kW.h for Old Crow zone (so as to equal the present level of net charges inclusive of riders).

- **Option B**:
  - **Demand charge** of $7.39/kW per month for non-government and $12.31/kW per month for government (minimum bill of 5 kW/month);
  - **First energy block** with a base energy rate of 10.23 ¢/kW.h for non-government and 21.48 ¢/kW.h for government (about 67% of general service non-government annual bills do not exceed this level);
  - **Second energy block** with a base energy rate of 12.88 ¢/kW.h for non-government and 12.97 ¢/kW.h for government (about 96% of general service non-government annual bills do not exceed this level);
  - **Third energy block** with a base energy rate of 13.99 ¢/kW.h for non-government and government (about 98% of general service non-government annual bills do not exceed this level); and
  - **Runoff energy block** with a fixed base energy rate for non-government and government of 12.86 ¢/kW.h for Hydro and Large Diesel zones, 15.22 ¢/kW.h for Small Diesel zone and 31.72 ¢/kW.h for Old Crow zone.

Table 4.2 – Summary of General Service Rate Options A and B

RATE CLASS	OPTION A					OPTION B				
	Dem. Charge /kW	Energy 0-2000 kWh	Energy 2001-15000 kWh	Energy 15001-20000 kWh	Energy >20000 kWh	Dem. Charge /kW	Energy 0-2000 kWh	Energy 2001-15000 kWh	Energy 15001-20000 kWh	Energy >20000 kWh
2160 Hydro NG	$6	$0.0831	$0.1490	$0.2239	$0.1286	$7.39	$0.1023	$0.1288	$0.1399	$0.1286
2260 Sm Diesel NG	$6	$0.0831	$0.1490	$0.2239	$0.1522	$7.39	$0.1023	$0.1288	$0.1399	$0.1522
2360 Lg Diesel NG	$6	$0.0831	$0.1490	$0.2239	$0.1286	$7.39	$0.1023	$0.1288	$0.1399	$0.1286
2460 Old Crow NG	$6	$0.0831	$0.1490	$0.2239	$0.3172	$7.39	$0.1023	$0.1288	$0.1399	$0.3172
2170 Hydro Municipal	$6	$0.0831	$0.1490	$0.2239	$0.1286	$7.39	$0.1023	$0.1288	$0.1399	$0.1286
2270 Sm Diesel Municipal	$6	$0.0831	$0.1490	$0.2239	$0.1522	$7.39	$0.1023	$0.1288	$0.1399	$0.1522
2370 Lg Diesel Municipal	$6	$0.0831	$0.1490	$0.2239	$0.1286	$7.39	$0.1023	$0.1288	$0.1399	$0.1286
2470 Old Crow Municipal	$6	$0.0831	$0.1490	$0.2239	$0.3172	$7.39	$0.1023	$0.1288	$0.1399	$0.3172
2180 Hydro Gov	$10	$0.1881	$0.1490	$0.2239	$0.1286	$12.31	$0.2148	$0.1297	$0.1399	$0.1286
2280 Sm Diesel Gov	$10	$0.1881	$0.1490	$0.2239	$0.1522	$12.31	$0.2148	$0.1297	$0.1399	$0.1522
2380 Lg Diesel Gov	$10	$0.1881	$0.1490	$0.2239	$0.1286	$12.31	$0.2148	$0.1297	$0.1399	$0.1286
2480 Old Crow Gov	$10	$0.1881	$0.1490	$0.2239	$0.3172	$12.31	$0.2148	$0.1297	$0.1399	$0.3172

- Rate Schedules for **Street Lighting** (61, 66, 67) and **Sentinel Lighting** (75, 76) to adjust base rates by an equal percentage of 23.126% to reflect the proposed elimination of Riders J and R.

- Rate Schedule 39 **Industrial** to provide for fixed Rider F component as approved in Order 2009-10.

- Rate Schedule 42 (**Wholesale** sales to Yukon Electrical) to adjust the base energy rate that applies throughout Yukon (as required to reflect adjusted retail base rates and removal of

Rider J and R); in the event that Option A is not adopted with respect to the residential Hydro zone non-government run-out rate, to incorporate the full incremental cost of diesel generation on the major systems (27.67 ¢/kW.h) as the Energy Reconciliation Adjustment rate.

- A revised Rate Schedule 51 (**Wholesale** sales to Yukon Energy) to provide for a single energy-only rate that applies to all firm Yukon Energy purchases from Yukon Electrical throughout Yukon.

- Cancellation of the earlier Rate Schedules 33, 38 and 40, each of which relates solely to unique circumstances of previous industrial customers, and do not have relevance today.

No changes are proposed today to the Secondary Energy rate schedules (32 and 43) or to Riders A (Multiple Residence Service) or B (Unmetered General Service Flat Rate).

YEC does not propose a new Rider D to collect for YECL the actual cost of purchase power for the Hydro zone, as this new rider does not reflect any past practice in Yukon and would, in effect, shift load forecast variance risk from YECL to all Yukon retail ratepayers.

4.1 OVERVIEW

The Application provides for rates sufficient to collect the 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million as approved for the Companies based on the approved loads as forecast for 2009 (see Tab 2, Table 2.3), as well as the rate revenue requirement as approved specifically for Yukon Energy and Yukon Electrical. At the present time (absent rate design adjustments), this requirement is collected through the current rates and riders, i.e., based on approved 2009 forecast sales for each rate class, the Consolidated Firm Rate Revenue Requirement is collected with current base rates as approved in the 1996/97 GRA for each rate class plus the Rider J and Rider R charges applied to retail base rates.[1] Table 4.3 below summarizes the resulting firm rate revenues by rate class (excludes secondary sales and wholesales, as well as non-rate revenues):

[1] As reviewed in Tab 2, section 2.1, this statement assumes correction of Rider J at 12.60% and Rider R at 10.526%, for a combined rider impact on retail base rates of 23.126%.

Table 4.3: 2009 Consolidated Firm Rate Revenue Requirement

Revenue by Rate Class at Existing Rates ($000)

Rate Class	
Residential Non Government	$ 19,412
Residential Government	$ 422
General Service Non-Government	$ 17,372
General Service Government	$ 9,272
Street Light Rate	$ 986
Sentinel Light Rate	$ 166
Sub-total Retail	$ 47,630
Industrial	$ 3,203
Total	$50,833

The Yukon Energy 2008/09 General Rate Application, filed September 2008, addressed overall rate decreases for Yukon retail ratepayers that are incorporated in Table 4.3. As part of that GRA, Yukon Energy addressed retail rate design issues and, to begin restoring efficient pricing for runoff rate blocks, proposed to focus the retail rate decrease on "first block" consumption in each rate class and also to increase price signals in "second block" residential consumption resulting concurrently in lower "first block" residential rates[2]. Order 2009-8 arising from that GRA did not accept at that time Yukon Energy's proposals to address rate design updates, but instructed the Companies to file a joint application to address these matters.

As directed by the Board in Directive 13 of Order 2009-8, the Companies have worked together during the intervening period to develop additional rate designs for consideration that are attentive to varying rate design criteria. Among the key "new" issues for the Companies to address (since the YEC GRA), the following are noted:

- Implementation of the YEC rate decrease on an "across the board" basis (through a reduction to Rider J) has resulted in reductions in the present level of runoff rates, at the same time as the Board has approved fuel costs that, based on past Yukon practice, would indicate a need to establish materially higher price signals in this component of the rate.

[2] As set out at Tab 4 of Yukon Energy's 2008/09 GRA. The YEC GRA noted that similar rate design adjustments for General Service would require joint review with YECL due to the relatively small share of class energy use accounted for in the first rate block.

- As a result of the incorporation of new higher fuel prices into the base rates for each Company, there is no longer a requirement for the previous substantial Rider F charge (1.86 cents/kW.h at the time of YEC's GRA) to address fuel price variances[3]. This has similarly led to reductions in the runoff block energy rate for each retail class compared to when YEC filed its GRA.

- Rate designs for the General Service class must also now be addressed, which YEC was not able to address on its own (i.e., without YECL involvement) leading into its 2008/09 GRA.

During this intervening period since the Yukon Energy GRA various options were identified by the Companies, including those arising from views expressed during customer consultation. The Companies developed a number of rate structures that were jointly viewed to have merit:

- The use of three blocks in the residential class at this time, with the third block applying to a few of the largest consumers, permits the third block to more fully reflect incremental costs reflective of the ongoing system pressures (i.e., diesel fuel generation costs).

- A parallel general service rate design incorporating three blocks for most users (all but the very largest users) with the third block applying only to a minority of customers, reflective of the same incremental cost pressures as applied to residential.

- A transitioning towards a future potential "Large General Service" class applying to a relatively few customers (on the order of 100) whose loads are unique and require specific consideration as diesel fuel requirements on the grid systems increase.

Option A, as set out in this Application, was jointly developed to incorporate these rate structures into rates consistent with past practice in Yukon, normal rate design principles, and future underlying characteristics of the system. Option A increased retail runoff rates to reflect 80% of 2009 incremental supply costs, and thereby concurrently resulted in notable rate decreases to the first block rates in each retail class. As a result, under Option A the vast majority of customers are provided with rate reductions compared to present rate levels (overall bill impacts for residential non-government customers will continue to be affected by the IER subsidy).

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[3] At the present time, Rider F is applied to bills as a credit of 0.35 cents/kW.h.

Shortly before filing this Application, a further alternative (Option B) was identified which demonstrates what occurs if first block retail rates are retained at approximately current levels and retail runoff rates are also retained at about 50% of 2009 incremental supply costs. Option B substantially reduces the focus on evolving system generation requirements and economic efficiency in the rate design for larger users. As a result, Option B reduces the price signal and bill effects to the largest users and concurrently reduces or eliminates rate decrease benefits for small customers.

Yukon Energy continues to propose that the Board begin today to restore efficient pricing for retail runoff rate blocks. Both Options A and Option B address major adjustments in Yukon rate structure in each residential and general service retail rate class, which can help facilitate this objective today and in future years. In Yukon Energy's view, Option A also enables material progress today in beginning to adjust the resulting retail runoff rates, and also facilitates first block residential bill adjustments today in the event that the IER is reduced or eliminated. In contrast, Option B illustrates, for consideration by the Board, rates that would defer restoring efficient pricing for retail runoff rates and thereby avoid any material change in rate bill impacts for almost all retail customers. Overall, Yukon Energy concludes that Options A and B thereby provide the Board with the range of potential rate adjustment options relevant for consideration at this time.

4.2 RATE DESIGN APPROACH

Rate design adjustments are considered in the Application in response to Directive 13 of Order 2009-8, which directed the Companies to provide rate design recommendations in the Phase II Application that comply with previous Board directions and current OICs. This requires that in determining whether, and what, rate adjustments are required at this time; the Companies must consider the rate design framework provided by OIC 1995/90, OIC 2008/149 and OIC 2007/94, as well as how the Companies and the Board have been guided by this framework in the past.[4] Noting that it has been over 12 years since the Companies have had a major review of rates, the Application addresses the need to adjust base rates to reflect current costs and revenue requirements and eliminate the current Rider J and Rider R from customer bills. The following are highlighted in this regard:

- In accordance with OIC 2007/94 and OIC 2008/149, the rate design adjustments proposed in the Application do not modify the firm rate revenues by rate class from the Table 4.1 amounts (based on the approved sales forecast by rate class for 2009).

[4] This would include interpretations provided by the Board of prior and current Yukon rate policy directions (such as that provided in prior major rate review undertaken in 1992, the results of which were subsequently affirmed by the Board in Order 1993-8 following the 1993/94 GRA and Order 1996-7 following 1996/97 GRA).

- In accordance with OIC 1995/90, the rate design adjustments proposed in the Application:
  - Reflect rate design principles established in Canada for utilities as well as past practice in Yukon (Option A; Option B only to a limited extent);
  - Continue to ensure that firm retail rates are equalized throughout Yukon within each rate class other than for runoff rates (Option A and B);
  - Adjust, on the basis of rate design principles, retail runoff rates to provide for economy and efficiency[5] by more accurately reflecting short term incremental generation cost as a price signal at higher levels of consumption (Option A to a large extent (80% of incremental costs); Option B in only a limited way (50% of incremental costs)); and
  - Adjust the wholesale rate as required to enable Yukon Energy to recover its costs that are not recovered from its other customers.

Since it has been over 12 years since the last major rate review, there is a need to address required rate adjustments in an orderly manner focusing first on what can, and should be considered for implementation today. In addition to complying with rate policy OIC direction (provided by OIC 1995/90) and past Yukon practice, it is relevant to reflect rate design principles and practice currently being implemented in other jurisdictions throughout Canada, particularly the increasing emphasis on ensuring incremental usage by larger customers (from larger residential customers through to industrial) reflect incremental supply costs on the system.

Yukon Energy recognizes the need to develop an orderly process for dealing today and in the coming years with the various rate matters that have been outstanding for some time. As reviewed in Section 1.6, three specific rate design matters have been identified as part of preparation of this Application:

- **Eliminate Riders:** Eliminate current general purpose Rate Riders (Riders J and R) from customer bills and adjust retail base rates to fully reflect approved 2009 costs. Since the last major rate review, various rate riders have been implemented which at this time can be absorbed into base rates.

- **Adjust Run off rates:** Address economy and efficiency rate principles/directives, including the need to adjust runoff rates to bring these rates towards the approved 2009 incremental costs based on current fuel prices and consistent with Yukon practice. Similar to Canada's other hydro-based jurisdictions, Yukon's power system includes material assets with

[5] Based on Board precedent, economy and efficiency in the Yukon context is expressed by sending a price signal for consumption on the margin based on the short run incremental cost of diesel.

embedded costs well below the cost to bring on new generation today, which provides the opportunity for lower rate levels than would otherwise be the case without these assets. However, Yukon's grid systems are approaching a state of diesel being on the margin for a major portion of the year, and the isolated diesel systems are in this state throughout the year. Under these changing circumstances, it is important to develop rate structures for all customer classes that once again reflect appropriate efficiency price signals "on the margin" based on current incremental costs, while still ensuring a fair sharing of the benefits of the past resources in the overall embedded cost rates.

- **Inability to "rebalance":** Inability at this time to address the outstanding directive from the Board to bring revenue:cost ratios for each customer class within a "zone of reasonableness" (which is not permitted under OIC 2008/149).

Attentive to these overriding concerns, rate design issues and principles are reviewed as follows in section 4.2:

- **Section 4.2.1 Canadian Practice - Normal Utility Principles of Rate Design** – Reviews normal utility principles of rate design as applied in Yukon.

- **Section 4.2.2 Yukon Rate Policy Directives and Other Considerations –** Reviews relevant OIC direction for purposes of rate design in this Application.

- **Section 4.2.3 Current Rates for Firm Service –** Reviews current base rates and riders based on 1996/97 GRA and any adjustments since that time.

- **Section 4.2.4 Rate Design Options for Residential and General Service –** Reviews options to address required rate adjustments for residential and general service classes in 2009 and issues and concerns raised by each option.

4.2.1 Canadian Practice – Normal Utility Principles Of Rate Design

Normal utility principles of rate design include the following criteria (as noted in the Companies' joint 1992 submission on COS and Rate Design and summarized by the Board in its related Report) that represent differing and sometimes conflicting objectives to be balanced in determining just and reasonable rates:[6]

- Rate simplification and ease of understanding;
- Promotion of efficient usage[7];
- Recovery of the cost of service by rate class and in total[8];
- Avoidance of undue discrimination;
- Comparisons with rate practices of other utilities;
- Consideration of the value of service provided; and
- Rate stability.

The overall objective is to achieve an appropriate balance between the differing rate design objectives, such as concurrently seeking to promote efficient usage (through increased prices that reflect incremental costs for new generation), recover embedded cost of service (which reflects average costs much lower than the costs of new generation), and ensure a fair sharing of this heritage resource benefit.

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[6] See page 7-8 of Board's 1992 Report and Recommendations on COS and Rate Design (Appendix 7.1, Tab 7). The YUB in its 1992 Report summarized the primary criteria for rate design as: "the need for rates which would provide sufficient revenue to meet the revenue requirement approved by the Board, as well as the requirement for revenue stability and predictability. The rates should fairly reflect the costs incurred by the utility to serve the various classes of customers. A further objective is the promotion of economy and efficiency in the generation, transmission, distribution and use of electricity, and involves the structuring of rates so as to provide price signals to users of electricity, and involves the structuring of rates so as to provide price signals to users of electricity which will encourage optimum use of the utilities' facilities rates should reflect the value of service provided to the customers, ...should be stable and reasonably predictable allowing customers to make realistic cost projections and rates generally should be practical and not overly complicated."

[7] The Companies noted in 1992 Submission on COS and Rate Design, that "an important step in promoting efficient use of electric energy is the provision of an effective price signal to the customer, such that the price paid for extra energy consumption reflects the cost of providing that same extra energy. With the normal utility principles of rate simplification, and promotion of efficient usage, in conjunction with the specific OIC directive to promote energy efficiency, it was considered desirable to design all rates as consistently as possible with run out energy blocks reflecting incremental energy costs regardless of rate class or zone." (see page 3-3 and 3-4 of Companies joint submission on COS and Rate Design filed in 1992).

[8] The concepts of fair and reasonable rates include maintaining a cost based standard, such that each group of customers is paying total amounts that reasonably reflect the measured costs to serve that class of customer.

4.2.2 Yukon Rate Policy Directives And Other Considerations

In Order 2009-8, the Board directed YEC and YECL to file a joint Phase II application that was to "provide rate design recommendations that comply with previous Board directions and comply with current OICs". Current overall Rate Policy OIC (OIC 1995/90) provides specific direction on the following matters related to rate design to be considered in advancing any rate proposal at this time:

1. **Normal principles to apply (Section 3)** – The Board must review and approve rates in accordance with principles established in Canada for utilities; this includes principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.[9]

2. **Retail Rates – non-government customers –** "Retail customer" means a customer other than a major industrial customer, an isolated industrial customer, or a wholesale customer (currently includes residential, general service and street lights/sentinel lights customers).
   a. **Equalized Rates (Section 4.(1))** – The Board must fix rates for retail customers, other than government customers, in accordance with the rate policy that the rates for each class of non-government retail customers must be the same throughout Yukon without variation between Yukon Energy Corporation and Yukon Electrical. This direction is subject to Section 4.(2) and 4.(3) as noted below.
   b. **Runoff Rate Blocks (Section 4.(2))** – The Board must fix a runoff rate block for each non-government retail customer class that is applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, such specified consumption level per customer not to be less than 1,000 kW.h for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.
   c. **Runoff Rate Design to Promote Economy and Efficiency (Section 4.(3))** – The Board must fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency; separate runoff rates may be allowed for customers in different communities or rate zones provided that such rates are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

[9] This section of the OIC applies, "except as otherwise stated by this Directive or the Act."

3. **Retail Rates for Government Customers (Section 5.(1))** – The Board must fix rates for government customers so that the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

4. **Rate – Major Industrial Customers (Section 6.(1))** – The Board must ensure that the rates charged to major industrial power customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same. This direction is constrained, until December 31, 2012, by the direction provided in OIC 2007/94 as noted below.

5. **Wholesale Rate Design (Section 7)** – The Board must fix rates of Yukon Energy Corporation for the wholesale power customer (defined as the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation) such that (a) YEC shall sell electricity to YECL at the same demand rate and the same energy rate throughout Yukon and those rates must be sufficient to enable Yukon Energy to recover its costs that are not recovered from its other customers, and (b) the wholesale rate to YECL shall include appropriate provisions to ensure that Yukon Energy will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers.

The following additional, limited term, OIC rate policy directive considerations also need to be considered to reflect amendments to OIC 1995/90:

1. Per **OIC 2007/94** the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary, attached as Schedule A to the OIC.

2. Per **OIC 2008/149** the Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers. This provision expires December 31, 2012.

In sum, rates for each non-government retail customer class must be equalized throughout Yukon except for runoff rates set for the runoff rate block that must be fixed for each such customer class. Runoff rate blocks for each such customer class cannot be set below minimum use levels per billing period (i.e., 1,000 kWh for residential and 2,000 kWh for general service). Subject to these restrictions, the following are noted:

(a) It is possible to create multiple equalized rate blocks.

(b) All rate blocks that are not the runoff rate block, for each non-government retail customer class, must be uniform (for that class) throughout Yukon.

4.2.3 Current Rates for Firm Service

The YEC/YECL 1996/97 GRA established the current levels of base firm energy rates for residential and general service retail rate classes as shown in Table 4.4:[10]

Table 4.4

Existing "Base" Firm Energy Rates (before riders and taxes) in $/kW.h

	First Block [Res=1,000 kWh/m; GS= 2,000 kWh/m]				Second Block (run-out rates)			
Rate Zone	NG & Mun		Govt		NG & Mun		Govt	
	res	GS	res	GS	res	GS	res	GS
hydro (WAF, MD)	0.0986	0.0831	0.1434	0.1745	0.1045	0.1045	0.1045	0.1045
large diesel (Watson)	0.0986	0.0831	0.1434	0.1745	0.1045	0.1045	0.1045	0.1045
small diesel (YECL)	0.0986	0.0831	0.1434	0.1745	0.1236	0.1236	0.1236	0.1236
Old Crow (YECL)	0.0986	0.0831	0.1434	0.1745	0.2577	0.2577	0.2577	0.2577

In addition to the base energy rates shown in Table 4.4, residential customers currently pay a monthly base fixed charge of $11.90 for non-government customers and $15.00 for government customers. General Service customers pay a base demand charge of $6.00 per kW for non-government or municipal government customers, and $10.00 per kW for federal and territorial government customers, in each case with a minimum monthly bill equal to 5 kW of the relevant demand charge.

Base rates set in the 1996/1997 GRA for the above retail classes reflected an approach to rate design taking into account the systems at that time, as well as the OIC 1995/90 requirements. Rates were

[10] Firm retail rates in Yukon for each retail customer class comprise "base" rates and riders in effect from time to time. For non-government retail customers, an income tax rebate is provided on bills (presently -0.5% of all base rate amounts). OIC 2008/70 which provided Government Rate Stabilization Fund ("RSF") subsidies for customer bills in the case of non-government and municipal government retail customers was terminated in July 2009 and for residential non-government retail customers a new interim electrical rebate (IER) was introduced. The IER provides non-government residential customers with a maximum rebate of $26.62 per month for the first 1,000 kilowatt hours of power used (at a rate of 2.662 cents/kW.h each month on the first 1000 kW.h of consumption). It is automatically applied to residential power bills and has been in effect since July 1, 2009.

designed by setting runoff rate levels (second block rates by rate zone) first and then, based on these rates, first block rate levels (along with other charges) were set to achieve the remaining revenue requirement not recovered from runoff rates. To meet the OIC requirement of "economy and efficiency", runoff rates were set at levels which approximated the incremental short term cost of generating an extra kW.h using diesel generation.[11]

Retail base rates also apply for Street Light and Sentinel Light customer classes.

Current rate charges for firm service to retail customers reflect the existing base rates as described above plus Rider J and Rider R applied to each of these base rates (combined rider impact of 23.123% on each retail base rate).[12]

Industrial firm rates as set in Rate Schedule 39 are applicable to Major Industrial Customers as defined in OIC 1995/90.[13] Rate Schedule 39 as directed by OIC 2007/94 and approved by Board Order 2008-13 includes the following (Rider J and Rider R do not apply to Rate Schedule 39):

- Demand charge per billing month of $15/kV.A of Billing Demand (as defined with winter ratchet).

- Energy charge of 7.60¢/kW.h for all energy used, subject to "Base Load Energy" provision whereby economy and efficiency price signal may be established with two block rate structure.[14]

- Fixed charge per month equal to payments then required under the PPA for monthly Capital Cost Contributions for transmission connection to the mine.

- Peak shaving credit for customers with an established Winter Contract Load in good standing.

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[11] As of the 1996/97 GRA, the WAF system (included in the Hydro rate zone) as well as the large diesel rate zone systems (Watson Lake and, at that time, Dawson), the small diesel rate zone systems and the Old Crow system were all operating with diesel being the total or incremental source of generation. The only exception was the Mayo system which, as part of the Hydro rate zone, had surplus hydro generation available at that time.

[12] Includes Rider J at the corrected rate of 12.60%.

[13] Defined as customers engaged in manufacturing, processing, or mining and whose peak demand for electricity exceeds 1 MW.

[14] A Base Load Energy amount per month may be established for a customer of 90% of forecast energy use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the YUB for amendment to adjust the Energy rate as required for a two part rate that yields the same overall charge at forecast energy use, with all energy consumed in excess of the Base Load being charges at a rate reflecting the incremental cost using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

- Provision for Rider F to be set to zero for fuel price forecast filed November 20, 2006. Implementation of this provision requires Rider F to be applied in a slightly different format than for other customers (i.e., a "fixed" Rider F provision is required), as reviewed in Yukon Energy's GRA Compliance filing.

Firm service for retail and industrial customers is also subject to Rider F (a charge or rebate per kW.h used) to address post-GRA fuel price variances from the prices approved in the GRA consolidated firm rate revenue requirements (in this case the 2009 approved GRA fuel price forecast). The current Rider J and Rider R reflect, in part, the extent to which diesel prices included in the 2009 Consolidated Firm Rate Revenue Requirement are well above the levels assumed in the 1996/97 base rates.[15]

4.2.4 Rate Design Options for Residential and General Service

Residential and general service runoff rates at present do not reflect incremental costs consistent with the price of diesel fuel today. The current runoff rates are based on very dated fuel prices that are well below what is required to fully reflect incremental costs. This is inconsistent with OIC direction (to provide for economy and efficiency per OIC 1995/90) and past practice in Yukon (including the 1992 YUB report which recommended that incremental costs be reflected in rates).

However, reflecting the full incremental cost today in a single adjustment to runoff block consumption raises material rate design issues. Simply increasing the current runoff rate without any rate structure changes would result in rate impacts for at least a group of general service customers that have significant usage in the current second block as compared to the first block.[16]

In addressing 2009 rate design options for residential and general service customer classes, the following additional factors require consideration:

1. **Rate adjustments can be made, subject to not resulting in rebalancing or unequal revenue increases between rate classes (per OIC 2008/149)**
    a. OIC 2008/149 in essence prevents inter-class rate rebalancing for these retail classes (i.e., there cannot be changes in overall revenues, at 2009 approved forecast loads, for any of the classes relative to Table 4.1); this requires, for example, that if the runoff rate is raised for a class that an offsetting rate decrease must be made in the first block

[15] See section 1.5, Tab 1 for review of the material increases in diesel prices since 1997 GRA forecasts.
[16] Residential customers are more homogenous and have (relative to general service customers) a small share of energy sales in the second block which makes addressing runoff block re-design for the residential class generally less complex than is the case for the general service class.

[and/or the customer or demand charge] for that class to keep the overall class revenue rate unchanged.

b. Subject to this requirement, OIC 2008/149 does not prevent the Companies from intra class adjustments (i.e., adjusting the runoff rate upwards to reflect incremental costs and lowering the lower block rate on an equal basis).

2. New non-runoff rate blocks can be considered subject to ensuring that rates within each such new non-government retail rate block are the same throughout Yukon

a. Variation is allowed for separate runoff energy rates for non-government retail customers in different communities or rate zones provided such rates are fixed for each community or zone based on the same rate design principles.

b. OIC 1995/90 (section 4.(2)) requires that there be at least 2 energy rate blocks for each non-government retail customer class: at least one equalized rate block and a runoff energy block that provides for economy and efficiency.

c. Provided any additional energy rate block in the rate class is equalized throughout Yukon, the OIC allows for multiple equalized rate blocks, e.g., this would allow in the residential non-government class for a first block set at 700 kWh and a higher second block set at 1000 kWh, 1,500 kWh or 2,000 kWh, with the third rate block for use in excess of the second block limit) then being the runoff rate.

3. A runoff rate must be set for each non-government retail class that provides for economy and efficiency

a. The runoff rate block applies to all consumption over a particular level.

b. Such runoff rates cannot initiate with usage below 1000 kWh/month for residential or 2000 kWh per month for general service.

c. Past Board direction has provided that economy and efficiency is promoted in Yukon runoff rate design through runoff rates that reflect at least the short-run incremental generation costs. In all prior GRA reviews this was based on the cost of diesel in each rate zone plus provision for short run incremental O&M costs for diesel generation.

The following options were considered by the Companies for each of the residential and general service rate classes:

1. **Stepped increase towards incremental cost** – This option is premised on applying only a partial increase today in the runoff block to start to provide a reasonable linkage to incremental cost (allowing for the full incremental cost increase to be staged over more than one GRA), and/or consider creating new rate blocks (see next point below) to allow for a stepped increase (today and in future) towards incremental cost as use levels increase.
    a. Initial consideration was given to using 100% of the 2009 incremental cost of diesel as a runoff rate, as well lesser percentages.
    b. A lesser percentage than 100% of incremental cost was considered more reasonable at this time due to limits related to inter-class rate balancing (runoff revenues increases result in revenues decreasing in one of the lower energy blocks or fixed charge, thus potentially creating issues as noted).
        i. In this manner, staged progress over time would be made towards fully reflecting incremental costs, and ratepayers would not receive such a single large step increase today in the runoff block rate.
        ii. Consideration would need to be given, however, to the manner of staged increase (how large should the percentage be today, and over what period of time would increments need to occur to make adequate progress towards full incremental costs).
    c. Further consideration would also need to be given to the practicality of this solution on its own for solving rate design issues for both residential and general service classes, i.e., due to homogeneity of residential customers, applying larger percentage increase in runoff block is feasible, while even a small percentage increase for the general service class (e.g., 2 cents) without any rate structure changes would still provide for impractical first block rates, while making very little progress towards full incremental costs in the runoff block.

2. **Create one or more new energy blocks –** This option could, for example, maintain the existing first block size for each of residential and general service classes and provide for a new equalized second block, with energy in excess of the new second block (i.e., a third block) subject to runoff rates. This option would potentially allow for runoff rates more representative of incremental costs to be applied to the third block, with a lesser increase being applied in the new second block. Due to the non-homogenous nature of the general

service class (with a number of users between 2,000 and 15,000 kW/h/month and a fair number of customers using above even 50,000 kW.h/month) the following concerns arise with this option for general service customers:

a. If the runoff block is set too low, than a material amount of usage by the very large customers may be subject to incremental costs (leading to rate shock and fairness concerns for the number of large consumers using in excess of 50,000 kWh who would have a majority of usage at incremental cost).
b. Conversely, if the runoff block is set too high (at the 40,000 or 50,000 kWh/month range or higher) then the vast majority of users who have all consumption below that level each month will not receive the desired incremental price signal.

For each of the residential and general service classes, different options for determining the block structure were considered before determining the final proposals to be included in this Application.

a. For the residential classes, four separate block energy structures were considered and tested:
    i. 0-1000, 1001-1500 and > 1500 kW.h per month
    ii. 0-1000, 1001-2000 and > 2000 kW.h per month
    iii. 0-700, 701-2000 and > 2000 kW.h per month
    iv. 1-1000, 1001-2,500 and > 2500 kW.h per month

b. For general service classes, two scenarios were considered and tested;
    i. 0-2000, 2001-15000 and >15000 kW.h (with separate consideration for usage >20,000 kW.h to address large users group); and
    ii. Create third block similar to the above, and establish a new rate class for high consumption users; e.g. users typically with >20,000 kW.h/month.

3. **Customer and/or Demand Charge** - Options for setting the adjusted customer and/or demand charge ranged in each case as follows:
    a. Recover 100% revenue to cost ratio;
    b. Apply the increase of 23.1% to the existing base rate (to effectively crystallize the current Rider J and Rider R impact); or
    c. Simply retain the present base rate excluding riders presently in place.

The first option (full cost recovery) did not present a practical alternative, as utilizing the "full cost" would require addressing for each rate class of the "other" non-energy costs not addressed, e.g., residential "customer costs" do not address residential "demand" costs, and general service "demand" costs do not address general service "customer" costs. Applying the 23.1% increase to the current customer charge for residential customers appears, on review, to provide a reasonable determination for 2009. In contrast, at least for general service, retaining the present base rate demand charge may facilitate a more reasonable solution for a blocked energy charge structure.

4. **Create separate "large GS" subclass and "small GS" subclass** – as initially conceived this approach to addressing specific concerns for the general service class would allow for both residential and general service rate design to retain the present two block structure. Multiple general service subclasses are common in other jurisdictions. While a variety of such options were considered to address general service rate design issues, most were considered too complex to implement (including implications for cost of service analysis) or could not be implemented within the timing constraints provided for in this Phase II Application.

Overall, it is concluded that incremental cost of diesel generation needs to be addressed (see section 4.3) and reflected to a material degree in rates for higher levels of use, even if not today reflected in full. To address the resulting impacts, it is also concluded that a new non-runoff energy block for each of these rate classes would facilitate the required rate design solutions. For general service, special additional measures (involving an added rate block for large users) are concluded to be required for 2009 as an interim step until a separate large GS rate class can be established in a future GRA.

4.3 INCREMENTAL COST OF DIESEL

Providing an efficient price signal is one key consideration to be balanced in rate design, and in this regard, the Board is required by OIC 1995/90 to fix runoff rates for each non-government retail customer class on the basis of rate design principles "to promote economy and efficiency."[17] The requirement to provide an efficiency signal tied to the incremental cost of diesel is heightened on a system moving towards increasing requirements for baseload diesel generation.

[17] While "economy and efficiency" are not specifically defined in the OIC, past precedent, including Board recommendations and Board Orders, provides clear definition for this principle in terms of Yukon runoff rate design, i.e., "the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity." See YUB 1992 Report and Recommendation on COS and Rates page 37.

The Board has previously noted that to promote economy and efficiency runoff rates should reflect at least short-run incremental costs[18] in each of the rate zones.[19] From 1989 to 1996, the Companies and the YUB applied the then-prevailing rate policy directives to set runoff rates that reflect short-term incremental energy costs in communities supplied primarily by generation other than hydro. The Board in its 1992 Report recognized the need to extend aspects of this approach to hydro communities,[20] and OIC 1995/90 implemented this recommendation.

Table 4.5 below summarizes the 1997and 2009 rates for the incremental cost of diesel in each rate zone.

Table 4.5: Summary on Incremental Cost of Diesel (¢/kWh)

		Updated
Zone	**1997**	**2009**
Hydro-Diesel	10.45	32.74
Large Diesel	10.45	27.23
Small Diesel	12.36	29.19
Old Crow	25.77	61.54

Given the clear convergence of the hydro zone, large diesel zone and small diesel zone incremental costs, for simplicity the rate design has been based (at least for residential classes) on consolidating these three zones into a single average incremental cost estimate of 27.99 cents/kW.h. The detailed calculations are set out in Table 4.6.

[18] Incremental cost is the cost of producing extra energy assuming no capital additions are necessary; it is typically calculated as the extra fuel cost, extra operation and maintenance cost and extra losses caused by the production and delivery of an extra kWh of energy (it is assumed to be synonymous with short run marginal cost).
[19] Noted in the 1992 recommendations, and subsequently confirmed in Orders 2993-8 and 1996-7.
[20] Based on past practice "second block" runoff rate design that conforms to this OIC directive reflect incremental energy costs, and is not tied to the cost of service study (which measures instead "embedded" or average energy costs, an entirely different concept).

Table 4.6: Incremental Cost of Diesel Calculation

Yukon Energy Corporation & Yukon Electrical Company Limited
2009 Incremental Cost of Diesel

2009 Incremental Rates

Incremental Rates	Hydro		Large Diesel	Old Crow
	WAF (Faro)	MD (Dawson)	Watson	
Forcast Cost of Fuel - (cent/L)	99.2	97.5	87.48	193.41
Approve Heat Rate - (KW.h/L)	3.55	3.71	3.82	3.56
Losses	8.46%	8.46%	5.82%	7.75%
Run-out Cost - (cent/KW.h)	30.31	28.50	24.23	58.54
Add O&M - (cent/KW.h)	3.00	3.00	3.00	3.00
Total	33.31	31.50	27.23	61.54
Generation (KW.h)	866,000	396,000	14,593,000	2,029,000
Weighting Factor	68.62%	31.38%	100.00%	100.00%
Blended Cost (cent/KW.h)	32.74		27.23	61.54
Blended Cost,WAF-Large Diesel (cent/KW.h)		27.67		

	Small Diesel			
	Destruction Bay	Beaver Creek	Swift River	
Forcast Cost of Fuel - (cent/L)	83.13	81.52	92.44	
Approve Heat Rate - (KW.h/L)	3.41	3.56	2.99	
Losses	8.48%	8.48%	8.48%	
Run-out Cost - (cent/KW.h)	26.45	24.84	33.54	
Add O&M - (cent/kW.h)	3.00	3.00	3.00	
Total	29.45	27.84	36.54	Blended Hydro, Large
Generation (KW.h)	1,741,000	2,115,000	326,000	Diesel and Small Diesel
Weighting Factor	41.63%	50.57%	7.80%	
Blended Cost (cent/KW.h)		29.19		27.99

The method used to determine current runoff rates is in accordance with past practice in this jurisdiction and follows generally accepted rate design criteria.

In this Application, to meet the OIC requirement of "economy and efficiency" runoff rates have been set at levels that reflect a relationship to the incremental short term cost of generating an extra kWh using diesel generation. In particular, Option A reflects a substantial portion of these costs (80% of the incremental cost) while Option B does not reflect a substantial portion (50%) given its focus on other rate design considerations.

4.4 RESIDENTIAL AND GENERAL SERVICE 2009 RATE OPTIONS AND PROPOSALS

In addressing the relevant issues and options for adjusting residential and general service rates at this time, this Application sets out a joint recommendation to establish new rate blocks for each class (with a joint approach in this regard specifically for general service classes), as well as new base rates that allow for removal of Rider J and Rider R along with inclining rates and an improved reflection of incremental diesel generation costs. However, rather than recommending one specific rate package within this framework, two sets of options are provided for residential and general service rate class 2009 rate adjustments as summarized below. This approach allows the Board and intervenors to review the new rate structures in the context of materially different degrees of rate change impact for different customer groups within each class:

- **Option A** – Reflects runoff rates at 80% of 2009 incremental costs, with resulting increased bill impacts for a minority of higher use customers and reduced bills for the majority of customers using only first block energy.

- **Option B** – Retains first block energy rates at approximately current levels (no material bill changes), and keeps runoff rate levels at only about 50% of 2009 incremental costs.

Under each option, the net overall consolidated Yukon impact compared to existing rates is forecast, at 2009 approved forecast loads, to be revenue neutral for each rate class.

As noted, the two sets of options for 2009 rate design address the need to provide runoff rates for residential and general service customers that reflect "economy and efficiency", and sending a fair efficiency price signal for some level of consumption above a stipulated threshold for each class:

- For residential, the runoff rate impacts start at either 1,501 kWh/month (Option A) or 2,501 kW.h/month (Option B); and

- For general service, the runoff rate impacts start at 15,001 kWh per month for both Options A and B.

Under both options, the redesign of general service rates in particular has addressed a number of factors to ensure that the principle of economy and efficiency is achieved, i.e., that customers receive an incremental price signal for some level of consumption above a certain threshold. In this proposal, 15,000 kWh/month was held to be a reasonable threshold for most general service customers to receive an efficiency price signal (i.e., rates based on the incremental cost of diesel); however, given that there is a high amount of energy still consumed above the 15,000 kW.h/month level by certain customers, a threshold of 20,000 kW.h/month was imposed (limiting the applicability of the "incrementally priced" block rate and providing for a rate thereafter at a lower average cost) and was determined to provide an appropriate economy and efficiency price signal at this time (i.e., higher use customers would be provided with the price signal, but only a limited level of energy would be charged at the higher incremental cost). As reviewed below, the 2009 general service rate design approach can be viewed as a first step before establishing an orderly process for separating the non-homogenous general service class into two subclasses (e.g., large users, and other users) at a future date.

Overall impacts on residential and general service customer monthly bills from each option will depend on average monthly use levels. The ultimate impact on the overall levels of bill by class, by rate zone and by usage tier are shown for each option in detailed bill impact tables provided in Appendix 4.1A and 4.1B.

4.4.1 Residential Rate Options and Proposals

The rate adjustment options for residential government and non-government customers provide for a new equalized second energy block with a rate that is equal in all rate zones, as well as (for use in excess of the second block) for adjusted runoff rates that in some way reflect the GRA incremental cost of diesel (at either 50% or 80% of the estimated cost).

Under both options, the monthly customer charge is proposed to incorporate the current effective charges with riders.

- **Residential Non-Government** customers - A monthly customer charge of $14.65[21]; and

- **Residential Government** customers - A monthly customer charge of $18.47 per month.[22]

The two options provide the following energy blocks and base energy rates:

- **Option A**:
  - **First energy block** for use up to 1,000 kW.h per month (about 70% of non-government class annual bills do not exceed this level), with an adjusted base energy rate as follows (under Option A, the first block charge recovers the remaining revenue to meet the design revenue not recovered by the customer charge, the second block rate and third block/runoff rate):
    - **Non government -** 10.90 ¢/kW.h
    - **Government –** 16.17 ¢/kW.h

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[21] The customer charge was derived by taking the current customer charge and applying the adjustment of 23.1% (11.90*1.231=14.65) and recovers approximately 39% of the customer costs allocated to residential non-government rate class. Note that there is no demand charge to collect demand costs for this rate class.

[22] The customer charge was derived by taking the current customer charge and applying the adjustment of 23.1% (15.00*1.231=18.47) and recovers approximately 48% of the customer costs allocated to residential government rate class. Note that there is no demand charge to collect demand costs for this rate class.

  - **A new equalized second energy block** for use from 1,001 to 1,500 kW.h per month (about 90% of non-government class annual bills do not exceed this level), with a base energy rate of 15.22 ¢/kW.h[23]; this energy rate is the same for non-government and government residential customers; and
  - **An adjusted runoff energy block** for all use in excess of 1,500 kW.h per month, with runoff rates for both non-government and government customers that reflect 80% of short term incremental generation costs (blended rate of 22.39 ¢/kW.h for Hydro, Large Diesel and Small Diesel zones, and 49.23 ¢/kW.h for Old Crow zone, based on fuel price forecasts as approved for 2009).

- **Option B**:
  - **First energy block** for use up to 1,000 kW.h per month (about 70% of residential non-government annual bills do not exceed this level), with an adjusted base energy rates as follows (these rates reflect current first block energy rates after rider impacts):
    - **Non government -** 12.14 ¢/kW.h
    - **Government –** 17.92 ¢/kW.h
  - **A new equalized second energy block** for use from 1,001 to 2,500 kW.h per month (about 98% of residential non-government annual bills do not exceed this level), with a base energy rate of 12.82 ¢/kW.h for both non-government and government customers; and
  - **An adjusted runoff energy block** for all use in excess of 2,500 kW.h per month with runoff rates for non-government and government customers that reflect 50% of short term incremental generation costs (blended rate of 13.99 ¢/kW.h for Hydro, Large Diesel and Small Diesel zones, and 30.77 ¢/kW.h for Old Crow zone), based on fuel price forecasts as approved for 2009.

The net effect of Option A is to provide all non-government customers using up to 1500 kW.h (hydro zone, small diesel zone, and large diesel zone) or 2000 kW.h (Old Crow zone) a net benefit/reduction in their overall bills.[24] This reduction totals approximately 11.7% at 1000 kW.h per month and, for all zones other than Old Crow, the benefit declines with increases in load above 1000 kW.h/month, such that a bill for 1500 kW.h of consumption is very close to the existing bill (reduction of 0.36%). This net overall bill reduction covers approximately 90% of all non-government residential users. Large residential users in

[23] This rate is derived by taking the existing small diesel runoff rate and applying the adjustment of 23.1% (12.36*1.231=15.22).
[24] See Appendix 4.1A, Tables A4.4, and A4.6; calculated excluding any impacts from any potential IER changes, and using Rider F in effect as at February 2009.

excess of these levels (>1500 kW.h per month in most communities, >2000 kW.h per month in Old Crow – a total of approximately 10% of non-government residential users) will see bills higher than under existing rates, but which remain below the levels proposed in Yukon Energy's 2008/09 GRA filing.[25]

In contrast, the net effect of Option B is to leave most bills generally unchanged for customers throughout all use levels (material bill decreases occur in small diesel and Old Crow zones once use exceeds about 1250 kW.h/month).[26]

4.4.2 General Service Rate Options and Proposals

In assessing options for General Service customers, the Companies identified the need for a long term rate design solution to address the wide variance in customer use levels within the existing general service class. The jointly proposed rate structure for energy blocks in this class moves toward two separate general service subclasses: one for high consumption users, and another for all other users. However, prior to implementation of this solution, a number of complexities need to be addressed that could not be resolved within the timeline required for filing the 2009 Phase II Application. These include:

- Approval of new rate class by the Board;

- Forecast, testing and approval of billing determinants;

- Forecast costs of implementation on the billing system;

- Implementation on the billing system (Operations);

- Altering of COS models to include new rate class;

- Altering of Phase II Schedules to include new rate class;

- Create separate specific MIL's for new rate class, if required; and

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[25] For example, in Yukon Energy's 2008/09 GRA filing the proposed bill for 3000 kW.h per month of non-government residential use totaled $558.19 per month including all riders, taxes and subsidies; under Option A, the bill for this same level of usage is $520.49 per month.

[26] See Appendix 4.1B, Tables B4.4, and B4.6. Calculated excluding any impacts from any potential IER changes, and using Rider F in effect as at February 2009, At 3000 kW.h/month, the bill increase is 1.4% (non-government) and 1.5% (government) in the hydro and large diesel zones.

- Contact eligible customers and inform and educate them as to the potential change.

With these considerations in mind, the approach in this Application reflects a staged approach to rate design for the general service class, that combines the requirement for a further rate block (to mitigate impacts of the higher incremental runoff rate on first and second block energy rates) and provides for an orderly process for separating the non-homogenous general service class into two subclasses at a future date.

The proposal to adjust rates for general service government and non-government customers provides for a new second energy block (from 2,001 to 15,000 kW.h per month use) with a stepped up rate that is equal in all rate zones, and for a new third energy block (from 15,001 to 20,000 kW.h/month) with a higher rate that is equal in all rate zones and that reflects incremental energy costs as charged to residential customer runoff rates in the Hydro rate zone. For all but approximately 109 of the largest GS customers[27] who consume over 20 MW.h in a month (on the order of 3% of overall GS customers), the rate design in all practical respects parallels the residential three block rate design with the third block linked to either 50% (Option B) or 80% (Option A) of the incremental cost of diesel.

To address rate design requirements for large users (e.g., those general service customers with typical monthly use in excess of 20,000 kW.h), the approach in this Application defers establishing a separate rate class for large users. At this time, as an interim measure until the next GRA, the proposed rate design provides for a fourth energy rate block for use in excess of 20,000 kW.h/month. The proposed energy rate for this fourth "large user" rate block reflects status quo current effective runoff rates in each zone (with Rider J and R). The overall result is that the establishment of a separate runoff rate block charge for general service large users is deferred.

The adjusted base **demand charge** for general service customers varies with the options as follows (minimum bill of 5 kW per month):

- **Option A:**
  - **General Service Non-Government** - a demand charge of $6.00 per kW per month[28]
  - **General Service Government** – a demand charge of $10.00 per kW per month[29]

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[27] Measured by the estimated # of bills exceeding 20,000 kW.h/month divided by 12. Approximately 50% Non-government customers, 15% Municipal customers, and 35% Federal and Territorial customers.
[28] The demand for GS Non-Government and Municipal was derived by maintaining the current demand charge for the class exclusive of riders and recovers 71.5% of the demand costs allocated to the GS Non-Government rate class. Note that there is no customer charge to collect customer costs for this rate class.

- **Option B:**
  - **General Service Non-Government** - a demand charge of $7.39 per kW per month
  - **General Service Government –** a demand charge of $12.31 per kW per month

Option A and Option B base energy rates for general service customers are described in more detail below.

- A first energy block set at up to 2,000 kWh/month with energy charges as follows (approximately 66% of General Service non-government and municipal customers do not exceed this block of consumption):
  - **Option A:** (charges for each rate class as residual requirement after consideration of all other rate revenues):
    - **General Service Non-Government and Municipal** - an energy charge of 8.31 cents/kWh for the first 2,000 kWh/month of energy consumed.
  - **General Service Government** - an energy charge of 18.81 cents/kWh for the first 2,000 kWh/month of energy consumed.
  - **Option B**:
    - **General Service Non-Government and Municipal** - an energy charge of 10.23 cents/kWh for the first 2,000 kWh/month of energy consumed.
    - **General Service Government** - an energy charge of 21.48 cents/kWh for the first 2,000 kWh/month of energy consumed.

- A second energy block set at 2,001 to 15,000 kWh/month with energy charge consistent across all rate zones (as per OIC 1995/90) as follows (approximately 96% of customers do not exceed 15,000 kW.h/month):
  - **Option A:**
    - **General Service Non-Government** - an energy charge of 14.90 cents/KWh for energy consumed between 2,001 and 15,000 kWh/month.
    - **General Service Government** - an energy charge of 14.90 cents/KWh for energy consumed between 2,001 and 15,000 kWh/month.[30]

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[29] The demand for GS Government was derived by maintaining the current demand charge for the class exclusive of riders and recovers 91.1% of the demand costs allocated to the GS government rate class. Note that there is no customer charge to collect customer costs for this rate class.

[30] This rate is derived by taking the existing small diesel runoff rate and applying the adjustment of 23.1% (12.36*1.231=15.22).

- **Option B**:
    - **General Service Non-Government** - an energy charge of 12.88 cents/KWh for energy consumed between 2,001 and 15,000 kWh/month.
    - **General Service Government** - an energy charge of 12.97 cents/KWh for energy consumed between 2,001 and 15,000 kWh/month.

- A third energy block set at 15,001 to 20,000 kWh/month with energy charge consistent across all rate zones (as per OIC 1995/90) for all general service retail rate classes and that reflects incremental energy costs as charged to residential customer runoff rates in the Hydro, Large Diesel and Small Diesel rate zone:
    - **Option A - General Service Non-Government and Government** - an energy charge of 22.39 cents/kWh (80% of blended incremental energy cost for hydro, large diesel and small diesels zones) for energy consumed between 15,001 and 20,000 KWh/month.
    - **Option B** - **General Service Non-Government and Government** - an energy charge of 13.99 cents/kWh (50% of blended incremental energy cost for hydro, large diesel and small diesels zones) for energy consumed between 15,001 and 20,000 KWh/month.

- A fourth energy block charge for all use in excess of 20,000 kW.h/month with energy charge as follows (reflects current runoff charge with riders):
    - **Option A and Option B** - **General Service Non-Government and Government** – an energy charge of 12.86 cents/kWh for energy consumed in excess of 20,000 kW.h/month in the Hydro and Large Diesel rate zones, 15.22 cents/kW.h in the Small Diesel rate zone, and 31.72 cents/kWh in the Old Crow rate zone.

Given the particular rate structure proposed, the net effect under Option A is to provide all GS non-government customers using up to approximately 5000 kW.h/month (hydro zone and large diesel zone) or over 15,000 kW.h/month (small hydro zone) a net benefit/reduction in their overall bills.[31] This net overall bill reduction covers approximately 86% of all GS non-government users. In the hydro and large diesel zones, bill increases are most significant for use ranging from about 15,000 kW.h/month to 40,000 kWh/month, peaking at 20,000 kWh/month (approximate 22% bill impact).

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[31] See Appendix 4.1A, Tables A4.7.Calculated using Rider F in effect as at February 2009.

In contrast, the net effect on bills under Option B is typically less than a fraction of 1%, peaking at 2% with use at 20,000 kW.h/month.[32]

4.5 OTHER 2009 RATE PROPOSALS

4.5.1 Secondary Sales Rate Schedule 32

Revenues for secondary sales were approved in Order 2009-10; no changes are sought to Rate Schedule 32 at this time.

4.5.2 Major Industrial Rate Schedule 39

Revenues for fixed Rider F were approved in Order 2009-10. The only requested change to Rate Schedule 39 at this time is to clarify the implementation details with respect to the way Rider F is charged to this class so as to implement the requirements for "Rider F to be set to zero for fuel price forecast filed November 20, 2006". Given the November 20, 2006 fuel price forecast is slightly different than the approved GRA fuel price (which is the zero-basis for Rider F for all other customers) it is necessary to implement a differential Rider F for the industrial customer of 0.211 cents/kW.h as approved in Yukon Energy's GRA compliance filing.

Board Order 2007-5, at finding #19, indicated that for industrial customers "Ratchet issues and changes to demand rate should be addressed in YEC's next GRA." Since that Order, the approval of Rate Schedule 39 in Order 2008-10 addresses all rate related matters in respect of Rate Schedule 39. In regard to issues raised in the proceeding leading to Order 2007-5, that the industrial demand charge should potentially be larger than the $15.00/kV.A level, it is noted that the COS indicates a demand-related cost for the bulk power system (service to industrials) at $157/kW-year, which is close to the $15/kV.A level approved in Rate Schedule 39. Consequently, there would not appear to be a basis for material concern over the present level of the industrial demand charge.

4.5.3 Wholesale Rate Schedule 42

Rate Schedule 42 is the rate provided for Yukon Energy sales to Yukon Electrical. It is necessary at this time to change Rate Schedule 42 to update the rate to reflect the termination of Riders J and R and the revision proposed to base rates. The precise rate is dependent on the retail rate design selected by the Board (i.e., within the range of Options A and B) but approximates 8.3 cents/kW.h. In the event Option A above is not adopted by the Board with respect to the residential Hydro zone non-government run-out

[32] See Appendix 4.1B, Tables B4.7.Calculated using Rider F in effect as at February 2009.

rate, YEC seeks approval to incorporate the full incremental cost of diesel generation on the major systems (27.67 ¢/kW.h) as the Energy Reconciliation Adjustment rate.

4.5.4 Wholesale Rate Schedule 51

This application seeks to update and clarify the older rate schedule under which Yukon Electrical sells to Yukon Energy at all required locations throughout Yukon. This rate schedule will be an energy-only rate, applicable throughout Yukon at the same level as the base Rate Schedule 42 rate (approximately 8.3 cents/kW.h).

4.5.5 Closure of Unused Rate Schedules

At the present time, approval is sought to close three rate schedules that were approved in the past for the specific situation of past industrial customers, but have no ongoing relevance:

- Rate Schedule 33 for service to mine sites no longer receiving power from the utilities.

- Rate Schedules 38 and 40 which were for firm standby and site maintenance power service approved for certain unique services provided to the Faro mine.

APPENDIX 4.1A YEC

RESIDENTIAL AND GENERAL SERVICE RATES AND BILLS UNDER OPTION A

Table A4.1
3/1/2010

Comparison of Existing and Proposed Rates - Option A

Summary of Existing 2009 Price Schedule Charges

Residential				At 1000 kWh
	Customer	Demand	Energy 1	Energy 2
1160	11.90 $/month		0.0986 $/kW.h	0.1045 $/kW.h
1260	11.90 $/month		0.0986 $/kW.h	0.1236 $/kW.h
1360	11.90 $/month		0.0986 $/kW.h	0.1045 $/kW.h
1460	11.90 $/month		0.0986 $/kW.h	0.2577 $/kW.h
1180	15.00 $/month		0.1434 $/kW.h	0.1045 $/kW.h
1280	15.00 $/month		0.1434 $/kW.h	0.1236 $/kW.h
1380	15.00 $/month		0.1434 $/kW.h	0.1045 $/kW.h
1480	15.00 $/month		0.1434 $/kW.h	0.2577 $/kW.h

General Service				At 2000 kWh
	Customer	Demand	Energy 1	Energy 2
2160		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2260		$6.00 /kW	0.0831 $/kW.h	0.1236 $/kW.h
2360		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2460		$6.00 /kW	0.0831 $/kW.h	0.2577 $/kW.h
2170		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2270		$6.00 /kW	0.0831 $/kW.h	0.1236 $/kW.h
2370		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2470		$6.00 /kW	0.0831 $/kW.h	0.2577 $/kW.h
2180		$10.00 /kW	0.1745 $/kW.h	0.1045 $/kW.h
2280		$10.00 /kW	0.1745 $/kW.h	0.1236 $/kW.h
2380		$10.00 /kW	0.1745 $/kW.h	0.1045 $/kW.h
2480		$10.00 /kW	0.1745 $/kW.h	0.2577 $/kW.h

Secondary Energy	Customer	Demand	Energy
3200			0.07200 $/kW.h

Industrial	Customer	Demand	Energy
3900		$15.00 /kW	0.07600 $/kW.h

Street Lights	Customer	Demand	Energy	High Mast Charge
61/66	6.36 $/month	$4.0300 /kW		1.03 $/month
67 - 250 W	15.47 $/month			
67 - 400 W	23.66 $/month			

Sentinel Lights	Customer	Demand	Energy	Energy 2
75/76 - Normal - 100 W	11.64 $/month			
75/76 - E & M - 100 W	6.46 $/month			
75/76 - Meter - 100 W	7.34 $/month			
75/76 - Normal - 175 W	14.18 $/month			
75/76 - E & M - 175 W	9.87 $/month			
75/76 - Meter - 175 W	7.97 $/month			
75/76 - Normal - 250 W	17.34 $/month			
75/76 - E & M - 250 W	13.16 $/month			
75/76 - Meter - 250 W	8.23 $/month			
75/76 - Normal - 400 W	23.03 $/month			
75/76 - E & M - 400 W	18.61 $/month			
75/76 - Meter - 400 W	7.84 $/month			
75/76 - Normal - 400 W Fl	25.44 $/month			
75/76 - E & M - 400 W FL	17.75 $/month			
75/76 - Meter - 400 W FL	10.26 $/month			

Summary of Proposed 2009 Price Schedule Charges

Residential				At 1000 kWh	At 1500 kWh
	Customer	Demand	Energy 1	Energy 2	Energy 3
1160	14.65 $/month		0.1090 $/kW.h	0.1522 $/kW.h	0.2239 $/kW.h
1260	14.65 $/month		0.1090 $/kW.h	0.1522 $/kW.h	0.2239 $/kW.h
1360	14.65 $/month		0.1090 $/kW.h	0.1522 $/kW.h	0.2239 $/kW.h
1460	14.65 $/month		0.1090 $/kW.h	0.1522 $/kW.h	0.4923 $/kW.h
1180	18.47 $/month		0.1617 $/kW.h	0.1522 $/kW.h	0.2239 $/kW.h
1280	18.47 $/month		0.1617 $/kW.h	0.1522 $/kW.h	0.2239 $/kW.h
1380	18.47 $/month		0.1617 $/kW.h	0.1522 $/kW.h	0.2239 $/kW.h
1480	18.47 $/month		0.1617 $/kW.h	0.1522 $/kW.h	0.4923 $/kW.h

General Service				At 2000 kWh	At 15000 kWh	At 20000 kWh
	Customer	Demand	Energy 1	Energy 2	Energy 3	Energy 3A
2160		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1286 $/kW.h
2260		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1522 $/kW.h
2360		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1286 $/kW.h
2460		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.3172 $/kW.h
2170		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1286 $/kW.h
2270		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1522 $/kW.h
2370		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1286 $/kW.h
2470		$6.00 /kW	0.0831 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.3172 $/kW.h
2180		$10.00 /kW	0.1881 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1286 $/kW.h
2280		$10.00 /kW	0.1881 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1522 $/kW.h
2380		$10.00 /kW	0.1881 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.1286 $/kW.h
2480		$10.00 /kW	0.1881 $/kW.h	0.1490 $/kW.h	0.2239 $/kW.h	0.3172 $/kW.h

Secondary Energy	Customer	Demand	Energy
3200			0.0720 $/kW.h

Industrial	Customer	Demand	Energy	Fixed Rider F
3900		$15.00 /kW	0.07600 $/kW.h	0.00211 $/kW.h

Street Lights	Customer	Demand	Energy	High Mast Charge
61/66	7.83 $/month	$4.9616 /kW		1.27 $/month
67 - 250 W	19.05 $/month			
67 - 400 W	29.13 $/month			

Sentinel Lights	Customer	Demand	Energy	Energy 2
75/76 - Normal - 100 W	14.33 $/month			
75/76 - E & M - 100 W	7.95 $/month			
75/76 - Meter - 100 W	9.04 $/month			
75/76 - Normal - 175 W	17.46 $/month			
75/76 - E & M - 175 W	12.15 $/month			
75/76 - Meter - 175 W	9.81 $/month			
75/76 - Normal - 250 W	21.35 $/month			
75/76 - E & M - 250 W	16.20 $/month			
75/76 - Meter - 250 W	10.13 $/month			
75/76 - Normal - 400 W	28.35 $/month			
75/76 - E & M - 400 W	22.91 $/month			
75/76 - Meter - 400 W	9.65 $/month			
75/76 - Normal - 400 W Fl	31.32 $/month			
75/76 - E & M - 400 W FL	21.85 $/month			
75/76 - Meter - 400 W FL	12.63 $/month			

Table A4.2
3/1/2010

Residential Effective Rate including all Riders, Rebates, and Subsidies - Option A

		Proposed							**Existing**					
		Residential Non-Government							Residential Non-Government					
		Customer Charge	First Block Energy 0-1000	Second Block Energy 1001-1500	Runoff Energy > 1500 kW.h				Customer Charge	First Block Energy 0-1000	Runoff Energy >1000 kW.h			
		all zones $/month	all zones $/kW.h	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h	all zones $/month	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h
Base Rate (1997 GRA)		$14.65	$0.1090	$0.1522	$0.2239	$0.2239	$0.2239	$0.4923	$11.90	$0.0986	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%								$1.48	$0.0123	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%								$1.25	$0.0104	$0.0110	$0.0110	$0.0130	$0.0271
Effective rate before Tax rebate, IER and GST		$14.65	$0.1055	$0.1487	$0.2204	$0.2204	$0.2204	$0.4888	$14.64	$0.1177	*$0.1250*	$0.1250	$0.1485	$0.3134
Income Tax Rebate (%)	-0.50%	-$0.07	-$0.0005	-$0.0008	-$0.0011	-$0.0011	-$0.0011	-$0.0025	-$0.06	-$0.0005	-$0.0005	-$0.0005	-$0.0006	-$0.0013
IER (1st block kW.h)	-$0.026621		-$0.0266							-$0.0266				
Total before GST		$14.58	$0.0783	$0.1479	$0.2192	$0.2192	$0.2192	$0.4863	$14.58	$0.0906	$0.1245	$0.1245	$0.1479	$0.3121
Change		*$0.00*	*-$0.0123*	*n/a*	*$0.0948*	*$0.0948*	*$0.0714*	*$0.1742*						
		0.00%	*-13.59%*		*76.16%*	*76.16%*	*48.28%*	*55.81%*						

		Proposed							**Existing**					
		Residential Government							Residential Government					
		Customer Charge	First Block Energy 0-1000	Second Block Energy 1001-1500	Runoff Energy > 1500 kW.h				Customer Charge	First Block Energy 0-1000	Runoff Energy >1000 kW.h			
		all zones $/month	all zones $/kW.h	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h	all zones $/month	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h
Base Rate		$18.47	$0.1617	$0.1522	$0.2239	$0.2239	$0.2239	$0.4923	$15.00	$0.1434	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.46%								$1.87	$0.0179	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.53%								$1.58	$0.0151	$0.0110	$0.0110	$0.0130	$0.0271
Total before GST		$18.47	$0.1582	$0.1487	$0.2204	$0.2204	$0.2204	$0.4888	$18.45	$0.1728	$0.1250	$0.1250	$0.1485	$0.3134
Change		*$0.02*	*-$0.0147*	*n/a*	*$0.0954*	*$0.0954*	*$0.0719*	*$0.1754*						
		0.12%	*-8.48%*		*76.32%*	*76.32%*	*48.42%*	*55.96%*						

Table A4.3
3/1/2010

General Service Effective Rate including all Riders, Rebates, and Subsidies - Option A

		Proposed								**Existing**					
		GS Non-Government								GS Non-Government					
		Demand Charge	First Block Energy 0-2000	Second Block Energy 2001-15000	Third Block Energy 15001-20000	Runoff Energy (>20,000 kW.h)				Demand Charge	First Block Energy	Runoff Energy (>2,000 kW.h)			
		all zones	all zones	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		$/kW	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/month	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h
Base Rate		$6.00	$0.0831	$0.1490	$0.2239	$0.1286	$0.1286	$0.1522	$0.3172	$6.00	$0.0831	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%									$0.75	$0.0104	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%									$0.63	$0.0087	$0.0110	$0.0110	$0.0130	$0.0271
Effective rate before Tax rebate		$6.00	$0.0796	$0.1455	$0.2204	$0.1251	$0.1251	$0.1487	$0.3137	$7.38	$0.0987	$0.1250	$0.1250	$0.1485	$0.3134
Income Tax Rebate (%)	-0.50%	-$0.03	-$0.0004	-$0.0007	-$0.0011	-$0.0006	-$0.0006	-$0.0008	-$0.0016	-$0.03	-$0.0004	-$0.0005	-$0.0005	-$0.0006	-$0.0013
Total before GST		$5.97	$0.0791	$0.1447	$0.2192	$0.1244	$0.1244	$0.1479	$0.3121	$7.35	$0.0982	$0.1245	$0.1245	$0.1479	$0.3121
Change		*-$1.38*	*-$0.0191*	*n/a*	*n/a*	*-$0.0001*	*-$0.0001*	*$0.0000*	*$0.0000*						
		-18.77%	*-19.44%*			*-0.08%*	*-0.08%*	*0.00%*	*0.00%*						

		Proposed								**Existing**					
		GS Municipal Government								GS Municipal Government					
		Demand Charge	First Block Energy 0-2000	Second Block Energy 2001-15000	Third Block Energy 15001-20000	Runoff Energy (>20,000 kW.h)				Demand Charge	First Block Energy 0-2000	Runoff Energy (>2,000 kW.h)			
		all zones	all zones	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		$/kW	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/month	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h
Base Rate		$6.00	$0.0831	$0.1490	$0.2239	$0.1286	$0.1286	$0.1522	$0.3172	$6.00	$0.0831	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%									$0.75	$0.0104	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%									$0.63	$0.0087	$0.0110	$0.0110	$0.0130	$0.0271
Total before GST		$6.00	$0.0796	$0.1455	$0.2204	$0.1251	$0.1251	$0.1487	$0.3137	$7.38	$0.0987	$0.1250	$0.1250	$0.1485	$0.3134
Change		*-$1.38*	*-$0.0191*	*n/a*	*n/a*	*$0.0001*	*$0.0001*	*$0.0002*	*$0.0003*						
		-18.69%	*-19.36%*			*0.08%*	*0.08%*	*0.13%*	*0.10%*						

		Proposed								**Existing**					
		GS Government								GS Government					
		Demand Charge	First Block Energy 0-2000	Second Block Energy 2001-15000	Third Block Energy 15001-20000	Runoff Energy (>20,000 kW.h)				Demand Charge	First Block Energy 0-2000	Runoff Energy (>2,000 kW.h)			
		all zones	all zones	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		$/kW	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/month	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h
Base Rate		$10.00	$0.1881	$0.1490	$0.2239	$0.1286	$0.1286	$0.1522	$0.3172	$10.00	$0.1745	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%									$1.25	$0.0217	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%									$1.05	$0.0184	$0.0110	$0.0110	$0.0130	$0.0271
Total before GST		$10.00	$0.1846	$0.1455	$0.2204	$0.1251	$0.1251	$0.1487	$0.3137	$12.30	$0.2111	$0.1250	$0.1250	$0.1485	$0.3134
Change		*-$2.30*	*-$0.0265*	*n/a*	*n/a*	*$0.0001*	*$0.0001*	*$0.0002*	*$0.0003*						
		-18.69%	*-12.56%*			*0.08%*	*0.08%*	*0.13%*	*0.10%*						

Table A4.4
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**-0.50%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - NON GOVERNMENT - Option A (with IER)**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro		Proposed Bill	$31.75	$39.97	$48.20	$56.42	$64.64	$76.98	$97.54	$136.36	$175.18	$290.28	$405.39	$520.49
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	-$2.59	-$3.88	-$5.17	-$6.47	-$7.76	-$9.70	-$12.93	-$6.78	-$0.62	$49.14	$98.90	$148.66
	Var. (%)	Var. ($)/Existing	-7.53%	-8.84%	-9.69%	-10.28%	-10.72%	-11.19%	-11.71%	-4.74%	-0.36%	20.38%	32.27%	39.98%
Large Diesel		Proposed Bill	$31.75	$39.97	$48.20	$56.42	$64.64	$76.98	$97.54	$136.36	$175.18	$290.28	$405.39	$520.49
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	-$2.59	-$3.88	-$5.17	-$6.47	-$7.76	-$9.70	-$12.93	-$6.78	-$0.62	$49.14	$98.90	$148.66
	Var. (%)	Proposed/Existing	-7.53%	-8.84%	-9.69%	-10.28%	-10.72%	-11.19%	-11.71%	-4.74%	-0.36%	20.38%	32.27%	39.98%
Small Diesel		Proposed Bill	$31.75	$39.97	$48.20	$56.42	$64.64	$76.98	$97.54	$136.36	$175.18	$290.28	$405.39	$520.49
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$149.28	$188.09	$265.71	$343.34	$420.96
	Var. ($)	Proposed - Existing	-$2.59	-$3.88	-$5.17	-$6.47	-$7.76	-$9.70	-$12.93	-$12.92	-$12.91	$24.57	$62.05	$99.53
	Var. (%)	Proposed/Existing	-7.53%	-8.84%	-9.69%	-10.28%	-10.72%	-11.19%	-11.71%	-8.65%	-6.86%	9.25%	18.07%	23.64%
Old Crow		Proposed Bill	$31.75	$39.97	$48.20	$56.42	$64.64	$76.98	$97.54	$136.36	$175.18	$430.49	$685.80	$941.10
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$192.40	$274.32	$438.18	$602.03	$765.89
	Var. ($)	Proposed - Existing	-$2.59	-$3.88	-$5.17	-$6.47	-$7.76	-$9.70	-$12.93	-$56.04	-$99.14	-$7.69	$83.76	$175.21
	Var. (%)	Proposed/Existing	-7.53%	-8.84%	-9.69%	-10.28%	-10.72%	-11.19%	-11.71%	-29.13%	-36.14%	-1.75%	13.91%	22.88%

	0-200	200-300	300-400	400-500	500-600	600-800	800-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
Cumulative percentage of customers	13.8%	19.2%	25.2%	32.2%	40.2%	56.4%	70.1%	84.3%	89.7%	96.1%	98.3%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$11.90	$11.90	$11.90	$11.90
1st. Block Energy (0-1000)	$0.0986	$0.0986	$0.0986	$0.0986
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%
Yukon Interim Electrical Rebate (1st block)	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$14.65	$14.65	$14.65	$14.65
1st. Block Energy (0-1000)	$0.1090	$0.1090	$0.1090	$0.1090
2nd. Block Energy (1001-1500)	$0.1522	$0.1522	$0.1522	$0.1522
3d. Block Energy (1500+)	$0.2239	$0.2239	$0.2239	$0.4923
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Yukon Interim Electrical Rebate (1st l	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table A4.5
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**-0.50%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - NON GOVERNMENT - Option A (assumes IER terminates)**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro		Proposed Bill	$37.34	$48.35	$59.37	$70.38	$81.40	$97.92	$125.46	$164.29	$203.11	$318.21	$433.30	$548.40
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	$3.00	$4.50	$6.00	$7.50	$9.00	$11.25	$15.00	$21.15	$27.30	$77.06	$126.82	$176.57
	Var. (%)	Var. ($)/Existing	8.74%	10.26%	11.24%	11.92%	12.43%	12.98%	13.57%	14.77%	15.53%	31.95%	41.38%	47.49%
Large Diesel		Proposed Bill	$37.34	$48.35	$59.37	$70.38	$81.40	$97.92	$125.46	$164.29	$203.11	$318.21	$433.30	$548.40
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	$3.00	$4.50	$6.00	$7.50	$9.00	$11.25	$15.00	$21.15	$27.30	$77.06	$126.82	$176.57
	Var. (%)	Proposed/Existing	8.74%	10.26%	11.24%	11.92%	12.43%	12.98%	13.57%	14.77%	15.53%	31.95%	41.38%	47.49%
Small Diesel		Proposed Bill	$37.34	$48.35	$59.37	$70.38	$81.40	$97.92	$125.46	$164.29	$203.11	$318.21	$433.30	$548.40
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$149.28	$188.09	$265.71	$343.34	$420.96
	Var. ($)	Proposed - Existing	$3.00	$4.50	$6.00	$7.50	$9.00	$11.25	$15.00	$15.01	$15.02	$52.49	$89.97	$127.44
	Var. (%)	Proposed/Existing	8.74%	10.26%	11.24%	11.92%	12.43%	12.98%	13.57%	10.05%	7.98%	19.76%	26.20%	30.27%
Old Crow		Proposed Bill	$37.34	$48.35	$59.37	$70.38	$81.40	$97.92	$125.46	$164.29	$203.11	$458.41	$713.71	$969.01
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$192.40	$274.32	$438.18	$602.03	$765.89
	Var. ($)	Proposed - Existing	$3.00	$4.50	$6.00	$7.50	$9.00	$11.25	$15.00	-$28.11	-$71.22	$20.23	$111.67	$203.12
	Var. (%)	Proposed/Existing	8.74%	10.26%	11.24%	11.92%	12.43%	12.98%	13.57%	-14.61%	-25.96%	4.62%	18.55%	26.52%

	0-200	200-300	300-400	400-500	500-600	600-800	800-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
Cumulative percentage of customers	13.8%	19.2%	25.2%	32.2%	40.2%	56.4%	70.1%	84.3%	89.7%	96.1%	98.3%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$11.90	$11.90	$11.90	$11.90
1st. Block Energy (0-1000)	$0.0986	$0.0986	$0.0986	$0.0986
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%
Yukon Interim Electrical Rebate (1st	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$14.65	$14.65	$14.65	$14.65
1st. Block Energy (0-1000)	$0.1090	$0.1090	$0.1090	$0.1090
2nd. Block Energy (1001-1500)	$0.1522	$0.1522	$0.1522	$0.1522
3d. Block Energy (1500+)	$0.2239	$0.2239	$0.2239	$0.4923
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Yukon Interim Electrical Rebate (1st b	$0.0000	$0.0000	$0.0000	$0.0000

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table A4.6
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**0.00%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - GOVERNMENT - Option A**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro		Proposed Bill	$52.61	$69.21	$85.82	$102.43	$119.03	$143.94	$185.46	$224.48	$263.51	$379.20	$494.89	$610.58
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$233.64	$266.45	$332.06	$397.68	$463.29
	Var. ($)	Proposed - Existing	-$3.06	-$4.60	-$6.13	-$7.67	-$9.21	-$11.52	-$15.37	-$9.16	-$2.94	$47.13	$97.21	$147.28
	Var. (%)	Var. ($)/Existing	-5.49%	-6.23%	-6.67%	-6.97%	-7.18%	-7.41%	-7.65%	-3.92%	-1.10%	14.19%	24.44%	31.79%
Large Diesel		Proposed Bill	$52.61	$69.21	$85.82	$102.43	$119.03	$143.94	$185.46	$224.48	$263.51	$379.20	$494.89	$610.58
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$233.64	$266.45	$332.06	$397.68	$463.29
	Var. ($)	Proposed - Existing	-$3.06	-$4.60	-$6.13	-$7.67	-$9.21	-$11.52	-$15.37	-$9.16	-$2.94	$47.13	$97.21	$147.28
	Var. (%)	Proposed/Existing	-5.49%	-6.23%	-6.67%	-6.97%	-7.18%	-7.41%	-7.65%	-3.92%	-1.10%	14.19%	24.44%	31.79%
Small Diesel		Proposed Bill	$52.61	$69.21	$85.82	$102.43	$119.03	$143.94	$185.46	$224.48	$263.51	$379.20	$494.89	$610.58
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$239.81	$278.78	$356.73	$434.67	$512.62
	Var. ($)	Proposed - Existing	-$3.06	-$4.60	-$6.13	-$7.67	-$9.21	-$11.52	-$15.37	-$15.32	-$15.27	$22.47	$60.21	$97.95
	Var. (%)	Proposed/Existing	-5.49%	-6.23%	-6.67%	-6.97%	-7.18%	-7.41%	-7.65%	-6.39%	-5.48%	6.30%	13.85%	19.11%
Old Crow		Proposed Bill	$52.61	$69.21	$85.82	$102.43	$119.03	$143.94	$185.46	$224.48	$263.51	$520.11	$776.71	$1,033.31
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$283.10	$365.37	$529.90	$694.43	$858.96
	Var. ($)	Proposed - Existing	-$3.06	-$4.60	-$6.13	-$7.67	-$9.21	-$11.52	-$15.37	-$58.61	-$101.86	-$9.79	$82.28	$174.34
	Var. (%)	Proposed/Existing	-5.49%	-6.23%	-6.67%	-6.97%	-7.18%	-7.41%	-7.65%	-20.70%	-27.88%	-1.85%	11.85%	20.30%

0-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
78.5%	87.6%	91.2%	95.8%	98.1%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$15.00	$15.00	$15.00	$15.00
1st. Block Energy (0-1000)	$0.1434	$0.1434	$0.1434	$0.1434
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$18.47	$18.47	$18.47	$18.47
1st. Block Energy (0-1000)	$0.1617	$0.1617	$0.1617	$0.1617
2nd. Block Energy (1001-1500)	$0.1522	$0.1522	$0.1522	$0.1522
3d. Block Energy (1500+)	$0.2239	$0.2239	$0.2239	$0.4923
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table A4.7
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate -0.50%
GST 5.00%

CUSTOMER CLASS: **GENERAL SERVICE - NON GOVERNMENT - Option A**

Zone		Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 700	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000	Monthly Consump. (kW.h) 3500	Monthly Consump. (kW.h) 4000	Monthly Consump. (kW.h) 5000	Monthly Consump. (kW.h) 6000	Monthly Consump. (kW.h) 7500	Monthly Consump. (kW.h) 10000	Monthly Consump. (kW.h) 15000	Monthly Consump. (kW.h) 20000	Monthly Consump. (kW.h) 40000	Monthly Consump. (kW.h) 100000
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00	27.00	41.00	55.00	110.00	274.00
Hydro	Proposed Bill	$64.58	$89.51	$114.44	$156.00	$197.55	$286.06	$368.30	$456.81	$539.06	$709.81	$874.30	$1,133.57	$1,551.06	$2,398.57	$3,637.34	$6,594.87	$15,461.17
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$325.67	$398.73	$479.50	$552.56	$706.39	$852.51	$1,087.11	$1,460.11	$2,221.55	$2,982.98	$6,021.01	$15,127.38
Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$39.61	-$30.43	-$22.69	-$13.50	$3.42	$21.80	$46.46	$90.95	$177.02	$654.36	$573.85	$333.79
Var. (%)	Var. ($)/Existing	-19.12%	-19.21%	-19.26%	-19.31%	-19.34%	-12.16%	-7.63%	-4.73%	-2.44%	0.48%	2.56%	4.27%	6.23%	7.97%	21.94%	9.53%	2.21%
Large Diesel	Proposed Bill	$64.58	$89.51	$114.44	$156.00	$197.55	$286.06	$368.30	$456.81	$539.06	$709.81	$874.30	$1,133.57	$1,551.06	$2,398.57	$3,637.34	$6,594.87	$15,461.17
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$325.67	$398.73	$479.50	$552.56	$706.39	$852.51	$1,087.11	$1,460.11	$2,221.55	$2,982.98	$6,021.01	$15,127.38
Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$39.61	-$30.43	-$22.69	-$13.50	$3.42	$21.80	$46.46	$90.95	$177.02	$654.36	$573.85	$333.79
Var. (%)	Proposed/Existing	-19.12%	-19.21%	-19.26%	-19.31%	-19.34%	-12.16%	-7.63%	-4.73%	-2.44%	0.48%	2.56%	4.27%	6.23%	7.97%	21.94%	9.53%	2.21%
Small Diesel	Proposed Bill	$64.58	$89.51	$114.44	$156.00	$197.55	$286.06	$368.30	$456.81	$539.06	$709.81	$874.30	$1,133.57	$1,551.06	$2,398.57	$3,637.34	$7,087.99	$17,433.66
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$337.96	$423.29	$516.35	$601.69	$780.08	$950.76	$1,222.21	$1,656.63	$2,540.89	$3,425.15	$6,954.47	$17,534.71
Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$51.90	-$54.99	-$59.54	-$62.63	-$70.27	-$76.46	-$88.64	-$105.57	-$142.32	$212.20	$133.52	-$101.05
Var. (%)	Proposed/Existing	-19.12%	-19.21%	-19.26%	-19.31%	-19.34%	-15.36%	-12.99%	-11.53%	-10.41%	-9.01%	-8.04%	-7.25%	-6.37%	-5.60%	6.20%	1.92%	-0.58%
Old Crow	Proposed Bill	$64.58	$89.51	$114.44	$156.00	$197.55	$286.06	$368.30	$456.81	$539.06	$709.81	$874.30	$1,133.57	$1,551.06	$2,398.57	$3,637.34	$10,535.66	$31,224.36
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$424.19	$595.76	$775.05	$946.62	$1,297.48	$1,640.63	$2,170.78	$3,036.36	$4,782.95	$6,529.54	$13,508.19	$34,436.42
Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$138.13	-$227.46	-$318.24	-$407.56	-$587.67	-$766.33	-$1,037.21	-$1,485.30	-$2,384.38	-$2,892.20	-$2,972.53	-$3,212.06
Var. (%)	Proposed/Existing	-19.12%	-19.21%	-19.26%	-19.31%	-19.34%	-32.56%	-38.18%	-41.06%	-43.05%	-45.29%	-46.71%	-47.78%	-48.92%	-49.85%	-44.29%	-22.01%	-9.33%
		0-400	400-700	700-1000	1000-1500	1500-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers		28.5%	39.2%	47.8%	58.7%	66.6%	72.3%	76.5%		86.0%			94.0%		96.5%	97.7%	99.1%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2001-15000)	$0.1490	$0.1490	$0.1490	$0.1490
3d. Block Energy (15001-20000)	$0.2239	$0.2239	$0.2239	$0.2239
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table A4.8
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**0.00%**
GST	**5.00%**

CUSTOMER CLASS: **GENERAL SERVICE - MUNICIPAL GOVERNMENT - Option A**

Zone			Monthly Consump. (kW.h) 400 5.00	Monthly Consump. (kW.h) 700 5.00	Monthly Consump. (kW.h) 1000 5.00	Monthly Consump. (kW.h) 1500 5.00	Monthly Consump. (kW.h) 2000 5.00	Monthly Consump. (kW.h) 2500 7.00	Monthly Consump. (kW.h) 3000 8.00	Monthly Consump. (kW.h) 3500 10.00	Monthly Consump. (kW.h) 4000 11.00	Monthly Consump. (kW.h) 5000 14.00	Monthly Consump. (kW.h) 6000 16.00	Monthly Consump. (kW.h) 7500 21.00	Monthly Consump. (kW.h) 10000 27.00	Monthly Consump. (kW.h) 15000 41.00	Monthly Consump. (kW.h) 20000 55.00	Monthly Consump. (kW.h) 40000 110.00	Monthly Consump. (kW.h) 100000 274.00
Hydro		Proposed Bill	$64.92	$89.98	$115.04	$156.81	$198.58	$287.54	$370.21	$459.18	$541.84	$713.48	$878.81	$1,139.41	$1,559.04	$2,410.91	$3,656.00	$6,628.76	$15,540.74
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$327.04	$400.40	$481.51	$554.88	$709.35	$856.08	$1,091.66	$1,466.22	$2,230.84	$2,995.46	$6,046.20	$15,190.65
	Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$39.50	-$30.19	-$22.34	-$13.03	$4.12	$22.73	$47.75	$92.82	$180.06	$660.53	$582.56	$350.08
	Var. (%)	Var. ($)/Existing	-19.04%	-19.13%	-19.18%	-19.23%	-19.25%	-12.08%	-7.54%	-4.64%	-2.35%	0.58%	2.66%	4.37%	6.33%	8.07%	22.05%	9.64%	2.30%
Large Diesel		Proposed Bill	$64.92	$89.98	$115.04	$156.81	$198.58	$287.54	$370.21	$459.18	$541.84	$713.48	$878.81	$1,139.41	$1,559.04	$2,410.91	$3,656.00	$6,628.76	$15,540.74
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$327.04	$400.40	$481.51	$554.88	$709.35	$856.08	$1,091.66	$1,466.22	$2,230.84	$2,995.46	$6,046.20	$15,190.65
	Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$39.50	-$30.19	-$22.34	-$13.03	$4.12	$22.73	$47.75	$92.82	$180.06	$660.53	$582.56	$350.08
	Var. (%)	Proposed/Existing	-19.04%	-19.13%	-19.18%	-19.23%	-19.25%	-12.08%	-7.54%	-4.64%	-2.35%	0.58%	2.66%	4.37%	6.33%	8.07%	22.05%	9.64%	2.30%
Small Diesel		Proposed Bill	$64.92	$89.98	$115.04	$156.81	$198.58	$287.54	$370.21	$459.18	$541.84	$713.48	$878.81	$1,139.41	$1,559.04	$2,410.91	$3,656.00	$7,124.36	$17,523.14
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$339.37	$425.07	$518.51	$604.21	$783.35	$954.74	$1,227.32	$1,663.54	$2,551.49	$3,439.43	$6,983.46	$17,607.81
	Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$51.83	-$54.86	-$59.34	-$62.36	-$69.87	-$75.93	-$87.91	-$104.50	-$140.58	$216.56	$140.89	-$84.67
	Var. (%)	Proposed/Existing	-19.04%	-19.13%	-19.18%	-19.23%	-19.25%	-15.27%	-12.91%	-11.44%	-10.32%	-8.92%	-7.95%	-7.16%	-6.28%	-5.51%	6.30%	2.02%	-0.48%
Old Crow		Proposed Bill	$64.92	$89.98	$115.04	$156.81	$198.58	$287.54	$370.21	$459.18	$541.84	$713.48	$878.81	$1,139.41	$1,559.04	$2,410.91	$3,656.00	$10,589.36	$31,383.14
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$425.96	$598.24	$778.27	$950.55	$1,302.86	$1,647.42	$2,179.76	$3,048.91	$4,802.70	$6,556.50	$13,563.94	$34,578.51
	Var. ($)	Proposed - Existing	-$15.26	-$21.28	-$27.30	-$37.33	-$47.35	-$138.42	-$228.03	-$319.09	-$408.71	-$589.38	-$768.61	-$1,040.35	-$1,489.87	-$2,391.80	-$2,900.50	-$2,974.58	-$3,195.38
	Var. (%)	Proposed/Existing	-19.04%	-19.13%	-19.18%	-19.23%	-19.25%	-32.50%	-38.12%	-41.00%	-43.00%	-45.24%	-46.66%	-47.73%	-48.87%	-49.80%	-44.24%	-21.93%	-9.24%
							0-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers							66.5%	69.8%	72.0%		81.4%			88.7%		91.8%	93.4%	97.6%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2001-15000)	$0.1490	$0.1490	$0.1490	$0.1490
3d. Block Energy (15001-20000)	$0.2239	$0.2239	$0.2239	$0.2239
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table A4.9
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**0.00%**
GST	**5.00%**

CUSTOMER CLASS: **GENERAL SERVICE - FED/TERR GOVERNMENT - Option A**

Zone			Monthly Consump. (kW.h) 400 5.00	Monthly Consump. (kW.h) 700 5.00	Monthly Consump. (kW.h) 1000 5.00	Monthly Consump. (kW.h) 1500 5.00	Monthly Consump. (kW.h) 2000 5.00	Monthly Consump. (kW.h) 2500 7.00	Monthly Consump. (kW.h) 3000 8.00	Monthly Consump. (kW.h) 3500 10.00	Monthly Consump. (kW.h) 4000 11.00	Monthly Consump. (kW.h) 5000 14.00	Monthly Consump. (kW.h) 6000 16.00	Monthly Consump. (kW.h) 7500 21.00	Monthly Consump. (kW.h) 10000 27.00	Monthly Consump. (kW.h) 15000 41.00	Monthly Consump. (kW.h) 20000 55.00	Monthly Consump. (kW.h) 40000 110.00	Monthly Consump. (kW.h) 100000 274.00
Hydro		Proposed Bill	$130.02	$188.15	$246.29	$343.18	$440.08	$537.44	$624.31	$721.68	$808.54	$992.78	$1,166.51	$1,448.11	$1,892.94	$2,803.61	$4,107.50	$7,311.26	$16,912.04
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$599.26	$677.79	$769.23	$847.76	$1,017.73	$1,174.78	$1,436.19	$1,841.75	$2,678.68	$3,515.62	$6,850.45	$16,842.04
	Var. ($)	Proposed - Existing	-$23.20	-$31.55	-$39.90	-$53.82	-$67.74	-$61.82	-$53.48	-$47.55	-$39.21	-$24.95	-$8.27	$11.91	$51.19	$124.92	$591.87	$460.80	$70.00
	Var. (%)	Var. ($)/Existing	-15.14%	-14.36%	-13.94%	-13.56%	-13.34%	-10.32%	-7.89%	-6.18%	-4.63%	-2.45%	-0.70%	0.83%	2.78%	4.66%	16.84%	6.73%	0.42%
Large Diesel		Proposed Bill	$130.02	$188.15	$246.29	$343.18	$440.08	$537.44	$624.31	$721.68	$808.54	$992.78	$1,166.51	$1,448.11	$1,892.94	$2,803.61	$4,107.50	$7,311.26	$16,912.04
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$599.26	$677.79	$769.23	$847.76	$1,017.73	$1,174.78	$1,436.19	$1,841.75	$2,678.68	$3,515.62	$6,850.45	$16,842.04
	Var. ($)	Proposed - Existing	-$23.20	-$31.55	-$39.90	-$53.82	-$67.74	-$61.82	-$53.48	-$47.55	-$39.21	-$24.95	-$8.27	$11.91	$51.19	$124.92	$591.87	$460.80	$70.00
	Var. (%)	Proposed/Existing	-15.14%	-14.36%	-13.94%	-13.56%	-13.34%	-10.32%	-7.89%	-6.18%	-4.63%	-2.45%	-0.70%	0.83%	2.78%	4.66%	16.84%	6.73%	0.42%
Small Diesel		Proposed Bill	$130.02	$188.15	$246.29	$343.18	$440.08	$537.44	$624.31	$721.68	$808.54	$992.78	$1,166.51	$1,448.11	$1,892.94	$2,803.61	$4,107.50	$7,806.86	$18,894.44
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$611.59	$702.45	$806.22	$897.09	$1,091.72	$1,273.44	$1,571.85	$2,039.07	$2,999.33	$3,959.59	$7,787.72	$19,259.19
	Var. ($)	Proposed - Existing	-$23.20	-$31.55	-$39.90	-$53.82	-$67.74	-$74.15	-$78.14	-$84.55	-$88.54	-$98.95	-$106.93	-$123.74	-$146.13	-$195.72	$147.91	$19.14	-$364.76
	Var. (%)	Proposed/Existing	-15.14%	-14.36%	-13.94%	-13.56%	-13.34%	-12.12%	-11.12%	-10.49%	-9.87%	-9.06%	-8.40%	-7.87%	-7.17%	-6.53%	3.74%	0.25%	-1.89%
Old Crow		Proposed Bill	$130.02	$188.15	$246.29	$343.18	$440.08	$537.44	$624.31	$721.68	$808.54	$992.78	$1,166.51	$1,448.11	$1,892.94	$2,803.61	$4,107.50	$11,271.86	$32,754.44
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$698.18	$875.62	$1,065.98	$1,243.43	$1,611.23	$1,966.12	$2,524.29	$3,424.43	$5,250.54	$7,076.66	$14,368.19	$36,229.89
	Var. ($)	Proposed - Existing	-$23.20	-$31.55	-$39.90	-$53.82	-$67.74	-$160.73	-$251.31	-$344.30	-$434.88	-$618.46	-$799.62	-$1,076.18	-$1,531.49	-$2,446.94	-$2,969.16	-$3,096.34	-$3,475.46
	Var. (%)	Proposed/Existing	-15.14%	-14.36%	-13.94%	-13.56%	-13.34%	-23.02%	-28.70%	-32.30%	-34.97%	-38.38%	-40.67%	-42.63%	-44.72%	-46.60%	-41.96%	-21.55%	-9.59%
							0-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers							63.3%	67.5%	70.7%		78.4%			87.0%		90.4%	92.5%	96.6%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$10.00	$10.00	$10.00	$10.00
1st. Block Energy (0-2000)	$0.1745	$0.1745	$0.1745	$0.1745
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$10.00	$10.00	$10.00	$10.00
1st. Block Energy (0-2000)	$0.1881	$0.1881	$0.1881	$0.1881
2nd. Block Energy (2001-15000)	$0.1490	$0.1490	$0.1490	$0.1490
3d. Block Energy (15001-20000)	$0.2239	$0.2239	$0.2239	$0.2239
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

APPENDIX 4.1B YEC

RESIDENTIAL AND GENERAL SERVICE RATES AND BILLS UNDER OPTION B

Table B4.1
3/1/2010

Comparison of Existing and Proposed Rates - Option B

Summary of Existing 2009 Price Schedule Charges

Residential	Customer	Demand	Energy 1	At 1000 kWh Energy 2
1160	11.90 $/month		0.0986 $/kW.h	0.1045 $/kW.h
1260	11.90 $/month		0.0986 $/kW.h	0.1236 $/kW.h
1360	11.90 $/month		0.0986 $/kW.h	0.1045 $/kW.h
1460	11.90 $/month		0.0986 $/kW.h	0.2577 $/kW.h
1180	15.00 $/month		0.1434 $/kW.h	0.1045 $/kW.h
1280	15.00 $/month		0.1434 $/kW.h	0.1236 $/kW.h
1380	15.00 $/month		0.1434 $/kW.h	0.1045 $/kW.h
1480	15.00 $/month		0.1434 $/kW.h	0.2577 $/kW.h

General Service	Customer	Demand	Energy 1	At 2000 kWh Energy 2
2160		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2260		$6.00 /kW	0.0831 $/kW.h	0.1236 $/kW.h
2360		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2460		$6.00 /kW	0.0831 $/kW.h	0.2577 $/kW.h
2170		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2270		$6.00 /kW	0.0831 $/kW.h	0.1236 $/kW.h
2370		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2470		$6.00 /kW	0.0831 $/kW.h	0.2577 $/kW.h
2180		$10.00 /kW	0.1745 $/kW.h	0.1045 $/kW.h
2280		$10.00 /kW	0.1745 $/kW.h	0.1236 $/kW.h
2380		$10.00 /kW	0.1745 $/kW.h	0.1045 $/kW.h
2480		$10.00 /kW	0.1745 $/kW.h	0.2577 $/kW.h

Secondary Energy	Customer	Demand	Energy
3200			0.07200 $/kW.h

Industrial	Customer	Demand	Energy
3900		$15.00 /kW	0.07600 $/kW.h

Street Lights	Customer	Demand	Energy	High Mast Charge
61/66	6.36 $/month	$4.0300 /kW		1.03 $/month
67 - 250 W	15.47 $/month			
67 - 400 W	23.66 $/month			

Sentinel Lights	Customer	Demand	Energy	Energy 2
75/76 - Normal - 100 W	11.64 $/month			
75/76 - E & M - 100 W	6.46 $/month			
75/76 - Meter - 100 W	7.34 $/month			
75/76 - Normal - 175 W	14.18 $/month			
75/76 - E & M - 175 W	9.87 $/month			
75/76 - Meter - 175 W	7.97 $/month			
75/76 - Normal - 250 W	17.34 $/month			
75/76 - E & M - 250 W	13.16 $/month			
75/76 - Meter - 250 W	8.23 $/month			
75/76 - Normal - 400 W	23.03 $/month			
75/76 - E & M - 400 W	18.61 $/month			
75/76 - Meter - 400 W	7.84 $/month			
75/76 - Normal - 400 W Fl	25.44 $/month			
75/76 - E & M - 400 W FL	17.75 $/month			
75/76 - Meter - 400 W FL	10.26 $/month			

Summary of Proposed 2009 Price Schedule Charges

Residential	Customer	Demand	Energy 1	At 1000 kWh Energy 2	At 2500 kWh Energy 3
1160	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1260	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1360	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1460	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.3077 $/kW.h
1180	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1280	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1380	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1480	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.3077 $/kW.h

General Service	Customer	Demand	Energy 1	At 2000 kWh Energy 2	At 15000 kWh Energy 3	At 20000 kWh Energy 3A
2160		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2260		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1522 $/kW.h
2360		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2460		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.3172 $/kW.h
2170		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2270		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1522 $/kW.h
2370		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2470		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.3172 $/kW.h
2180		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2280		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.1522 $/kW.h
2380		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2480		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.3172 $/kW.h

Secondary Energy	Customer	Demand	Energy
3200			0.0720 $/kW.h

Industrial	Customer	Demand	Energy	Fixed Rider F
3900		$15.00 /kW	0.07600 $/kW.h	0.00211 $/kW.h

Street Lights	Customer	Demand	Energy	High Mast Charge
61/66	7.83 $/month	$4.9616 /kW		1.27 $/month
67 - 250 W	19.05 $/month			
67 - 400 W	29.13 $/month			

Sentinel Lights	Customer	Demand	Energy	Energy 2
75/76 - Normal - 100 W	14.33 $/month			
75/76 - E & M - 100 W	7.95 $/month			
75/76 - Meter - 100 W	9.04 $/month			
75/76 - Normal - 175 W	17.46 $/month			
75/76 - E & M - 175 W	12.15 $/month			
75/76 - Meter - 175 W	9.81 $/month			
75/76 - Normal - 250 W	21.35 $/month			
75/76 - E & M - 250 W	16.20 $/month			
75/76 - Meter - 250 W	10.13 $/month			
75/76 - Normal - 400 W	28.35 $/month			
75/76 - E & M - 400 W	22.91 $/month			
75/76 - Meter - 400 W	9.65 $/month			
75/76 - Normal - 400 W Fl	31.32 $/month			
75/76 - E & M - 400 W FL	21.85 $/month			
75/76 - Meter - 400 W FL	12.63 $/month			

Table B4.2
3/1/2010

Residential Effective Rate including all Riders, Rebates, and Subsidies - Option B

		Proposed							**Existing**					
		Residential Non-Government							Residential Non-Government					
		Customer Charge	First Block Energy 0-1000	Second Block Energy 1001-2500	Runoff Energy > 2500 kW.h				Customer Charge	First Block Energy 0-1000	Runoff Energy >1000 kW.h			
		all zones $/month	all zones $/kW.h	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h	all zones $/month	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h
Base Rate (1997 GRA)		$14.65	$0.1214	$0.1282	$0.1399	$0.1399	$0.1399	$0.3077	$11.90	$0.0986	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%								$1.48	$0.0123	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%								$1.25	$0.0104	$0.0110	$0.0110	$0.0130	$0.0271
Effective rate before Tax rebate, IER and GST		$14.65	$0.1179	$0.1247	$0.1364	$0.1364	$0.1364	$0.3042	$14.64	$0.1177	*$0.1250*	$0.1250	$0.1485	$0.3134
Income Tax Rebate (%)	-0.50%	-$0.07	-$0.0006	-$0.0006	-$0.0007	-$0.0007	-$0.0007	-$0.0015	-$0.06	-$0.0005	-$0.0005	-$0.0005	-$0.0006	-$0.0013
IER (1st block kW.h)	-$0.026621		-$0.0266							-$0.0266				
Total before GST		$14.58	$0.0906	$0.1240	$0.1357	$0.1357	$0.1357	$0.3026	$14.58	$0.0906	$0.1245	$0.1245	$0.1479	$0.3121
Change		*$0.00*	*$0.0000*	*n/a*	*$0.0112*	*$0.0112*	*-$0.0122*	*-$0.0095*						
		0.00%	*0.02%*		*9.00%*	*9.00%*	*-8.25%*	*-3.04%*						

		Proposed							**Existing**					
		Residential Government							Residential Government					
		Customer Charge	First Block Energy 0-1000	Second Block Energy 1001-2500	Runoff Energy > 2500 kW.h				Customer Charge	First Block Energy 0-1000	Runoff Energy >1000 kW.h			
		all zones $/month	all zones $/kW.h	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h	all zones $/month	all zones $/kW.h	Hydro $/kW.h	Lg Diesel $/kW.h	Sm Diesel $/kW.h	Old Crow $/kW.h
Base Rate		$18.47	$0.1792	$0.1282	$0.1399	$0.1399	$0.1399	$0.3077	$15.00	$0.1434	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.46%								$1.87	$0.0179	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.53%								$1.58	$0.0151	$0.0110	$0.0110	$0.0130	$0.0271
Total before GST		$18.47	$0.1757	$0.1247	$0.1364	$0.1364	$0.1364	$0.3042	$18.45	$0.1728	$0.1250	$0.1250	$0.1485	$0.3134
Change		*$0.02*	*$0.0028*	*n/a*	*$0.0114*	*$0.0114*	*-$0.0121*	*-$0.0092*						
		0.12%	*1.64%*		*9.11%*	*9.11%*	*-8.16%*	*-2.95%*						

Table B4.3
3/1/2010

General Service Effective Rate including all Riders, Rebates, and Subsidies - Option B

		Proposed								Existing					
		GS Non-Government								GS Non-Government					
		Demand Charge	First Block Energy 0-2000	Second Block Energy 2001-15000	Third Block Energy 15001-20000	Runoff Energy (>20,000 kW.h)				Demand Charge	First Block Energy	Runoff Energy (>2,000 kW.h)			
		all zones	all zones	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		$/kW	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/month	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h
Base Rate		$7.39	$0.1023	$0.1288	$0.1399	$0.1286	$0.1286	$0.1522	$0.3172	$6.00	$0.0831	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%									$0.75	$0.0104	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%									$0.63	$0.0087	$0.0110	$0.0110	$0.0130	$0.0271
Effective rate before Tax rebate		$7.39	$0.0988	$0.1253	$0.1364	$0.1251	$0.1251	$0.1487	$0.3137	$7.38	$0.0987	$0.1250	$0.1250	$0.1485	$0.3134
Income Tax Rebate (%)	-0.50%	-$0.04	-$0.0005	-$0.0006	-$0.0007	-$0.0006	-$0.0006	-$0.0008	-$0.0016	-$0.03	-$0.0004	-$0.0005	-$0.0005	-$0.0006	-$0.0013
Total before GST		$7.35	$0.0982	$0.1246	$0.1357	$0.1244	$0.1244	$0.1479	$0.3121	$7.35	$0.0982	$0.1245	$0.1245	$0.1479	$0.3121
Change		*$0.00*	*$0.0000*	*n/a*	*n/a*	*-$0.0001*	*-$0.0001*	*$0.0000*	*$0.0000*						
		0.05%	*0.00%*			*-0.08%*	*-0.08%*	*0.00%*	*0.00%*						

		Proposed								Existing					
		GS Municipal Government								GS Municipal Government					
		Demand Charge	First Block Energy 0-2000	Second Block Energy 2001-15000	Third Block Energy 15001-20000	Runoff Energy (>20,000 kW.h)				Demand Charge	First Block Energy 0-2000	Runoff Energy (>2,000 kW.h)			
		all zones	all zones	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		$/kW	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/month	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h
Base Rate		$7.39	$0.1023	$0.1288	$0.1399	$0.1286	$0.1286	$0.1522	$0.3172	$6.00	$0.0831	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%									$0.75	$0.0104	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%									$0.63	$0.0087	$0.0110	$0.0110	$0.0130	$0.0271
Total before GST		$7.39	$0.0988	$0.1253	$0.1364	$0.1251	$0.1251	$0.1487	$0.3137	$7.38	$0.0987	$0.1250	$0.1250	$0.1485	$0.3134
Change		*$0.01*	*$0.0001*	*n/a*	*n/a*	*$0.0001*	*$0.0001*	*$0.0002*	*$0.0003*						
		0.15%	*0.10%*			*0.08%*	*0.08%*	*0.13%*	*0.10%*						

		Proposed								Existing					
		GS Government								GS Government					
		Demand Charge	First Block Energy 0-2000	Second Block Energy 2001-15000	Third Block Energy 15001-20000	Runoff Energy (>20,000 kW.h)				Demand Charge	First Block Energy 0-2000	Runoff Energy (>2,000 kW.h)			
		all zones	all zones	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow	all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		$/kW	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/month	$/kW.h	$/kW.h	$/kW.h	$/kW.h	$/kW.h
Base Rate		$12.31	$0.2148	$0.1297	$0.1399	$0.1286	$0.1286	$0.1522	$0.3172	$10.00	$0.1745	$0.1045	$0.1045	$0.1236	$0.2577
Rider F (kW.h)	-$0.00354		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035		-$0.0035	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider J (%)	12.460%									$1.25	$0.0217	$0.0130	$0.0130	$0.0154	$0.0321
Rider R (%)	10.526%									$1.05	$0.0184	$0.0110	$0.0110	$0.0130	$0.0271
Total before GST		$12.31	$0.2113	$0.1262	$0.1364	$0.1251	$0.1251	$0.1487	$0.3137	$12.30	$0.2111	$0.1250	$0.1250	$0.1485	$0.3134
Change		*$0.01*	*$0.0002*	*n/a*	*n/a*	*$0.0001*	*$0.0001*	*$0.0002*	*$0.0003*						
		0.09%	*0.09%*			*0.08%*	*0.08%*	*0.13%*	*0.10%*						

Table B4.4
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**-0.50%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - NON GOVERNMENT - Option B (with IER)**

Zone		Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro	Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$377.04
	Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$0.09	-$0.21	-$0.44	-$0.67	$5.21
Var. (%)	Var. ($)/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-0.06%	-0.12%	-0.18%	-0.22%	1.40%
Large Diesel	Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$377.04
	Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$0.09	-$0.21	-$0.44	-$0.67	$5.21
Var. (%)	Proposed/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-0.06%	-0.12%	-0.18%	-0.22%	1.40%
Small Diesel	Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$377.04
	Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$149.28	$188.09	$265.71	$343.34	$420.96
Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$6.23	-$12.49	-$25.00	-$37.51	-$43.92
Var. (%)	Proposed/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-4.18%	-6.64%	-9.41%	-10.93%	-10.43%
Old Crow	Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$464.70
	Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$192.40	$274.32	$438.18	$602.03	$765.89
Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$49.35	-$98.72	-$197.47	-$296.21	-$301.19
Var. (%)	Proposed/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-25.65%	-35.99%	-45.07%	-49.20%	-39.33%

	0-200	200-300	300-400	400-500	500-600	600-800	800-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
Cumulative percentage of customers	13.8%	19.2%	25.2%	32.2%	40.2%	56.4%	70.1%	84.3%	89.7%	96.1%	98.3%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$11.90	$11.90	$11.90	$11.90
1st. Block Energy (0-1000)	$0.0986	$0.0986	$0.0986	$0.0986
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%
Yukon Interim Electrical Rebate (1st block)	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$14.65	$14.65	$14.65	$14.65
1st. Block Energy (0-1000)	$0.1214	$0.1214	$0.1214	$0.1214
2nd. Block Energy (1001-2500)	$0.1282	$0.1282	$0.1282	$0.1282
3d. Block Energy (2500+)	$0.1399	$0.1399	$0.1399	$0.3077
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Yukon Interim Electrical Rebate (1st I	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table B4.5
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**-0.50%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - NON GOVERNMENT - Option B (assumes IER terminates)**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro		Proposed Bill	$39.93	$52.24	$64.55	$76.86	$89.17	$107.64	$138.42	$170.97	$203.53	$274.75	$345.97	$417.19
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	$5.59	$8.39	$11.18	$13.98	$16.77	$20.96	$27.95	$27.83	$27.72	$33.60	$39.48	$45.36
	Var. (%)	Var. ($)/Existing	16.28%	19.12%	20.95%	22.22%	23.16%	24.19%	25.30%	19.45%	15.77%	13.93%	12.88%	12.20%
Large Diesel		Proposed Bill	$39.93	$52.24	$64.55	$76.86	$89.17	$107.64	$138.42	$170.97	$203.53	$274.75	$345.97	$417.19
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	$5.59	$8.39	$11.18	$13.98	$16.77	$20.96	$27.95	$27.83	$27.72	$33.60	$39.48	$45.36
	Var. (%)	Proposed/Existing	16.28%	19.12%	20.95%	22.22%	23.16%	24.19%	25.30%	19.45%	15.77%	13.93%	12.88%	12.20%
Small Diesel		Proposed Bill	$39.93	$52.24	$64.55	$76.86	$89.17	$107.64	$138.42	$170.97	$203.53	$274.75	$345.97	$417.19
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$149.28	$188.09	$265.71	$343.34	$420.96
	Var. ($)	Proposed - Existing	$5.59	$8.39	$11.18	$13.98	$16.77	$20.96	$27.95	$21.69	$15.44	$9.03	$2.63	-$3.77
	Var. (%)	Proposed/Existing	16.28%	19.12%	20.95%	22.22%	23.16%	24.19%	25.30%	14.53%	8.21%	3.40%	0.77%	-0.90%
Old Crow		Proposed Bill	$39.93	$52.24	$64.55	$76.86	$89.17	$107.64	$138.42	$170.97	$203.53	$362.40	$521.27	$680.14
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$192.40	$274.32	$438.18	$602.03	$765.89
	Var. ($)	Proposed - Existing	$5.59	$8.39	$11.18	$13.98	$16.77	$20.96	$27.95	-$21.42	-$70.80	-$75.78	-$80.76	-$85.75
	Var. (%)	Proposed/Existing	16.28%	19.12%	20.95%	22.22%	23.16%	24.19%	25.30%	-11.14%	-25.81%	-17.29%	-13.42%	-11.20%

	0-200	200-300	300-400	400-500	500-600	600-800	800-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
Cumulative percentage of customers	13.8%	19.2%	25.2%	32.2%	40.2%	56.4%	70.1%	84.3%	89.7%	96.1%	98.3%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$11.90	$11.90	$11.90	$11.90
1st. Block Energy (0-1000)	$0.0986	$0.0986	$0.0986	$0.0986
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%
Yukon Interim Electrical Rebate (1st	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$14.65	$14.65	$14.65	$14.65
1st. Block Energy (0-1000)	$0.1214	$0.1214	$0.1214	$0.1214
2nd. Block Energy (1001-2500)	$0.1282	$0.1282	$0.1282	$0.1282
3d. Block Energy (2500+)	$0.1399	$0.1399	$0.1399	$0.3077
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Yukon Interim Electrical Rebate (1st b	$0.0000	$0.0000	$0.0000	$0.0000

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table B4.6
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate 0.00%
GST 5.00%

CUSTOMER CLASS: **RESIDENTIAL - GOVERNMENT - Option B**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000	
Hydro		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$471.77	
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$233.64	$266.45	$332.06	$397.68	$463.29	
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	$2.92	$2.83	$2.67	$2.50	$8.47	
	Var. (%)	Var. ($)/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	1.25%	1.06%	0.80%	0.63%	1.83%	
Large Diesel		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$471.77	
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$233.64	$266.45	$332.06	$397.68	$463.29	
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	$2.92	$2.83	$2.67	$2.50	$8.47	
	Var. (%)	Proposed/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	1.25%	1.06%	0.80%	0.63%	1.83%	
Small Diesel		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$471.77	
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$239.81	$278.78	$356.73	$434.67	$512.62	
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	-$3.25	-$9.50	-$22.00	-$34.50	-$40.86	
	Var. (%)	Proposed/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	-1.35%	-3.41%	-6.17%	-7.94%	-7.97%	
Old Crow		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$559.86	
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$283.10	$365.37	$529.90	$694.43	$858.96	
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	-$46.54	-$96.08	-$195.17	-$294.25	-$299.10	
	Var. (%)	Proposed/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	-16.44%	-26.30%	-36.83%	-42.37%	-34.82%	
									0-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
									78.5%	87.6%	91.2%	95.8%	98.1%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$15.00	$15.00	$15.00	$15.00
1st. Block Energy (0-1000)	$0.1434	$0.1434	$0.1434	$0.1434
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$18.47	$18.47	$18.47	$18.47
1st. Block Energy (0-1000)	$0.1792	$0.1792	$0.1792	$0.1792
2nd. Block Energy (1001-2500)	$0.1282	$0.1282	$0.1282	$0.1282
3d. Block Energy (2500+)	$0.1399	$0.1399	$0.1399	$0.3077
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table B4.7
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate -0.50%
GST 5.00%

CUSTOMER CLASS: **GENERAL SERVICE - NON GOVERNMENT - Option B**

Zone		Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)
		400	700	1000	1500	2000	2500	3000	3500	4000	5000	6000	7500	10000	15000	20000	40000	100000
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00	27.00	41.00	55.00	110.00	274.00
Hydro	Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$6,081.58	$15,186.05
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$325.67	$398.73	$479.50	$552.56	$706.39	$852.51	$1,087.11	$1,460.11	$2,221.55	$2,982.98	$6,021.01	$15,127.38
Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	$0.12	$0.20	$0.30	$0.38	$0.56	$0.74	$1.00	$1.44	$2.33	$61.20	$60.57	$58.66
Var. (%)	Var. ($)/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	0.04%	0.05%	0.06%	0.07%	0.08%	0.09%	0.09%	0.10%	0.10%	2.05%	1.01%	0.39%
Large Diesel	Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$6,081.58	$15,186.05
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$325.67	$398.73	$479.50	$552.56	$706.39	$852.51	$1,087.11	$1,460.11	$2,221.55	$2,982.98	$6,021.01	$15,127.38
Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	$0.12	$0.20	$0.30	$0.38	$0.56	$0.74	$1.00	$1.44	$2.33	$61.20	$60.57	$58.66
Var. (%)	Proposed/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	0.04%	0.05%	0.06%	0.07%	0.08%	0.09%	0.09%	0.10%	0.10%	2.05%	1.01%	0.39%
Small Diesel	Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$6,574.70	$17,158.54
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$337.96	$423.29	$516.35	$601.69	$780.08	$950.76	$1,222.21	$1,656.63	$2,540.89	$3,425.15	$6,954.47	$17,534.71
Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	-$12.17	-$24.36	-$36.55	-$48.75	-$73.13	-$97.52	-$134.10	-$195.07	-$317.01	-$380.96	-$379.76	-$376.18
Var. (%)	Proposed/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	-3.60%	-5.75%	-7.08%	-8.10%	-9.37%	-10.26%	-10.97%	-11.78%	-12.48%	-11.12%	-5.46%	-2.15%
Old Crow	Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$10,022.38	$30,949.24
	Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$424.19	$595.76	$775.05	$946.62	$1,297.48	$1,640.63	$2,170.78	$3,036.36	$4,782.95	$6,529.54	$13,508.19	$34,436.42
Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	-$98.40	-$196.83	-$295.25	-$393.68	-$590.53	-$787.39	-$1,082.67	-$1,574.80	-$2,559.07	-$3,485.36	-$3,485.81	-$3,487.18
Var. (%)	Proposed/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	-23.20%	-33.04%	-38.09%	-41.59%	-45.51%	-47.99%	-49.87%	-51.86%	-53.50%	-53.38%	-25.81%	-10.13%
		0-400	400-700	700-1000	1000-1500	1500-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers		28.5%	39.2%	47.8%	58.7%	66.6%	72.3%	76.5%		86.0%			94.0%		96.5%	97.7%	99.1%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$7.39	$7.39	$7.39	$7.39
1st. Block Energy (0-2000)	$0.1023	$0.1023	$0.1023	$0.1023
2nd. Block Energy (2001-15000)	$0.1288	$0.1288	$0.1288	$0.1288
3d. Block Energy (15001-20000)	$0.1399	$0.1399	$0.1399	$0.1399
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table B4.8
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate 0.00%
GST 5.00%

CUSTOMER CLASS: **GENERAL SERVICE - MUNICIPAL GOVERNMENT - Option B**

Zone			Monthly Consump. (kW.h) 400 5.00	Monthly Consump. (kW.h) 700 5.00	Monthly Consump. (kW.h) 1000 5.00	Monthly Consump. (kW.h) 1500 5.00	Monthly Consump. (kW.h) 2000 5.00	Monthly Consump. (kW.h) 2500 7.00	Monthly Consump. (kW.h) 3000 8.00	Monthly Consump. (kW.h) 3500 10.00	Monthly Consump. (kW.h) 4000 11.00	Monthly Consump. (kW.h) 5000 14.00	Monthly Consump. (kW.h) 6000 16.00	Monthly Consump. (kW.h) 7500 21.00	Monthly Consump. (kW.h) 10000 27.00	Monthly Consump. (kW.h) 15000 41.00	Monthly Consump. (kW.h) 20000 55.00	Monthly Consump. (kW.h) 40000 110.00	Monthly Consump. (kW.h) 100000 274.00
Hydro		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$6,112.89	$15,264.23
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$327.04	$400.40	$481.51	$554.88	$709.35	$856.08	$1,091.66	$1,466.22	$2,230.84	$2,995.46	$6,046.20	$15,190.65
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	$0.43	$0.59	$0.76	$0.92	$1.25	$1.56	$2.06	$2.86	$4.49	$64.39	$66.69	$73.57
	Var. (%)	Var. ($)/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	0.13%	0.15%	0.16%	0.17%	0.18%	0.18%	0.19%	0.20%	0.20%	2.15%	1.10%	0.48%
Large Diesel		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$6,112.89	$15,264.23
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$327.04	$400.40	$481.51	$554.88	$709.35	$856.08	$1,091.66	$1,466.22	$2,230.84	$2,995.46	$6,046.20	$15,190.65
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	$0.43	$0.59	$0.76	$0.92	$1.25	$1.56	$2.06	$2.86	$4.49	$64.39	$66.69	$73.57
	Var. (%)	Proposed/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	0.13%	0.15%	0.16%	0.17%	0.18%	0.18%	0.19%	0.20%	0.20%	2.15%	1.10%	0.48%
Small Diesel		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$6,608.49	$17,246.63
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$339.37	$425.07	$518.51	$604.21	$783.35	$954.74	$1,227.32	$1,663.54	$2,551.49	$3,439.43	$6,983.46	$17,607.81
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	-$11.90	-$24.07	-$36.24	-$48.41	-$72.75	-$97.10	-$133.60	-$194.46	-$316.15	-$379.57	-$374.97	-$361.18
	Var. (%)	Proposed/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	-3.51%	-5.66%	-6.99%	-8.01%	-9.29%	-10.17%	-10.89%	-11.69%	-12.39%	-11.04%	-5.37%	-2.05%
Old Crow		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$10,073.49	$31,106.63
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$425.96	$598.24	$778.27	$950.55	$1,302.86	$1,647.42	$2,179.76	$3,048.91	$4,802.70	$6,556.50	$13,563.94	$34,578.51
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	-$98.48	-$197.24	-$295.99	-$394.75	-$592.26	-$789.78	-$1,086.03	-$1,579.82	-$2,567.37	-$3,496.64	-$3,490.45	-$3,471.88
	Var. (%)	Proposed/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	-23.12%	-32.97%	-38.03%	-41.53%	-45.46%	-47.94%	-49.82%	-51.82%	-53.46%	-53.33%	-25.73%	-10.04%
							0-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers							66.5%	69.8%	72.0%		81.4%			88.7%		91.8%	93.4%	97.6%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$7.39	$7.39	$7.39	$7.39
1st. Block Energy (0-2000)	$0.1023	$0.1023	$0.1023	$0.1023
2nd. Block Energy (2001-15000)	$0.1288	$0.1288	$0.1288	$0.1288
3d. Block Energy (15001-20000)	$0.1399	$0.1399	$0.1399	$0.1399
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table B4.9
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**0.00%**
GST	**5.00%**

CUSTOMER CLASS: **GENERAL SERVICE - FED/TERR GOVERNMENT - Option B**

Zone			Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 700	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000	Monthly Consump. (kW.h) 3500	Monthly Consump. (kW.h) 4000	Monthly Consump. (kW.h) 5000	Monthly Consump. (kW.h) 6000	Monthly Consump. (kW.h) 7500	Monthly Consump. (kW.h) 10000	Monthly Consump. (kW.h) 15000	Monthly Consump. (kW.h) 20000	Monthly Consump. (kW.h) 40000	Monthly Consump. (kW.h) 100000
			5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00	27.00	41.00	55.00	110.00	274.00
Hydro		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$6,929.69	$16,928.25
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$599.26	$677.79	$769.23	$847.76	$1,017.73	$1,174.78	$1,436.19	$1,841.75	$2,678.68	$3,515.62	$6,850.45	$16,842.04
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	$1.10	$1.73	$2.38	$3.01	$4.28	$5.54	$7.46	$10.63	$16.99	$76.90	$79.23	$86.21
	Var. (%)	Var. ($)/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	0.18%	0.26%	0.31%	0.35%	0.42%	0.47%	0.52%	0.58%	0.63%	2.19%	1.16%	0.51%
Large Diesel		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$6,929.69	$16,928.25
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$599.26	$677.79	$769.23	$847.76	$1,017.73	$1,174.78	$1,436.19	$1,841.75	$2,678.68	$3,515.62	$6,850.45	$16,842.04
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	$1.10	$1.73	$2.38	$3.01	$4.28	$5.54	$7.46	$10.63	$16.99	$76.90	$79.23	$86.21
	Var. (%)	Proposed/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	0.18%	0.26%	0.31%	0.35%	0.42%	0.47%	0.52%	0.58%	0.63%	2.19%	1.16%	0.51%
Small Diesel		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$7,425.29	$18,910.65
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$611.59	$702.45	$806.22	$897.09	$1,091.72	$1,273.44	$1,571.85	$2,039.07	$2,999.33	$3,959.59	$7,787.72	$19,259.19
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	-$11.23	-$22.93	-$34.62	-$46.32	-$69.71	-$93.12	-$128.20	-$186.69	-$303.65	-$367.07	-$362.43	-$348.54
	Var. (%)	Proposed/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	-1.84%	-3.26%	-4.29%	-5.16%	-6.39%	-7.31%	-8.16%	-9.16%	-10.12%	-9.27%	-4.65%	-1.81%
Old Crow		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$10,890.29	$32,770.65
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$698.18	$875.62	$1,065.98	$1,243.43	$1,611.23	$1,966.12	$2,524.29	$3,424.43	$5,250.54	$7,076.66	$14,368.19	$36,229.89
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	-$97.82	-$196.10	-$294.38	-$392.66	-$589.22	-$785.80	-$1,080.63	-$1,572.05	-$2,554.87	-$3,484.13	-$3,477.91	-$3,459.25
	Var. (%)	Proposed/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	-14.01%	-22.40%	-27.62%	-31.58%	-36.57%	-39.97%	-42.81%	-45.91%	-48.66%	-49.23%	-24.21%	-9.55%
							0-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers							63.3%	67.5%	70.7%		78.4%			87.0%		90.4%	92.5%	96.6%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$10.00	$10.00	$10.00	$10.00
1st. Block Energy (0-2000)	$0.1745	$0.1745	$0.1745	$0.1745
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$12.31	$12.31	$12.31	$12.31
1st. Block Energy (0-2000)	$0.2148	$0.2148	$0.2148	$0.2148
2nd. Block Energy (2001-15000)	$0.1297	$0.1297	$0.1297	$0.1297
3d. Block Energy (15001-20000)	$0.1399	$0.1399	$0.1399	$0.1399
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

TAB 4YECL

YUKON ELECTRICAL'S PROPOSED RATE DESIGN

4.0 TAB 4YECL - YUKON ELECTRICAL'S PROPOSED RATE DESIGN

An effective rate design approach that is intended to reflect principles of economy and efficiency, based on sending a price signal for consumption on the margin of the short run incremental cost of diesel, should reflect the manner in which incremental costs are incurred on the system as reasonably practical. Yukon Electrical's proposal seeks to reflect the degree to which the optimal level of current incremental costs should be reflected in the base rates at this time due to the inherent uncertainty in supply conditions. Yukon Electrical's proposed approach is based on introducing a small adjustment to rates at this time and will be in a more reasonable position to address the full optimal level of incremental costs in rates when inter-class rebalancing is allowed and when incremental costs from diesel generating sources in the Hydro zone are playing an increasingly prominent role in the process of setting electric rates.

In submitting this Joint Phase II Application, YEC and Yukon Electrical have worked diligently in an effort to present a uniform and consistent approach whenever possible. However, this goal has not always been achieved, as each Company has its own views regarding how best to address certain matters. This Section of the Phase II Application sets out Yukon Electrical's proposed rate design.

This Tab provides Yukon Electrical's rate design option and proposal to collect the approved 2009 Consolidated Firm Rate Revenue Requirement.

Tab 4YECL – Yukon Electrical's Proposed Rate Design consists of the following items:

- Overview;

- Rate Design Considerations;

- Incremental Costs;

- Residential and General Service 2009 Rate Proposals; and

- Other 2009 Rate Proposals.

In addition, in order to illustrate and assist the Board and interested parties in understanding the proposed rate design, Yukon Electrical has provided a number of Schedules in Appendix 4.1 YECL B herein as follows:

Schedule 4.1 Provides a summary of revenue to cost ratios by rate class on Yukon Electrical's proposed 2009 rates.

Schedule 4.2 Provides a comparison of revenues at existing rates and Yukon Electrical's proposed 2009 rates.

Schedule 4.3 Provides a detailed summary of revenue to cost ratios by rate class on proposed 2009 rates.

Schedule 4.4 Provides a description of rate codes.

Schedule 4.5 Provides a comparison of the existing rates and Yukon Electrical's proposed 2009 rates.

Schedule 4.6 Provides the billing determinants for each rate within each rate class in 2009 at existing rates.

Schedule 4.7 Provides the billing determinants for each rate within each rate class in 2009 at Yukon Electrical's 2009 proposed rates.

Bill impact Tables have been provided in Appendix 4.1 YECL A.

4.1 OVERVIEW

The Application provides for rates sufficient to collect the 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million as approved for the Companies based on the approved loads as forecast for 2009 (see Tab 2, Table 2.3), as well as the rate revenue requirement as approved specifically for Yukon Energy and Yukon Electrical. At the present time (absent rate design adjustments), this requirement is collected through the current rates and riders, i.e., based on the approved 2009 forecast sales for each rate class, the Consolidated Firm Rate Revenue Requirement is collected with current base rates as approved in the 1996/97 GRA for each rate class plus the Rider J and Rider R charges applied to retail base rates.[1] Table 4.1 below summarizes the resulting firm rate revenues by rate class (excludes secondary sales and wholesales):

Table 4.1: 2009 Consolidated Firm Rate Revenue Requirement

Revenue by Rate Class at Existing Rates ($000)

Rate Class	
Residential Non Government	$ 19,412
Residential Government	$ 422
General Service Non-Government	$ 17,372
General Service Government	$ 9,272
Street Light Rate	$ 986
Sentinel Light Rate	$ 166
Sub-total Retail	$ 47,630
Industrial	$ 3,203
Total	$50,833

Rate design adjustments are considered in the Application in response to Directive 13 of Order 2009-8, which directed the Companies to provide rate design recommendations in the Phase II Application that comply with previous Board directions and current OICs. This requires that in determining whether, and what, rate adjustments are required at this time the Companies must consider the rate design framework provided by OIC 1995/90, OIC 2008/149 and OIC 2007/94, as well as how the Companies and the Board have been guided by this framework in the past and how the framework may or may not be applicable today.[2] Noting that it has been over 12 years since the Companies have had a major review of rates, the Application addresses the need to adjust base rates to reflect current costs and revenue requirements and eliminate the current Rider J and Rider R from customer bills. The following are highlighted in this regard:

[1] As reviewed in Tab 2, section 2.1, this statement assumes correction of Rider J at 12.60% and Rider R at 10.526%, for a combined rider impact on retail base rates of 23.123%.

[2] This would include interpretations provided by the Board of prior and current Yukon rate policy directions (such as that provided in prior major rate review undertaken in 1992, the results of which were subsequently affirmed by the Board in Order 1993-8 following the 1993/94 GRA and Order 1996-7 following 1996/97 GRA).

- In accordance with OIC 2007/94 and OIC 2008/149, the rate design adjustments proposed in the Application do not modify the firm rate revenues by rate class from the Table 4.1 amounts (based on the approved sales forecast by rate class for 2009).

- In accordance with OIC 1995/90, the rate design adjustments proposed in the Application:
  - Reflect rate design principles established in Canada for utilities as well as past practice in Yukon;
  - Continue to ensure that firm retail rates are equalized throughout Yukon within each rate class other than for runoff rates;
  - Adjust, on the basis of rate design principles, where and to the extent practicable based on the level of incremental diesel generation that is being triggered due to increasing consumption, retail runoff rates to provide for economy and efficiency by reflecting short term incremental generation cost as a price signal at higher levels of consumption; and
  - Adjust the wholesale rate as required to enable Yukon Energy to recover its costs that are not recovered from its other customers.

Changes are sought in this Application to remove the current Rider J and Rider R from customer bills, and to adjust the following rate schedules effective September 1, 2010, as follows:

Residential Rate Classes

Rate Schedules for Residential Non-Government (1160, 1260, 1360, 1460 for the respective zones) and Residential Government (1180, 1280, 1380, 1480), Yukon Electrical proposes to provide adjusted base rates and an adjusted rate design that includes a new equalized second energy block as follows:

Customer Charge

Yukon Electrical proposes to adjust the Customer Charge to $14.65 per month for non-government and $18.47 per month for government residential classes, reflecting the current charge after rider impacts.

Energy Charge

Yukon Electrical proposes the following charges for the energy component of the residential rate class.

Energy Block	Charge	Applicability
Blk 1: for use up to 1,000 kWh	12.14 c/kWh 17.92 c/kWh	non-government government
Blk 2: for use from 1,001 kWh to 2,500 kWh	12.82 c/kWh	non-government and government
Blk 3: for use in excess of 2,500 kWh	 13.99 c/kWh 30.77 c/kWh	non-government and government: Hydro, Large Diesel and Small Diesel Old Crow

Commercial Rate Classes

Rate Schedules for General Service Non-Government and Municipal Government (2160, 2170, 2260, 2270, 2360, 2370, 2460, 2470) and General Service Federal and Territorial Government (2180, 2280, 2380, 2480), Yukon Electrical proposes to provide adjusted base rates and an adjusted rate design that includes a new equalized second energy block, a new equalized third energy block, and an adjusted runoff energy block to address large users prior to future consideration of a possible separate General Service Large User rate class.

Demand Charge

Yukon Electrical proposes to change the Demand Charge to $7.39 per kW per month for non-government and $12.31 per month for government commercial classes, with a minimum bill of 5 kW per month, reflecting the current charge after rider impacts.

Energy Charge

Yukon Electrical proposes the following charges for the energy component of the commercial rate class.

Energy Block	Charge	Applicability
Blk 1: for use up to 2,000 kWh	10.23 c/kWh 21.48 c/kWh	non-government government
Blk 2: for use from 2,001 kWh to 15,000 kWh	12.88 c/kWh 12.97 c/kWh	non-government government
Blk 3: for use from 15,001 kWh to 20,000 kWh	13.99 c/kWh	non-government and government
Blk 4: for use in excess of 20,000 kWh	 12.86 c/kWh 15.22 c/kWh 31.72 c/kWh	non-government and government: Hydro and Large Diesel Zones Small Diesel Zone Old Crow Zone

- Adjust base rates for Rate Schedules for Street Lighting (61, 66, 67) and Sentinel Lighting (75, 76).

- Regarding Rate Schedule 42 (wholesale sales to Yukon Electrical), Yukon Electrical proposes to adjust the Energy Reconciliation Adjustment clause as set out in Yukon Electrical's application for a new Rider D, which is attached to this Application.

- A new Rider D – Diesel Energy Cost Recovery Rider to flow through to Yukon customers the actual cost of purchase power for the Hydro zone during the period when diesel generation is on the margin that has not been forecasted. Yukon Electrical is proposing this Rider under a separate cover, but it is intended to form part of this Application.

Attached in Appendix 4.1 YECL B, Schedule 4.5 is a comparison of existing and proposed rates.

4.2 RATE DESIGN CONSIDERATIONS

Since it has been over 12 years since the last major rate review, there is a need to address required rate adjustments in an orderly manner. Yukon Electrical submits that rate adjustments should focus first on what can reasonable be implemented today, recognizing that what might have been appropriate in the past may not be necessarily appropriate today. Yukon Electrical recognizes the need to develop an orderly process for dealing with the current cost environment and how it may impact customer rates today (i.e., rate shock) and in the coming years, when supply conditions with respect to high cost diesel generation in the Hydro zone is more predominant.

The logic behind Yukon Electrical's proposed rate design is based on taking a balanced approach between sending customers an effective price signal that tells them that costs increase as consumption increases and the economic considerations regarding the price of incremental cost of diesel generation today. An optimum rate design should be a mechanism whereby the cost of the more expensive resources is recovered in higher rates charged for consumption above a certain level, so that customers that take actions to reduce energy consumption will realize savings in their electricity bills based more closely on the actual cost of the energy saved. However, part of the problem is defining what the optimum level is when the vast majority of customers who consume more will not see those higher costs at this point.

Normal utility principles of rate design include the following criteria (as noted in the Companies' joint 1992 submission on COS and Rate Design and summarized by the Board in its related Report) that represent differing and sometimes conflicting objectives to be balanced in determining just and reasonable rates:[3]

- Rate simplification and ease of understanding;

- Promotion of efficient usage;[4]

- Recovery of the cost of service by rate class and in total;[5]

- Avoidance of undue discrimination;

- Comparisons with rate practices of other utilities;

- Consideration of the value of service provided; and

- Rate stability.

The overall objective is to achieve an appropriate balance between the differing rate design objectives recognizing that no one rate design will fully achieve each differing objective and that rate design priorities may change in light of changing conditions on the system. Rate stability objectives, for example, can moderate short-term adjustments either to promote efficient usage or to recover cost of service by rate class. Rate design can also be challenged when concurrently seeking to promote efficient usage (through increased prices that reflect incremental costs for new generation), recover embedded cost of service (costs less than new generation), and ensure fair sharing of heritage resource benefits.

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[3] See page 7-8 of Board's 1992 Report and Recommendations on COS and Rate Design (Appendix 7.1, Tab 7). The YUB in its 1992 Report summarized the primary criteria for rate design as: "the need for rates which would provide sufficient revenue to meet the revenue requirement approved by the Board, as well as the requirement for revenue stability and predictability. The rates should fairly reflect the costs incurred by the utility to serve the various classes of customers. A further objective is the promotion of economy and efficiency in the generation, transmission, distribution and use of electricity, and involves the structuring of rates so as to provide price signals to users of electricity, and involves the structuring of rates so as to provide price signals to users of electricity which will encourage optimum use of the utilities' facilities rates should reflect the value of service provided to the customers, ...should be stable and reasonably predictable allowing customers to make realistic cost projections and rates generally should be practical and not overly complicated."

[4] The Companies noted in 1992 Submission on COS and Rate Design, that "an important step in promoting efficient use of electric energy is the provision of an effective price signal to the customer, such that the price paid for extra energy consumption reflects the cost of providing that same extra energy. With the normal utility principles of rate simplification, and promotion of efficient usage, in conjunction with the specific OIC directive to promote energy efficiency, it was considered desirable to design all rates as consistently as possible with run out energy blocks reflecting incremental energy costs regardless of rate class or zone." (see page 3-3 and 3-4 of Companies joint submission on COS and Rate Design filed in 1992).

[5] The concepts of fair and reasonable rates include maintaining a cost based standard, such that each group of customers is paying total amounts that reasonably reflect the costs to serve that class of customer.

Three specific rate design matters have been identified as part of preparation of this Application:

- Eliminate the current general purpose Rate Riders (Riders J and R) from customer bills and adjust retail base rates to fully reflect approved 2009 costs. Since the last major rate review, various rate riders have been implemented which at this time can be absorbed into base rates.

- Address economy and efficiency rate principles/directives to the extent reasonably practical at this time, i.e., the need to adjust runoff rates towards the approved 2009 incremental costs based on current fuel prices and consistent with Yukon practice.

- Inability at this time to address the outstanding directive from the Board to bring revenue to cost ratios for each customer class within a "zone of reasonableness" (which is not permitted under OIC 2008/149).

4.3 INCREMENTAL COST OF DIESEL

Providing an efficient price signal is one key consideration to be balanced in rate design, and in this regard, the Board is required by OIC 1995/90 to fix runoff rates for each non-government retail customer class on the basis of rate design principles "to promote economy and efficiency."[6] As noted at the outset of this Application, the key to the currently proposed rate design is to find the optimal level that current incremental costs should be reflected in the base rates, due to the inherent uncertainty in supply conditions relating to the level of incremental high cost diesel generation that may impact customer rates.

The Board has previously noted that, to promote economy and efficiency, runoff rates should reflect at least short-run incremental costs[7] in each of the rate zones. From 1989 to 1996, the Companies and the YUB applied the then-prevailing rate policy directives to set runoff rates that reflect short-term incremental energy costs in communities supplied primarily by generation other than hydro. The Board in its 1992 Report recognized the need to extend aspects of this approach to hydro communities, and OIC 1995/90 implemented this recommendation.

[6] "Economy and efficiency" are not defined in the OIC.
[7] Incremental cost is the cost of producing extra energy assuming no capital additions are necessary; it is typically calculated as the extra fuel cost, extra operation and maintenance cost and extra losses caused by the production and delivery of an extra kWh of energy (it is assumed to be synonymous with short run marginal cost).

Table 4.2 below summarizes the 1997 and updated 2009 rates for the incremental cost of diesel in each rate zone.

Table 4.2: Summary on Incremental Cost of Diesel (¢/kWh)

Zone	1997	Updated 2009
Hydro-Diesel	10.45	32.74
Large Diesel	10.45	27.23
Small Diesel	12.36	29.19
Old Crow	25.77	61.54

Given the clear convergence of the hydro zone, large diesel zone and small diesel zone incremental costs, for simplicity the rate design has been based (at least for residential classes) on consolidating these three zones into a single average incremental cost estimate of 27.99 cents/kW.h. The detailed calculations are set out in Table 4.3.

Table 4.3: Incremental Cost of Diesel Calculation

Yukon Energy Corporation & Yukon Electrical Company Limited
2009 Incremental Cost of Diesel

2009 Incremental Rates

Incremental Rates	Hydro-Diesel		Larger Diesel	Old Crow
	WAF (Faro)	MD (Dawson)	Watson	
Forcast Cost of Fuel - (cent/L)	99.2	97.5	87.48	193.41
Approve Heat Rate - (KW.h/L)	3.55	3.71	3.82	3.56
Losses	8.46%	8.46%	5.82%	7.75%
Run-out Cost - (cent/KW.h)	30.31	28.50	24.23	58.54
Add O&M - (cent/KW.h)	3.00	3.00	3.00	3.00
Total	33.31	31.50	27.23	61.54
Generation (KW.h)	866,000	396,000	14,593,000	2,029,000
Weighting Factor	68.62%	31.38%	100.00%	100.00%
Blended Cost (cent/KW.h)	32.74		27.23	61.54
Blended Cost,WAF-Large Diesel (cent/KW.h)		27.67		

	Small Diesel			Blended Hydro, Large Diesel and Small Diesel
	Destruction Bay	Beaver Creek	Swift River	
Forcast Cost of Fuel - (cent/L)	83.13	81.52	92.44	
Approve Heat Rate - (KW.h/L)	3.41	3.56	2.99	
Losses	8.48%	8.48%	8.48%	
Run-out Cost - (cent/KW.h)	26.45	24.84	33.54	
Add O&M - (cent/kW.h)	3.00	3.00	3.00	
Total	29.45	27.84	36.54	
Generation (KW.h)	1,741,000	2,115,000	326,000	
Weighting Factor	41.63%	50.57%	7.80%	
Blended Cost (cent/KW.h)		29.19		27.99

The method used to determine current runoff rates is in accordance with past practice in this jurisdiction and follows generally accepted rate design criteria.

In this Application, to meet the OIC requirement of "economy and efficiency" runoff rates have been set at levels that reflect a substantial portion of the incremental short term cost of generating an extra kWh using diesel generation, fixed at 50% of the measured incremental cost.

4.4 RESIDENTIAL AND GENERAL SERVICE 2009 RATE PROPOSALS

1. **Stepped increase towards incremental cost** – Yukon Electrical's approach towards reflecting incremental costs in ratemaking is based on assessing the optimal level at which to set usage rates that embody the incremental cost that customers see as they consume more electricity. In other words, incorporating forward looking information on the price of electricity that allows customers today to make informed decisions about how much electricity to purchase should be reasonably linked to the incremental costs that are becoming more prominent on the system today, and not at some unknown period in the future, as customers consume more electricity.

   An inverted rate structure should reflect the cost differential from low cost hydro sources and then from higher cost diesel sources so that customers that take actions to reduce energy consumption will realize savings in their electricity bills based more closely on the 'actual' cost of the energy saved. Yukon Electrical's present proposal is based on applying only a partial increase in the runoff block to be consistent with Board precedent to reflect economy and efficiency in the design of base rates. However, it is important to recognize that economy and efficiency must also be considered in the context of ensuring that rates are set as close to the cost pattern as practical (cost based) so that no group of customers is subsidized by another group of customers.

   A lesser percentage of 50% of incremental cost was considered more reasonable at this time due to:

   - Limits related to inter-class rate balancing (i.e., OIC 2008/149);
   - Reducing rate shock impact across customer classes;
   - Avoidance of undue discrimination; and
   - Allowing further adjustments to rates when more accurate signals showing how costs move with usage is identified.

In this manner, Yukon Electrical's proposal does allow for staged progress over time towards reflecting more incremental costs as appropriate. This would also minimize rate shock, and strike a balance between providing predictable and affordable bills over time for customers when the limits related to inter-class rate balancing are removed.

Consideration will need to be given to the manner in which staged increases are implemented, considering how customer choices under this rate design proposal will affect how supply costs will vary over time due to changes in energy consumption.

Further consideration would also need to be given to the practicality of this solution on its own for solving rate design issues for both residential and general service classes. Important rate design matters need to be fully examined and understood in the context of ensuring a fair and reasonable approach is taken towards sending the right price signals to customers. Such issues include: understanding homogeneity of residential customers, estimating elasticity and customer discretionary use across the rate classes, understanding customer response to a proposed rate change, and reflecting more accurate cost based signals in the base rates when current OIC's expire.

2. **Create one or more new energy blocks –** This option could, for example, maintain the existing first block size for each of residential and general service classes and provide for a new second block, with energy in excess of the new second block (i.e., a third block) subject to runoff rates. This option would potentially allow for future runoff rates that are more representative of incremental costs to be applied to the third block when those incremental costs are more prominent on the system and are seen by the vast majority of customers.

   For each of the residential and general service classes, different options for determining the block structure were considered before determining the final proposals to be included in this Application.

   a. For the residential classes, four separate block energy structures were considered and tested:
      ii. 0-1000, 1000-1500 and > 1500 kW.h per month
      iii. 0-1000, 1001-2000 and > 2000 kW.h per month
      iv. 0-700, 701-2000 and > 2000 kW.h per month
      v. 1-1000, 1001-2,500 and > 2500 kW.h per month

b. For general service classes, two scenarios were considered and tested;
    i. 0-2000, 2001-15000 and >15000 kW.h (with separate consideration for usage >20,000 kW.h to address large users group); and
    ii. Create third block similar to the above, and establish a new rate class for high consumption users; e.g. users typically with >20,000 kW.h/month.

3. **Customer and/or Demand Charge** - Options for setting the adjusted customer and/or demand charge ranged in each case as follows:
    a. Recover 100% revenue to cost ratio;
    b. Apply the increase of 23.1% to the existing base rate (to effectively crystallize the current Rider J and Rider R impact); or
    c. Simply retain the present base rate excluding riders presently in place.

    The first option (full cost recovery) did not present a practical alternative, due to the restrictions under the current OIC's. Applying the 23.1% increase to the current customer charge for residential customers and commercial customers appears, on review, to provide a reasonable determination for 2009.

4. **Create separate "large General Service" subclass and "small General Service" subclass** – as initially conceived this approach to addressing specific concerns for the general service class would allow for both residential and general service rate design to retain the present two block structure. Multiple general service subclasses are common in other jurisdictions. While a variety of such options were considered to address general service rate design issues, most were considered too complex to implement (including implications for cost of service analysis) or could not be implemented within the timing constraints provided for this Phase II Application.

Yukon Electrical proposes to make a modest adjustment to the current run-off rates towards reflecting a slightly higher incremental cost of diesel than current run-off rates. Yukon Electrical's proposal clearly conveys the current costing environment in the Yukon that strikes a reasonable balance between Board precedent of providing signals to promote energy conservation and providing predictable, affordable rates. For general service, special additional measures (involving an added rate block for large users) are concluded to be required for 2009 as an interim step until a further review can be conducted to determine whether a separate large General Service rate class can be established in a future GRA.

Overall impacts on residential and general service customer monthly bills from will depend on average monthly use levels. The impact on the overall levels of bill by class, by rate zone and by usage tier are shown in the detailed bill impact tables provided in Appendix 4.1 YECL A.

Residential Rate Classes

Yukon Electrical's proposal to adjust rates for residential government and non-government customers provides for a new equalized second energy block with a stepped up rate that is equal in all rate zones, as well as (for use in excess of the second block) for adjusted runoff rates that more closely reflect the GRA incremental cost of diesel, at 50% of the estimated cost.

The monthly customer charge is proposed to incorporate the current effective charges with riders.

- **Residential Non-Government** customers - a monthly customer charge of $14.65, derived by taking the current customer charge and applying the adjustment of 23.1% (11.90*1.231=14.65). The proposed customer charges recovers approximately 39% of the customer costs allowed to residential non-government rate class.

- **Residential Government** customers - a monthly customer charge of $18.47 per month, derived by taking the current customer charge and applying the adjustment of 23.1% (15.00*1.231=18.47) and recovers approximately 48% of the customer costs allowed to residential government rate class.
    - **First energy block** for use up to 1,000 kW.h per month, with an adjusted base energy rate. The second block charge recovers the remaining revenue to meet the design revenue not recovered by the customer charge, the first block rate and third block/runoff rate:
        - **Non government -** 12.14 ¢/kW.h;
        - **Government –** 17.92 ¢/kW.h
    - **A new equalized second energy block** for use from 1,001 to 2,500 kW.h per month, with a base energy rate of 12.82 c/kW.h for both non-government and government customers; and
    - **An adjusted runoff energy block** for all use in excess of 2,500 kW.h per month with runoff rates for non-government and government customers that reflect 50% of short term incremental generation costs (blended rate of 13.99 c/kW.h for Hydro, Large Diesel and Small Diesel zones, and 30.77 c/kW.h for Old Crow zone), based on fuel price forecasts as approved for 2009.

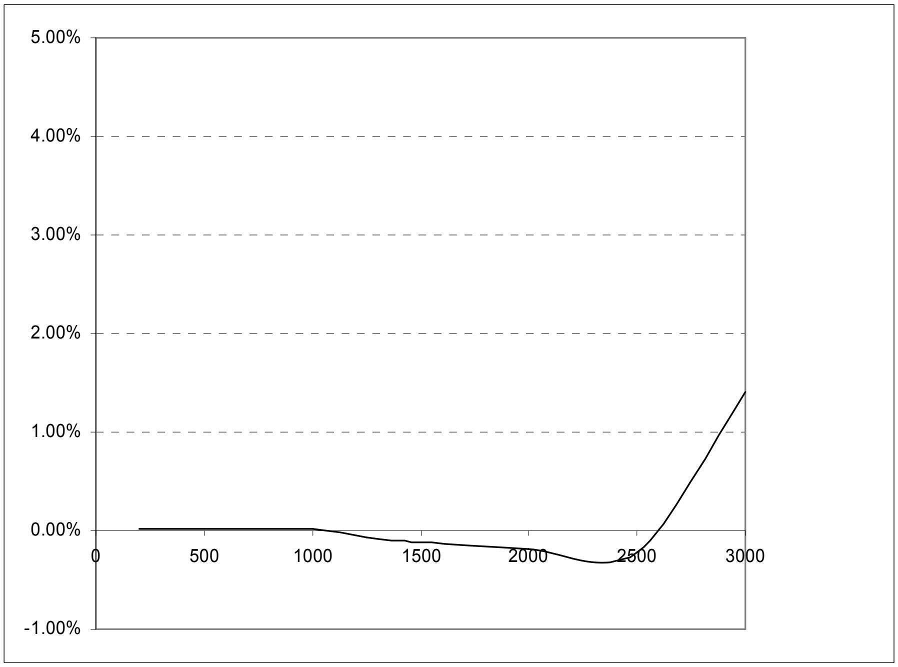
Yukon Electrical's proposed rate design generally leaves bills unchanged for customers throughout all use levels. Refer to Appendix 4.1 YECL A for a sample bill comparison at various consumption levels.

As noted in Appendix 4 YECL B, Schedule 4.3, the revenue to cost ratio for the residential non-government rate class is approximately 79%, with the revenue to cost ratio for the customer charge at approximately 39%. Any significant adjustments to base rates at this time without considering the effects when OIC 2008/149 has with respect to sending a fair price signal would not be prudent.

Introducing a third block for consumption in excess of 2,500 kWh targets customers that may have more 'discretionary' use moving the price of electricity for loads such as electric heating closer to incremental cost, making conservation more effective. Based on Yukon Electrical's proposal, the run-off rate for consumption in excess of 2,500 kWh is priced higher than the beginning block, which Yukon Electrical believes it is made up of relatively inelastic lighting and appliance needs. Proposing significant changes to the current residential blocking structure without assessing residential price elasticities throughout customer consumption levels to predict energy and revenue impact to Yukon Electrical would not be prudent in a cost environment when surplus hydro generation serves the vast majority of customers' base load. In addition, once OIC 2008/149 expires and interclass rebalancing is allowed, Yukon Electrical will be in a position to address the fair apportionment of costs, which is a critical component in the rate making process to establish more effective "economy and efficient" rates.

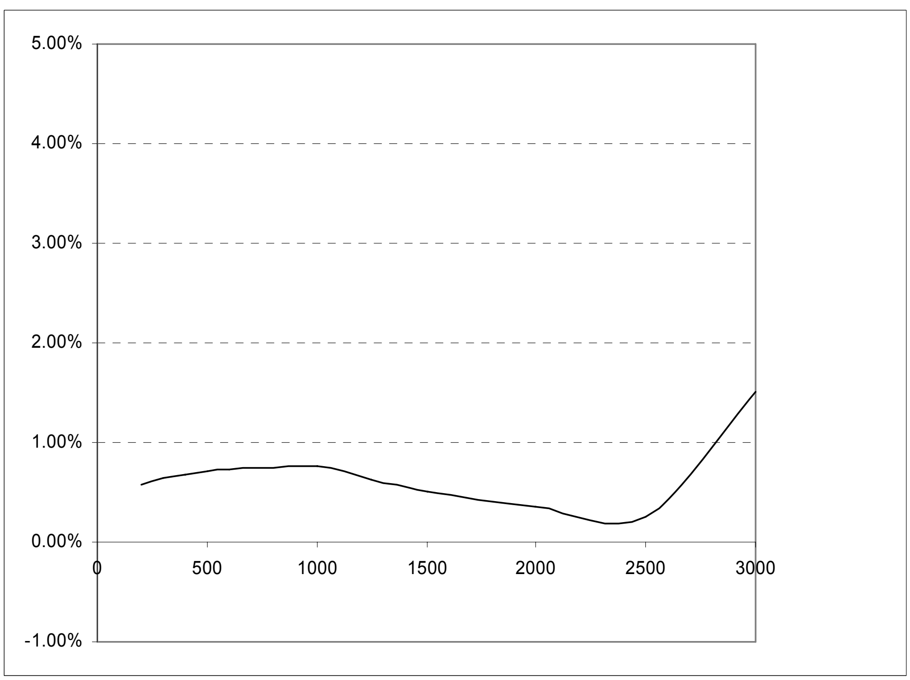
The following graphs illustrate the sample bill impact in percentages at various consumption levels.

1 **Graph 1: Sample Bill Impact in Percent for Residential Non-Government at Various**
2 **Consumption Levels (Hydro Zone)**



3

4 **Graph 2: Sample Bill Impact in Percent for Residential Government at Various Consumption**
5 **Levels (Hydro Zone)**



6

General Service Rate Classes

Yukon Electrical considered that the most feasible long term rate design solution to address the wide variance in customer use levels within the existing general service class is to create two separate general service subclasses: one for high consumption users, and another for all other users. However, prior to implementation of this solution, a number of complexities need to be addressed that could not be resolved within the timeline required for filing the 2009 Phase II Application. These include:

- Approval of new rate class by the Board;

- Forecast, testing and approval of billing determinants;

- Forecast costs of implementation on the billing system;

- Implementation on the billing system (Operations);

- Altering of COS models to include new rate class;

- Altering of Phase II Schedules to include new rate class;

- Create separate specific MIL's for new rate class, if required; and

- Contact eligible customers and inform and educate them as to the potential change.

With these considerations in mind, Yukon Electrical, in this Application, proposes a staged approach to rate design for the general service class, that combines the requirement for a further rate block (to mitigate impacts of the higher incremental runoff rate on first and second block energy rates) and establishes an orderly process for separating the non-homogenous general service class into two subclasses at a future date.

Yukon Electrical's proposal to adjust rates for general service government and non-government customers provides for a new second energy block (from 2,001 to 15,000 kW.h per month use) with a stepped up rate that is equal in all rate zones, and for a new third energy block (from 15,001 to 20,000 kW.h/month) with a higher rate that is equal in all rate zones and that reflects incremental energy costs as charged to residential customer runoff rates in the Hydro rate zone. For all but approximately 109 of the largest GS customers[8] who consume over 20 MW.h in a month (on the order of 3% of GS customers), the rate design in all practical respects parallels the residential three block rate design with the third block linked to 50% of the incremental cost of diesel.

To address rate design requirements for large users (e.g., those general service customers with typical monthly use in excess of 20,000 kW.h), Yukon Electrical's proposal defers establishing a separate rate class for large users. At this time, Yukon Electrical proposes (as an interim measure) a fourth energy rate block for use in excess of 20,000 kW.h/month. The proposed energy rate for this fourth "large user" rate block reflects status quo current effective runoff rates in each zone (with Rider J and R). The overall result is that a separate runoff rate block charge for general service large users is deferred.

The adjusted base **demand charge** for general service customers varies with the options as follows (minimum bill of 5 kW per month):

- **General Service Non-Government** - a demand charge of $7.39 per kW per month
- **General Service Government** – a demand charge of $12.31 per kW per month

The base energy rates for general service customers are described in more detail below.

- **General Service Non-Government and Municipal** - an energy charge of 10.23 cents/kWh for the first 2,000 kWh/month of energy consumed.
- **General Service Government** - an energy charge of 21.48 cents/kWh for the first 2,000 kWh/month of energy consumed.

- A second energy block set at 2,001 to 15,000 kWh/month, with the energy charge consistent across all rate zones (as per OIC 1995/90) as follows (approximately 96% of customers do not exceed 15,000 kW.h/month, but consume approximately 66% of the total energy):
  - **General Service Non-Government** - an energy charge of 12.88 cents/KWh for energy consumed between 2,000 and 15,000 kWh/month.
  - **General Service Government** - an energy charge of 12.97 cents/KWh for energy consumed between 2,000 and 15,000 kWh/month.

- A third energy block set at 15,001 to 20,000 kWh/month with the energy charge consistent across all rate zones (as per OIC 1995/90) for all general service retail rate classes and that

[8] Measured by the estimated # of bills exceeding 20,000 kW.h/month divided by 12.

reflects incremental energy costs as charged to residential customer runoff rates in the Hydro, Large Diesel and Small Diesel rate zone:

- **General Service Non-Government and Government** - an energy charge of 13.99 cents/kWh (50% of blended incremental energy cost for hydro, large diesel and small diesels zones) for energy consumed between 15,001 and 20,000 KWh/month.

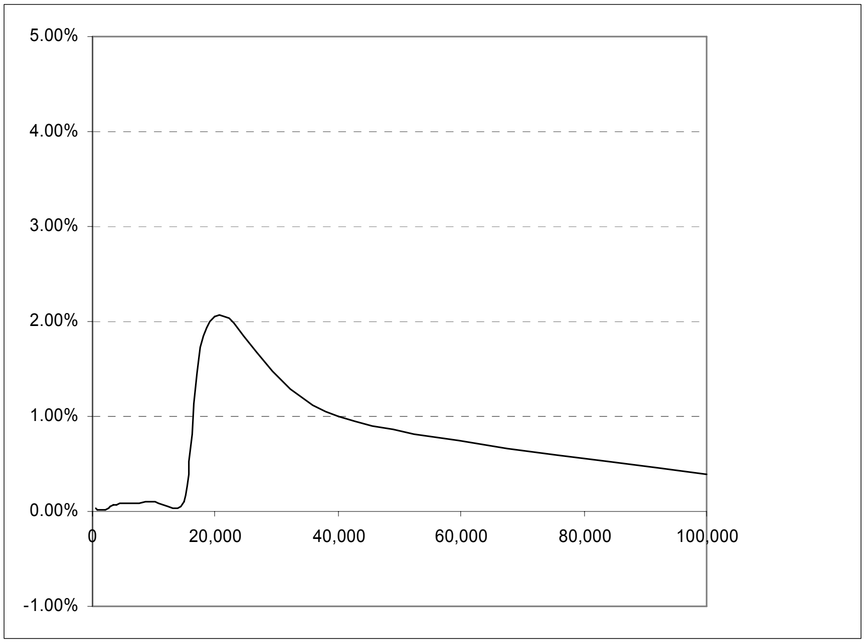
- A fourth energy block charge for all use in excess of 20,000 kW.h/month with the energy charge as follows (reflects current runoff charge with riders):
  - **General Service Non-Government and Government** – an energy charge of 12.88 cents/kWh for energy consumed in excess of 20,000 kW.h/month in the Hydro and Large Diesel rate zones, 15.22 cents/kW.h in the Small Diesel rate zone, and 31.72 cents/kWh in the Old Crow rate zone.

The net effect on bills is less than 1%, peaking at 2% with use at 20,000 kW.h/month in the Hydro and large diesel zones. Refer to Appendix 4.1 YECL A for sample bill comparisons at different consumption levels. Similar to the proposed rate design approach for the residential rate class, Yukon Electrical is not proposing to make significant adjustments to the rate design charges as it believes the current cost environment does not provide sufficient cost signals to make material changes to the current structure.

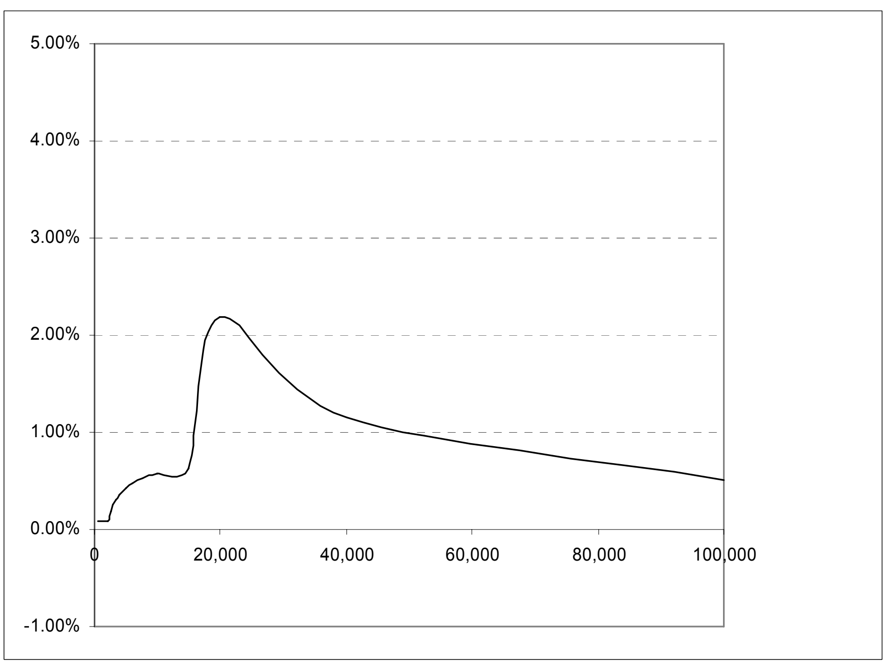
Efficiency or optimum use for inverted rates exists on the basis of price signals. Customers that consume less energy should see the savings linked to the actual cost of the energy saved. Proposing significant changes to the current general service rate structure and rate levels without assessing general service price elasticities throughout customer consumption levels to predict energy and revenue impact to Yukon Electrical would not be prudent in a cost environment when surplus hydro generation serves the vast majority of customers throughout the day and foreseeable future.

The following graph illustrates the sample bill impact in percentages at various consumption levels for general service non-government Graph 3 and general service government Graph 4.

Graph 3: Sample Bill Impact in Percent for General Service Non-Government at Various Consumption Levels (Hydro Zone)



Graph 4: Sample Bill Impact in Percent for General Service Government at Various Consumption Levels (Hydro Zone)



4.5 OTHER 2009 RATE PROPOSALS

4.5.1 Wholesale Rate Schedule 42

Rate Schedule 42 is the basis for Yukon Energy sales to Yukon Electrical. Under Yukon Electrical's rate design option, Rate Schedule 42 is updated to 8.299 cents/kW.h.

To the extent that Rate Schedule 42 links with Yukon Electrical's proposal to implement a new Rider D to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted, Yukon Electrical has reflected further proposed adjustments to Rate Schedule 42 in its Application to implement Rider D, which is provided in this joint Application.

4.5.2 Wholesale Rate Schedule 51

The Companies are seeking to update and clarify the older rate schedule under which Yukon Electrical sells to Yukon Energy at all required locations throughout Yukon. This rate schedule will be an energy-only rate, applicable throughout Yukon at 8.299 cents/kWh based on Yukon Electrical's rate design proposal.

4.5.3 Rider D – Diesel Generation Energy Cost Recovery Rider

This Rider is proposed to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted. Yukon Electrical is proposing this Rider under a separate cover attached to this Application.

APPENDIX 4.1A YECL

RESIDENTIAL AND GENERAL SERVICE RATES AND BILLS UNDER YECL OPTION

Table YECL A4.1
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**-0.50%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - NON GOVERNMENT**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro		Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$377.04
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$0.09	-$0.21	-$0.44	-$0.67	$5.21
	Var. (%)	Var. ($)/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-0.06%	-0.12%	-0.18%	-0.22%	1.40%
Large Diesel		Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$377.04
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$143.14	$175.81	$241.15	$306.49	$371.83
	Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$0.09	-$0.21	-$0.44	-$0.67	$5.21
	Var. (%)	Proposed/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-0.06%	-0.12%	-0.18%	-0.22%	1.40%
Small Diesel		Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$377.04
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$149.28	$188.09	$265.71	$343.34	$420.96
	Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$6.23	-$12.49	-$25.00	-$37.51	-$43.92
	Var. (%)	Proposed/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-4.18%	-6.64%	-9.41%	-10.93%	-10.43%
Old Crow		Proposed Bill	$34.34	$43.86	$53.38	$62.90	$72.42	$86.69	$110.49	$143.05	$175.60	$240.71	$305.82	$464.70
		Existing Bill	$34.34	$43.85	$53.37	$62.89	$72.40	$86.68	$110.47	$192.40	$274.32	$438.18	$602.03	$765.89
	Var. ($)	Proposed - Existing	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	-$49.35	-$98.72	-$197.47	-$296.21	-$301.19
	Var. (%)	Proposed/Existing	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	-25.65%	-35.99%	-45.07%	-49.20%	-39.33%

	0-200	200-300	300-400	400-500	500-600	600-800	800-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
Cumulative percentage of customers	13.8%	19.2%	25.2%	32.2%	40.2%	56.4%	70.1%	84.3%	89.7%	96.1%	98.3%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$11.90	$11.90	$11.90	$11.90
1st. Block Energy (0-1000)	$0.0986	$0.0986	$0.0986	$0.0986
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%
Yukon Interim Electrical Rebate (1st block)	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$14.65	$14.65	$14.65	$14.65
1st. Block Energy (0-1000)	$0.1214	$0.1214	$0.1214	$0.1214
2nd. Block Energy (1001-2500)	$0.1282	$0.1282	$0.1282	$0.1282
3d. Block Energy (2500+)	$0.1399	$0.1399	$0.1399	$0.3077
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Yukon Interim Electrical Rebate (1st I	-$0.0266	-$0.0266	-$0.0266	-$0.0266

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table YECL A4.2
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**0.00%**
GST	**5.00%**

CUSTOMER CLASS: **RESIDENTIAL - GOVERNMENT**

Zone			Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$471.77
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$233.64	$266.45	$332.06	$397.68	$463.29
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	$2.92	$2.83	$2.67	$2.50	$8.47
	Var. (%)	Var. ($)/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	1.25%	1.06%	0.80%	0.63%	1.83%
Large Diesel		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$471.77
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$233.64	$266.45	$332.06	$397.68	$463.29
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	$2.92	$2.83	$2.67	$2.50	$8.47
	Var. (%)	Proposed/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	1.25%	1.06%	0.80%	0.63%	1.83%
Small Diesel		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$471.77
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$239.81	$278.78	$356.73	$434.67	$512.62
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	-$3.25	-$9.50	-$22.00	-$34.50	-$40.86
	Var. (%)	Proposed/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	-1.35%	-3.41%	-6.17%	-7.94%	-7.97%
Old Crow		Proposed Bill	$56.28	$74.73	$93.17	$111.62	$130.06	$157.73	$203.84	$236.56	$269.28	$334.73	$400.18	$559.86
		Existing Bill	$55.66	$73.81	$91.96	$110.10	$128.25	$155.47	$200.83	$283.10	$365.37	$529.90	$694.43	$858.96
	Var. ($)	Proposed - Existing	$0.62	$0.92	$1.22	$1.51	$1.81	$2.26	$3.00	-$46.54	-$96.08	-$195.17	-$294.25	-$299.10
	Var. (%)	Proposed/Existing	1.11%	1.24%	1.32%	1.37%	1.41%	1.45%	1.50%	-16.44%	-26.30%	-36.83%	-42.37%	-34.82%

0-1000	1000-1300	1300-1500	1500-2000	2000-2500	2500-3000	3000 +
78.5%	87.6%	91.2%	95.8%	98.1%	99.1%	100.0%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$15.00	$15.00	$15.00	$15.00
1st. Block Energy (0-1000)	$0.1434	$0.1434	$0.1434	$0.1434
2nd. Block Energy (1000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$18.47	$18.47	$18.47	$18.47
1st. Block Energy (0-1000)	$0.1792	$0.1792	$0.1792	$0.1792
2nd. Block Energy (1001-2500)	$0.1282	$0.1282	$0.1282	$0.1282
3d. Block Energy (2500+)	$0.1399	$0.1399	$0.1399	$0.3077
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table YECL A4.3
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**-0.50%**
GST	**5.00%**

CUSTOMER CLASS: **GENERAL SERVICE - NON GOVERNMENT**

Zone			Monthly Consump. (kW.h) 400 5.00	Monthly Consump. (kW.h) 700 5.00	Monthly Consump. (kW.h) 1000 5.00	Monthly Consump. (kW.h) 1500 5.00	Monthly Consump. (kW.h) 2000 5.00	Monthly Consump. (kW.h) 2500 7.00	Monthly Consump. (kW.h) 3000 8.00	Monthly Consump. (kW.h) 3500 10.00	Monthly Consump. (kW.h) 4000 11.00	Monthly Consump. (kW.h) 5000 14.00	Monthly Consump. (kW.h) 6000 16.00	Monthly Consump. (kW.h) 7500 21.00	Monthly Consump. (kW.h) 10000 27.00	Monthly Consump. (kW.h) 15000 41.00	Monthly Consump. (kW.h) 20000 55.00	Monthly Consump. (kW.h) 40000 110.00	Monthly Consump. (kW.h) 100000 274.00
Hydro		Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$6,081.58	$15,186.05
		Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$325.67	$398.73	$479.50	$552.56	$706.39	$852.51	$1,087.11	$1,460.11	$2,221.55	$2,982.98	$6,021.01	$15,127.38
	Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	$0.12	$0.20	$0.30	$0.38	$0.56	$0.74	$1.00	$1.44	$2.33	$61.20	$60.57	$58.66
	Var. (%)	Var. ($)/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	0.04%	0.05%	0.06%	0.07%	0.08%	0.09%	0.09%	0.10%	0.10%	2.05%	1.01%	0.39%
Large Diesel		Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$6,081.58	$15,186.05
		Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$325.67	$398.73	$479.50	$552.56	$706.39	$852.51	$1,087.11	$1,460.11	$2,221.55	$2,982.98	$6,021.01	$15,127.38
	Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	$0.12	$0.20	$0.30	$0.38	$0.56	$0.74	$1.00	$1.44	$2.33	$61.20	$60.57	$58.66
	Var. (%)	Proposed/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	0.04%	0.05%	0.06%	0.07%	0.08%	0.09%	0.09%	0.10%	0.10%	2.05%	1.01%	0.39%
Small Diesel		Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$6,574.70	$17,158.54
		Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$337.96	$423.29	$516.35	$601.69	$780.08	$950.76	$1,222.21	$1,656.63	$2,540.89	$3,425.15	$6,954.47	$17,534.71
	Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	-$12.17	-$24.36	-$36.55	-$48.75	-$73.13	-$97.52	-$134.10	-$195.07	-$317.01	-$380.96	-$379.76	-$376.18
	Var. (%)	Proposed/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	-3.60%	-5.75%	-7.08%	-8.10%	-9.37%	-10.26%	-10.97%	-11.78%	-12.48%	-11.12%	-5.46%	-2.15%
Old Crow		Proposed Bill	$79.87	$110.82	$141.76	$193.34	$244.93	$325.79	$398.93	$479.80	$552.94	$706.95	$853.24	$1,088.11	$1,461.56	$2,223.88	$3,044.19	$10,022.38	$30,949.24
		Existing Bill	$79.85	$110.79	$141.74	$193.32	$244.90	$424.19	$595.76	$775.05	$946.62	$1,297.48	$1,640.63	$2,170.78	$3,036.36	$4,782.95	$6,529.54	$13,508.19	$34,436.42
	Var. ($)	Proposed - Existing	$0.02	$0.02	$0.02	$0.02	$0.03	-$98.40	-$196.83	-$295.25	-$393.68	-$590.53	-$787.39	-$1,082.67	-$1,574.80	-$2,559.07	-$3,485.36	-$3,485.81	-$3,487.18
	Var. (%)	Proposed/Existing	0.03%	0.02%	0.02%	0.01%	0.01%	-23.20%	-33.04%	-38.09%	-41.59%	-45.51%	-47.99%	-49.87%	-51.86%	-53.50%	-53.38%	-25.81%	-10.13%
			0-400	400-700	700-1000	1000-1500	1500-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers			28.5%	39.2%	47.8%	58.7%	66.6%	72.3%	76.5%		86.0%			94.0%		96.5%	97.7%	99.1%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$7.39	$7.39	$7.39	$7.39
1st. Block Energy (0-2000)	$0.1023	$0.1023	$0.1023	$0.1023
2nd. Block Energy (2001-15000)	$0.1288	$0.1288	$0.1288	$0.1288
3d. Block Energy (15001-20000)	$0.1399	$0.1399	$0.1399	$0.1399
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table YECL A4.4
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate 0.00%
GST 5.00%

CUSTOMER CLASS: **GENERAL SERVICE - MUNICIPAL GOVERNMENT**

Zone			Monthly Consump. (kW.h) 400 5.00	Monthly Consump. (kW.h) 700 5.00	Monthly Consump. (kW.h) 1000 5.00	Monthly Consump. (kW.h) 1500 5.00	Monthly Consump. (kW.h) 2000 5.00	Monthly Consump. (kW.h) 2500 7.00	Monthly Consump. (kW.h) 3000 8.00	Monthly Consump. (kW.h) 3500 10.00	Monthly Consump. (kW.h) 4000 11.00	Monthly Consump. (kW.h) 5000 14.00	Monthly Consump. (kW.h) 6000 16.00	Monthly Consump. (kW.h) 7500 21.00	Monthly Consump. (kW.h) 10000 27.00	Monthly Consump. (kW.h) 15000 41.00	Monthly Consump. (kW.h) 20000 55.00	Monthly Consump. (kW.h) 40000 110.00	Monthly Consump. (kW.h) 100000 274.00
Hydro		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$6,112.89	$15,264.23
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$327.04	$400.40	$481.51	$554.88	$709.35	$856.08	$1,091.66	$1,466.22	$2,230.84	$2,995.46	$6,046.20	$15,190.65
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	$0.43	$0.59	$0.76	$0.92	$1.25	$1.56	$2.06	$2.86	$4.49	$64.39	$66.69	$73.57
	Var. (%)	Var. ($)/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	0.13%	0.15%	0.16%	0.17%	0.18%	0.18%	0.19%	0.20%	0.20%	2.15%	1.10%	0.48%
Large Diesel		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$6,112.89	$15,264.23
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$327.04	$400.40	$481.51	$554.88	$709.35	$856.08	$1,091.66	$1,466.22	$2,230.84	$2,995.46	$6,046.20	$15,190.65
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	$0.43	$0.59	$0.76	$0.92	$1.25	$1.56	$2.06	$2.86	$4.49	$64.39	$66.69	$73.57
	Var. (%)	Proposed/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	0.13%	0.15%	0.16%	0.17%	0.18%	0.18%	0.19%	0.20%	0.20%	2.15%	1.10%	0.48%
Small Diesel		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$6,608.49	$17,246.63
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$339.37	$425.07	$518.51	$604.21	$783.35	$954.74	$1,227.32	$1,663.54	$2,551.49	$3,439.43	$6,983.46	$17,607.81
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	-$11.90	-$24.07	-$36.24	-$48.41	-$72.75	-$97.10	-$133.60	-$194.46	-$316.15	-$379.57	-$374.97	-$361.18
	Var. (%)	Proposed/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	-3.51%	-5.66%	-6.99%	-8.01%	-9.29%	-10.17%	-10.89%	-11.69%	-12.39%	-11.04%	-5.37%	-2.05%
Old Crow		Proposed Bill	$80.28	$111.39	$142.50	$194.34	$246.19	$327.47	$401.00	$482.28	$555.80	$710.60	$857.64	$1,093.72	$1,469.09	$2,235.33	$3,059.86	$10,073.49	$31,106.63
		Existing Bill	$80.18	$111.26	$142.34	$194.13	$245.93	$425.96	$598.24	$778.27	$950.55	$1,302.86	$1,647.42	$2,179.76	$3,048.91	$4,802.70	$6,556.50	$13,563.94	$34,578.51
	Var. ($)	Proposed - Existing	$0.10	$0.13	$0.16	$0.21	$0.26	-$98.48	-$197.24	-$295.99	-$394.75	-$592.26	-$789.78	-$1,086.03	-$1,579.82	-$2,567.37	-$3,496.64	-$3,490.45	-$3,471.88
	Var. (%)	Proposed/Existing	0.12%	0.12%	0.11%	0.11%	0.11%	-23.12%	-32.97%	-38.03%	-41.53%	-45.46%	-47.94%	-49.82%	-51.82%	-53.46%	-53.33%	-25.73%	-10.04%
							0-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers							66.5%	69.8%	72.0%		81.4%			88.7%		91.8%	93.4%	97.6%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$6.00	$6.00	$6.00	$6.00
1st. Block Energy (0-2000)	$0.0831	$0.0831	$0.0831	$0.0831
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$7.39	$7.39	$7.39	$7.39
1st. Block Energy (0-2000)	$0.1023	$0.1023	$0.1023	$0.1023
2nd. Block Energy (2001-15000)	$0.1288	$0.1288	$0.1288	$0.1288
3d. Block Energy (15001-20000)	$0.1399	$0.1399	$0.1399	$0.1399
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

Table YECL A 4.5
3/1/2010

Bill Comparisons: 2010 Proposed Rates Vs. Existing

Income Tax Rebate	**0.00%**
GST	**5.00%**

CUSTOMER CLASS: **GENERAL SERVICE - FED/TERR GOVERNMENT**

Zone			Monthly Consump. (kW.h) 400 5.00	Monthly Consump. (kW.h) 700 5.00	Monthly Consump. (kW.h) 1000 5.00	Monthly Consump. (kW.h) 1500 5.00	Monthly Consump. (kW.h) 2000 5.00	Monthly Consump. (kW.h) 2500 7.00	Monthly Consump. (kW.h) 3000 8.00	Monthly Consump. (kW.h) 3500 10.00	Monthly Consump. (kW.h) 4000 11.00	Monthly Consump. (kW.h) 5000 14.00	Monthly Consump. (kW.h) 6000 16.00	Monthly Consump. (kW.h) 7500 21.00	Monthly Consump. (kW.h) 10000 27.00	Monthly Consump. (kW.h) 15000 41.00	Monthly Consump. (kW.h) 20000 55.00	Monthly Consump. (kW.h) 40000 110.00	Monthly Consump. (kW.h) 100000 274.00
Hydro		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$6,929.69	$16,928.25
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$599.26	$677.79	$769.23	$847.76	$1,017.73	$1,174.78	$1,436.19	$1,841.75	$2,678.68	$3,515.62	$6,850.45	$16,842.04
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	$1.10	$1.73	$2.38	$3.01	$4.28	$5.54	$7.46	$10.63	$16.99	$76.90	$79.23	$86.21
	Var. (%)	Var. ($)/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	0.18%	0.26%	0.31%	0.35%	0.42%	0.47%	0.52%	0.58%	0.63%	2.19%	1.16%	0.51%
Large Diesel		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$6,929.69	$16,928.25
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$599.26	$677.79	$769.23	$847.76	$1,017.73	$1,174.78	$1,436.19	$1,841.75	$2,678.68	$3,515.62	$6,850.45	$16,842.04
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	$1.10	$1.73	$2.38	$3.01	$4.28	$5.54	$7.46	$10.63	$16.99	$76.90	$79.23	$86.21
	Var. (%)	Proposed/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	0.18%	0.26%	0.31%	0.35%	0.42%	0.47%	0.52%	0.58%	0.63%	2.19%	1.16%	0.51%
Small Diesel		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$7,425.29	$18,910.65
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$611.59	$702.45	$806.22	$897.09	$1,091.72	$1,273.44	$1,571.85	$2,039.07	$2,999.33	$3,959.59	$7,787.72	$19,259.19
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	-$11.23	-$22.93	-$34.62	-$46.32	-$69.71	-$93.12	-$128.20	-$186.69	-$303.65	-$367.07	-$362.43	-$348.54
	Var. (%)	Proposed/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	-1.84%	-3.26%	-4.29%	-5.16%	-6.39%	-7.31%	-8.16%	-9.16%	-10.12%	-9.27%	-4.65%	-1.81%
Old Crow		Proposed Bill	$153.36	$219.90	$286.45	$397.36	$508.27	$600.36	$679.52	$771.60	$850.76	$1,022.01	$1,180.33	$1,443.66	$1,852.38	$2,695.68	$3,592.52	$10,890.29	$32,770.65
		Existing Bill	$153.22	$219.70	$286.19	$397.00	$507.82	$698.18	$875.62	$1,065.98	$1,243.43	$1,611.23	$1,966.12	$2,524.29	$3,424.43	$5,250.54	$7,076.66	$14,368.19	$36,229.89
	Var. ($)	Proposed - Existing	$0.14	$0.20	$0.26	$0.36	$0.46	-$97.82	-$196.10	-$294.38	-$392.66	-$589.22	-$785.80	-$1,080.63	-$1,572.05	-$2,554.87	-$3,484.13	-$3,477.91	-$3,459.25
	Var. (%)	Proposed/Existing	0.09%	0.09%	0.09%	0.09%	0.09%	-14.01%	-22.40%	-27.62%	-31.58%	-36.57%	-39.97%	-42.81%	-45.91%	-48.66%	-49.23%	-24.21%	-9.55%
							0-2000	2000-2500	2500-3000		3000-5000			5000-10000		10000-15000	15000-20000	20000-40000	40000+
Cumulative percentage of customers							63.3%	67.5%	70.7%		78.4%			87.0%		90.4%	92.5%	96.6%	100%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	$10.00	$10.00	$10.00	$10.00
1st. Block Energy (0-2000)	$0.1745	$0.1745	$0.1745	$0.1745
2nd. Block Energy (2000+)	$0.1045	$0.1045	$0.1236	$0.2577
Rider J	12.46%	12.46%	12.46%	12.46%
Rider F (Fuel Adjustment Rider)	-$0.0035	-$0.0035	-$0.0035	-$0.0035
Rider R	10.53%	10.53%	10.53%	10.53%

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	$12.31	$12.31	$12.31	$12.31
1st. Block Energy (0-2000)	$0.2148	$0.2148	$0.2148	$0.2148
2nd. Block Energy (2001-15000)	$0.1297	$0.1297	$0.1297	$0.1297
3d. Block Energy (15001-20000)	$0.1399	$0.1399	$0.1399	$0.1399
4th. Block Energy (20000+)	$0.1286	$0.1286	$0.1522	$0.3172
Rider F	-$0.0035	-$0.0035	-$0.0035	-$0.0035

APPENDIX 4.1B YECL

YUKON ELECTRICAL SCHEDULES

APPENDIX 4.1B YECL – YUKON ELECTRICAL SCHEDULES

Schedule 4.1	Provides a summary of revenue to cost ratios by rate class on Yukon Electrical's proposed 2009 rates.
Schedule 4.2	Provides a comparison of revenues at existing rates and Yukon Electrical's proposed 2009 rates.
Schedule 4.3	Provides a detailed summary of revenue to cost ratios by rate class on proposed 2009 rates.
Schedule 4.4	Provides a description of rate codes.
Schedule 4.5	Provides a comparison of the existing rates and Yukon Electrical's proposed 2009 rates.
Schedule 4.6	Provides the billing determinants for each rate within each rate class in 2009 at existing rates.
Schedule 4.7	Provides the billing determinants for each rate within each rate class in 2009 at Yukon Electrical's 2009 proposed rates.

Schedule YECL B 4.1

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application

Revenue to Cost Summary on Proposed Rates

Line No.	Rate	2009 Revenue ($000)	2009 Cost ($000)	2009 Rev/Cost
1	**Residential Non-Government Rate**	$19,412	$24,592	78.9%
2	**Residential Government Rate**	$422	$401	105.3%
3	**General Service Non-Government Rate**	$17,372	$14,909	116.5%
4	**General Service Government**	$9,272	$6,442	143.9%
5	**Industrial Rate**	$3,203	$2,946	108.7%
6	**Street Light Rate**	$985	$1,432	68.8%
7	**Sentinel Light Rate**	$166	$112	148.4%
8	**Secondary Sales**	$546	NA	NA
9	**Other**	$952	NA	NA
10	**COMPANY TOTAL**	**$52,331**	**$50,833**	**102.9%**

Schedule YECL B 4.2

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application

Comparison of Revenue (2009 Existing Rates vs 2009 Proposed Rates)

Line No.	Rate	2009 Existing Rates ($000)	2009 Proposed Rates ($000)	Increase%
1	Residential Non-Government Rate	$15,767	$19,412	23.1%
2	Residential Government Rate	$343	$422	23.1%
3	General Service Non-Government Rate	$14,110	$17,372	23.1%
4	General Service Government	$7,531	$9,272	23.1%
5	Industrial Rate	$3,142	$3,203	1.9%
6	Street Light Rate	$800	$985	23.1%
7	Sentinel Light Rate	$135	$166	23.1%
8	Secondary Sales	$546	$546	0.0%
9	Other	$952	$952	0.0%
8	**COMPANY TOTAL**	**$43,326**	**$52,331**	**20.8%**

Schedule YECL B 4.3

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application

Revenue to Cost Details on 2009 Proposed Rates

Line No.	Rate	2009 Customer ($000's)	Demand ($000's)	Energy ($000's)	Riders ($000's)	Other ($000's)	Total ($000's)
1	**Residential Non-Government Rate**						
2	**Cost**	$6,402	$6,509	$11,681			$24,592
3	**Revenue**	$2,484	$0	$16,928	$0		$19,412
4	**R/C**	38.8%	0.0%	144.9%			78.9%
5	**Residential Government Rate**						
6	**Cost**	$116	$102	$183			$401
7	**Revenue**	$56	$0	$366	$0		$422
8	**R/C**	48.4%	0.0%	199.7%			105.3%
9	**General Service Non-Government Rate**						
10	**Cost**	$1,207	$4,069	$9,632			$14,909
11	**Revenue**	$0	$3,580	$13,792	$0		$17,372
12	**R/C**	0.0%	88.0%	143.2%			116.5%
13	**General Service Government**						
14	**Cost**	$260	$1,819	$4,363			$6,442
15	**Revenue**	$0	$2,040	$7,232	$0		$9,272
16	**R/C**	0.0%	112.1%	165.8%			143.9%
17	**Industrial Rate**						
18	**Cost**	$0	$676	$2,270			$2,946
19	**Revenue**	$0	$936	$2,206	$61		$3,203
20	**R/C**	0.0%	138.5%	97.2%			108.7%
21	**Street Light Rate**						
22	**Cost**	$898	$212	$322			$1,432
23	**Revenue**	$526	$460	$0	$0		$985
24	**R/C**	58.6%	216.8%	0.0%			68.8%
25	**Sentinel Light**						
26	**Cost**	$21	$37	$55			$112
27	**Revenue**	$166	$0	$0	$0		$166
28	**R/C**	807.3%	0.0%	0.0%			148.4%
29	**Secondary Sales**						
30	**Cost**	NA	NA	NA			NA
31	**Revenue**	$0	$0	$546	$0		$546
32	**R/C**	NA	NA	NA			NA
33	**Other**						
34	**Cost**	NA	NA	NA			NA
35	**Revenue**	$0	$0	$0	$0	$952	$952
36	**R/C**	NA	NA	NA			NA
37	**COMPANY TOTAL**						
38	**Cost**	$8,903	$13,424	$28,506			$50,833
39	**Revenue**	$3,232	$7,015	$41,071	$61	$952	$52,331
40	**R/C**	36.3%	52.3%	144.1%			102.9%

Schedule YECL B 4.4

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application

Description of Rate Codes

Residential	Use Class	Zone	Government
1160	Residential	Hydro	Non-Government
1260	Residential	Small Diesel	Non-Government
1360	Residential	Large Diesel	Non-Government
1460	Residential	Old Crow	Non-Government
1180	Residential	Hydro	Government
1280	Residential	Small Diesel	Government
1380	Residential	Large Diesel	Government
1480	Residential	Old Crow	Government

General Service	Use Class	Zone	Government
2160	General Service	Hydro	Non-Government
2260	General Service	Small Diesel	Non-Government
2360	General Service	Large Diesel	Non-Government
2460	General Service	Old Crow	Non-Government
2170	General Service	Hydro	Government - Municipal
2270	General Service	Small Diesel	Government - Municipal
2370	General Service	Large Diesel	Government - Municipal
2470	General Service	Old Crow	Government - Municipal
2180	General Service	Hydro	Government - Federal/Territorial
2280	General Service	Small Diesel	Government - Federal/Territorial
2380	General Service	Large Diesel	Government - Federal/Territorial
2480	General Service	Old Crow	Government - Federal/Territorial

Secondary Energy	Use Class
3200	Secondary Energy

Industrial	Use Class	Description
3900	Industrial	

Street Lights	Use Class	Classification
Rate Schedule 61	Street Light	
Rate Schedule 66	Street Light	
Rate Schedule 67		
67 - 250 W	Street Light	250 W Mercury Vapor
67 - 400 W	Street Light	400 W Mercury Vapor

Sentinel Lights	Use Class	Classification
Rate Schedule 75		
Rate Schedule 76		
75/76 - Normal	Sentinel Light	Normal: Normal 12-month unmeterd service - various wattages
75/76 - E & M	Sentinel Light	E & M: Energy and Maintenance only (Cust. Pays installation costs) - various wattages
75/76 - Meter	Sentinel Light	Meter: 12-month service through customer meter - various wattages

Schedule YECL B 4.5

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application

Comparison of Existing and Proposed Rates

Summary of Existing 2009 Price Schedule Charges

Residential

	Customer	Demand	Energy 1	Energy 2
1160	11.90 $/month		0.0986 $/kW.h	0.1045 $/kW.h
1260	11.90 $/month		0.0986 $/kW.h	0.1236 $/kW.h
1360	11.90 $/month		0.0986 $/kW.h	0.1045 $/kW.h
1460	11.90 $/month		0.0986 $/kW.h	0.2577 $/kW.h
1180	15.00 $/month		0.1434 $/kW.h	0.1045 $/kW.h
1280	15.00 $/month		0.1434 $/kW.h	0.1236 $/kW.h
1380	15.00 $/month		0.1434 $/kW.h	0.1045 $/kW.h
1480	15.00 $/month		0.1434 $/kW.h	0.2577 $/kW.h

General Service

	Customer	Demand	Energy 1	Energy 2
2160		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2260		$6.00 /kW	0.0831 $/kW.h	0.1236 $/kW.h
2360		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2460		$6.00 /kW	0.0831 $/kW.h	0.2577 $/kW.h
2170		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2270		$6.00 /kW	0.0831 $/kW.h	0.1236 $/kW.h
2370		$6.00 /kW	0.0831 $/kW.h	0.1045 $/kW.h
2470		$6.00 /kW	0.0831 $/kW.h	0.2577 $/kW.h
2180		$10.00 /kW	0.1745 $/kW.h	0.1045 $/kW.h
2280		$10.00 /kW	0.1745 $/kW.h	0.1236 $/kW.h
2380		$10.00 /kW	0.1745 $/kW.h	0.1045 $/kW.h
2480		$10.00 /kW	0.1745 $/kW.h	0.2577 $/kW.h

Secondary Energy

	Customer	Demand	Energy
3200			0.07200 $/kW.h

Industrial

	Customer	Demand	Energy
3900		$15.00 /kW	0.07600 $/kW.h

Street Lights

	Customer	Demand	Energy	High Mast Charge
61/66	6.36 $/month	$4.0300 /kW		1.03 $/month
67 - 250 W	15.47 $/month			
67 - 400 W	23.66 $/month			

Sentinel Lights

	Customer	Demand	Energy	Energy 2
75/76 - Normal - 100 W	11.64 $/month			
75/76 - E & M - 100 W	6.46 $/month			
75/76 - Meter - 100 W	7.34 $/month			
75/76 - Normal - 175 W	14.18 $/month			
75/76 - E & M - 175 W	9.87 $/month			
75/76 - Meter - 175 W	7.97 $/month			
75/76 - Normal - 250 W	17.34 $/month			
75/76 - E & M - 250 W	13.16 $/month			
75/76 - Meter - 250 W	8.23 $/month			
75/76 - Normal - 400 W	23.03 $/month			
75/76 - E & M - 400 W	18.61 $/month			
75/76 - Meter - 400 W	7.84 $/month			
75/76 - Normal - 400 W Fl	25.44 $/month			
75/76 - E & M - 400 W FL	17.75 $/month			
75/76 - Meter - 400 W FL	10.26 $/month			

Summary of Proposed 2009 Price Schedule Charges

Residential

	Customer	Demand	Energy 1	Energy 2	Energy 3
1160	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1260	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1360	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1460	14.65 $/month		0.1214 $/kW.h	0.1282 $/kW.h	0.3077 $/kW.h
1180	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1280	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1380	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.1399 $/kW.h
1480	18.47 $/month		0.1792 $/kW.h	0.1282 $/kW.h	0.3077 $/kW.h

General Service

	Customer	Demand	Energy 1	Energy 2	Energy 3	Energy 4
2160		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2260		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1522 $/kW.h
2360		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2460		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.3172 $/kW.h
2170		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2270		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1522 $/kW.h
2370		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2470		$7.39 /kW	0.1023 $/kW.h	0.1288 $/kW.h	0.1399 $/kW.h	0.3172 $/kW.h
2180		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2280		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.1522 $/kW.h
2380		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.1286 $/kW.h
2480		$12.31 /kW	0.2148 $/kW.h	0.1297 $/kW.h	0.1399 $/kW.h	0.3172 $/kW.h

Secondary Energy

	Customer	Demand	Energy
3200			0.0720 $/kW.h

Industrial

	Customer	Demand	Energy	Rider F
3900		$15.00 /kW	0.07600 $/kW.h	0.00211 $/kW.h

Street Lights

	Customer	Demand	Energy	High Mast Charge
61/66	7.83 $/month	$4.9616 /kW		1.27 $/month
67 - 250 W	19.05 $/month			
67 - 400 W	29.13 $/month			

Sentinel Lights

	Customer	Demand	Energy	Energy 2
75/76 - Normal - 100 W	14.33 $/month			
75/76 - E & M - 100 W	7.95 $/month			
75/76 - Meter - 100 W	9.04 $/month			
75/76 - Normal - 175 W	17.46 $/month			
75/76 - E & M - 175 W	12.15 $/month			
75/76 - Meter - 175 W	9.81 $/month			
75/76 - Normal - 250 W	21.35 $/month			
75/76 - E & M - 250 W	16.20 $/month			
75/76 - Meter - 250 W	10.13 $/month			
75/76 - Normal - 400 W	28.35 $/month			
75/76 - E & M - 400 W	22.91 $/month			
75/76 - Meter - 400 W	9.65 $/month			
75/76 - Normal - 400 W Fl	31.32 $/month			
75/76 - E & M - 400 W FL	21.85 $/month			
75/76 - Meter - 400 W FL	12.63 $/month			

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

Residential-Non Government

Billing Determinants	Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h) 2009	Block 2 Energy (kW.h)	Total Energy (kW.h)
YECL					
1160 NG - H	11,570		94,533,720	24,081,364	118,615,084
1260 NG - SD	308		962,877	153,601	1,116,479
1360 NG - LD	682		5,309,797	818,261	6,128,058
1460 NG - OC	125		763,968	110,080	874,048
YEC					
1160 NG - H	1,443		9,179,779	1,724,179	10,903,958
1260 NG - SD	0		0	0	0
1360 NG - LD	0		0	0	0
1460 NG - OC	0		0	0	0
Total					
1160 NG - H	13,013		103,713,498	25,805,544	129,519,042
1260 NG - SD	308		962,877	153,601	1,116,479
1360 NG - LD	682		5,309,797	818,261	6,128,058
1460 NG - OC	125		763,968	110,080	874,048
Residential-Non Government	14,128		110,750,140	26,887,486	137,637,626

Existing Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
1160 NG - H	11.90		9.86	10.45	0.000%	0.000%
1260 NG - SD	11.90		9.86	12.36	0.000%	0.000%
1360 NG - LD	11.90		9.86	10.45	0.000%	0.000%
1460 NG - OC	11.90		9.86	25.77	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL							
1160 NG - H	1,652,153		9,321,025	2,516,503	0	0	**13,489,681**
1260 NG - SD	43,923		94,940	18,985	0	0	**157,848**
1360 NG - LD	97,432		523,546	85,508	0	0	**706,487**
1460 NG - OC	17,886		75,327	28,368	0	0	**121,581**
Revenue - YEC							
1160 NG - H	206,108		905,126	180,177	0	0	**1,291,411**
1260 NG - SD	0		0	0	0	0	**0**
1360 NG - LD	0		0	0	0	0	**0**
1460 NG - OC	0		0	0	0	0	**0**
Revenue - Sub Total							
1160 NG - H	1,858,261		10,226,151	2,696,679	0	0	**14,781,092**
1260 NG - SD	43,923		94,940	18,985	0	0	**157,848**
1360 NG - LD	97,432		523,546	85,508	0	0	**706,487**
1460 NG - OC	17,886		75,327	28,368	0	0	**121,581**
Revenue ($)	2,017,502		10,919,964	2,829,540	0	0	**15,767,007**

Schedule YECL B 4.6

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

Residential-Government

2009

Billing Determinants	Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Total Energy (kW.h)
YECL					
1180 G - H	155		994,502	341,744	1,336,245
1280 G - SD	26		172,183	40,679	212,862
1380 G - LD	30		186,366	25,400	211,766
1480 G - OC	12		81,418	39,051	120,470
YEC					
1180 G - H	29		233,131	45,963	279,095
1280 G - SD	0		0	0	0
1380 G - LD	0		0	0	0
1480 G - OC	0		0	0	0
Total					
1180 G - H	184		1,227,633	387,707	1,615,340
1280 G - SD	26		172,183	40,679	212,862
1380 G - LD	30		186,366	25,400	211,766
1480 G - OC	12		81,418	39,051	120,470
Residential-Government	252		1,667,600	492,838	2,160,438

Existing Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
1160 G - H	15.00		14.34	10.45	0.000%	0.000%
1260 G - SD	15.00		14.34	12.36	0.000%	0.000%
1360 G - LD	15.00		14.34	10.45	0.000%	0.000%
1460 G - OC	15.00		14.34	25.77	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - YECL							
1160 G - H	27,924		142,612	35,712	0	0	**206,248**
1260 G - SD	4,680		24,691	5,028	0	0	**34,399**
1360 G - LD	5,406		26,725	2,654	0	0	**34,785**
1460 G - OC	2,160		11,675	10,064	0	0	**23,899**
Revenue - YEC							
1160 G - H	5,265		33,431	4,803	0	0	**43,499**
1260 G - SD	0		0	0	0	0	**0**
1360 G - LD	0		0	0	0	0	**0**
1460 G - OC	0		0	0	0	0	**0**
Revenue - Sub Total							
1160 G - H	33,189		176,043	40,515	0	0	**249,747**
1260 G - SD	4,680		24,691	5,028	0	0	**34,399**
1360 G - LD	5,406		26,725	2,654	0	0	**34,785**
1460 G - OC	2,160		11,675	10,064	0	0	**23,899**
Revenue ($)	45,435		239,134	58,261	0	0	**342,830**

Schedule YECL B 4.6

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

General Service-Non Government

2009

Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
YECL					
2160 NG - H	1,737	336,399	24,820,709	54,623,327	79,444,037
2260 NG - SD	92	7,311	830,009	801,336	1,631,346
2360 NG - LD	157	18,643	1,855,569	2,328,879	4,184,447
2460 NG - OC	16	1,551	177,660	187,117	364,777
2170 GM - H	165	52,808	2,008,485	12,400,137	14,408,622
2270 GM - SD	0	0	0	0	0
2370 GM - LD	18	4,751	256,304	829,166	1,085,471
2470 GM - OC	0	0	0	0	0
YEC					
2160 NG - H	299	46,355	2,358,146	6,759,783	9,117,929
2260 NG - SD	0	0	0	0	0
2360 NG - LD	0	0	0	0	0
2460 NG - OC	0	0	0	0	0
2170 GM - H	55	16,580	452,883	2,808,385	3,261,268
2270 GM - SD	0	0	0	0	0
2370 GM - LD	0	0	0	0	0
2470 GM - OC	0	0	0	0	0
Total					
2160 NG - H	2,037	382,754	27,178,855	61,383,111	88,561,966
2260 NG - SD	92	7,311	830,009	801,336	1,631,346
2360 NG - LD	157	18,643	1,855,569	2,328,879	4,184,447
2460 NG - OC	16	1,551	177,660	187,117	364,777
2170 GM - H	220	69,388	2,461,368	15,208,522	17,669,889
2270 GM - SD	0	0	0	0	0
2370 GM - LD	18	4,751	256,304	829,166	1,085,471
2470 GM - OC	0	0	0	0	0
General Service-Non Government	2,539	484,399	32,759,765	80,738,130	113,497,895

Existing Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
2160 NG - H 2170 GM - H	0.00	6.00	8.31	10.45	0.000%	0.000%
2260 NG - SD 2270 GM - SD	0.00	6.00	8.31	12.36	0.000%	0.000%
2360 NG - LD 2370 GM - LD	0.00	6.00	8.31	10.45	0.000%	0.000%
2460 NG - OC 2470 GM - OC	0.00	6.00	8.31	25.77	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL							
2160 NG - H	0	2,018,397	2,062,601	5,708,138	0	0	**9,789,135**
2260 NG - SD	0	43,868	68,974	99,045	0	0	**211,887**
2360 NG - LD	0	111,858	154,198	243,368	0	0	**509,423**
2460 NG - OC	0	9,309	14,764	48,220	0	0	**72,293**
2170 GM - H	0	316,847	166,905	1,295,814	0	0	**1,779,566**
2270 GM - SD	0	0	0	0	0	0	**0**
2370 GM - LD	0	28,506	21,299	86,648	0	0	**136,453**
2470 GM - OC	0	0	0	0	0	0	**0**
Revenue - YEC							
2160 NG - H	0	278,130	195,962	706,397	0	0	**1,180,489**
2260 NG - SD	0	0	0	0	0	0	**0**
2360 NG - LD	0	0	0	0	0	0	**0**
2460 NG - OC	0	0	0	0	0	0	**0**
2170 GM - H	0	99,480	37,635	293,476	0	0	**430,591**
2270 GM - SD	0	0	0	0	0	0	**0**
2370 GM - LD	0	0	0	0	0	0	**0**
2470 GM - OC	0	0	0	0	0	0	**0**
Revenue - Sub Total							
2160 NG - H	0	2,296,526	2,258,563	6,414,535	0	0	**10,969,624**
2260 NG - SD	0	43,868	68,974	99,045	0	0	**211,887**
2360 NG - LD	0	111,858	154,198	243,368	0	0	**509,423**
2460 NG - OC	0	9,309	14,764	48,220	0	0	**72,293**
2170 GM - H	0	416,327	204,540	1,589,291	0	0	**2,210,157**
2270 GM - SD	0	0	0	0	0	0	**0**
2370 GM - LD	0	28,506	21,299	86,648	0	0	**136,453**
2470 GM - OC	0	0	0	0	0	0	**0**
Revenue ($)	0	2,906,394	2,722,336	8,481,106	0	0	**14,109,837**

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

General Service-Government

Billing Determinants	Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Total Energy (kW.h)
				2009	
YECL					
2180 GFT - H	337	128,900	4,617,896	36,341,345	40,959,241
2280 GFT - SD	51	3,972	406,476	344,619	751,095
2380 GFT - LD	36	8,468	535,831	1,571,207	2,107,037
2480 GFT - OC	20	2,522	220,500	208,620	429,120
YEC					
2180 GFT - H	103	21,854	837,208	6,327,033	7,164,240
2280 GFT - SD	0	0	0	0	0
2380 GFT - LD	0	0	0	0	0
2480 GFT - OC	0	0	0	0	0
Total					
2180 GFT - H	440	150,753	5,455,104	42,668,377	48,123,481
2280 GFT - SD	51	3,972	406,476	344,619	751,095
2380 GFT - LD	36	8,468	535,831	1,571,207	2,107,037
2480 GFT - OC	20	2,522	220,500	208,620	429,120
General Service-Government	547	165,716	6,617,910	44,792,823	51,410,733

Existing Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
2180 GFT - H	0.00	10.00	17.45	10.45	0.000%	0.000%
2280 GFT - SD	0.00	10.00	17.45	12.36	0.000%	0.000%
2380 GFT - LD	0.00	10.00	17.45	10.45	0.000%	0.000%
2480 GFT - OC	0.00	10.00	17.45	25.77	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - YECL							
2180 GFT - H	0	1,288,998	805,823	3,797,671	0	0	**5,892,492**
2280 GFT - SD	0	39,717	70,930	42,595	0	0	**153,242**
2380 GFT - LD	0	84,684	93,502	164,191	0	0	**342,378**
2480 GFT - OC	0	25,223	38,477	53,761	0	0	**117,462**
Revenue - YEC							
2180 GFT - H	0	218,535	146,093	661,175	0	0	**1,025,803**
2280 GFT - SD	0	0	0	0	0	0	**0**
2380 GFT - LD	0	0	0	0	0	0	**0**
2480 GFT - OC	0	0	0	0	0	0	**0**
Revenue - Sub Total							
2180 GFT - H	0	1,507,533	951,916	4,458,845	0	0	**6,918,294**
2280 GFT - SD	0	39,717	70,930	42,595	0	0	**153,242**
2380 GFT - LD	0	84,684	93,502	164,191	0	0	**342,378**
2480 GFT - OC	0	25,223	38,477	53,761	0	0	**117,462**
Revenue ($)	0	1,657,158	1,154,825	4,719,393	0	0	**7,531,376**

Schedule YECL B 4.6

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

Industrial

2009

Billing Determinants		**Number of Customers Billed/year**	**Demand kVA**	**Total Energy (kW.h)**
YECL				
	39	0	0	0
YEC				
	39	1	62400	29,023,000
Total				
	39	1	62,400	29,023,000
Industrial		1	62,400	29,023,000

Existing Rate		Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kVA.)	Energy Charge (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)	Rider F Charge (¢ / kW.h)
	39	0.00	15.00	7.600	0.00%	0.00%	0.000

		Customer Revenue	Demand Revenue	Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue		**Total Rate Revenue**
Revenue - YECL								
	39	0	0	0	0	0	0	**0**
Revenue - YEC								
	39	0	936,000	2,205,748	0	0	0	**3,141,748**
Revenue - Sub Total								
	39	0	936,000	2,205,748	0	0	0	**3,141,748**
Revenue ($)		0	936,000	2,205,748	0	0	0	**3,141,748**

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

Street Lights - Rate 61/66

2009

Billing Determinants		**Number of Customers Billed/year**	**Demand W**	**Total Energy (kW.h)**	**Highmast Customers Billed/year**
YECL					
	61/66	4,825	8,578,680	3,438,012	160
YEC					
	61/66	567	685,400	274,112	0
Total					
	61/66	5,392	9,264,080	3,712,124	160
Street Lights - Rate 61/66		5,392	9,264,080	3,712,124	160

Existing Rate		Customer Charge ($/ cust/ mo.)	Demand Charge (¢ / W/ mo.)	Energy Chg (¢ / kW.h)	Highmast Charge ($/ cust/ mo.)	Rider J Charge Revenue	Rider R Charge (%)
	61/66	6.36	4.03		1.03	0.000%	0.000%

Revenue ($)		Customer Revenue	Demand Revenue	Energy Revenue	Highmast Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL								
	61/66	368,244	345,721		1,978	0	0	**715,942**
Revenue - YEC								
	61/66	43,305	27,622		0	0	0	**70,927**
Revenue - Sub Total								
	61/66	411,549	373,342		1,978	0	0	**786,869**
Revenue ($)		411,549	373,342		1,978	0	0	**786,869**

Street Lights - Rate 67

2009

Billing Determinants		**Number of Customers Billed/year**	**Demand W**	**Total Energy (kW.h)**
YECL				
	67 - 250 W	47	141,000	55,428
	67 - 400 W	15	72,000	28,440
YEC				
	67 - 250 W	0	0	0
	67 - 400 W	2	9,600	3,792
Total				
	67 - 250 W	47	141,000	55,428
	67 - 400 W	17	81,600	32,232
Street Lights - Rate 67		64	222,600	87,660

Existing Rate		Customer Charge ($/ cust/ mo.)	Demand Charge (¢ / W/ mo.)	Energy Chg (¢ / kW.h)	Rider J Charge Revenue	Rider R Charge (%)
	67 - 250 W	15.47			0.000%	0.000%
	67 - 400 W	23.66			0.000%	0.000%

Revenue ($)		Customer Revenue	Demand Revenue	Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL							
	67 - 250 W	8,725			0	0	**8,725**
	67 - 400 W	4,259			0	0	**4,259**
Revenue - YEC							
	67 - 250 W	0			0	0	**0**
	67 - 400 W	568			0	0	**568**
Revenue - Sub Total							
	67 - 250 W	8,725			0	0	**8,725**
	67 - 400 W	4,827			0	0	**4,827**
Revenue ($)		13,552			0	0	**13,552**

Schedule YECL B 4.6

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

Sentinal Lights - Rate 75/76

2009

Billing Determinants	Number of Customers Billed/year	Demand W	Total Energy (kW.h)
Total			
75/76 - Normal - 100 W	393	471,700	188,680
75/76 - E & M - 100 W	314	376,800	150,720
75/76 - Meter - 100 W	7	8,400	0
75/76 - Normal - 175 W	150	315,000	129,600
75/76 - E & M - 175 W	0	0	0
75/76 - Meter - 175 W	17	35,700	0
75/76 - Normal - 250 W	1	3,000	1,164
75/76 - E & M - 250 W	0	0	0
75/76 - Meter - 250 W	0	0	0
75/76 - Normal - 400 W	2	9,600	3,816
75/76 - E & M - 400 W	0	0	0
75/76 - Meter - 400 W	0	0	0
75/76 - Normal - 400 W FL	85	408,000	162,180
75/76 - E & M - 400 W FL	5	24,000	9,540
75/76 - Meter - 400 W FL	3	14,400	0
Sentinal Lights - Rate 75/76	977	1,666,600	645,700

Normal: Normal 12-month unmeterd service
E & M: Energy and Maintenance only
(Cust. Pays installation costs)
Meter: 12-month service through customer meter

Existing Rate	Customer Charge ($/ cust/ mo.)	Demand Charge (¢ / W/ mo.)	Energy Chg (¢ / kW.h)	Rider J Charge Revenue	Rider R Charge (%)
75/76 - Normal - 100 W	11.64			0.000%	0.000%
75/76 - E & M - 100 W	6.46			0.000%	0.000%
75/76 - Meter - 100 W	7.34			0.000%	0.000%
75/76 - Normal - 175 W	14.18			0.000%	0.000%
75/76 - E & M - 175 W	9.87			0.000%	0.000%
75/76 - Meter - 175 W	7.97			0.000%	0.000%
75/76 - Normal - 250 W	17.34			0.000%	0.000%
75/76 - E & M - 250 W	13.16			0.000%	0.000%
75/76 - Meter - 250 W	8.23			0.000%	0.000%
75/76 - Normal - 400 W	23.03			0.000%	0.000%
75/76 - E & M - 400 W	18.61			0.000%	0.000%
75/76 - Meter - 400 W	7.84			0.000%	0.000%
75/76 - Normal - 400 W FL	25.44			0.000%	0.000%
75/76 - E & M - 400 W FL	17.75			0.000%	0.000%
75/76 - Meter - 400 W FL	10.26			0.000%	0.000%

Revenue ($)	Customer Revenue	Demand Revenue	Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - Sub Total						
75/76 - Normal - 100 W	54,906			0	0	**54,906**
75/76 - E & M - 100 W	24,341			0	0	**24,341**
75/76 - Meter - 100 W	617			0	0	**617**
75/76 - Normal - 175 W	25,524			0	0	**25,524**
75/76 - E & M - 175 W	0			0	0	**0**
75/76 - Meter - 175 W	1,626			0	0	**1,626**
75/76 - Normal - 250 W	208			0	0	**208**
75/76 - E & M - 250 W	0			0	0	**0**
75/76 - Meter - 250 W	0			0	0	**0**
75/76 - Normal - 400 W	553			0	0	**553**
75/76 - E & M - 400 W	0			0	0	**0**
75/76 - Meter - 400 W	0			0	0	**0**
75/76 - Normal - 400 W FL	25,949			0	0	**25,949**
75/76 - E & M - 400 W FL	1,065			0	0	**1,065**
75/76 - Meter - 400 W FL	369			0	0	**369**
Revenue ($)	135,158			0	0	**135,158**

Schedule YECL B 4.6

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

Secondary Sales

Billing Determinants		**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**		
				2009				
YECL								
	3200	23		6,954,050		6,954,050		
YEC								
	3200			629,950		629,950		
Total								
	3200	23		7,584,000	0	7,584,000		
Secondary Sales		23		7,584,000	0	7,584,000		
Existing Rate		Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)	
	3200	0.00		7.20	0	0.00%	0.00%	
		Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL								
	3200	0		500,692	0	0	0	**500,692**
Revenue - YEC								
	3200	0		45,356	0	0	0	**45,356**
Revenue - Sub Total								
	3200	0		546,048	0	0	0	**546,048**
Revenue ($)		0		546,048	0	0	0	**546,048**

Schedule YECL B 4.6

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Existing Rates

TOTAL RATE REVENUE - EXISTING RATE

Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Rider F Charge Revenue			Total Rate Revenue
					2009					
Revenues - YECL										
Residential										
Non-Government	1,811,394		10,014,838	2,649,364	0	0				**14,475,596**
Government	40,170		205,703	53,458	0	0				**299,331**
General Service										
Non-Government	0	2,528,784	2,488,740	7,481,233	0	0				**12,498,757**
Government	0	1,438,623	1,008,733	4,058,218	0	0				**6,505,573**
Industrial	0	0	0	0	0	0	0			**0**
Street Lights	383,205	345,721	0		0	0				**728,926**
Space Lights	132,216	0	0	0	0	0				**132,216**
Secondary Sales	0		500,692	0	0	0				**500,692**
Revenues - Primary - YECL	2,366,985	4,313,128	13,718,013	14,242,272						**34,640,398**
Revenues - Industrial - YECL	0	0	0	0			0			**0**
Revenues - Secondary - YECL	0	0	500,692	0						**500,692**
Revenues - Riders - YECL					0	0				**0**
Revenues - Other - YECL									827,000	**827,000**
Revenues - Total - YECL	2,366,985	4,313,128	14,218,705	14,242,272	0	0	0	0	827,000	**35,968,090**
Revenues - YEC										
Residential										
Non-Government	206,108		905,126	180,177	0	0				**1,291,411**
Government	5,265		33,431	4,803	0	0				**43,499**
General Service										
Non-Government	0	377,610	233,596	999,874	0	0				**1,611,080**
Government	0	218,535	146,093	661,175	0	0				**1,025,803**
Industrial	0	936,000	2,205,748	0	0	0	0			**3,141,748**
Street Lights	43,873	27,622	0		0	0				**71,495**
Space Lights	2,942	0	0	0	0	0				**2,942**
Secondary Sales	0		45,356	0	0	0				**45,356**
Revenues - Primary - YEC	258,188	623,767	1,318,246	1,846,028						**4,046,230**
Revenues - Industrial - YEC	0	936,000	2,205,748	0			0			**3,141,748**
Revenues - Secondary - YEC	0	0	45,356	0						**45,356**
Revenues - Riders - YEC					0	0				**0**
Revenues - Other - YEC									125,000	**125,000**
Revenues - Total - YEC	258,188	1,559,767	3,569,351	1,846,028	0	0	0		125,000	**7,358,334**
Revenues - Total										
Residential										
Non-Government	2,017,502		10,919,964	2,829,540	0	0				**15,767,007**
Government	45,435		239,134	58,261	0	0				**342,830**
General Service										
Non-Government	0	2,906,394	2,722,336	8,481,106	0	0				**14,109,837**
Government	0	1,657,158	1,154,825	4,719,393	0	0				**7,531,376**
Industrial	0	936,000	2,205,748	0	0	0	0			**3,141,748**
Street Lights	427,079	373,342	0		0	0				**800,421**
Space Lights	135,158	0	0		0	0				**135,158**
Secondary Sales	0		546,048	0	0	0				**546,048**
Revenues - Primary	2,625,173	4,936,894	15,036,259	16,088,301						**38,686,628**
Revenues - Industrial	0	936,000	2,205,748	0			0			**3,141,748**
Revenues - Secondary	0	0	546,048	0						**546,048**
Revenues - Riders					0	0				**0**
Revenues - Other									952,000	**952,000**
Revenues - Total	2,625,173	5,872,894	17,788,055	16,088,301	0	0	0		952,000	**43,326,424**

Schedule YECL B 4.7

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Proposed Rates

Residential-Non Government

Billing Determinants	Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Block 3 Energy (kW.h)	Total Energy (kW.h)
			2009			
YECL						
1160 NG - H	11,570		94,533,720	21,353,217	2,728,147	118,615,084
1260 NG - SD	308		962,877	150,252	3,349	1,116,479
1360 NG - LD	682		5,309,797	769,237	49,024	6,128,058
1460 NG - OC	125		763,968	108,332	1,748	874,048
YEC						
1160 NG - H	1,443		9,179,779	1,429,773	294,407	10,903,958
1260 NG - SD	0		0	0	0	0
1360 NG - LD	0		0	0	0	0
1460 NG - OC	0		0	0	0	0
Total						
1160 NG - H	13,013		103,713,498	22,782,990	3,022,554	129,519,042
1260 NG - SD	308		962,877	150,252	3,349	1,116,479
1360 NG - LD	682		5,309,797	769,237	49,024	6,128,058
1460 NG - OC	125		763,968	108,332	1,748	874,048
Residential-Non Government	14,128		110,750,140	23,810,811	3,076,676	137,637,626

Proposed Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
1160 NG - H	14.65		12.14	12.82	13.99	0.000%	0.000%
1260 NG - SD	14.65		12.14	12.82	13.99	0.000%	0.000%
1360 NG - LD	14.65		12.14	12.82	13.99	0.000%	0.000%
1460 NG - OC	14.65		12.14	12.82	30.77	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL								
1160 NG - H	2,033,953		11,476,394	2,737,253	381,772	0	0	**16,629,372**
1260 NG - SD	54,073		116,893	19,261	469	0	0	**190,696**
1360 NG - LD	119,948		644,609	98,608	6,860	0	0	**870,026**
1460 NG - OC	22,019		92,746	13,887	538	0	0	**129,190**
Revenue - YEC								
1160 NG - H	253,738		1,114,425	183,281	41,199	0	0	**1,592,643**
1260 NG - SD	0		0	0	0	0	0	**0**
1360 NG - LD	0		0	0	0	0	0	**0**
1460 NG - OC	0		0	0	0	0	0	**0**
Revenue - Sub Total								
1160 NG - H	2,287,691		12,590,819	2,920,534	422,971	0	0	**18,222,015**
1260 NG - SD	54,073		116,893	19,261	469	0	0	**190,696**
1360 NG - LD	119,948		644,609	98,608	6,860	0	0	**870,026**
1460 NG - OC	22,019		92,746	13,887	538	0	0	**129,190**
Revenue ($)	2,483,732		13,445,067	3,052,290	430,838	0	0	**19,411,927**

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Proposed Rates

Residential-Government

			2009			
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Block 3 Energy (kW.h)	**Total Energy (kW.h)**
YECL						
1180 G - H	155		994,502	309,674	32,070	1,336,245
1280 G - SD	26		172,183	39,189	1,490	212,862
1380 G - LD	30		186,366	25,400	0	211,766
1480 G - OC	12		81,418	19,656	19,396	120,470
YEC						
1180 G - H	29		233,131	29,218	16,746	279,095
1280 G - SD	0		0	0	0	0
1380 G - LD	0		0	0	0	0
1480 G - OC	0		0	0	0	0
Total						
1180 G - H	184		1,227,633	338,891	48,816	1,615,340
1280 G - SD	26		172,183	39,189	1,490	212,862
1380 G - LD	30		186,366	25,400	0	211,766
1480 G - OC	12		81,418	19,656	19,396	120,470
Residential-Government	252		1,667,600	423,136	69,701	2,160,438
					0.032262534	

Proposed Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
1160 G - H	18.47		17.92	12.82	13.99	0.000%	0.000%
1260 G - SD	18.47		17.92	12.82	13.99	0.000%	0.000%
1360 G - LD	18.47		17.92	12.82	13.99	0.000%	0.000%
1460 G - OC	18.47		17.92	12.82	30.77	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL								
1160 G - H	34,384		178,247	39,697	4,488	0	0	**256,815**
1260 G - SD	5,763		30,861	5,024	209	0	0	**41,856**
1360 G - LD	6,657		33,403	3,256	0	0	0	**43,315**
1460 G - OC	2,660		14,593	2,520	5,968	0	0	**25,740**
Revenue - YEC								
1160 G - H	6,483		41,785	3,745	2,343	0	0	**54,356**
1260 G - SD	0		0	0	0	0	0	**0**
1360 G - LD	0		0	0	0	0	0	**0**
1460 G - OC	0		0	0	0	0	0	**0**
Revenue - Sub Total								
1160 G - H	40,866		220,032	43,442	6,831	0	0	**311,172**
1260 G - SD	5,763		30,861	5,024	209	0	0	**41,856**
1360 G - LD	6,657		33,403	3,256	0	0	0	**43,315**
1460 G - OC	2,660		14,593	2,520	5,968	0	0	**25,740**
Revenue ($)	55,945		298,888	54,242	13,008	0	0	**422,083**

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Proposed Rates

General Service-Non Government

			2009				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Block 3 Energy (kW.h)	Block 4 Energy (kW.h)	**Total Energy (kW.h)**
YECL							
2160 NG - H	1,737	336,399	24,820,709	31,981,777	2,939,429	19,702,121	79,444,037
2260 NG - SD	92	7,311	830,009	799,705	1,631	0	1,631,346
2360 NG - LD	157	18,643	1,855,569	1,751,425	142,271	435,183	4,184,447
2460 NG - OC	16	1,551	177,660	187,117	0	0	364,777
2170 GM - H	165	52,808	2,008,485	3,927,867	677,205	7,795,064	14,408,622
2270 GM - SD	0	0	0	0	0	0	0
2370 GM - LD	18	4,751	256,304	679,371	39,077	110,718	1,085,471
2470 GM - OC	0	0	0	0	0	0	0
YEC							
2160 NG - H	299	46,355	2,358,146	4,480,301	355,599	1,923,883	9,117,929
2260 NG - SD	0	0	0	0	0	0	0
2360 NG - LD	0	0	0	0	0	0	0
2460 NG - OC	0	0	0	0	0	0	0
2170 GM - H	55	16,580	452,883	1,953,933	322,865	531,587	3,261,268
2270 GM - SD	0	0	0	0	0	0	0
2370 GM - LD	0	0	0	0	0	0	0
2470 GM - OC	0	0	0	0	0	0	0
Total							
2160 NG - H	2,037	382,754	27,178,855	36,462,078	3,295,029	21,626,004	88,561,966
2260 NG - SD	92	7,311	830,009	799,705	1,631	0	1,631,346
2360 NG - LD	157	18,643	1,855,569	1,751,425	142,271	435,183	4,184,447
2460 NG - OC	16	1,551	177,660	187,117	0	0	364,777
2170 GM - H	220	69,388	2,461,368	5,881,800	1,000,071	8,326,651	17,669,889
2270 GM - SD	0	0	0	0	0	0	0
2370 GM - LD	18	4,751	256,304	679,371	39,077	110,718	1,085,471
2470 GM - OC	0	0	0	0	0	0	0
General Service-Non Government	2,539	484,399	32,759,765	45,761,496	4,478,079	30,498,556	113,497,895
					0.03945517	0.268714724	

Proposed Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)	Block 4 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
2160 NG - H 2170 GM - H	0.00	7.39	10.23	12.88	13.99	12.86	0.000%	0.000%
2260 NG - SD 2270 GM - SD	0.00	7.39	10.23	12.88	13.99	15.22	0.000%	0.000%
2360 NG - LD 2370 GM - LD	0.00	7.39	10.23	12.88	13.99	12.86	0.000%	0.000%
2460 NG - OC 2470 GM - OC	0.00	7.39	10.23	12.88	13.99	31.72	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Block 4 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL									
2160 NG - H	0	2,485,992	2,539,159	4,117,702	411,339	2,533,693	0	0	**12,087,884**
2260 NG - SD	0	54,030	84,910	102,963	228	0	0	0	**242,132**
2360 NG - LD	0	137,771	189,825	225,499	19,909	55,964	0	0	**628,968**
2460 NG - OC	0	11,466	18,175	24,092	0	0	0	0	**53,732**
2170 GM - H	0	390,250	205,468	505,719	94,767	1,002,445	0	0	**2,198,649**
2270 GM - SD	0	0	0	0	0	0	0	0	**0**
2370 GM - LD	0	35,110	26,220	87,470	5,468	14,238	0	0	**168,507**
2470 GM - OC	0	0	0	0	0	0	0	0	**0**
Revenue - YEC									
2160 NG - H	0	342,563	241,238	576,845	49,762	247,411	0	0	**1,457,820**
2260 NG - SD	0	0	0	0	0	0	0	0	**0**
2360 NG - LD	0	0	0	0	0	0	0	0	**0**
2460 NG - OC	0	0	0	0	0	0	0	0	**0**
2170 GM - H	0	122,527	46,330	251,572	45,181	68,362	0	0	**533,972**
2270 GM - SD	0	0	0	0	0	0	0	0	**0**
2370 GM - LD	0	0	0	0	0	0	0	0	**0**
2470 GM - OC	0	0	0	0	0	0	0	0	**0**
Revenue - Sub Total									
2160 NG - H	0	2,828,555	2,780,397	4,694,547	461,101	2,781,104	0	0	**13,545,704**
2260 NG - SD	0	54,030	84,910	102,963	228	0	0	0	**242,132**
2360 NG - LD	0	137,771	189,825	225,499	19,909	55,964	0	0	**628,968**
2460 NG - OC	0	11,466	18,175	24,092	0	0	0	0	**53,732**
2170 GM - H	0	512,776	251,798	757,291	139,948	1,070,807	0	0	**2,732,620**
2270 GM - SD	0	0	0	0	0	0	0	0	**0**
2370 GM - LD	0	35,110	26,220	87,470	5,468	14,238	0	0	**168,507**
2470 GM - OC	0	0	0	0	0	0	0	0	**0**
Revenue ($)	0	3,579,709	3,351,324	5,891,861	626,655	3,922,114	0	0	**17,371,663**

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General Service-Government

Billing Determinants	Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Block 3 Energy (kW.h)	Block 4 Energy (kW.h)	Total Energy (kW.h)
				2009			
YECL							
2180 GFT - H	337	128,900	4,617,896	12,625,944	2,375,636	21,339,764	40,959,241
2280 GFT - SD	51	3,972	406,476	344,619	0	0	751,095
2380 GFT - LD	36	8,468	535,831	1,057,090	183,312	330,805	2,107,037
2480 GFT - OC	20	2,522	220,500	208,620	0	0	429,120
YEC							
2180 GFT - H	103	21,854	837,208	2,279,237	308,062	3,739,734	7,164,240
2280 GFT - SD	0	0	0	0	0	0	0
2380 GFT - LD	0	0	0	0	0	0	0
2480 GFT - OC	0	0	0	0	0	0	0
Total							
2180 GFT - H	440	150,753	5,455,104	14,905,181	2,683,698	25,079,498	48,123,481
2280 GFT - SD	51	3,972	406,476	344,619	0	0	751,095
2380 GFT - LD	36	8,468	535,831	1,057,090	183,312	330,805	2,107,037
2480 GFT - OC	20	2,522	220,500	208,620	0	0	429,120
General Service-Government	547	165,716	6,617,910	16,515,510	2,867,011	25,410,303	51,410,733

Proposed Rate	Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)	Block 4 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
2180 GFT - H	0.00	12.31	21.48	12.97	13.99	12.86	0.000%	0.000%
2280 GFT - SD	0.00	12.31	21.48	12.97	13.99	15.22	0.000%	0.000%
2380 GFT - LD	0.00	12.31	21.48	12.97	13.99	12.86	0.000%	0.000%
2480 GFT - OC	0.00	12.31	21.48	12.97	13.99	31.72	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Block 4 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL									
2180 GFT - H	0	1,586,757	991,924	1,637,519	332,442	2,744,294	0	0	**7,292,936**
2280 GFT - SD	0	48,891	87,311	44,695	0	0	0	0	**180,898**
2380 GFT - LD	0	104,246	115,096	137,099	25,652	42,542	0	0	**424,636**
2480 GFT - OC	0	31,050	47,363	27,057	0	0	0	0	**105,470**
Revenue - YEC									
2180 GFT - H	0	269,017	179,832	295,605	43,110	480,930	0	0	**1,268,493**
2280 GFT - SD	0	0	0	0	0	0	0	0	**0**
2380 GFT - LD	0	0	0	0	0	0	0	0	**0**
2480 GFT - OC	0	0	0	0	0	0	0	0	**0**
Revenue - Sub Total									
2180 GFT - H	0	1,855,773	1,171,756	1,933,124	375,552	3,225,223	0	0	**8,561,430**
2280 GFT - SD	0	48,891	87,311	44,695	0	0	0	0	**180,898**
2380 GFT - LD	0	104,246	115,096	137,099	25,652	42,542	0	0	**424,636**
2480 GFT - OC	0	31,050	47,363	27,057	0	0	0	0	**105,470**
Revenue ($)	0	2,039,961	1,421,527	2,141,975	401,205	3,267,765	0	0	**9,272,433**

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Schedule of Determinants on Proposed Rates

Industrial

2009

Billing Determinants		Number of Customers Billed/year	Demand kVA	Total Energy (kW.h)
YECL				
	39	0	0	0
YEC				
	39	1	62400	29,023,000
Total				
	39	1	62,400	29,023,000
Industrial		1	62,400	29,023,000

Proposed Rate		Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kVA.)	Energy Charge (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)	Rider F Charge (¢ / kW.h)
	39	0.00	15.00	7.600	0.00%	0.00%	0.211

		Customer Revenue	Demand Revenue	Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Rider F Charge Revenue	Total Rate Revenue
Revenue - YECL								
	39	0	0	0	0	0	0	**0**
Revenue - YEC								
	39	0	936,000	2,205,748	0	0	61,239	**3,202,987**
Revenue - Sub Total								
	39	0	936,000	2,205,748	0	0	61,239	**3,202,987**
Revenue ($)		0	936,000	2,205,748	0	0	61,239	**3,202,987**

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Street Lights - Rate 61/66

2009

Billing Determinants		Number of Customers Billed/year	Demand W	Total Energy (kW.h)	Highmast Customers Billed/year
YECL					
	61/66	4,825	8,578,680	3,438,012	160
YEC					
	61/66	567	685,400	274,112	0
Total					
	61/66	5,392	9,264,080	3,712,124	160
Street Lights - Rate 61/66		5,392	9,264,080	3,712,124	160

Proposed Rate		Customer Charge ($/ cust/ mo.)	Demand Charge (¢ / W/ mo.)	Energy Chg (¢ / kW.h)	Highmast Charge ($/ cust/ mo.)	Rider J Charge Revenue	Rider R Charge (%)
	61/66	7.83	4.96		1.27	0.000%	0.000%

Revenue ($)		Customer Revenue	Demand Revenue	Energy Revenue	Highmast Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - YECL								
	61/66	453,372	425,642		2,435	0	0	**881,450**
Revenue - YEC								
	61/66	53,316	34,007		0	0	0	**87,323**
Revenue - Sub Total								
	61/66	506,689	459,649		2,435	0	0	**968,773**
Revenue ($)		506,689	459,649		2,435	0	0	**968,773**

Street Lights - Rate 67

2009

Billing Determinants		Number of Customers Billed/year	Demand W	Total Energy (kW.h)
YECL				
	67 - 250 W	47	141,000	55,428
	67 - 400 W	15	72,000	28,440
YEC				
	67 - 250 W	0	0	0
	67 - 400 W	2	9,600	3,792
Total				
	67 - 250 W	47	141,000	55,428
	67 - 400 W	17	81,600	32,232
Street Lights - Rate 67		64	222,600	87,660

Proposed Rate		Customer Charge ($/ cust/ mo.)	Demand Charge (¢ / W/ mo.)	Energy Chg (¢ / kW.h)	Rider J Charge Revenue	Rider R Charge (%)
	67 - 250 W	19.05			0.000%	0.000%
	67 - 400 W	29.13			0.000%	0.000%

Revenue ($)		Customer Revenue	Demand Revenue	Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - YECL							
	67 - 250 W	10,742			0	0	**10,742**
	67 - 400 W	5,243			0	0	**5,243**
Revenue - YEC							
	67 - 250 W	0			0	0	**0**
	67 - 400 W	699			0	0	**699**
Revenue - Sub Total							
	67 - 250 W	10,742			0	0	**10,742**
	67 - 400 W	5,942			0	0	**5,942**
Revenue ($)		16,685			0	0	**16,685**

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
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Sentinal Lights - Rate 75/76

2009

Billing Determinants	Number of Customers Billed/year	Demand W	Total Energy (kW.h)
Total			
75/76 - Normal - 100 W	393	471,700	188,680
75/76 - E & M - 100 W	314	376,800	150,720
75/76 - Meter - 100 W	7	8,400	0
75/76 - Normal - 175 W	150	315,000	129,600
75/76 - E & M - 175 W	0	0	0
75/76 - Meter - 175 W	17	35,700	0
75/76 - Normal - 250 W	1	3,000	1,164
75/76 - E & M - 250 W	0	0	0
75/76 - Meter - 250 W	0	0	0
75/76 - Normal - 400 W	2	9,600	3,816
75/76 - E & M - 400 W	0	0	0
75/76 - Meter - 400 W	0	0	0
75/76 - Normal - 400 W FL	85	408,000	162,180
75/76 - E & M - 400 W FL	5	24,000	9,540
75/76 - Meter - 400 W FL	3	14,400	0
Sentinal Lights - Rate 75/76	977	1,666,600	645,700

Normal: Normal 12-month unmeterd service
E & M: Energy and Maintenance only
(Cust. Pays installation costs)
Meter: 12-month service through customer meter

Proposed Rate	Customer Charge ($/ cust/ mo.)	Demand Charge (¢ / W/ mo.)	Energy Chg (¢ / kW.h)	Rider J Charge Revenue	Rider R Charge (%)
75/76 - Normal - 100 W	14.33			0.000%	0.000%
75/76 - E & M - 100 W	7.95			0.000%	0.000%
75/76 - Meter - 100 W	9.04			0.000%	0.000%
75/76 - Normal - 175 W	17.46			0.000%	0.000%
75/76 - E & M - 175 W	12.15			0.000%	0.000%
75/76 - Meter - 175 W	9.81			0.000%	0.000%
75/76 - Normal - 250 W	21.35			0.000%	0.000%
75/76 - E & M - 250 W	16.20			0.000%	0.000%
75/76 - Meter - 250 W	10.13			0.000%	0.000%
75/76 - Normal - 400 W	28.35			0.000%	0.000%
75/76 - E & M - 400 W	22.91			0.000%	0.000%
75/76 - Meter - 400 W	9.65			0.000%	0.000%
75/76 - Normal - 400 W FL	31.32			0.000%	0.000%
75/76 - E & M - 400 W FL	21.85			0.000%	0.000%
75/76 - Meter - 400 W FL	12.63			0.000%	0.000%

Revenue ($)	Customer Revenue	Demand Revenue	Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - Sub Total						
75/76 - Normal - 100 W	67,599			0	0	**67,599**
75/76 - E & M - 100 W	29,968			0	0	**29,968**
75/76 - Meter - 100 W	759			0	0	**759**
75/76 - Normal - 175 W	31,424			0	0	**31,424**
75/76 - E & M - 175 W	0			0	0	**0**
75/76 - Meter - 175 W	2,002			0	0	**2,002**
75/76 - Normal - 250 W	256			0	0	**256**
75/76 - E & M - 250 W	0			0	0	**0**
75/76 - Meter - 250 W	0			0	0	**0**
75/76 - Normal - 400 W	680			0	0	**680**
75/76 - E & M - 400 W	0			0	0	**0**
75/76 - Meter - 400 W	0			0	0	**0**
75/76 - Normal - 400 W FL	31,947			0	0	**31,947**
75/76 - E & M - 400 W FL	1,311			0	0	**1,311**
75/76 - Meter - 400 W FL	455			0	0	**455**
Revenue ($)	166,402			0	0	**166,402**

Schedule YECL B 4.7

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Proposed Rates

Secondary Sales

Billing Determinants		Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	Total Energy (kW.h) (2009)
YECL						
	3200	23		6,954,050		6,954,050
YEC						
	3200			629,950		629,950
Total						
	3200	23		7,584,000	0	7,584,000
Secondary Sales		23		7,584,000	0	7,584,000

Proposed Rate		Customer Charge ($/ cust/ mo.)	Demand Charge ($ / kW/ mo.)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Rider J Charge (%)	Rider R Charge (%)
	3200	0.00		7.20	0	0.00%	0.00%

		Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - YECL								
	3200	0		500,692	0	0	0	**500,692**
Revenue - YEC								
	3200	0		45,356	0	0	0	**45,356**
Revenue - Sub Total								
	3200	0		546,048	0	0	0	**546,048**
Revenue ($)		0		546,048	0	0	0	**546,048**

Schedule YECL B 4.7

Yukon Energy Corporation & Yukon Electrical Company Limited - 2009 Phase II Application
Schedule of Determinants on Proposed Rates

TOTAL RATE REVENUE - PROPOSED RATE

	2009									
Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Block 4 Energy Revenue	Rider J & R Charge Revenue	Rider F Charge Revenue		**Total Rate Revenue**
Revenues - YECL										
Residential										
Non-Government	2,229,994		12,330,642	2,869,008	389,639		0			**17,819,283**
Government	49,462		257,104	50,496	10,664		0			**367,727**
General Service										
Non-Government	0	3,114,619	3,063,756	5,063,444	531,712	3,606,341	0			**15,379,871**
Government	0	1,770,945	1,241,695	1,846,370	358,095	2,786,835	0			**8,003,940**
Industrial	0	0	0				0	0		**0**
Street Lights	471,793	425,642	0				0			**897,435**
Space Lights	162,780	0	0				0			**162,780**
Secondary Sales	0		500,692	0			0			**500,692**
Revenues - Primary - YECL	2,914,029	5,311,206	16,893,196	9,829,318	1,290,110	6,393,176				**42,631,036**
Revenues - Industrial - YECL	0	0	0					0		**0**
Revenues - Secondary - YECL	0	0	500,692	0						**500,692**
Revenues - Riders - YECL							0	0		**0**
Revenues - Other - YECL									827,000	**827,000**
Revenues - Total - YECL	2,914,029	5,311,206	17,393,888	9,829,318	1,290,110	6,393,176	0	0	827,000	**43,958,728**
Revenues - YEC										
Residential										
Non-Government	253,738		1,114,425	183,281	41,199		0			**1,592,643**
Government	6,483		41,785	3,745	2,343		0			**54,356**
General Service										
Non-Government	0	465,090	287,568	828,417	94,943	315,773	0			**1,991,792**
Government	0	269,017	179,832	295,605	43,110	480,930	0			**1,268,493**
Industrial	0	936,000	2,205,748	0			0	61,239		**3,202,987**
Street Lights	54,015	34,007	0				0			**88,022**
Space Lights	3,622	0	0	0			0			**3,622**
Secondary Sales	0		45,356	0			0			**45,356**
Revenues - Primary - YEC	317,859	768,113	1,623,610	1,311,049	181,595	796,703				**4,998,929**
Revenues - Industrial - YEC	0	936,000	2,205,748	0				61,239		**3,202,987**
Revenues - Secondary - YEC	0	0	45,356	0						**45,356**
Revenues - Riders - YEC							0			**0**
Revenues - Other - YEC									125,000	**125,000**
Revenues - Total - YEC	317,859	1,704,113	3,874,715	1,311,049	181,595	796,703	0	61,239	125,000	**8,372,272**
Revenues - Total										
Residential										
Non-Government	2,483,732		13,445,067	3,052,290	430,838		0			**19,411,927**
Government	55,945		298,888	54,242	13,008		0			**422,083**
General Service										
Non-Government	0	3,579,709	3,351,324	5,891,861	626,655	3,922,114	0			**17,371,663**
Government	0	2,039,961	1,421,527	2,141,975	401,205	3,267,765	0			**9,272,433**
Industrial	0	936,000	2,205,748	0			0	61,239		**3,202,987**
Street Lights	525,808	459,649	0				0	0		**985,457**
Space Lights	166,402	0	0				0			**166,402**
Secondary Sales	0		546,048	0			0			**546,048**
Revenues - Primary	3,231,888	6,079,319	18,516,806	11,140,367	1,471,705	7,189,879				**47,629,965**
Revenues - Industrial	0	936,000	2,205,748	0				61,239		**3,202,987**
Revenues - Secondary	0	0	546,048	0						**546,048**
Revenues - Riders							0			**0**
Revenues - Other									952,000	**952,000**
Revenues - Total	3,231,888	7,015,319	21,268,602	11,140,367	1,471,705	7,189,879	0	61,239	952,000	**52,331,000**

TAB 5

TERMS AND CONDITIONS OF SERVICE

5.0 TERMS AND CONDITIONS OF SERVICE

The existing Rate Schedules for each class of customer incorporate the terms under which the rate is offered. The document that presently sets out these terms, including the responsibilities of both the utility and the customer, is the approved Electric Service Regulations ("ESRs"). The Companies have completed a review of the terms of service in response to Board Order 2009-08 Directive#13, and propose to update the terms under which service is offered under a new title as the "Terms and Conditions of Service" ("T&Cs").

This Tab consists of the following sections:

- Overview;
- Updated Terms and Conditions of Service; and
- Maximum Company Investment.

5.1 OVERVIEW

As approved in Board Order 2005-12, the terms under which the companies provide service were last amended effective October 18, 2005 to update the definition of "Interconnected System", and to update the Maximum Company Investment in respect of General Service Customers and Secondary Energy customers. The previous revision to the terms was January 29, 1998 (Order 1998-1) when clause 4.18(d) in respect of Restoration of Service was approved. Prior to these limited scope amendments, the existing ESR document had not been changed since the 1996/97 GRA.

The proposals in this Application are supported by four appendices of material:

- **Appendix 5.1** contains the proposed T&Cs to govern service under the approved Rate Schedules.
- **Appendix 5.2** provides a blackline version comparing the new T&Cs to the existing approved ESRs to help guide the Board and intervenors of the proposed changes. Note that certain sections of the document have been renumbered or moved, so not all changes are readily blacklined (see Appendix 5.3).

- **Appendix 5.3** provides a comparison of the existing and proposed Table of Contents for the document.

- **Appendix 5.4** provides a Maximum Investment Level Study prepared by Yukon Electrical to examine potential changes in Maximum Company Investment levels for residential, general service and streetlight customers (discussed in Section 5.3 of this Tab).

The proposed Terms and Conditions of service are comprised of three notable updates:

- **Revised Terms and Conditions of Service Document** - The main proposed changes are to clarify and improve the wording of clauses that were not sufficiently clear in previous versions to fully communicate the rights and obligations of each of the utility and the customer.

- **Changes to Schedule B, Maximum Company Investment -** The Companies propose changes to the Maximum Company Investment levels for Residential, General Service and Street Lighting customer classes as well as for non-standard customers for 2011. YECL seeks further approval of incremental increases over the period 2012-2015 based on an "average cost" standard, as set out in the YECL Maximum Investment Level (MIL) study provided in Attachment 5.4, which YEC does not support. Schedule B also addresses Maximum Company Investment approach for Industrial customers.

- **Changes to Schedule D Fees and Service Charge Summary -** All fees and service charges previously stated within the respective articles throughout the main T&C document are now located in Schedule D – Fees and Service Charge Summary. Where required, the fees have been adjusted to reflect increased costs of performing the associated services since at least the 1996/97 GRA, which was the last time these charge levels were reviewed.

5.2 UPDATED TERMS AND CONDITIONS OF SERVICE

The proposed amendments filed in this Application are intended to enhance the clarity, transparency and ease of understanding of the provisions under which electricity is provided, including the rights and obligations of both the utility and the customer, and to reflect the Companies' practices and policies, industry legislation and regulations.

The proposed changes, as contained in the Terms and Conditions of Service document in Appendix 5.2, reflect agreement between the Companies with one exception. The Terms and Conditions of service are proposed by YECL to be updated to eliminate what is presently section 4.18(d) in respect of "reconnection" (the terms related to reconnection are revised to now be section 4.15). The existing text is as follows:

> 4.18
> Before reconnecting or restoring service, the customer shall pay:
>
> (d) the minimum monthly bill for each month of disconnection, if service is reconnected within 12 months of disconnection for all rate schedules and service except seasonal service.

YECL's proposed edits is to increase the degree of discretion provided to the Companies in applying the provision, as follows:

> If Service is reconnected within 12 months of disconnection, with the exception of seasonal Service, the Company may request that the Customer pay the minimum monthly bill for each month of disconnection.

The term in question was inserted into the existing ESRs by a specific Board Order in 1998 (Order 1998-1, pursuant to a joint application of the Companies "to address concerns related to gaming noted in Order 1997-6"). The specific concerns at that time related to the Faro mine in particular, which had disconnected from the system and consequently sought to avoid paying minimum monthly bills related to fixed charges and demand ratchets that would otherwise be payable regardless as to energy consumption in any given month. The provision was critical for two reasons: first, to ensure all other continuing ratepayers were protected from the actions of customers that effectively "game" the rate design, particularly costs arising from ratchets; and, second, to ensure customers are fully apprised that such gaming will not be permitted. YEC's view is that, at least for Major Industrial and large General Service customers (such as with peak demands greater than 1 MW), where minimum monthly bills include material minimum demand charges (based on the annual demand ratchet), this term is still required.

5.3 MAXIMUM COMPANY INVESTMENT

The purpose of an investment policy is to establish rules and guidelines that govern Company investments in customer extensions. The Company will make a specified investment in the costs of extending facilities consistent with Schedule B, and all other costs required to connect the customer will be recovered from the customer as a "Construction Contribution". As set out in the T&Cs definitions, the Construction Contribution is "a specific payment by a Customer to offset Company costs incurred in providing Service that will primarily benefit that Customer or group of Customers only and not the other ratepayers in the distribution system". These guidelines must allow new customers to receive a fair level of investment, while still ensuring that existing customers are not unduly burdened by the cost of such new extensions.

5.3.1 Non-Industrial Maximum Company Investment Background

There have not been any changes to the Companies' Residential and Street Light Maximum Company Investment since 1989. General Service investment levels were increased in 2005 from $180/kW to $400/kW as approved in Board Order 2005-12, direction #8.

A summary of the existing Maximum Company Investment levels is set out in Table 5.1.

Table 5.1 Existing Yukon Maximum Company Investment Levels

Residential	$900/site
Residential Multiple Dwelling	$450/multiple dwelling unit
General Service	$400/kW estimated billing demand
Municipal Street Lighting	$700/light
General Service Secondary	one half year of estimated revenues

Actual new extension construction costs have risen considerably in the Yukon between 1989 and 2009. Some of the increased pressures in costs that the Companies have experienced include higher material and contractor services as well as a move towards underground residential subdivisions. As there have been no comparable increases to the Companies' Residential and Street Light investment levels, a greater share of the costs of extending facilities are presently being passed onto the customer via their share of the total cost (Construction Contribution).

As a separate cross-check on the Companies' Maximum Company Investment levels, the levels are noted to be below that of neighbouring utilities (Table 5.2).

Table 5.2: 2009 Maximum Company Investment Levels of Neighbouring Utilities

	Northland Utilities (NUY)	Northland Utilities (NWT)	NTPC	BC Hydro	ATCO Electric	Fortis Alberta
Residential	$2100/site	$1500/site	$1500/site	$1475/site	$1200/site	$1200/site
Residential – Multi Dwelling	$700/site	$750/Site	$750/unit			
General Service	$300/kW	$300/kW	$250/kW	$200/kW	$1256/kW	$5275 Fixed plus $839/kW
Street Lighting	Cost of installation	$1200/light	Cost of installation	$150/Fixture	$1400/Light	$1400/Light

5.3.2 Non-Industrial Maximum Company Investment Study Results

In order to assess the potential for changes to the Maximum Company Investment levels for non-industrial customers, Yukon Electrical prepared a Study on Maximum Investment Levels provided in Appendix 5.4. This study reviews the present Maximum Company Investments levels for Residential, General Service and Street lighting, in light of recent costs to extend service to new customers.

The study applies an approach to determining potential Maximum Company Investment levels, based on the average cost that has been required to connect new customers in recent periods, with consideration to ten guiding principles identified in the study. The study notes that this approach is used by some neighbouring utilities, such as Northland Utilities, Fortis Alberta and ATCO Electric. The cost analysis is based on the costs for new extensions in Whitehorse as the majority of the Companies' customer additions occur in Whitehorse.[1] Having a common MIL among all the communities is consistent with historical MILs and is further supported by the fact that all customers of the respective rate classes pay the same fixed charges which go toward recovery of the investment throughout the various communities.

The attached study concludes, based on the methodology adopted, that the present Maximum Company Investment levels are too low. The study proposes that the Maximum Company Investment within each customer class be based on a cost-based approach to determine new "target" levels that will be achieved over a 5 year period (2011 to 2015) which will reflect the average cost of a new extension. Customers with costs greater than average would continue to be required to make a cost contribution and customers with costs below the average would continue to receive investment up to the full cost of their extension.

[1] As reviewed in Appendix 5.4: the average cost (2011$) of a new Residential extension is $4,373 per site; the average cost for a new General Service extension is $17,627 per project and $454 per kW per project; the average cost of a new street light extension is $2,772 per light.

The MIL Study's proposed investment levels for residential, general service and street light customers are summarized in Table 5.3.

Table 5.3: Summary of Maximum Company Investment Levels for Yukon
As Proposed in YECL's Maximum Investment Level Study

Year	Residential Single Family Dwelling (Per Site)	Residential Multi Dwelling Unit (Per Site)	General Service		Street Lighting (Per Light)
			Fixed (Per Site)	Variable (Per kW)	
Current	$ 900	$ 450	$ -	$ 400	$ 700
2011	$ 1,250	$ 625	$ 5,355	$ 275	$ 930
2012	$ 1,740	$ 870	$ 5,500	$ 280	$ 1,240
2013	$ 2,420	$ 1,210	$ 5,650	$ 290	$ 1,660
2014	$ 3,360	$ 1,680	$ 5,800	$ 295	$ 2,220
2015	$ 4,700	$ 2,350	$ 5,955	$ 305	$ 2,975

As indicated in Table 5.3, YECL's study indicates a proposal to increase Maximum Company Investment levels, to phase in the higher investment levels over 5 years, and to adopt a new "fixed plus variable" level of investment for general service customers.

5.3.3 Non-Industrial Maximum Company Investment – Proposal for 2011

Agreement exists between the Companies in respect of the present Application, for one-time increases to the Maximum Company Investment to take effect as part of this Application, for connections starting January 2011. There is no agreement between the Companies in respect of the "cost based approach", or any multi-year implementation of the Maximum Company Investment levels summarized in Table 5.3.

In light of the lengthy time since at least Residential and Street Lighting Maximum Company Investment Levels were increased, and the clear distinction between present Yukon levels and the levels used in other jurisdictions for these classes of customers, increases in the Maximum Company Investment levels for these classes are appropriate. In the first step (2011), YECL's study proposes increasing these values by 30-40% to $1,250/site for Residential, $625/dwelling unit for Residential Multi-Dwelling, and $930/light for Street Lighting. As these items have not been increased in over 20 years, and the proposed values are approximately within the ranges used by neighbouring utilities, this adjustment is timely and appropriate.

With respect to General Service, the YECL study proposal in year 1 has very little net effect on mid-size GS loads[2], who will see an increase in investment of approximately 3%. As this value was updated more recently (in 2005) and is presently within the range of values used by neighbouring utilities, the first year change proposed in the YECL study (to $5,355 plus $275/kW) is reasonable.

For secondary sales, as noted in Tab 1, the availability of secondary sales on each hydro grid system is presently diminishing and interruptions are becoming more common. The emphasis at the present time has shifted, since 2005 when the Maximum Company Investment provision was instituted for secondary sales, to maintaining the secondary program for existing customers but not expanding the program for new customers who will see limited availability. Consequently, utility investment in extensions for Secondary Energy customers is proposed to be terminated.

For non-standard customers, paragraph 3 of Schedule B of the existing document provides direction as to the Maximum Company Investment policy for any extension of service not specified in paragraph 2 of Schedule B:

> "The Maximum Company Investment for an extension of service not specified in paragraph 2 and the Maximum Company Investment in any extension of service, whether or not specified in paragraphs 2, the Load characteristic of which are expected to vary materially from the average for that type of service, shall be determined on the basis of a detailed analysis of the Annual Cost[3] of such extension and the revenue expected to be derived there from. If the Annual Cost of serving a customer is higher than the revenue expected to be received from such service, then the Maximum Company Investment shall be the Cost[4] of the extension less the present value of the annual amounts over the expected life of the service by which the Annual Cost is expected to exceed the revenue."

The Companies propose to simplify and reword the section as follows:

> "The Maximum Company Investment in any extension of service, whether or not specified in paragraph 1, the Load characteristic and service life of which are expected to vary materially

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[2] Such as 39 kW as noted in the YECL study as average loads.
[3] "Annual Cost", as defined in paragraph 1 of the existing Schedule B, "means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers."
[4] "Cost", as defined in paragraph 1, "means the estimated costs of materials, labour, equipment, expenses, and any other direct costs incurred by the Company in extending Service to a Point of Delivery."

from the average for that type of service, shall be determined based on an analysis of the load characteristics and service life, as a pro-ration of the full Maximum Company Investment for that class of customer."

5.3.4 Maximum Company Investment – 2012 to 2015

The YECL study provided in Appendix 5.4 sets out a proposal to further increase Maximum Company Investment levels annually through 2015. YECL requests approval of the annual increments to take effect January 1 of each respective year.

YEC does not support this proposal to increase the Maximum Company Investment after 2011 at this time. Based on past practice in Yukon and on the current evidence offered on neighboring jurisdictions, YEC does not support YECL's new "cost based approach" or the resulting proposal for higher Maximum Company Investment levels after 2011.

5.3.5 Industrial Maximum Company Investment

Directive 10 of Order 2007-5, directed a review of utility investment policies for industrial customers to clarify to potential industrial customers what the utility will invest in new facilities and provide consistency in the approach when constructing facilities to serve new loads.

Paragraph 3, Schedule B, in the existing document provides direction as to Maximum Company Investment policy for any extension of service not specified in paragraph 2 of Schedule B, including all Industrial customer extensions. The basic elements of this policy have been a component of the terms of service since YEC was first before the YUB for rate regulation, and these basic elements of determining the maximum investment for industrial customers are not proposed to be revised today.

The premise of the existing Maximum Company Investment approach is to allow for the maximum reasonable investment by the Company, while constraining the Company from over-investing to connect any new customer such that other remaining customers are adversely impacted by the new customer. It allows the Company to invest the entire net benefit of the new customer into the assets needed for the connection, but no more. The calculation determines the exact maximum amount that a Company can invest in a new customer extension such that the benefits of the new customer match the costs. The net result limits the contribution required from the specific customer benefitting from any new extension.

Principles Applied in Yukon

Since there are typically only a few major industrial customers (at most) at any one time in Yukon, YEC has established since the 1996/97 GRA, and will continue to rely upon at this time, principles related to determining capital cost contributions to be negotiated with individual customers seeking grid service through a Power Purchase Agreement. In contrast to the existing Maximum Company Investment principles reviewed above from Schedule B, the current approach secures material contributions from the new Industrial customer and does not seek to ensure that all expected benefits are invested in providing the extension to that customer.

Key principles related to investment in facilities required to provide Company service to industrials were examined during the YUB review of the Minto Power Purchase Agreement (Minto PPA) between Minto Explorations Ltd. (Minto) and YEC, as reviewed and approved by the Board in 2007. This included discussion related to the required customer contributions for the capital costs related to bulk transmission and to spur lines. In sum, and as discussed in detail in response to YUB-YEC-1-7 filed during the Minto PPA hearing, the following principles are currently applied in Yukon related to investment in facilities required to provide service to industrial customers:

- **Future industrial customers connecting to the Carmacks-Stewart Transmission Project ("CSTP") must pay appropriate share of CSTP and any spur line** - Section 5.7 of the Minto PPA specifically requires that New Industrial Customers (receiving grid electricity from the Transmission Project serving the Minto mine or the Carmacks-Stewart Transmission Project) be required to pay a Capital Cost Contribution for their appropriate share of Capital Costs of the Carmacks-Stewart Transmission Project and any spur lines.
  - **Principle underlying payments towards any spur line** – When only one customer is planned to be served by specific transmission facilities, that one customer generally should pay the full actual cost of the facilities so required. Minto Mine paid the full cost of its Mine Spur contribution. This reflects the fact that these specific transmission facilities were built to serve a single customer (Minto) and are generally expected to be decommissioned and removed after the Mine closes.
  - **Principle underlying payment towards bulk transmission (such as Carmacks – Stewart Transmission Project (CSTP)) –** Long term use is planned for CSTP facilities (or other bulk transmission) to benefit all Yukon ratepayers and such facilities are not built solely to serve one customer (i.e., no plans for decommissioning or shutdown of facilities when the current industrial customer ends service). Capital Cost Contributions by new major industrial customers towards these facilities is to be based on the need to

secure from the new Mine the maximum reasonable customer capital cost contribution that would otherwise be required by the Mine to secure grid service (i.e., reasonable costs estimated for the minimum-sized line segment and voltage level that the Mine would otherwise require to receive Grid Electricity on its own without the CSTP). In general, due to projected diesel generation cost savings that a mine secures by grid connection, this approach reflects the extent to which a new mine connecting to the CSTP can afford to pay for capital costs otherwise required for it to connect to the grid system; for Minto there were material cost savings available from the grid even if the Carmacks to Minto Landing portion of Stage 1 was not built and the mine was required to pay 100% of the cost estimated for the basic additional facilities to connect the mine to the grid (i.e., additional 35 kV line facilities between Carmacks and Minto Landing).

- **Determination of Capital Cost Contribution** - The Capital Cost Contribution required from Minto pursuant to the Minto PPA (and anticipated to be expected from other mines) was negotiated directly with the customer and not based on the maximum utility investment as set out in Schedule B of the then-current ESRs. The contribution to capital costs applied to Minto under the Minto PPA (and that would be applied per the PPA as approved to other industrial customers connecting to the CSTP) is based on the segment and voltage level of a transmission line that each new industrial customer would be required to receive Electricity in the absence of the Transmission Project serving the Minto mine.

- **Principles related to payments towards existing transmission infrastructure –** Following the policy applied in the past by the Board for directly assigning 85% of the existing Whitehorse-Faro transmission line annual costs as a Fixed Charge to the Faro mine site operator, annual depreciation and return costs related to transmission facilities primarily developed in the past to serve industrial customers in an area will be assigned to (shared among) mine sites served by such facilities so long as the mines are operating.

The net result of the Minto PPA was to ensure, with the agreement of Minto, that the resulting benefits were used to secure substantial long-term positive rate impacts and infrastructure benefits for other Yukon ratepayers. In summary, YEC sought through the PPA to secure the maximum reasonable capital cost contribution to be paid by the industrial customer, thereby minimizing the investment needed by the utility for major new infrastructure (CSTP) that could provide ongoing benefits to all customers. This reflected the special circumstances where Minto could secure material cost savings by displacing diesel generation and ratepayers could secure major benefits from use of surplus hydro to serve the mine.

Looking beyond these special circumstances, the current Industrial investment policy for the Company focuses on maximizing potential industrial customer investment to new transmission facilities developed to extend service to them as well as to retain direct assignment of annual capital-related transmission costs for existing facilities where appropriate based on past practice in Yukon.

Principles from other Jurisdictions

As directed by the Board, the attached Table 5.4 shows a summary of the industrial Maximum Company Investment provisions from readily available similar (i.e. hydro-based) jurisdictions.

Table 5.4 Maximum Company Investment for Industrials – Other Utilities

Utility	Reference	Industrial Investment
Manitoba Hydro	Presently there is no formal Board-approved investment policy for industrials[5].	In Manitoba, since June 23, 2005, there has been no utility investment provided for facilities required to serve new loads exceeding 30 kV or loads in excess of 5 MW without approval of the Manitoba Hydro Executive Committee. Generally, and subject to certain exceptions, Manitoba Hydro will invest up to three (3) times the forecast annual revenue to extend service to any customer served at less than 30 kV. This is applicable only to facilities which are not on private property. If the extension cost is greater than Manitoba Hydro's allowance, customer contribution is required to make up the difference. There are, however, limitations on the amount Manitoba Hydro will invest in specific facilities such as the following: dedicated facilities on private property; special services such as underground services; seasonal residences; location of the point of delivery; three (3) phase service; and pad-mounted transformers. Manitoba Hydro has recently (February 12, 2010) filed for review with the Manitoba Public Utilities Board a proposal for a system extension policy for General Service Large customers that would provide as follows: • The Customer is responsible for the cost of any improvements to Manitoba Hydro's grid to enable service to the customer, proportionate to the Customer's use of those facilities. Manitoba Hydro would base its extension cost on actual estimates, but would not apply the entire cost against the customer if the extension costs were not totally dedicated to that customer. • Costs associated with upgrading the grid would have a Revenue Based Allowance applied against them. The customer would be responsible for extension costs less the Allowance. The customer would be responsible for 100% of the costs of any facilities dedicated to serve that customer, and there would be no Allowance applied against those costs. • Standard Manitoba Hydro Revenue Allowance of 15 months anticipated customer revenue at standard rates would be applied against the costs to extend service, except that costs of dedicated facilities would not be eligible for revenue testing. Any extension costs not covered by the Allowance are to be paid by Customer Contribution. The Customer Contribution would be trued-up after 15 months of operations and the customer would be entitled to a refund, if appropriate, or charged an additional Contribution. • Manitoba Hydro also intends to develop a feasibility approach to evaluating the costs and benefits of major load additions, such as in the order of 50 MW or more. The feasibility approach would examine proposed new service extensions to individual large loads. It would evaluate all costs required to extend service, including Generation, Transmission, Sub-transmission facilities. It would also evaluate benefits including revenues to Manitoba Hydro and provincial economic benefits. These costs and benefits would be evaluated over an appropriate time period and a Net Present Value determined. Once this approach had been developed, Manitoba Hydro may propose tying Customer Capital Contributions to the results of the feasibility test. The new approaches noted above form Manitoba Hydro have not yet been reviewed or approved by the Manitoba PUB.

[5] Manitoba Hydro discussed their system extension policy at the following transcript reference http://www.pub.gov.mb.ca/pdf/transcripts/hydro/2008/dec_8_2008.pdf at transcript pages 95-98.

Utility	Reference	Industrial Investment
B.C. Hydro	Tariff Supplement #6	The policy followed by BC Hydro (as set out in a tariff approved by the BCUC) is as follows: • The customer is responsible for the cost of the connection for dedicated transmission facilities required to connect the customer's plant to BC Hydro's existing transmission system. • The customer may request that BC Hydro own and operate the connection, provided that the connection is built to a standard suitable to BC Hydro. • If system reinforcement is required to serve the customer's load, the customer must pay the cost of constructing the system reinforcement. • The cost of system reinforcement may be offset by BC Hydro based upon a formula set out in Tariff Supplement #6 (TS#6). The Tariff (TS#6) arises from negotiations with customers. BC Hydro may pay a portion of the costs of required reinforcements of the existing transmission system, based on a formula[6] that calculates BC Hydro's contribution based on the net revenue expected from the new load, and applies a rate of return to that revenue[7]. The formula also deducts the depreciation of the transmission investment and adds in other possible benefits (e.g. savings by displacing diesel generation). Higher loads mean higher net revenues, and a higher contribution from BC Hydro. If a new or incremental load exceeds 150 MV.A (roughly 150 MW depending on load factors and power factors), an industrial customer is also subject to an analogous generation-related payment, for the costs required to be incurred by BC Hydro to enhance its generation system to serve the new load increment. Also, all new customers are required to provide security (e.g. a Letter of Credit) in order to reduce the default and performance risk. This provision has never been used.
Nfld Hydro	P.U 12(2005)	The only industrial customer connection easily identified is for the Duck Pond mine. This mine required a 45 km, $5.825 million transmission interconnection dedicated solely to service to the mine. In Board Order P.U. 12(2005) the Board approved 100% investment in this line by the customer with no net utility rate base investment.

[6] The formula is the Offset = (R-E), divided by 0.135, +B+D, where R is the annual revenue from the new load, E is the annual O&M cost of reinforcement to supply the new load, B is extra benefits to BC Hydro if applicable (e.g. displacing higher cost diesel generation in a community that can now be connected to the grid), and D is half the annual depreciation at 3% of system reinforcement cost. So there may be a "credit" in the form of a higher offset if there are benefits to BC Hydro.

[7] BC Hydro provides an offset to the cost of the system reinforcement based on a 13.5% rate of return on the transmission investment.

Utility	Reference	Industrial Investment
Hydro Quebec	Distribution Tariff (section 10.6)	Section 10.6 of the Distribution Tariff provides that, in cases where the Distributor supplies electricity and the conditions of service have not been specified in the Conditions of Electricity Service or in another Hydro-Québec bylaw, such conditions of service shall be stipulated in a written agreement between the Distributor and the customer. Service extensions are addressed under section 16 and 17 the Conditions of Service. However, section 1.1 notes that these provisions apply only to low voltage service and medium voltage service where the maximum current does not exceed 260 A at three-phase voltage. The Distributor's Rates and Conditions do not oblige the Distributor to enter into a contract for any new load involving more than 50 megawatts, to supply any additional load of more than 50 megawatts or to accede to any request from a special contract holder[8]. Loads that grow above this level are required to deal with the Government of Quebec (not Hydro Quebec or the regulator, the Regie) to determine their rate, which could be the standard industrial rate or could be something different. Policy documents from the Government of Quebec indicate this determination is made in part based on the socio-economic benefits that an industry brings to the province.

[8] Until recently (early 2008), this cutoff was stated at 175 MW but has been reduced to 50 MW.

Appendix 5.1

YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

TERMS AND CONDITIONS

OF

SERVICE

TABLE OF CONTENTS

1. INTRODUCTION

The Yukon Electrical Company Limited (Yukon Electrical) and Yukon Energy Corporation (Yukon Energy) each provide direct electrical Service to Yukon Territory Customers under a common Electric Service Tariff. The Electric Service Tariff is comprised of the Rate Schedules and these Terms and Conditions of Service (the “ Terms and Conditions” , formerly known as the “ Electric Service Regulations”). Yukon Electrical and Yukon Energy conduct their business activities in compliance with these Terms and Conditions.

These Terms and Conditions are regulated by the Yukon Utilities Board (hereinafter referred to as the “ Board”), in accordance with the Yukon *Public Utilities Act*, and may not be changed without the approval of the Board. Parties having any inquiries or complaints regarding these Terms and Conditions may direct such inquiries or complaints directly to Yukon Electrical, Yukon Energy or the Board.

The Electric Service Tariff is available for public inspection during normal business hours at the business offices of Yukon Electrical and Yukon Energy and at the offices of the Board and can be accessed on the Companies’ respective websites at: www.yukonelectrical.com and www.yukonenergy.ca .

2. INTERPRETATION

2.1 Definitions

The following words or phrases, when used in these Terms and Conditions, the Electric Service Tariff or an application, contract or agreement for service, shall have the meaning set forth below.

"Billing Demand" - the demand upon which billing to a Customer is based as specified in a rate schedule or contract

"Board" - the Yukon Utilities Board.

"Capital Cost" the cost of materials, labour, equipment, expenses and any other direct or indirect costs incurred by the Company in extending Service to a Point of Service.

"Company" - The Yukon Electrical Company Limited or Yukon Energy Corporation.

"Connected Load" - the sum of the capacities or ratings of the electric Energy consuming apparatus connected to a supplying system.

"Connection Fee" – a non-refundable fee charged when a new Service is connected or an existing Service is reconnected or a meter reading is required to add the Customer to the Company's system. (refer to Schedule D for fees).

"Construction Contribution" – a specific payment by a Customer to offset Company costs incurred in extending Service that will primarily benefit that Customer or group of Customers only and not the other ratepayers in the distribution system. The contribution will be the difference between the cost of extending the Company's Facilities to serve a Customer or group of Customers and the Maximum Available Company Investment specified in Schedule B.

"Cost Sharing" – the process whereby a new Customer or group of Customers who connect to an existing Facility for which another Customer or group of Customers has paid a Construction Contribution, is assessed their share of that Construction Contribution which must be paid to the Company to be refunded to the existing Customer(s).

"Current Limiting Device" – a device that limits the amount of Demand available to a specific Customer.

"Customer" - a person, firm, partnership, corporation, association or organization (including, without limitation, individual members of any unincorporated entity) to who the Company provides any Service hereunder including all owners and occupants of a premises, whom normally reside at the premises during the time for which Service was provided to that premises whether or not such owner or occupant's name appears on the application for Service.

"Demand" - the maximum rate at which electric Energy is delivered by the Company (expressed in kilowatts, kilovolt amperes or other suitable unit) at a given instant or averaged over any designated period of time.

"Electric Service Regulations" – the former title of this document outlining the terms and conditions governing Service, which title has been replaced by Terms and Conditions of Service. Where reference is made to Electric Service Regulations it shall be deemed to be a reference to these Terms and Conditions of Service as amended from time to time.

"Energy" - electric energy consumed expressed in kilowatt hours.

"Estimated Capital Cost" – the estimated cost of materials, labour, equipment, expenses, and any other direct or indirect costs for extending Service to a Point of Service.

"Facilities" - a physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

"Force Majeure" - circumstances not reasonably within the control of the Company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, pandemics, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, mechanical breakdowns, the intervention of federal, territorial, or local government or from any of their agencies or boards (excluding Decisions and/or Orders made by the Board in the normal course of it exercising its authority to establish the revenue requirement of the parties to this agreement), the order or direction of any court and any other cause, whether of the kind herein enumerated or otherwise.

"In-Service Date" - the date on which the Customer specifies Service is to be available or the date the Service is actually available, whichever is later.

"Interconnected System" - those portions of the Company's Facilities which are connected to the Whitehorse/Aishihik/Faro (WAF) power grid or to the Mayo-Dawson grid.

"Isolated System" - those portions of the Company's Facilities which do not form part of the Interconnected System.

"Load" - the Demand and Energy delivered to or required at any Point of Service.

"Load Factor" - the ratio of the average Demand (in kilowatts) supplied during a designated period to the peak or maximum Demand(in kilowatts) occurring in the period expressed as a percentage derived by:

(a) multiplying the Energy used in the designated period by 100;
(b) multiplying the maximum Demand by the number of hours in the designated period; and
(c) dividing (a) by (b).

"Maximum Company Investment" – the maximum Capital Cost which the Company will incur to extend Service to a Point of Service as set forth in Schedule B hereto.

"Multiple Dwelling" - a residential building containing more than one Single Family Dwelling unit.

"Point of Service" - the point at which the Company's service conductors are connected to the wires or apparatus of a Customer.

"Power Factor" - the ratio of the highest metered kilowatt Demand in a billing period to the highest metered kilovolt ampere Demand in that same billing period.

"Satisfactory Credit Rating" – determined subject to the discretion of the Company, and may include the Customer having paid all bills on an existing Company account in full on or before the due date of the said bill for 12 consecutive months or a similar payment record as established with another utility service provider within the past twelve months.

"Security Deposit" – the amount determined in accordance with Article 4.6.

"Service" - the delivery of Energy by the Company at the Demand required by the Customer.

"Service Connection" the Facilities required to physically connect the Customer's facilities to the Company's system.

"Single Family Dwelling" - a private residence which is not a Multiple Dwelling, consisting of single family living quarters having, in one self-contained unit, at least sleeping quarters, and, a kitchen.

2.2 Conflicts

If there is any conflict between a provision expressly set out in an Order of the Board and these Terms and Conditions, the Order of the Board shall govern.

2.3 Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

2.4 Schedules and Appendices

The following schedules and appendices are attached to and form part of these Terms and Conditions:

- Schedule A - Standard Supply Specifications
- Schedule B - Maximum Company Investment
- Schedule C - Conditions for Underground Subdivisions
- Schedule D - Fees and Service Charge Summary

3. GENERAL PROVISIONS

3.1 Board Approval

These Terms and Conditions have been approved by the Board. The Company may amend these Terms and Conditions by filing a notice of amendment with the Board and interested parties from the preceding General Rate Application. Included in the notice shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. If the Board approves the notice of the amendment, the amendment will take effect upon the date set by the Board. If no specific date is set by the Board then the amendment will take effect on the date of the Board's Order approving the notice of amendment.

3.2 Terms and Conditions Prevail

(a) These Terms and Conditions, as amended from time to time, apply to the Company and to every Customer to which the Company provides a Service Connection.

(b) The application for a Service Connection (whether verbal or written), the use by the Customer of a Service Connection to obtain Electricity Services or the payment by the Customer of an account rendered by the Company in relation to a Service Connection shall constitute acceptance by the Customer of these Terms and Conditions.

(c) No agreement can provide for the waiver or alteration of any part of these Terms and Conditions unless such agreement is first filed with and approved by the Board.

3.3 Ownership of Facilities

Unless otherwise specifically provided in a contract with the Customer, notwithstanding the payment by a Customer of any costs incurred by the Company, the Company shall install, maintain and retain full title and ownership of all lines, equipment and other Facilities on its side of the Point of Service and of all meters and metering equipment provided and/or installed by it.

3.4 Use of Energy

Service is provided only for the purposes specified by contract or by the rate schedule applicable to such Service. A Customer shall not sell Energy provided by the Company unless otherwise provided by a contract with the Company, or unless the Company has first given written consent.

3.5 Customer Extensions

A Customer shall not extend service Facilities beyond property owned or occupied by the Customer.

3.6 Customer Generation

A Customer must notify the Company and sign an agreement with the Company if the Customer wishes to have service;

a) in parallel operation with; or
b) as supplementary, auxiliary or stand-by Service to any other source of electric Energy.

3.7 Frequency and Voltage Levels

The Company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and shall be in accordance with the Company's standard supply specifications as set out in Schedule A except in locations where the voltage levels set out in Schedule A are not available.

3.8 Fees and Other Charges

The Company will provide all standard services hereunder pursuant to the approved Electric Service Tariff. All additional and supplementary services provided by the Company to a Customer will be charged a separate rate or fee, such as those included, without limitation, in Schedule D herein. Payment for these services shall be in accordance with the provisions of these Terms and Conditions.

4. APPLICATION FOR AND CONDITIONS OF SERVICE

4.1 General Requirements

(a) Any applicant for Service may be required to sign an application or a contract for Service, and shall supply information respecting Load, preferred supply conditions and the manner in which Energy will be utilized. An applicant may also be required to establish a Satisfactory Credit Rating with the Company and/or provide a Security Deposit prior to being connected for Service.

(b) The Company reserves the right to verify the identity of the Customer and the accuracy of the information provided and to require the Customer to sign an application in writing on forms provided by the Company. If a Customer is not of legal age, a Security Deposit may be required in order to obtain Services and, in addition, a person of legal age may be required to accept responsibility for the Services on that Customer's behalf.

(c) Contacts for Service are not transferable. Persons taking over premises, where Energy has been used previously, must make a new application for Service and pay the necessary Connection Fee per Article 4.3 and Security Deposit per Article 4.6.

4.2 Conditions of Service

Upon receipt of an application or contract for Service, the Company shall notify the applicant of any conditions which must be satisfied before the application or contract will be accepted and Service may be commenced.

4.3 Connection Fee

Whenever a connection is made, the Customer will pay a non-refundable Connection Fee as specified in Schedule D, which shall be included in the Customer's first billing or paid with the application for Service, (save and except that, where the Customer has paid a Construction Contribution for the Service, the Connection Fee shall be deemed to be included in the Construction Contribution).

4.4 Application of Rate Schedules

Whether or not a Customer has signed an application or contract for Service, these Terms and Conditions and the Rate Schedule applicable to the Service supplied by the Company shall apply. In addition to payments for Service, the Customer is required to pay the Company the amount of any tax or assessment levied by any tax authority on Service delivered to the Customers.

4.5 Extensions to Electric Heat Customers

On Isolated Systems, Service for electric space heating purposes may be supplied to Customers only with the prior written permission of the Company.

4.6 Security Deposit

(a) Security Deposit Requirements
The Company may require payment of a Security Deposit by an applicant or Customer under the following circumstances:

(i) the applicant has not established a Satisfactory Credit Rating with the Company;

(ii) the Customer's Service has been disconnected or restricted by a Current-Limiting Device; or

(iii) the Customer has not paid all past bills for Service.

If a Security Deposit is required and not been provided prior to connection, it will be added to the bill for Service and due in full on the due date identified on the bill.

(b) Amount of Security Deposits
The amount to be deposited with the Company shall be determined by the Company at the time of the Service application and shall be based on an estimate of the total amount billed over a period of three months in which Energy consumption by the Customer is expected to be the highest. The Security Deposit required may be adjusted accordingly based on the Customer's actual use of the Service or other information made available to the Company.

(c) Interest on Security Deposits
The Company will pay simple interest on the Security Deposit from the date the deposit is paid, at the rate of interest specified from time to time in the Yukon Landlord and Tenant Act and such interest will be credited to the Customer's account annually on the first bill following December 31 or when the deposit is refunded.

(d) Refunds of Security Deposit

A Security Deposit may be refunded or credited to the Customer's account with interest by the Company when:
(i) the Customer's Service is disconnected, other than for default in payment of accounts, and the Customer has paid all amounts owing to the Company; or
(ii) the Customer has established a Satisfactory Credit Rating.

(e) Use of Security Deposit
If a Customer fails to pay any amount billed, the Company may apply all or any portion of that Customer's Security Deposit to the unpaid amount. The Customer will then be required to fully restore the Security Deposit before Service is reconnected or continued.

4.7 Delay in Taking Service - Other than Subdivision

Except in the case of a Customer who requests service to a subdivision if Service is not taken within 30 days of the In Service Date, the Company may begin billing the Customer for the minimum amount specified in the appropriate rate schedule or as specified in the contract between the Company and the Customer, whichever is greater.

4.8 Extension of Service

(a) Customer’s Construction Contribution
If the Company's estimated costs of extending Facilities at the request of a Customer are less than the Maximum Company Investment specified in Schedule B for the type of Service requested, the Customer will not be required to make any Construction Contribution. In all other cases, an agreement for payment of the Construction Contribution must be made between the Customer and the Company before any work on the extension is commenced.

(b) Cost Sharing
If a new Customer shares a portion or all of the costs of an existing extension, the existing Customers may be entitled to Cost Sharing of the Construction Contribution based on the amount of extension shared.

Cost Sharing will be administered for a five year term commencing December 31 of the year of construction of the original extension. The Company will not administer refunds of less than $50.00.

Cost sharing will not be elegible for non metered, public services such as street lights, and heat tapes.

4.9 Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule C.

4.10 Conversion from Overhead to Underground Service

When a Customer requests that existing Company Facilities be converted from overhead to underground, the Customer may be charged for all costs incurred by the Company in connection with the conversion, including the following:

(a) the actual cost of removing the existing Facilities, less the estimated value of the salvaged material, plus
(b) the actual cost of installing the new underground Facilities, less any available Company Investment as specified in Schedule B.

4.11 Temporary Service

Where the Company reasonably believes that a requested Service will be temporary, a Connection Fee as specified in Schedule D will be assessed and the Company may require the Customer requesting the Service to pay the Company's total estimated cost of installation and removal of Facilities necessary for the desired Service less the estimated value of the salvaged material.

The Company may require that such payment be made before the temporary Service is installed.

4.12 Mobile Homes

(a) Service shall normally be provided to mobile homes through separate Points of Service, based on the applicable residential rate.

(b) Service provided to common use areas (e.g., laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

(c) In mobile home parks or trailer courts where the Company reasonably believes homes are temporary, the Company may elect to provide Service only through the Point of Service billed to the mobile home park or trailer court.

4.13 Multiple Dwellings

Each individual unit within a Multiple Dwelling will be served as a separate Point of Service and billed individually on the applicable residential rate. The Company and a Customer may agree that one bill will be issued covering all individual units in a Multiple Dwelling and, in such case, the applicable general service (non-residential) rate will apply to the Service.

4.14 Relocation of Company Facilities

The Company may require a Customer to pay all reasonable costs incurred by the Company in relocating any Company Facility at the Customer's request and may require payment of the estimated cost of the relocation in advance.

4.15 <u>Reconnection</u>

When the circumstances resulting in discontinuance of a Customer's Service or restriction of Service through the installation of a Current Limiting Device have been rectified to the satisfaction of the Company, or when a Customer has requested a reconnection after having requested a previous disconnection, the Company shall reconnect and continue the provision of Service upon payment by that Customer of:

(a) any amount owing to the Company;
(b) a Reconnection Fee as specified in Schedule D; and
(c) the Security Deposit, if any, required under Article 4.6;

If Service is reconnected within 12 months of disconnection, with the exception of seasonal Service, the Company may request that the Customer pay the minimum monthly bill for each month of disconnection.

The Company may add a Collection Fee as specified in Schedule D if a site visit is required to attempt collection of overdue accounts and Service is not disconnected or for delivery of a notice of pending disconnection.

This section does <u>not</u> apply when a Customer's Service was disconnected for safety reasons. (Refer to Article 11.2)

[NTD: Yukon Energy does not agree with the proposed edits to what was previously subpart (d) as discussed in Tab 5]

5. RIGHTS OF WAY AND ACCESS TO FACILITIES

5.1 Easements

At the request of the Company, the Customer shall grant, or cause to be granted, to the Company, without cost to the Company, such easements or rights-of-way over, upon or under the property owned or controlled by the Customer as the Company reasonably requires for the construction, installation, maintenance, repair and operation of the Facilities required for a Service Connection to the Customer and the performance of all other obligations required to be performed by the Company hereunder.

5.2 Right of Entry

The Company's employees, agents or other representatives shall have the right to enter a Customer's property at all reasonable times for the purpose of installing, maintaining, repairing, replacing, testing, monitoring, meter reading or removing the Company's Facilities and for any other purpose incidental to the provision of Service. The Customer shall provide the Company with reasonable access to the Company Facilities located on the Customer's property. The Company will endeavour to provide reasonable notice to the Customer when the Company requires entry to the Customer’s property for planned maintenance or repair to the Company’s Facilities.

5.3 Vegetation Management

The Customer shall permit the Company to manage vegetation on the property owned or controlled by the Customer. Access is required to maintain the proper clearances and reduce the risk of contact with the Company's overhead high and low voltage distribution equipment. The Company shall make reasonable efforts to notify the Customer before such work is performed.

Vegetation management in the vicinity of the high voltage distribution system (primary) is the responsibility of the Company. Vegetation will be maintained to established standards to reduce contact with the energized conductors or equipment.

Vegetation management in the vicinity of the low voltage (service drops or secondary) distribution on the Customer’s property is the responsibility of the Customer. Where the Company determines that vegetation management is required to maintain the integrity of the Company’s low voltage overhead distribution system, the Company may, at the Customer’s expense, perform the work that is the responsibility of the Customer as set out herein. With respect to the low voltage overhead distribution system only, the Company shall make reasonable efforts to notify the Customer that such work is required, and shall provide the Customer a reasonable opportunity to undertake the work required, before such work is performed by the Company.

5.4 Interference with Company's Facilities

Customers shall not install, or allow to be installed, temporary or permanent structures that could interfere with the proper and safe operation of the Company's Facilities or result in non-compliance with applicable statutes, regulations, standards or codes.

5.5 Customer Brushing

Customers requesting Service that requires the extension of Facilities to the Customer's property shall be responsible for brushing on the Customer's property in accordance with the Company's specifications. In addition, unobstructed access to each structure requiring Service must be provided.

6. METERS

6.1 Installation

(a) Provision and Ownership
The Company shall provide, install and seal all meters necessary for measuring the Energy and Demand supplied to a Customer, unless otherwise specifically provided in a contract with the Customer. Each meter shall remain the sole property of the Company.

If required, as determined in the Company's sole discretion, current and voltage transformers and metering test switches will be supplied to the Customer for installation by the Customer's qualified personnel or contractor. Current and voltage transformers shall be installed in accordance with the Company's specifications and all codes, legislation and reference to applicable metering standards.

(b) Responsibility of Customer
Each Customer shall provide and install a CSA-approved meter receptacle or other CSA-approved Facilities suitable to the Company for the installation of the Company's meter or metering equipment.

6.2 Location

The location of any meter shall be subject to the approval by the Company having regard to the type of Service being provided and so as to permit safe and convenient access to the meter by the Company. Where a meter is installed on a Customer owned pole, the pole shall be provided and maintained by the Customer as required by the Canadian Electric Code and any other applicable legislation.

Meter sockets for self-contained meters shall be mounted on the exterior of a building at an accessible location acceptable to the Company. The centerline of the meter socket must be 1.5 to 1.8 meters above the finished grade or permanent platform of the Customer's Facility and in an appropriately lighted area.

Metering instrument transformer enclosures shall contain only the Company's metering auxiliary equipment and shall not be used as a raceway, splitter box or cabinet for any other purpose.

6.3 Meter Tests and Adjustments

(a) The Company may inspect and test a meter at any reasonable time. At the request of a Customer, and upon payment of a Meter Accuracy Test Handling Fee as specified in Schedule D, the Company shall arrange for a meter to be tested by an official designated for that purpose by Industry Canada or such other federal government agency as may, from time to time, be designated for that purpose.

(b) If a test determines that the meter is not accurate within the limits set by government standards, the Customer's bill will be adjusted back to the time that the error can reasonably be determined to have commenced . Where the commencement of the error cannot reasonably be determined, it shall be deemed to have commenced three months before the test or on the date of the meter installation, whichever occurred later.

(c) In the event that an adjustment is required, the Meter Accuracy Test Handling Fee shall be refunded.

6.4 Access to Meters

(a) The Company may, at any reasonable time, read, inspect, remove and test a meter installed on property owned or controlled by the Customer.

(b) Where the Customer’s Service address or location is generally locked during normal business hours, the Customer shall provide the Company with a key to permit access to the meter.

(c) If the Company provides notice to a Customer that reasonable access to metering equipment is not being provided, the Customer must take immediate action to remedy the situation. If the Customer fails to remedy the situation to the Company’s satisfaction within a reasonable time:

(i) the Company may, at its sole discretion, estimate consumption until the situation has been remedied and the Customer shall be billed on the basis of the Company’s estimate;

(ii) the Company may remedy the situation on behalf of the Customer and apply the costs to the Customer’s next regular bill;

(iii) the Company may do both i) and ii); or

(iv) the Company may discontinue Service in accordance with Section 11 of these Terms and Conditions of Service.

7. METER READING AND BILLING

7.1 Reading and Estimates

Unless otherwise specifically provided in a contract with a Customer, meters shall be read monthly or bi-monthly or at such other intervals as are practical in the circumstances. Customers' bills will be based on meter readings made by the Company or on estimates for those billing periods when the meter is not read. Whenever a bill is based on an estimate, an adjustment to reflect actual Energy consumption and Demand (if applicable) used will be made when the meter is next read.

7.2 Calculation of Bills

(a) The amount of any initial and final charges will be prorated, based upon the ratio of the number of days that Service was provided to a Customer in the billing period to the total number of days in the billing period.

(b) The Company may elect not to charge a Customer for the billing period if, during that period, Demand was five kilowatts or less, Service was provided for five days or less and Energy consumption was five kilowatt hours or less.

(c) For all new accounts, the Company may add the charges for Service provided during the initial period to the bill for the following billing period.

(d) The Company may elect to change a Customer's meter reading schedule.

(e) Where a meter reading schedule is changed, any charges during the transition period between the old and new meter reading schedule, may be prorated based upon the ratio of the number of days that Service was provided to a Customer in the billing period to the total number of days in the billing period.

7.3 Payment

(a) The amount billed is due and owing when the bill is rendered and payable by the date indicated on the bill.

(b) Bills shall be deemed rendered and other notices duly given when delivered to the Customer at the mailing address provided by the Customer. Failure to receive a bill does not entitle a Customer to any delay in payment or release a Customer from the obligation to pay the amount owing.

(c) Payment of a bill for Service may be requested by the Company from any or all of the Customers, on a joint and several basis, even if the Customer no longer resides in the same premises when payment is due.

7.4 Late Payment Charge

The Company may add a Late Payment Charge as specified in Schedule D on any overdue amount. A Collection Fee as specified in Schedule D will be charged if a personal visit is required to collect an overdue amount.

7.5 Dishonoured Payments

The Company may add a Dishonoured Payments Fee as specified in Schedule D to a Customer's bill in respect of any cheque, or other form of payment tendered by the Customer as payment of a bill, returned by the Customer's bank for any reason.

Following the receipt of two (2) dishonoured payments from the Customer, the Company may notify the Customer that only cash, a money order or certified cheque will be accepted for payment.

7.6 Outstanding Charges

The Company may add to the Customer's bill any outstanding charges due and owing to the Company (e.g. construction contribution, account receivable charges, former overdue accounts etc.).

7.7 Totalized Metering

When Service is provided through multiple Points of Service to a Customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the Customer, where such multiple Points of Service are located within a radius of half a mile of each other, or where specified in a contract, the Customer and Company may agree that the Demand and Energy at each Point of Service be totalized and only one bill issued for each billing period. The Customer shall pay the incremental metering cost associated with totalized metering.

7.8 Combined Service

A residential Customer shall notify the Company when the Customer receives Service at their premises for the purposes of operating a business or commercial undertaking. The applicable general service rate may be applied in those cases in which Service for both residential and non-residential purposes is received by a Customer through a single meter.

7.9 Consolidated Billing

The Company will issue a separate bill for each Point of Service. However, the Customer and Company may agree that the Company will issue one bill totaling charges for Service delivered at more than one Point of Service.

7.10 Unauthorized Use

If, under any circumstances, a person prevents a meter from accurately recording the total Demand or Energy supplied, the Company may disconnect the Service, or take other appropriate actions.

The Company may then estimate the Demand and amount of Energy supplied but not registered, at the Point of Service. The Customer shall pay the cost of the estimated Demand and Energy consumption plus all costs related to the investigation and resolution of the diversion including repairs of damage or reconstruction of Facilities.

7.11 Billing Error

The Customer must provide written notice to the Company in order to dispute any or all amounts owing on a bill. In the event the Customer disputes an amount owing, the Customer shall nonetheless pay such disputed amount. Following resolution of any such dispute, the Company will return any amount found owing to the Customer forthwith.

8. SERVICE CHANGES

8.1 Notice by Customer

A Customer shall give to the Company reasonable prior written notice of any change in Service requirements, including any material change in Connected Load, to enable the Company to determine whether or not it can supply such revised Service without changes to its Facilities. The Customer shall not change its Service requirements without the Company's written permission.

8.2 Responsibility for Damage

The Customer shall be responsible for and shall pay for all damage caused to the Company's Facilities as the result of the Customer changing the Connected Load without the Company's permission.

8.3 Changes to Company Facilities

If the Company must modify its Facilities to accommodate a Customer Load or Service change, the Customer shall pay for all costs in connection with such modification including the following costs:

(a) the actual cost of removing the existing Facilities, less the estimated salvage value, less

(b) any applicable adjustment required to the Company Investment as specified in Schedule B.

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1 Continuous Supply

The Company shall make all reasonable efforts to maintain a continuous supply of Energy to its Customers, but the Company cannot guarantee an uninterrupted supply of Energy.

9.2 Interruption

Without liability of any kind to the Company, the Company shall have the right to disconnect or otherwise curtail, interrupt or reduce service to Customers:

(a) whenever the Company reasonably determines that the Service must be interrupted, including to facilitate construction, installation, maintenance, repairs, replacement or inspection of any of the Company's Facilities, or to permit the connection or disconnection of other Customers;

(b) to maintain the safety and reliability of the Company's Facilities; or

(c) due to any other reason related to dangerous or hazardous circumstances including emergencies, forced outages, potential overloading of the Company's Facilities or Force Majeure.

9.3 Reasonable Efforts

The Company shall endeavor to give reasonable notice to Customers who will have Service interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

9.4 Company Liability

Notwithstanding anything to the contrary contained in these Terms and Conditions, the Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether of direct, indirect, special or consequential nature, (excepting only direct physical loss, injury or damage to a Customer or a Customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising out of or in any way connected with the provision of Service by the Company to its Customers including, but not limited to, any failure, defect, fluctuation, reduction or interruption in the provision of Service by the Company to its Customers. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct physical loss, injury or damage" shall not include loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of purchased or replacement capacity and Energy, cost of capital, and loss of use of any Facilities or property, or any other similar damage or loss whatsoever, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of Service by the Company to its Customers.

9.5 Force Majeure

Should the Company be unable to provide a continuous supply of Energy to a Customer because of an event of Force Majeure, the Company's responsibilities, so far as they are affected by the Force Majeure, shall be relieved and suspended during the duration of such circumstances and the Company shall not be liable for any failure to perform any term of these Terms and Conditions to the extent that and when such failure is due to, or is a consequence of, an event of Force Majeure. Where practical, the Company shall give notice to the affected Customers of such Force Majeure.

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1 Provide Permit

The Customer shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations necessary for the installation and operation of the Service Connection. The Company shall not be required to commence or continue installation or operation of a Service Connection unless and until the Customer has complied with the requirements of all permits, certificates, licenses, inspections, reports and other authorizations, and all right-of-way agreements, and all Company requirements applicable to the installation and operation of the Service Connection.

10.2 Customer Responsibility

The Customer shall be solely responsible for the use, installation, condition of all Facilities on the Customer's side of the Point of Service, except Facilities owned by the Company. The Customer shall be responsible for and shall pay for any damage to the Company's Facilities located on the Customer's premises which is caused by the negligent acts or omissions or willful misconduct of the Customer or of anyone permitted by the Customer to be on the Customer's premises..

10.3 Customer Liability

(a) The Customer assumes full responsibility for the proper use of Facilities and for the condition, suitability and safety of any and all wires, cables, devices or equipment energized on the Customer's premises or on premises owned or controlled by the Customer that are not the Customer's property.

(b) Where a Customer uses its Service Connection in a manner that causes interference with the operation of the Company's Facilities or with any Customer's use of a Service Connection, such as abnormal voltage levels, frequency levels and harmonic levels, at the Company's request, and at the Customer's own expense, the Customer shall take whatever action is required to correct the interference or disturbance.

(c) The Customer shall indemnify and save harmless the Company from and against any claim or demand for injury to persons or damage to property (including loss of use thereof and of any other property affected by the damage to property) arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees and agents.

(d) The Customer releases the Company and its agents, directors, officers, employees, independent contractors, consultants, representatives, successors and assignees from any and all claims and liabilities whatsoever relating to or arising as a result of the Customer, or its agents, directors, officers, employees, independent contractors, consultants, representatives, successors and assignees carrying out any acts required by or related to these Terms and Conditions for the provision of Service, maintenance of Service, or any other act whatsoever arising out of or in any way connected with the existence or use of the Service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees or agents.

10.4 <u>Protective Devices</u>

The Customer shall be responsible for determining whether any devices are required to protect the Customer's Facilities from damage that may result from the provision of Service by the Company. The Customer shall provide and install any such devices.

10.5 <u>Service Calls</u>

The Company may require a Customer to pay the actual costs of a Customer-requested service call if the source of the problem is the Customer's Facilities.

11. TERMINATION OF SERVICE

11.1 Termination by Customer

Except where otherwise provided in a written agreement between the Company and a Customer, a Customer may, at any time, give the Company reasonable notice to terminate Service. Upon receipt of such notice, the Company shall read the Customer's meter within a reasonable time, and, shall use its best efforts to read the Customer's meter at the time requested by the Customer. A Customer shall pay for all Service provided to the time of such reading.

11.2 Company Termination for Safety Reasons

The Company may, without notice, terminate a Customer's Service where, in the Company's opinion:

(a) the Customer has permitted the wiring of their Facilities to become hazardous;
(b) the wiring of the Customer's Facilities fails to comply with applicable law; or
(c) the Customer has caused any other safety hazards, including, but not limited to, using their Service in such a way that causes damage to the Company's Facilities or interferes with or disturbs Service to any other Customer.

The Company will reconnect the Service when the safety problem is resolved and when the Customer has provided, or paid the Company's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance. The Company may assess a Reconnection Fee, as specified in Schedule D.

11.3 Company Termination Other Than For Safety

The Company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the Customer, terminate the Customer's Service or install a Current-Limiting Device to restrict the Service to such Customer if the Customer:

(a) fails to meet its obligation under these Terms and Conditions, the terms of a contract for Service, or of the Company's Rate Schedules;
(b) uses their Service Connection in such a way that causes interference with operation of the Company's Facilities or any other Customer's use of a Service Connection such as abnormal voltage levels, frequency levels and harmonic levels.
(c) tampers with any Company Facilities;
(d) neglects or refuses to pay the amount billed for Service due and owing to the Company by the date indicated on the bill for Service;
(e) changes Service requirements without the permission of the Company; or

(f) makes use of the Service for illegal purposes or in circumstances where the Company has evidence of Energy theft, or fraud by the Customer.

11.4 <u>Removal of Facilities</u>

Upon discontinuance of Service for whatsoever reason, the Company shall be entitled to remove any of its Facilities located upon the property of the Customer and to enter upon the Customer's property for that purpose.

SCHEDULE A
STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

(a) Residential:

240/120 V
- single phase, three wire
- secondary conductors are supplied by the Company
- overhead or, in designated areas, underground conductors are supplied by the Company

(b) General Service:

240/120 V
- single phase, three wire
- overhead secondary conductors are supplied by the Company
- underground secondary conductors are supplied by the customer

208 Y/120 V
- three phase, four wire
- overhead secondary conductors are supplied by the Company
- underground secondary conductors are supplied by the customer

480 Y/277 V
- three phase, four wire
- overhead secondary conductors are supplied by the Company for loads 15 KVA to 300 KVA
- overhead secondary conductors are supplied by the customer for loads 300 KVA to 1,500 KVA

600 Y/347 V
- three phase, four wire
- underground secondary conductors are supplied by the customer for loads 150 KVA to 2,500 KVA; and

4160 Y/2400 Y
- three phase, four wire, 2,000 KVA to 10,000 KVA

- overhead secondary conductors are supplied by the customer

SCHEDULE B
MAXIMUM COMPANY INVESTMENT

1. Subject to the provisions of paragraph 2 of this Schedule B, the maximum Capital Cost which the Company will incur to extend Service to a Point of Service (herein referred to as the "Maximum Company Investment") shall be determined as follows. Under no circumstances would the Maximum Company Investment exceed the Customer extension cost:

(a) Residential Service:

Year	Residential Single Family Dwelling ($/Site)	Residential Multi Dwelling Unit ($/Site)
2011	$ 1,250	$ 625
2012	$ 1,740	$ 870
2013	$ 2,420	$ 1,210
2014	$ 3,360	$ 1,680
2015	$ 4,700	$ 2,350

(b) General Service:

As per table below, the Company will invest a fixed amount as indicated plus a variable amount per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated service life is less than 25 years or seasonal, then the Maximum Company Investment shall be determined in the manner described in paragraph 2;

Year	General Service ($Fixed)	General Service ($/kW)
2011	$ 5,355	$ 275
2012	$ 5,500	$ 280
2013	$ 5,650	$ 290
2014	$ 5,800	$ 295
2015	$ 5,955	$ 305

At the end of one year of Service the Company will re-assess whether the Customer’s estimates of their Demand were accurate and, if the loads are significantly different than originally estimated, will collect from the Customer (or refund) any contributions, that are required based on the Maximum Company Investment rules in place when the contribution was originally paid.

c) Municipal Street Lighting:

Year	Street Lighting ($/Light)
2011	$ 930
2012	$ 1,240
2013	$ 1,660
2014	$ 2,220
2015	$ 2,975

2. The Maximum Company Investment in any extension of service, whether or not specified in paragraph 1, the Load characteristic and service life of which are expected to vary materially from the average for that type of Service, shall be determined based on an analysis of the load characteristics and service life, as a pro-ration of the full Maximum Company Investment for that class of customer.

3. In this section Annual Cost means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers. For Major Industrial Customers, if the Annual Cost of serving a Customer is higher than the revenue expected to be received from such Service, then the Maximum Company Investment shall be the Capital Cost of the extension less the present value of the annual amounts over the expect life of the Service by which the Annual Cost is expected to exceed the revenue.

[NTD: Yukon Energy does not support the proposal to increase the the maximum company investment after 2011 at this time.]

SCHEDULE C

CONDITIONS FOR UNDERGROUND SUBDIVISIONS

"**Developer**" is defined as the person or party who has requested the underground service. The Company shall extend service by underground conductor lines upon and subject to the following terms and conditions

(a) At the time of the request for underground Service no Service available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Company) will be connected to such extension (the "underground service area"), each of which is situated upon said subdivision;

(b) All permanent Service in the underground service area shall be provided exclusively through underground conductor lines;

(c) The Developer shall provide, without cost to the Company, such rights-of-way, easements, utility corridors and transformer locations as the Company may require for the installation, operation and maintenance of such extension, which the Developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Company in installing, maintaining or removing its Facilities;

(d) The Company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the Developer;

(e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the Company;

(f) In relation to the standard underground Service, the Developer shall provide a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure the installation of a service having a 200 ampere capacity. Non-standard Services will be subject to prior written approval by the utility;

(g) The Developer shall provide to the Company a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, driveways (if known) and underground utilities together with such evidence as the Company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the Developer;

(h) Survey stakes indicating grades and property lines shall be installed and maintained by the Developer;

(i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

(j) Unless otherwise agreed to by the Company, the Developer shall provide a survey for the location of transformers, street light bases and cable routing, as required;

(k) Sidewalks, curbs and gutters may be constructed by the Developer but no other permanent improvements shall be made until approved by the Company.

(l) Costs related to the installation of distribution system infrastructure shall be the responsibility of the Developer; and

(m) The Company investment will be applied toward the individual Customer Service connection in accordance with Schedule B.

In addition, the Service shall be subject to such other conditions as may be specified by the Company from time to time.

SCHEDULE D - FEES AND SERVICE CHARGE SUMMARY

CONNECTION, and RECONNECTION FEES

Connection Fee (4.3, 4.11):	
During normal business hours:	$50.00
Outside of normal business hours:	Company's actual cost (min. $50.00)
Reconnection Fee (4.15, 11.2)	
During normal business hours:	$60.00
Outside of normal business hours:	Company's actual cost (min. $60.00)

LATE PAYMENT AND DISCONNECTION

Collection Fee (4.15, 7.4)	$30.00 (personal visit)
Late Payment Charge (7.4):	1.5% per month (19.56% per annum)
Dishonoured Payments Fee (7.5):	$25.00

METER DISPUTES

Meter Accuracy Test Handling Fee (6.3)	
Self Contained Meter	$100.00
Instrument Meter	$200.00

Appendix 5.2

YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

~~ELECTRIC SERVICE REGULATIONS~~TERMS AND CONDITIONS

OF

SERVICE

~~**Updated to: October 18, 2005**~~

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9. COMPANY RESPONSIBILITY AND LIABILITY

10. CUSTOMER RESPONSIBILITY AND LIABILITY

11. TERMINATION OF SERVICE

~~**YUKON ENERGY CORPORATION**~~

~~**AND**~~

~~**THE YUKON ELECTRICAL COMPANY LIMITED**~~

1. IN~~TERPRETATION~~TRODUCTION

The Yukon Electrical Company Limited (Yukon Electrical) and Yukon Energy Corporation (Yukon Energy) each provide direct electrical Service to Yukon Territory Customers under a common Electric Service Tariff. The Electric Service Tariff is comprised of the Rate Schedules and these Terms and Conditions of Service (the "Terms and Conditions", formerly known as the "Electric Service Regulations"). Yukon Electrical and Yukon Energy conduct their business activities in compliance with these Terms and Conditions.

These Terms and Conditions are regulated by the Yukon Utilities Board (hereinafter referred to as the "Board"), in accordance with the Yukon *Public Utilities Act*, and may not be changed without the approval of the Board. Parties having any inquiries or complaints regarding these Terms and Conditions may direct such inquiries or complaints directly to Yukon Electrical, Yukon Energy or the Board.

The Electric Service Tariff is available for public inspection during normal business hours at the business offices of Yukon Electrical and Yukon Energy and at the offices of the Board and can be accessed on the Companies' respective websites at: www.yukonelectrical.com and www.yukonenergy.ca .

~~2.1 Board Approval~~

~~These regulations have been approved by the Board.~~

~~The Company may amend these regulations by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which customer groups are affected by the amendment and an explanation of how affected customers will be notified of the amendments. The amendment will take effect 120 days after such notice is filed unless the Board orders otherwise.~~

~~2.2 Electric Service Tariff~~

~~These regulations are the Electric Service Regulations referred to in the Company's Electric Service Tariff and form part of the Electric Service Tariff.~~

~~2.3 Effective Date~~

~~These regulations come into force on October 18, 2005, and replace the Company's previous Electric Service Regulations. Whenever the Board approves an amendment to these Regulations, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.~~

2. INTERPRETATION~~NTRODUCTION~~

2~~1~~.1 Definitions

~~Unless the context requires otherwise, t~~The following words or ~~and~~ phrases, when~~ever~~ used in these ~~Regulations~~Terms and Conditions, the _Electric Service Tariff or an application, contract or agreement for service, shall have the meaning~~s~~ set ~~out~~ forth below.

"B~~b~~illing D~~d~~emand" - the demand upon which billing to a C~~c~~ustomer is based as specified in a rate schedule or contract~~.~~

"Board" - the Yukon Utilities Board.

"Capital Cost" the cost of materials, labour, equipment, expenses and any other direct or indirect costs incurred by the Company in extending Service to a Point of Service.

"Company" - The Yukon Electrical Company Limited or Yukon Energy Corporation.

"C~~c~~onnected L~~l~~oad" - the sum of the capacities or ratings of the electric E~~e~~nergy consuming apparatus connected to a supplying system.

"Connection Fee" – a non-refundable fee charged when a new Service is connected or an existing Service is reconnected or a meter reading is required to add the Customer to the Company's system. (refer to Schedule D for fees).

"C~~c~~onstruction C~~c~~ontribution" ~~-~~– a specific payment by a Customer to offset Company costs incurred in extending Service that will primarily benefit that Customer or group of Customers only and not the other ratepayers in the distribution system. The contribution will be the difference between the cost of extending the Company's Facilities to serve a Customer or group of Customers and the Maximum Available Company Investment specified in Schedule B.

~~the difference between the cost of extending the Company's facilities to serve a customer and the maximum Company investment specified in Schedule B~~.

"Cost Sharing" – the process whereby a new Customer or group of Customers who connect to an existing Facility for which another Customer or group of Customers has paid a Construction Contribution, is assessed their share of that Construction Contribution which must be paid to the Company to be refunded to the existing Customer(s).

"Current Limiting Device" – a device that limits the amount of Demand available to a specific Customer.

"C~~c~~ustomer" - ~~means~~ a person, firm, partnership, corporation, association or organization (including, without limitation, individual members of any unincorporated entity) to who the Company provides any ~~s~~Service hereunder ~~which has applied for or is receiving the provision of service by the utility. This would~~ includinge all ~~joint tenants~~owners and occupants of a premises, whom normally reside at the premises during the time for which Service was provided to that premises whether or not such owner or occupant's ~~their~~ name appears on the application for Service.

"D~~d~~emand" - the maximum rate at which electric E~~e~~nergy is delivered by the Company (expressed in kilowatts, kilovolt amperes or other suitable unit) at a given instant or averaged over any designated period of time.

"Electric Service Regulations" – the former title of this document outlining the terms and conditions governing Service, which title has been replaced by Terms and Conditions of Service. Where reference is made to Electric Service Regulations it shall be deemed to be a reference to these Terms and Conditions of Service as amended from time to time.

"E~~e~~nergy" - electric energy consumed ~~(~~expressed in kilowatt hours~~)~~.

"Estimated Capital Cost" – the estimated cost of materials, labour, equipment, expenses, and any other direct or indirect costs for extending Service to a Point of Service.

"Facilities" - a physical plant ~~(~~including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery~~)~~.

~~**"extraordinary circumstances-**~~**"Force Majeure" -** circumstances not reasonably within the control of the Company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, pandemics, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, mechanical breakdowns, the intervention of federal, territorial, or local government or from any of their agencies or boards (excluding Decisions and/or Orders made by the Board in the normal course of it exercising its authority to establish the revenue requirement of the parties to this agreement), the order or direction of any court and any other cause, whether of the kind herein enumerated or otherwise.

~~**"family dwelling"** - a residential dwelling unit which is not a multiple dwelling, consists of single family living quarters having in one self-contained unit at least sleeping quarters, a kitchen and bathroom (see definition of "multiple dwelling").~~

"I~~i~~n-S~~s~~ervice D~~d~~ate" - the date on which the C~~c~~ustomer specifies S~~s~~ervice is to be available or the date the S~~s~~ervice is actually available, whichever is later.

"I~~i~~nterconnected S~~s~~ystem" - those portions of the Company's F~~f~~acilities which are connected to the Whitehorse/Aishihik/Faro (WAF) power grid or to the Mayo-Dawson grid.

"I~~i~~solated S~~s~~ystem" - those portions of the Company's F~~f~~acilities which do not form part of the I~~i~~nterconnected S~~s~~ystem.

"L~~l~~oad" - the D~~d~~emand and E~~e~~nergy delivered to or required at any P~~p~~oint of Service~~delivery~~.

"L~~l~~oad F~~f~~actor" - the ratio of the average D~~d~~emand (in kilowatts) supplied during a designated period to the peak or maximum Demand~~load~~ (in kilowatts) occurring in the period expressed as a percentage derived by~~. To express load factor as a percentage~~:

(a) multiplying the E~~e~~nergy used in the designated period by 100;
(b) multiplying the maximum D~~d~~emand by the number of hours in the designated period; and
(c) dividing~~e~~ (a) by (b).

"Maximum Company Investment" – the maximum Capital Cost which the Company will incur to extend Service to a Point of Service as set forth in Schedule B hereto.

"M~~m~~ultiple D~~d~~welling" - a residential building containing more than one ~~-s~~Single ~~f~~Family ~~residential d~~Dwelling unit.

"P~~p~~oint of Service~~delivery~~" - the point at which the Company's service conductors are connected to the wires or apparatus of a C~~c~~ustomer.

"P~~p~~ower F~~f~~actor" - the ratio of the highest metered kilowatt D~~d~~emand in a billing period to the highest metered kilovolt ampere D~~d~~emand in that same billing period.

"Satisfactory Credit Rating" – determined subject to the discretion of the Company, and may include the Customer having paid all bills on an existing Company account in full on or before the due date of the said bill for 12 consecutive months or a similar payment record as established with another utility service provider within the past twelve months.

"Security Deposit" – the amount determined in accordance with Article 4.6.

"S~~s~~ervice" - the delivery of E~~e~~nergy by the Company at the D~~d~~emand required by the~~a~~ C~~c~~ustomer.

"Service Connection" the Facilities required to physically connect the Customer's facilities to the Company's system.

"Single Family D~~d~~welling" - a private residence ~~residential dwelling unit~~ which is not a M~~m~~ultiple D~~d~~welling, consisting~~s~~ of single family living quarters having, in one self-contained unit, at least sleeping quarters, and, a kitchen. ~~and bathroom (see definition of "multiple dwelling").~~

2.2 Conflicts

If there is any conflict between a provision expressly set out in an Order of the Board and these Terms and Conditions, the Order of the Board shall govern.

2.3 Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

2.4 Schedules and Appendices

The following schedules and appendices are attached to and form part of these Terms and Conditions:

- Schedule A - Standard Supply Specifications
- Schedule B - Maximum Company Investment
- Schedule C - Conditions for Underground Subdivisions
- Schedule D - Fees and Service Charge Summary

3. GENERAL PROVISIONS

3.1 Board Approval

These Terms and Conditions have been approved by the Board. The Company may amend these Terms and Conditions by filing a notice of amendment with the Board and interested parties from the preceding General Rate Application. Included in the notice shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. If the Board approves the notice of the amendment, the amendment will take effect upon the date set by the Board. If no specific date is set by the Board then the amendment will take effect on the date of the Board's Order approving the notice of amendment.

3.2~~1~~ ~~Regulations~~Terms and Conditions Prevail

(a) These Terms and Conditions, as amended from time to time, apply to the Company and to every C~~c~~ustomer to which the Company provides a Service Connection.

~~(a)~~(b) The application for a Service Connection (whether verbal or written), the use by the Customer of a Service Connection to obtain Electricity Services or the payment by the Customer of an account rendered by the Company in relation to a Service Connection shall constitute acceptance by the Customer of these Terms and Conditions.

~~(b)~~(c) No agreement can provide for the waiver or alteration of any part of these Terms and Conditions ~~regulations~~ unless such agreement is first filed with and approved by the Board.

3.3~~2~~ Ownership of Facilities

Unless otherwise specifically provided in a contract with the Customer, notwithstanding the payment by a Customer of any costs incurred by the Company, the Company shall install, maintain and retain full title and ownership of all lines, equipment and other Facilities on its side of the Point of Service and of all meters and metering equipment provided and/or installed by it.

~~The Company remains the owner of all facilities it provides to serve the customer, unless a contract between the Company and customer specifically provides otherwise.~~

~~Payment made by customers for costs incurred by the Company in installing facilities does not entitle customers to ownership of any such facilities, unless a contract between the Company and the customer specifically provides otherwise.~~

3.4~~3~~ Use of Energy

Service is provided only for the purposes specified by contract or by the rate schedule applicable to such Service. A Customer shall not sell Energy provided by the Company unless otherwise provided by a contract with the Company, or unless the Company has first given written consent.
~~Unless otherwise provided in a contract with the Company, a customer shall not sell energy provided by the Company unless the Company has first given written consent.~~

3.5~~4~~ Customer Extensions

A C~~c~~ustomer shall not extend service F~~f~~acilities beyond property owned or occupied by the C~~c~~ustomer.

3.6~~5~~ Customer Generation

A C~~c~~ustomer must notify the Company and sign an agreement with the Company if the Customer ~~he/she~~ wishes to have ~~use~~ service;

a) in parallel operation with; or
b) as supplementary, auxiliary or stand-by S~~s~~ervice to any other source of electric E~~e~~nergy.

3.7~~6~~ Frequency and Voltage Levels

The Company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and shall be in accordance with the Company's standard supply specifications as set out ~~as specified~~ in Schedule A except in locations where the ~~.~~

~~Some~~ voltage levels set out in Schedule A are ~~may~~ not ~~be~~ available. ~~at all locations served by the Company.~~

3.8 Fees and Other Charges

The Company will provide all standard services hereunder pursuant to the approved Electric Service Tariff~~Terms and Conditions~~. All additional and supplementary services provided by the Company to a Customer will be charged a separate rate or fee, such as those included, without limitation, in Schedule D herein. Payment for these services shall be in accordance with the provisions of these Terms and Conditions.

4. APPLICATION FOR AND CONDITIONS OF SERVICE

4.1 General Requirements

(a) Any applicant for Service may be required to sign an application or a contract for Service, and shall supply information respecting Load, preferred supply conditions and the manner in which Energy will be utilized. An applicant may also be required to establish a Satisfactory Credit Rating with the Company and/or provide a Security Deposit prior to being connected for Service.

(b) The Company reserves the right to verify the identity of the Customer and the accuracy of the information provided and to require the Customer to sign an application in writing on forms provided by the Company. If a Customer is not of legal age, a Security Deposit may be required in order to obtain Services and, in addition, a person of legal age may be required to accept responsibility for the Services on that Customer's behalf.

(c) Contacts for Service are not transferable. Persons taking over premises, where Energy has been used previously, must make a new application for Service and pay the necessary Connection Fee per Article 4.3 and Security Deposit per Article 4.6.

~~(a) To enable the Company to provide the requested service, applicants for service shall supply information regarding their load and preferred supply conditions.~~

~~An applicant shall be required to sign an application or a contract for service and may be required to provide credit information or references.~~

4.2 Conditions of Service

Upon receipt of an application or contract for Service, the Company shall notify the applicant of any conditions which must be satisfied before the application or contract will be accepted and Service may be commenced.~~Before connecting any service, the Company will inform the customer if there are any special conditions that must be satisfied.~~

4.3 Connection Fee

Whenever a connection is made, the ~~customer~~ Customer will pay a non-refundable C~~c~~onnection F~~f~~ee ~~of either:~~ as specified in Schedule D,

~~(a) $15 if the connection is made during the Company's regular business hours; or~~

~~(b) an amount not to exceed the Company's actual costs if the connection is made at any other time,~~ which shall be included in the C~~c~~ustomer's first billing or paid with the application for -Service, (save and except that, where the C~~c~~ustomer has paid a C~~c~~onstruction C~~c~~ontribution for the ~~-~~S~~s~~ervice, the C~~c~~onnection F~~f~~ee shall be deemed to be included in the C~~c~~onstruction C~~c~~ontribution).

4.4 Application of Rate Schedules

Whether or not a Customer has signed an application or contract for S~~s~~ervice, these Terms and Conditions ~~the Regulations~~ and the R~~r~~ate S~~s~~chedule applicable to the S~~s~~ervice supplied by the Company shall apply. In addition to payments for ~~electric~~ S~~s~~ervice, the C~~c~~ustomer is required to pay the Company the amount of any tax or assessment levied by any tax authority on ~~electric~~ S~~s~~ervice delivered to the C~~c~~ustomers.

4.5 Extensions to Electric Heat Customers

On I~~i~~solated S~~s~~ystems, S~~s~~ervice for electric space heating purposes may be supplied to C~~c~~ustomers only with the prior written permission of the Company.

4.6 Security Deposit

~~The Company may require any customer who has not established a satisfactory credit rating with the utility and cannot provide evidence of employment or who has been disconnected or where a current-limiting device has been installed, to provide a security deposit which shall not exceed the Company's estimate of the customer's total bills for any three-month period.~~

(a) Security Deposit Requirements

The Company may require payment of a Security Deposit by an applicant or Customer under the following circumstances:

(i) the applicant has not established a Satisfactory Credit Rating with the Company;

(ii) the Customer's Service has been disconnected or restricted by a Current-Limiting Device; or

(iii) the Customer has not paid all past bills for Service.

If a Security Deposit is required and not been provided prior to connection, it will be added to the bill for Service and due in full on the due date identified on the bill.

(b) Amount of Security Deposits

The amount to be deposited with the Company shall be determined by the Company at the time of the Service application and shall be based on an estimate of the total amount billed over a period of three months in which Energy consumption by the Customer is expected to be the highest. The Security Deposit required may be adjusted accordingly based on the Customer's actual use of the Service or other information made available to the Company.

(c) Interest on Security Deposits

The Company will pay simple interest on the S~~s~~ecurity D~~d~~eposit from the date the deposit is paid, at the~~a~~ rate of interest ~~equal to the rate fixed for the most recent rate of~~ specified from time to time in the Yukon Landlord and Tenant Act and such interest will be credited to the C~~c~~ustomer's account annually on the first bill~~ing~~ following December 31 or when the deposit is refunded. ~~of each year.~~

(d) Refunds of Security Deposit

~~The Company may refund a security deposit when the customer has established a satisfactory payment history over a 12-month period or when the customer's service is terminated. Any interest owing at the time a security deposit is refunded will be included in the refund or credited to the customer's account.~~

A Security Deposit may be refunded or credited to the Customer's account with interest by the Company when:

(i) the Customer's Service is disconnected, other than for default in payment of accounts, and the Customer has paid all amounts owing to the Company; or

(ii) the Customer has established a Satisfactory Credit Rating.

~~4.10 Use of Security Deposit~~

~~(a)~~(e) Use of Security Deposit

If a C~~c~~ustomer fails to pay any amount billed, the Company may apply all or any portion of that C~~c~~ustomer's S~~s~~ecurity D~~d~~eposit to the unpaid amount. ~~When the Company has to take this step, the customer may be required to pay a security deposit up to the maximum amount allowed in regulation 4.9.~~The Customer will then be required to fully restore the Security Deposit before Service is reconnected or continued.

4.7~~11~~ Delay in Taking Service - Other than Subdivision

Except in the case of a C~~c~~ustomer who requests service to a subdivision if S~~s~~ervice is not taken within 30 days of the I~~i~~n S~~s~~ervice D~~d~~ate, the Company may begin billing the C~~c~~ustomer for the minimum amount specified in the appropriate rate schedule or as specified in the contract between the Company and the C~~c~~ustomer, whichever is greater.

4.8~~12~~ Extension of Service

(a) Customer's Construction Contribution

If the Company's estimated costs of extending F~~f~~acilities at the request of a C~~c~~ustomer are less than the M~~m~~aximum Company I~~i~~nvestment specified in Schedule B for the type of S~~s~~ervice requested~~provided~~, the C~~c~~ustomer will not be required to make any Construction C~~c~~ontribution. In all other cases, an agreement for payment of the C~~c~~onstruction C~~c~~ontribution must be made between the C~~c~~ustomer and the Company before any work on the extension is commenced.

(b) Cost Sharing

If a new Customer shares a portion or all of the costs of an existing extension, the existing Customers may be entitled to Cost Sharing of the Construction Contribution based on the amount of extension shared.

Cost Sharing will be administered for a five year term commencing December 31 of the year of construction of the original extension. The Company will not administer refunds of less than $50.00.

Cost sharing will not be elegible for non metered, public services such as street lights, and heat tapes.

4.9~~13~~ Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule C.

4.10 ~~14~~ Conversion from Overhead to Underground Service

When a C~~c~~ustomer requests that existing Company F~~f~~acilities be converted from overhead to underground, the C~~c~~ustomer may ~~will~~ be charged for all costs incurred by the Company in connection with the conversion, including the following:

(a) the actual ~~estimated~~ cost of removing the existing F~~f~~acilities, less the estimated value of the salvaged material, ~~salvage value,~~ plus

(b) the actual ~~estimated~~ cost of installing ~~for the installation of~~ the new underground F~~f~~acilities, less any ~~applicable increase in~~ available Company I~~i~~nvestment as specified in Schedule B.

4.11~~5~~ Temporary Service

Where the Company reasonably believes that a requested S~~s~~ervice will be temporary, a Connection Fee as specified in Schedule D will be assessed and the Company ~~it~~ may require the C~~c~~ustomer requesting the S~~s~~ervice to pay the Company's total estimated cost of installation and removal of Facilities necessary for the desired Service ~~the service, plus the cost of unsalvageable material.~~ less the estimated value of the salvaged material.

The Company may require that such payment be made before the temporary S~~s~~ervice is installed.

4.12~~6~~ Mobile Homes

(a) Service shall normally be provided to mobile homes through separate P~~p~~oints of Service~~delivery~~, based on the applicable residential rate ~~schedule~~.

(b) Service provided to common use areas (e.g., laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

(c) In mobile home parks or trailer courts where the Company reasonably believes homes are temporary, the Company may elect to provide S~~s~~ervice only through the P~~p~~oint of Service ~~delivery~~ billed to the mobile home park or trailer court.

4.13~~6~~ Multiple Dwellings

Each individual unit within a M~~m~~ultiple D~~d~~welling will be served as a separate P~~p~~oint of Service and billed individually ~~delivery~~ on the applicable residential rate. ~~unless the Company agrees otherwise.~~ The Company and ~~the~~ a C~~c~~ustomer may agree that one bill will be issued covering all individual units in a M~~m~~ultiple D~~d~~welling~~.~~ and, in such case, ~~Where T~~~~the Company and a C~~~~customer may have agreed that service to a M~~~~multiple D~~~~dwelling shall be delivered through a single P~~~~point of Service, and, in such case, delivery,~~ the applicable general service (non-residential) rate will apply to the S~~s~~ervice.

4.14~~7~~ Relocation of Company Facilities

The Company may require a C~~c~~ustomer to pay all reasonable costs incurred by the Company in relocating any Company F~~f~~acility at the C~~c~~ustomer's request and may require payment of ~~.~~

~~If requested by the Company, the customer shall pay~~ the estimated cost of the relocation in advance.

4.15~~8~~ Reconnection ~~or Restoration of Service~~

~~This section applies when the Company is asked to reconnect or restore service to a customer whose service was previously restricted by a current-limiting device or discontinued (whether at the request of the customer or not).~~ When the circumstances resulting in discontinuance of a Customer's Service or restriction of Service through the installation of a Current Limiting Device have been rectified to the satisfaction of the Company, or when a Customer has requested a reconnection after having requested a previous disconnection, the Company shall reconnect and continue the provision of Service upon payment by that Customer of:
~~Before reconnecting or restoring service, the customer shall pay:~~

(a) any amount owing to the Company;

(b) a Reconnection Fee ~~collection charge of \$45~~ as specified in Schedule D; and ~~if the reconnection is made during the Company's normal business hours, or, in any other case, an amount not exceeding the Company's actual cost of reconnection;~~

(c) the S~~s~~ecurity D~~d~~eposit, if any, required under Article ~~regulation~~ 4.6~~9~~;

~~(d) the minimum monthly bill for each month of disconnection, if service is reconnected within 12 months of disconnection for all rate schedules and service except for seasonal service.~~

If Service is reconnected within 12 months of disconnection, with the exception of seasonal Service, the Company may request that the Customer pay the minimum monthly bill for each month of disconnection.

The Company may add a Collection Fee as specified in Schedule D if a site visit is required to attempt collection of overdue accounts and Service is not disconnected or for delivery of a notice of pending disconnection.

This section does not apply when a C~~c~~ustomer's S~~s~~ervice was disconnected for safety reasons. (~~See regulation~~ Refer to Article 11.2)

[NTD: Yukon Energy does not agree with the proposed edits to what was previously subpart (d) as discussed in Tab 5]

~~**4.19 Construction Contribution Cost Sharing**~~

~~Existing electrical customers may be entitled to cost sharing of the construction contribution for their extension, in accordance with the following terms. "Cost Sharing" refers to the procedure of having new customers who connect to an existing facility for which someone else has paid a contribution, assessed their share of that cost, which is then refunded to the existing customer.~~

~~Construction contributions share costing will be administered for a five year term commencing December 31 of the year of construction of the original extension. The utility will not administer refunds of less than $50.00.~~

5. RIGHTS OF WAY AND ACCESS TO FACILITIES

5.1 Easements

At the request of the Company, t~~T~~he C~~c~~ustomer shall grant, or cause to be granted, to the Company, without cost to the Company, such easements or rights-of-way over, upon or under the property owned or controlled by the C~~c~~ustomer as the Company reasonably requires for the construction, installation, maintenance, repair and operation of the Facilities required for a Service Connection to the Customer and the performance of all other obligations required to be performed by the Company hereunder. ~~to provide service to such customer, including extensions thereof.~~

5.2 Right of Entry

The Company's employees, ~~or~~ agents or other representatives shall have the right to enter a C~~c~~ustomer's property at all reasonable times for the purpose of installing, maintaining, repairing, replacing, testing, monitoring, meter reading or ~~and~~ removing the Company's F~~f~~acilities and for any other purpose incidental to the provision of S~~s~~ervice. The C~~c~~ustomer shall provide the Company with reasonable access to the Company F~~f~~acilities located on the C~~c~~ustomer's property. The Company will endeavour to provide reasonable notice to the Customer when the Company requires entry to the Customer's property for planned maintenance or repair to the Company's Facilities.

5.3 Vegetation Management

The C~~c~~ustomer shall permit the Company to manage vegetation on the property owned or controlled by the C~~c~~ustomer. Access is required to maintain the proper clearances and reduce the risk of contact with the Company's overhead high and low voltage distribution equipment. ~~facilities~~ The Company shall make reasonable efforts ~~endeavor~~ to notify the~~a~~ C~~c~~ustomer before such work is performed.

Vegetation management in the vicinity of the high voltage distribution system (primary) is the responsibility of the Company. Vegetation will be maintained to established standards to reduce contact with the energized conductors or equipment.

Vegetation management in the vicinity of the low voltage (service drops or secondary) distribution on the Customer's property is the responsibility of the Customer. Where the Company determines that vegetation management is required to maintain the integrity of the Company's low voltage overhead distribution system, the Company may, at the Customer's expense, perform the work that is the responsibility of the Customer as set out herein~~,~~. With respect to the low voltage overhead distribution system only, the Company shall make reasonable efforts to notify the Customer that such work is required, and shall provide the Customer a reasonable opportunity to undertake the work required, before such work is performed by the Company.

5.4 Interference with Company's Facilities

~~Customers shall not place any structures that would interfere with the proper and safe operation of the Company's facilities or which would adversely affect compliance with any applicable legislation.~~Customers shall not install, or allow to be installed, temporary or permanent structures that could interfere with the proper and safe operation of the Company's Facilities or result in non-compliance with applicable statutes, regulations, standards or codes.

5.5 Customer Brushing

Customers requesting S~~s~~ervice that requires the extension of ~~new electrical~~ F~~f~~acilities~~powerlines,~~ to the Customer's property shall be responsible for brushing on the Customer's property in accordance with the ~~to~~ Company's specifications. In addition, ~~along with providing an~~ unobstructed access to each structure requiring Service must be provided.~~.~~

6. METERS

6.1 Installation

(a) Provision and Ownership
The Company shall provide, install and seal all meters necessary for measuring the E~~e~~nergy and Demand supplied to a C~~c~~ustomer, unless otherwise specifically provided in a contract with the C~~c~~ustomer. Each meter shall remain the sole property of the Company.

If required, as determined in the Company's sole discretion, current and voltage transformers and metering test switches will be supplied to the Customer for installation by the Customer's qualified personnel or contractor. Current and voltage transformers shall be installed in accordance with the Company's specifications and all codes, legislation and reference to applicable metering standards.

~~(a)~~(b) Responsibility of Customer
Each C~~c~~ustomer shall provide and install a CSA-approved meter receptacle or other CSA-approved F~~f~~acilities suitable to the Company for the installation of the Company's meter or metering equipment.

6.2 Location

The location of any meter shall be subject to the approval by the Company having regard to the type of Service being provided and so as to permit safe and convenient access to the meter by the Company. Where a meter is installed on a Customer owned pole, the pole shall be provided and maintained by the Customer as required by the Canadian Electric Code and any other applicable legislation.

Meter sockets for self-contained meters shall be mounted on the exterior of a building at an accessible location acceptable to the Company. The centerline of the meter socket must be 1.5 to 1.8 meters above the finished grade or permanent platform of the Customer's Facility and in an appropriately lighted area.

Metering instrument transformer enclosures shall contain only the Company's metering auxiliary equipment and shall not be used as a raceway, splitter box or cabinet for any other purpose. ~~Meter locations shall be approved by the Company based on type of service and convenience of access to the meter. Where a meter is installed on a customer-owned pole, the pole shall be provided and maintained by the customer as required by the Canadian Electric Code and any other applicable legislation.~~

6.3 Meter Tests and Adjustments

(a) The Company may inspect and test a meter at any reasonable time. At the request of a C~~c~~ustomer, and upon payment of a Meter Accuracy Test Handling Fee ~~$25~~

~~fee~~as specified in Schedule D, the Company shall arrange for a meter to be tested by an official designated for that purpose by Industry Canada or such other federal government agency as may, from time to time, be designated for that~~e~~ purpose.

(b) If a test determines that the meter is not accurate within the limits set by government standards, the C~~c~~ustomer's bill will be adjusted back to the time that the error can reasonably be determined to have commenced ~~accordingly~~. Where the commencement of the error cannot reasonably be determined, ~~it is impossible to determine when the error commenced,~~ it shall be deemed to have commenced three months before the test or on the date of the meter installation, whichever occurred later.

(c) In the event that an adjustment is required, the Meter Accuracy Test Handling Fee ~~the $25~~ shall be refunded.

6.4 Access to Meters

(a) The Company may, at any reasonable time, read, inspect, remove and test a meter installed on property owned or controlled by the Customer.

(b) Where the Customer's Service address or location is generally locked during normal business hours, the Customer shall provide the Company with a key to permit access to the meter.

(c) If the Company provides notice to a Customer that reasonable access to metering equipment is not being provided, the Customer must take immediate action to remedy the situation. If the Customer fails to remedy the situation to the Company's satisfaction within a reasonable time:

(i) the Company may, at its sole discretion, estimate consumption until the situation has been remedied and the Customer shall be billed on the basis of the Company's estimate;

(ii) the Company may remedy the situation on behalf of the Customer and apply the costs to the Customer's next regular bill;

(iii) the Company may do both i) and ii); or

(iv) the Company may discontinue Service in accordance with Section 11 of these Terms and Conditions of Service.

~~6.4 Energy or Demand Diversion~~

~~If under any circumstances, a person prevents a meter from accurately recording the total demand or energy supplied, the Company may disconnect the service, or take other appropriate actions.~~

7. METER READING AND BILLING

7.1 Reading and Estimates

Unless otherwise specifically provided in a contract with a Customer, meters shall be read monthly or bi-monthly or at such other intervals as are practical in the circumstances. Customers' bills will be based on meter readings made by the Company ~~from time to time~~ or on estimates for those billing periods when the meter is not read. Whenever a bill is based on an estimate, an adjustment to reflect actual Energy consumption and Demand (if applicable) used ~~usage~~ will be made when ~~after~~ the meter is next read.

7.2 ~~Proration of Initial and Final Billings~~ Calculation of Bills

(a) The amount of any initial and final charges~~, other than Eenergy, may,~~ will be prorated, based upon the ratio of the number of days that Service was provided to a Customer in the billing period to the total number of days in the billing period.

(b) The Company may elect not to charge a Customer for the billing period if, during that period, Demand was five kilowatts or less, Service was provided for five days or less and Energy consumption was five kilowatt hours or less.

(c) For all new accounts, the Company may add the charges for Service provided during the initial period to the bill for the following billing period.

(d) The Company may elect to change a Customer's meter reading schedule.

~~(c)~~(e) Where a meter reading schedule is changed, any charges during the transition period between the old and new meter reading schedule, may be prorated based upon the ratio of the number of days that Service was provided to a Customer in the billing period to the total number of days in the billing period.

7.3 Payment ~~of Accounts~~

(a) The amount billed ~~Payment of a bill for service~~ is due and owing when the bill is rendered and payable by the date indicated on the bill.

(b) Bills shall be deemed rendered and other notices duly given when delivered to the Customer at the mailing address provided by the Customer. Failure to receive a bill does not entitle a Customer to any delay in payment or release a Customer from the obligation to pay the amount owing.

(c) Payment of a bill for Service may be requested by the Company from any or all of the Customers, on a joint and several basis, even if the Customer no longer resides in the same premises when payment is due. ~~for any service provided by the Company.~~

7.4 Late Payment Charge

The Company may add a Late Payment Charge ~~service charge equal to 1.0% per month (effectively 12.68% per annum)~~as specified in Schedule D on any overdue amount. A Collection Fee as specified in Schedule D will be charged if a personal visit is required to collect an overdue amount.

7.5 Dishonoured Payments~~Cheques~~

The Company may add a Dishonoured Payments Fee as specified in Schedule D ~~a service charge of $20~~ to a C~~c~~ustomer's bill in respect of any cheque, or other form of payment tendered by the Customer as payment of a bill, returned by the C~~c~~ustomer's bank for any reason.

Following the receipt of two (2) dishonoured payments from the Customer, the Company may notify the Customer that only cash, a money order or certified cheque will be accepted for payment.

7.6 Outstanding Charges

The Company may add to the C~~c~~ustomer's bill any outstanding charges due and owing to the Company (e.g. construction contribution, account receivable charges, former overdue accounts etc.).

7.7~~4.7~~ Totalized Metering

~~The Normally, the Company will generally issue a separate bill for each Ppoint of Service.delivery.~~When S~~s~~ervice is provided through multiple P~~p~~oints of Service ~~delivery~~ to a C~~c~~ustomer's plant site consisting of centralized processing f~~f~~acilities or product transportation facilities located on lands leased or owned by the C~~c~~ustomer, where such multiple P~~p~~oints of Service ~~delivery~~ are located within a radius of half a mile of each other, or where specified in a contract, the C~~c~~ustomer and Company may agree that the D~~d~~demand and E~~e~~nergy at each P~~p~~oint of Service ~~delivery~~ be totalized and only one bill issued for each billing period. The C~~c~~ustomer shall pay the incremental metering cost associated with totalized metering.

7.8 Combined Service

A residential Customer shall notify the Company when the Customer receives Service at their premises for the purposes of operating a business or commercial undertaking. The applicable general service rate may be applied in those cases in which Service for both residential and non-residential purposes is received by a Customer through a single meter.

7.9~~4.8~~ Consolidated Billing

The Company will issue a separate bill for each P~~p~~oint of Service. ~~delivery.~~ However, the C~~c~~ustomer and Company may agree that the Company will issue one bill totaling charges for S~~s~~ervice delivered at more than one P~~p~~oint of Service.~~delivery~~

7.10 ~~6.4~~ Unauthorized Use ~~Energy or Demand Diversion~~

If~~,~~ under any circumstances, a person prevents a meter from accurately recording the total D~~d~~emand or E~~e~~nergy supplied, the Company may disconnect the S~~s~~ervice, or take other appropriate actions.

The Company may then estimate the D~~d~~emand and amount of E~~e~~nergy supplied but not registered, at the P~~p~~oint of~~-~~ Service~~delivery~~. The C~~c~~ustomer shall pay the cost of the estimated D~~d~~emand and E~~e~~nergy consumption plus all costs related to the investigation and resolution of the diversion including repairs of damage or reconstruction of Facilities.

7.11 Billing Error

The Customer must provide written notice to the Company in order to dispute any or all amounts owing on a bill. In the event the Customer disputes an amount owing, the Customer shall nonetheless pay such disputed amount. Following resolution of any such dispute, the Company will return any amount found owing to the Customer forthwith.

8. SERVICE CHANGES

8.1 Notice by Customer

A C~~c~~ustomer shall give to the Company reasonable prior written notice of any change in S~~s~~ervice requirements, including any material change in Connected L~~l~~oad, to enable the Company to determine whether or not it can supply such revised S~~s~~ervice without changes to its F~~f~~acilities. The Customer shall not change its Service requirements without the Company's written permission.
~~When a residential customer operates a business or commercial undertaking (collectively, a "business") in the customer's residence and when that business consumes electric energy, the customer shall notify the company of that fact. When the company is notified of business energy consumption, or has reasonable grounds to suspect business energy consumption, the company may request the customer to provide full particulars of all business energy consumption at the residence. The customer shall promptly provide the requested particulars. When the provided particulars confirm business energy consumption at the residence or when the customer provides inadequate or no particulars, the company may commence charging a general service rate for all energy provided. The general service rate shall apply until the customer has, to the company's reasonable satisfaction, caused separate metering systems to be installed for accurate and segregated recording of residential and business energy consumption at the residence (and, if such metering is installed, then the general service rate would apply only to the metered business energy consumption).~~

8.2 Responsibility for Damage

The C~~c~~ustomer shall be responsible for and shall pay for all damage caused to the Company's F~~f~~acilities as the result of the C~~c~~ustomer changing the Connected Load ~~service requirements~~ without the Company's permission.

8.3 Changes to Company F~~f~~acilities

If the Company must modify its F~~f~~acilities to accommodate a C~~c~~ustomer L~~l~~oad or S~~s~~ervice change, the C~~c~~ustomer shall pay for all costs in connection with such modification including the following costs:

(a) the actual ~~estimated~~ cost of removing the existing F~~f~~acilities, less the estimated salvage value, less

(b) any applicable adjustment required to the ~~increased~~ Company I~~i~~nvestment as specified in Schedule B.

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1 Continuous Supply

The Company shall make all reasonable efforts to maintain a continuous supply of E~~e~~nergy to its C~~c~~ustomers, but the Company cannot guarantee an uninterrupted supply of E~~e~~nergy.

9.2 Interruption~~Planned Outages~~

Without liability of any kind to the Company, the Company shall have the right to disconnect or otherwise curtail, interrupt or reduce service to Customers:

(a) whenever the Company reasonably determines that the Service must be interrupted, including to facilitate construction, installation, maintenance, repairs, replacement or inspection of any of the Company's Facilities, or to permit the connection or disconnection of other Customers;

(b) to maintain the safety and reliability of the Company's Facilities; or

(c) due to any other reason related to dangerous or hazardous circumstances including emergencies, forced outages, potential overloading of the Company's Facilities or Force Majeure.

~~The Company reserves the right to interrupt, discontinue or reduce the supply of energy to any customer to allow for repairs and improvements to its facilities.~~

9.3 Reasonable Efforts

The Company shall endeavor to give reasonable ~~prior~~ notice to C~~c~~ustomers who will have S~~s~~ervice interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

9.4~~3~~ Company Liability

Notwithstanding anything to the contrary contained in these Terms and Conditions, t~~T~~he Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether of direct, indirect, special or consequential nature, (excepting only direct physical loss, injury or damage to a ~~customer~~ Customer or a ~~customer's~~ Customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising out of or in any way connected with the provision of Service by the Company to its Customers including, but not limited to, any failure, defect, fluctuation, reduction or interruption in the provision of S~~s~~ervice by the Company to its C~~c~~ustomers. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct physical loss, injury or damage" shall not include loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of purchased or replacement capacity and Energy, cost of capital, and loss of use of any Facilities or property, or any other similar damage or loss whatsoever, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of S~~s~~ervice by the Company to its ~~to a~~ C~~c~~ustomers.

9.5~~4~~ Force Majeure~~Extraordinary Circumstances~~

Should the Company be unable~~, because of extraordinary circumstances,~~ to provide a continuous supply of ~~e~~Energy to a C~~c~~ustomer because of an event of Force Majeure, the Company's responsibilities, so far as they are affected by the Force Majeure, ~~extraordinary circumstances,~~ shall be relieved and suspended during the duration of such circumstances and the C~~c~~ompany shall not be liable for any failure to perform any term of these Terms and Conditions to the extent that and when such failure is due to, or is a consequence of, an event of Force Majeure. Where practical, the Company shall give notice to the affected C~~c~~ustomers of such Force Majeure.~~extraordinary circumstances~~.

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1 Provide Permit

The Customer shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations necessary for the installation and operation of the Service Connection. The Company shall not be required to commence or continue installation or operation of a Service Connection unless and until the Customer has complied with the requirements of all permits, certificates, licenses, inspections, reports and other authorizations, and all right-of-way agreements, and all Company requirements applicable to the installation and operation of the Service Connection.

~~The customer shall provide permits, licences and authorizations prior to commencement of service or any change of service requirements at any point of delivery.~~

10.2 Customer Responsibility

The C~~c~~ustomer shall be solely responsible for the use, installation, ~~and~~ condition of all F~~f~~acilities on the C~~c~~ustomer's side of the Point of Service, except Facilities owned by the Company. The Customer shall be responsible for and shall pay for any damage to the Company's Facilities located on the Customer's premises which is caused by the negligent acts or omissions or willful misconduct of the Customer or of anyone permitted by the Customer to be on the Customer's premises.~~delivery~~.

10.3 Customer Liability

(a) The Customer assumes full responsibility for the proper use of Facilities and for the condition, suitability and safety of any and all wires, cables, devices or equipment energized on the Customer's premises or on premises owned or controlled by the Customer that are not the Customer's property.

(b) Where a Customer uses its Service Connection in a manner that causes interference with the operation of the Company's Facilities or with any Customer's use of a Service Connection, such as abnormal voltage levels, frequency levels and harmonic levels, at the Company's request, and at the Customer's own expense, the Customer shall take whatever action is required to correct the interference or disturbance.

(c) The C~~c~~ustomer shall indemnify and save harmless the Company from and against any claim or demand for injury to persons or damage to property (including loss of use thereof and of any other property affected by the damage to property) arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees and agents.

~~(c)~~(d) The Customer releases the Company and its agents, directors, officers, employees, independent contractors, consultants, representatives, successors and assignees from any and all claims and liabilities whatsoever relating to or arising as a result of the Customer, or its agents, directors, officers, employees, independent contractors, consultants, representatives, successors and assignees carrying out any acts required by or related to these Terms and Conditions for the provision of Service, maintenance of Service, or any other act whatsoever arising out of or in any way connected with the existence or use of the Service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees or agents.

~~The customer shall be responsible for any damage to Company facilities located on the customer's premises where the damage is caused by the negligent acts or omissions or willful misconduct of the customer or anyone permitted by the customer to be on the premises.~~

10.4~~3~~ Protective Devices

The C~~c~~ustomer shall be responsible for determining whether ~~the customer needs~~ any devices are required to protect the Customer's Facilities ~~his equipment~~ from damage that may result from the provision of S~~s~~ervice by the Company. The C~~c~~ustomer shall provide and install any such devices.

10.5~~4~~ Service Calls

The Company may require a C~~c~~ustomer to pay the actual costs of a C~~c~~ustomer-requested service call if the source of the problem is the C~~c~~ustomer's ~~own~~ F~~f~~acilities.

11. TERMINATION OF SERVICE

11.1 ~~Customer-requested~~ Termination by Customer

Except where otherwise provided in a written agreement between the Company and a ~~c~~Customer, a C~~c~~ustomer may, at any time, give the Company reasonable notice ~~(in writing) that he wishes to~~ terminate ~~his~~ S~~s~~ervice. Upon receipt of such notice, the Company shall read the ~~c~~C~~c~~ustomer's meter within a reasonable time, and, shall use its best efforts to read the C~~c~~ustomer's meter at the time requested by the C~~c~~ustomer. A C~~c~~ustomer shall pay for all S~~s~~service provided to the time of such reading.

~~A customer is responsible for all service provided until notice of termination is given and the meter is read.~~

11.2 Company Termination for Safety ~~or Technical~~ Reasons

The Company may, without notice, terminate a C~~c~~ustomer's S~~s~~ervice where, in the Company's opinion:

(a) the C~~c~~ustomer has permitted the wiring of their ~~his/her~~ F~~f~~acilities to become hazardous; ~~or~~

(b) the wiring of the C~~c~~ustomer's F~~f~~acilities fails to comply with applicable law; or

(c) the Customer has caused any other ~~the~~ safety hazards, including, but not limited to, ~~use~~ using ~~of~~ their S~~s~~ervice in such as way that ~~may~~ causes damage to the Company's F~~f~~acilities or interferes with or disturbs S~~s~~ervice to any other C~~c~~ustomer.

The Company will reconnect the S~~s~~ervice when the safety problem is resolved and when the C~~c~~ustomer has provided, or paid the Company's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance. The Company may assess a Reconnection Fee, as specified in Schedule D.

11.3 Company Termination Other Than For Safety

The Company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the C~~c~~ustomer, terminate the C~~c~~ustomer's S~~s~~ervice or install a C~~c~~urrent-L~~l~~imiting D~~d~~evice to restrict the S~~s~~ervice to such C~~c~~ustomer if the C~~c~~ustomer:

(a) ~~(a) violates any provision of these regulations or of the Company's tariff;~~ fails to meet its obligation under these Terms and Conditions, the terms of a contract for Service, or of the Company's Rate Schedules;

(b) Uses their Service Connection in such a way that causes interference with operation of the Company's Facilities or any other Customer's use of a Service Connection such as abnormal voltage levels, frequency levels and harmonic levels.

(c~~b~~) tampers with any Company Facilities;~~service conductors, meters, seals or any other facilities of the Company~~

(d~~c~~) neglects or refuses to pay the amount billed ~~charges~~ for S~~s~~ervice due and owing to the Company~~.~~ by the date indicated on the bill for Service; ~~(d)~~

(e~~e~~) changes S~~s~~ervice requirements without the permission of the Company; or

(f~~f~~) ~~makes fraudulent use of the service being provided.~~makes use of the Service for illegal purposes or in circumstances where the Company has evidence of Energy theft, or fraud by the Customer.

11.4 Removal of Facilities

Upon discontinuance of ~~termination of~~ S~~s~~ervice for whatsoever reason, the Company shall be entitled to remove any of its F~~f~~acilities located upon the property of the C~~c~~ustomer and to enter upon the C~~c~~ustomer's property for that purpose.

SCHEDULE A
STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

(a) Residential:

240/120 V
- single phase, three wire
- secondary conductors are supplied by the Company
- overhead or, in designated areas, underground conductors are supplied by the Company

(b) General Service:

240/120 V
- single phase, three wire
- overhead secondary conductors are supplied by the Company
- underground secondary conductors are supplied by the customer

208 Y/120 V
- three phase, four wire
- overhead secondary conductors are supplied by the Company
- underground secondary conductors are supplied by the customer

480 Y/277 V
- three phase, four wire
- overhead secondary conductors are supplied by the Company for loads 15 KVA to 300 KVA
- overhead secondary conductors are supplied by the customer for loads 300 KVA to 1,500 KVA

600 Y/347 V
- three phase, four wire
- underground secondary conductors are supplied by the customer for loads 150 KVA to 2,500 KVA; and

4160 Y/2400 Y
- three phase, four wire, 2,000 KVA to 10,000 KVA
- overhead secondary conductors are supplied by the customer

SCHEDULE B
MAXIMUM COMPANY INVESTMENT

~~1. (a) **"Cost"** means the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Company in extending Service to a Point of Delivery.~~

~~(b) **"Annual Cost"** means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers.~~

~~2~~1. Subject to the provisions of paragraph 2~~3~~ of this Schedule B, the maximum Capital C~~c~~ost which the Company will incur to extend S~~s~~ervice to a P~~p~~oint of Service ~~delivery~~ (herein referred to as the "Maximum Company Investment") shall be determined as follows. Under no circumstances would the Maximum Company Investment exceed the Customer extension cost:

(a) **Residential Service:**
~~$900 per single family dwelling; and~~
~~$450 per Multiple Dwelling Unit~~

Year	Residential Single Family Dwelling ($/Site)	Residential Multi Dwelling Unit ($/Site)
2011	$ 1,250	$ 625
2012	$ 1,740	$ 870
2013	$ 2,420	$ 1,210
2014	$ 3,360	$ 1,680
2015	$ 4,700	$ 2,350

(b) **General Service:**
~~$400~~ As per table below, the Company will invest a fixed amount as indicated plus a variable amount per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated service life is less than 25 years or seasonal, ~~the Company investment will be reduced proportionally,~~ then the Maximum Company Investment shall be determined in the manner described in paragraph 2~~3~~;

Year	General Service ($Fixed)	General Service ($/kW)
2011	$ 5,355	$ 275
2012	$ 5,500	$ 280
2013	$ 5,650	$ 290
2014	$ 5,800	$ 295
2015	$ 5,955	$ 305

At the end of one year of S~~s~~ervice the Company will re-assess whether the C~~c~~ustomer's estimates of their ~~consumption~~ Demand were accurate and, if the loads are significantly different than originally estimated, will collect from the C~~c~~ustomer (or refund) any contributions, ~~based on the Maximum Company Investment rules then in place in paragraph 1~~~~2~~ ~~or paragraph 2~~~~3,~~ that are required based on the Maximum Company Investment rules in place when the contribution was originally paid.

c) Municipal Street Lighting:
~~$700 per light~~

Year	Street Lighting ($/Light)
2011	$ 930
2012	$ 1,240
2013	$ 1,660
2014	$ 2,220
2015	$ 2,975

2. ~~**3.**~~ The Maximum Company Investment in any extension of Service, whether or not specified in paragraph 1, where the Load characteristic and service life are expected to vary materially from the average for that type of Service, shall be determined based on an analysis of the load characteristics and service life, as a pro-ration of the full Maximum Company Investment for that class of Customer.

3. In this section Annual Cost means the estimated cost of generating and transmitting electric Energy to the Customer, operating and maintaining the Facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of Facilities constructed to serve the Customers. For Major Industrial Customers, if the Annual Cost of serving a Customer is higher than the revenue expected to be received from such Service, then the Maximum Company Investment shall be the Capital Cost of the extension less the present value of the annual amounts over the expected life of the Service by which the Annual Cost is expected to exceed the revenue.

[NTD: Yukon Energy does not support the proposal to increase the the maximum company investment after 2011 at this time.]

SCHEDULE C

CONDITIONS FOR UNDERGROUND SUBDIVISIONS

"**Developer**" is defined as the person or party who has requested the underground service. The Company shall extend service by underground conductor lines upon and subject to the following terms and conditions ~~(**"developer"** means the person or party who has requested the underground service):~~

(a) At the time of the request for underground Service n~~N~~o S~~s~~ervice ~~is then~~ available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Company) will be connected to such extension (the "underground service area"), each of which is situated upon said subdivision;

(b) All permanent S~~s~~ervice in the underground service area shall be provided exclusively through underground conductor lines;

(c) The D~~d~~eveloper shall provide, without cost to the Company, such rights-of-way, easements, utility corridors and transformer locations as the Company may require for the installation, operation and maintenance of such extension, which the D~~d~~eveloper shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Company in installing, maintaining or removing its F~~f~~acilities;

(d) The Company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the D~~d~~eveloper;

(e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the Company;

(f) In relation to the standard underground S~~s~~ervice, the D~~d~~eveloper shall ~~cause to be provided~~ provide a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure the installation of a service having a 200 ampere capacity. Non-standard S~~s~~ervices will be subject to prior written approval by the utility;

(g) The D~~d~~eveloper shall provide to the Company a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, driveways (if known) and underground utilities together with such evidence as the Company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the D~~d~~eveloper;

(h) Survey stakes indicating grades and property lines shall be installed and maintained by the D~~d~~eveloper;

(i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

(j) Unless otherwise agreed to by the Company, the D~~d~~eveloper shall provide a survey for the location of transformers, street light bases and cable routing, as required;

(k) Sidewalks, curbs and gutters may be constructed by the D~~d~~eveloper but no other permanent improvements shall be made until approved by the Company.

(l) Costs related to the installation of distribution system infrastructure shall be the responsibility of the D~~d~~eveloper; and

(m) The Company investment will be applied toward the individual C~~c~~ustomer S~~s~~ervice connection in accordance with ~~“~~Schedule B~~”~~.

In addition, the S~~s~~ervice shall be subject to such other conditions as may be specified by the Company from time to time.

SCHEDULE D - FEES AND SERVICE CHARGE SUMMARY

CONNECTION, and RECONNECTION FEES

Connection Fee (4.3, 4.11):

During normal business hours:	$50.00
Outside of normal business hours:	Company's actual cost (min. $50.00)

Reconnection Fee (4.15, 11.2)

During normal business hours:	$60.00
Outside of normal business hours:	Company's actual cost (min. $60.00)

LATE PAYMENT AND DISCONNECTION

Collection Fee (4.15, 7.4)	$30.00 (personal visit)
Late Payment Charge (7.4):	1.5% per month (19.56% per annum)
Dishonoured Payments Fee (7.5):	$25.00

METER DISPUTES

Meter Accuracy Test Handling Fee (6.3)

Self Contained Meter	$100.00
Instrument Meter	$200.00

Appendix 5.3

	EXISTING		PROPOSED	COMMENTS
	ELECTRIC SERVICE REGULATIONS		TERMS AND CONDITIONS OF SERVICE	name of document different
1	Interpretations (Definitions)	1	Introduction	
1.1	Definitions			switched Article 1 and Article 2's order
2	Introduction	2	Interpretation (Definitions)	
2.1	Board Approval	2.1	Definitions	
2.2	Electric Service Tariff	2.2	NEW - Conflicts	
2.3	Effective Date	2.3	NEW - Headings	
		2.4	NEW - Schedules and Appendices	
3	General Provisions	3	General Provisions	
3.1	Regulations Prevail	3.1	Board Approval	partially taken from old Article 3.1 "Regulations Prevail" and made into it's own Article 3.1 "Board Approval"
3.2	Ownership of Facilities	3.2	Terms and Conditions Prevail	Changed name from Article 3.1 "Regulations Prevail" to 3.2 "Terms and Conditions Prevail"
3.3	Use of Energy	3.3	Ownership of Facilities	
3.4	Customer Extensions	3.4	Use of Energy	
3.5	Customer Generation	3.5	Customer Extensions	
3.6	Frequency and Voltage Levels	3.6	Customer Generation	
		3.7	Frequency and Voltage Levels	
		3.8	NEW - Fees and Other Charges	
4	Application for Conditions of Service	4	Application for Conditions of Service	
4.1	General Requirements	4.1	General Requirements	
4.2	Conditions of Service	4.2	Conditions of Service	
4.3	Connection Fee	4.3	Connection Fee	
4.4	Application of Rate Schedules	4.4	Application of Rate Schedules	
4.5	Extensions to Electric Heat Customers	4.5	Extensions to Electric Heat Customers	
4.6	Multiple Dwellings	4.6	Security Deposit	"Multiple Dwellings" moved from 4.6 to 4.13
4.7	Totalized Metering	4.7	Delay in Taking Service - Other than Subdivision	"Totalized Metering" moved from Article 4.7 to Article 7.7
4.8	Consolidated Billing	4.8	Extension of Service	"Consolidated Billing" moved from Article 4.8 to 7.9
4.9	Security Deposit	4.9	Underground Subdivision Extensions	
4.10	Use of Security Deposit	4.10	Conversion from Overhead to Underground Service	Article 4.10 "Use of Security Deposit" now included in 4.6 "Security Deposit"
4.11	Delay in Taking Service - Other than Subdivision	4.11	Temporary Service	
4.12	Extension of Service	4.12	Mobile Homes	
4.13	Underground Subdivision Extensions	4.13	Multiple Dwellings	
4.14	Conversion from Overhead to Underground Service	4.14	Relocation of Company Facilities	
4.15	Temporary Service	4.15	Reconnection	
4.16	Mobile Homes			
4.17	Relocation of Company Facilities			
4.18	Reconnection or Restoration of Service			
4.19	Construction Contribution Cost Sharing			"Construction Contribution Cost Sharing" moved from 4.19 to 4.8 "Extension of Service"
5	Rights of Way and Access to Facilities	5	Rights of Way and Access to Facilities	
5.1	Easements	5.1	Easements	
5.2	Right of Entry	5.2	Right of Entry	
5.3	Vegetation Management	5.3	Vegetation Management	
5.4	Interference with Company's Facilities	5.4	Interference with Company's Facilities	
5.5	Customer Brushing	5.5	Customer Brushing	
6	Meters	6	Meters	
6.1	Installation	6.1	Installation	
6.2	Location	6.2	Location	
6.3	Meter Tests and Adjustments	6.3	Meter Tests and Adjustments	
6.4	Energy or Demand Diversion	6.4	NEW - Access to Meters	
7	Meter Reading and Billing	7	Meter Reading and Billing	
7.1	Reading and Estimates	7.1	Reading and Estimates	
7.2	Proration of Initial and Final Billings	7.2	Calculation of Bills	
7.3	Payment of Accounts	7.3	Payment	
7.4	Late Payment Charge	7.4	Late Payment Charge	
7.5	Dishonored Cheques	7.5	Dishonoured Payments	
7.6	Outstanding Charges	7.6	Outstanding Charges	
		7.7	Totalized Metering	"Totalized Metering" moved from Article 4.7 to Article 7.7
		7.8	Combined Service	Pulled from old 8.1 "Notice by Customer" and made into it's own Article 7.8 "Combined Service"
		7.9	Consolidated Billing	"Consolidated Billing" moved from Article 4.8 to 7.9
		7.10	Unauthorized Use	Moved from 6.4 "Energy or Demand Diversion" and renamed 7.10 "Unauthorized Use"
		7.11	NEW - Billing Error	
8	Service Changes	8	Service Changes	
8.1	Notice by Customer	8.1	Notice by Customer	
8.2	Responsibility for Damage	8.2	Responsibility for Damage	
8.3	Changes to Company Facilities	8.3	Changes to Company Facilities	
9	Company Responsibility and Liability	9	Company Responsibility and Liability	

	EXISTING		PROPOSED	COMMENTS
	ELECTRIC SERVICE REGULATIONS		TERMS AND CONDITIONS OF SERVICE	name of document different
9.1	Continuous Supply	9.1	Continuous Supply	
9.2	Planned Outages	9.2	Interruption	Changed name of Article 9.2 from "Planned Outages" to "Interruption"
9.3	Company Liability	9.3	Reasonable Efforts	moved part of Article 9.2 "Planned Outages" to it's own Article 9.3 "Reasonable Efforts"
9.4	Extraordinary Circumstances	9.4	Company Liability	
		9.5	Force Majeure	Changed name from Article 9.4 "Extraordinary Circumstances" to Article 9.5 "Force Majeure"
10	Customer Responsibility and Liability	10	Customer Responsibility and Liability	
10.1	Provide Permit	10.1	Provide Permit	
10.2	Customer Responsibility	10.2	Customer Responsibility	
10.3	Protective Devices	10.3	Customer Liability	broke former Article 10.2 into Article 10.2 "Customer Responsibility" and Article 10.3 "Customer Liability"
10.4	Service Calls	10.4	Protective Devices	
		10.5	Service Calls	
11	Terminations of Service	11	Termination of Service	
11.1	Customer-requested Termination	11.1	Termination by Customer	Changed name of Article 11.1 from "Customer-requested Termination" to "Termination by Customer"
11.2	Company Termination for Safety or Technical Reasons	11.2	Company Termination for Safety Reasons	Changed Name of Article 11.2 from "Company Termination for Safety or Technical Reasons" to "Company Termination for Safety Reasons"
11.3	Company Termination Other Than For Safety	11.3	Company Termination Other Than For Safety	
11.4	Removal of Facilities	11.4	Removal of Facilities	
Schedule A	Standard Supply Specifications	Schedule A	Standard Supply Specifications	
Schedule B	Maximum Company Investment	Schedule B	Maximum Company Investment	
Schedule C	Conditions for Underground Subdivisions	Schedule C	Conditions of Underground Service	
		Schedule D	NEW Fees and Service Charge Summary	

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Appendix 5.4

THE YUKON ELECTRICAL COMPANY LIMITED

STUDY ON MAXIMUM INVESTMENT LEVELS

A. Introduction

Yukon Electrical Company Limited (YECL) has prepared this Maximum Investment Level (MIL) Study addressing the non-industrial MILs for YECL and Yukon Energy Corporation (YEC) (hereinafter to be referred to as "the Companies") in response to Board Order 2009-08, Direction #13, from the Yukon Energy Corporation's General Rate Application for 2008-09 which states:

> *"13. The Board directs YEC and YECL as agreed to file a joint Phase II application …. The Phase II application is to …, provide updated terms and conditions of service, and contain a review on investment levels. …"*

With an anticipated implementation of the proposed MILs occurring in 2011, this study will outline the derivation of the MILs for 2011 and onward.

B. History

There have not been any changes to the Residential and Street Light MILs since 1989. General Service MILs were increased in 2005 from $180/kW to $400kW as approved in Board Order 2005-12, direction #8. Table 1 provides a history of the changes to investment levels.

Table 1: YECL/YEC Historical MILs

	Residential Single Family Dwelling (per site)	Residential Multi-Dwelling Unit (per site)	General Service (per kW)	Street Lighting (per light)
1983	$750	$375	$150	$600
Apr 1989	$900	$450	$180	$700
Oct 2005	$900	$450	$400	$700

Actual new extension construction costs have risen considerably in the Yukon between 1989 and 2009. Some of the increased pressures in costs include higher material and contractor services as well as a move towards underground residential subdivisions. As there have been no comparable increases to the Residential and Street Light MILs, a disproportionate share of the costs is presently being passed onto the customer via their share of the total cost (customer contribution). Each rate class will be discussed in more detail in the following sections.

C. Guiding Principles

The purpose of an investment policy is to establish rules and guidelines that govern investments in customer extensions. YECL has considered the following Guiding Principles for this study of the MILs. These Guiding Principles were developed in response to the Alberta Utilities Commission (AUC) Decision 2008-011 regarding Fortis Alberta's (FAI) 2008/2009 Negotiated Settlement Agreement (NSA), which states,

> *"Commencing in the first half of 2008, FAI will initiate discussions with other utilities and stakeholders to attempt to arrive at a common approach to MIL between Alberta utilities …"*

through the collaborative efforts (including conference calls and working sessions) of several Alberta utilities and stakeholders including ATCO Electric, FAI, the Consumers' Coalition of Alberta (CCA), Central Alberta REA, Enmax, Epcor and the Utilities Consumer Advocate (UCA). The resultant Guiding Principles were included in FAI's 2010/2011 Distribution Tariff Application, Section 9 – Appendix O: **Common Approach to Maximum Investment Levels**:

(1) MILs should be set to achieve a reasonable balance of what an individual Customer pays upfront through a Customer contribution versus what all Customers in a particular rate class pay through ongoing rates;

As per AEUB Decision 2000-1, Page 270,

> *"…An appropriate contribution policy (investment policy) therefore provides a suitable balance to an unlimited obligation to serve by imposing economic discipline on siting decisions…it exerts some of the discipline of the utilities economics on the economic decision-making of the customer."*

(2) MILs should provide economic discipline and price signals to new Customers;

(3) The maximum amount that the Company invests in a new extension on behalf of all customers should consider the expected longevity or any other risks associated with the new service;

(4) The current cost to connect new Customers is the appropriate starting point for establishing MILs;

As per AEUB Decision 2005-096, Page 56,

> *"…the Board has determined that cost, not revenue, is the appropriate starting point for establishing the investment policy."*

(5) Setting of MILs needs to respect the utility's standards of service, while recognizing that these standards and the associated costs will change over time;

(6) Changes to MILs should balance the need to attain the target MILs over a reasonable timeframe, while ensuring there is not undue upward pressure on tariff rates;

(7) Adjustments to MILs should consider minimizing intergenerational inequity and cross-subsidy, whereby the portion of the cost of an extension that the Company invests in should be in similar proportion with previously established investment levels. Both new and existing Customers should be treated similarly to the extent possible and should see similar price signal when the system is or was extended to provide service;

(8) To the extent practical, the structure of MILs should generally align with cost causation and the rate structure which is applied to the Customer;

(9) MILs should be simple to administer and applied in a consistent and transparent manner; and

(10) Utilities should take into consideration the approaches of neighbouring utilities when developing MILs.

D. Analysis

The Companies' MIL levels (shown in Table 1) are currently lower than that of neighbouring utilities. A summary of the 2009 MIL levels of neighbouring utilities is shown in Table 2.

Table 2: 2009 MILs of Neighbouring Utilities

	Northland Utilities (NUY)	Northland Utilities (NWT)	NTPC	BC Hydro	ATCO Electric	Fortis Alberta
Residential	$2100/site	$1500/site	$1500/site	$1475/site	$1200/site	$1200/site
Residential – Multi Dwelling	$700/site	$750/Site	$750/unit			
General Service	$300/kW	$300/kW	$250/kW	$200/kW	$1256/kW	$5275 Fixed plus $839/kW
Street Lighting	Cost of installation	$1200/light	Cost of installation	$150/Fixture	$1400/Light	$1400/Light

i) Residential

The Residential MIL has been at the same level of $900 per site since 1989. As part of this study, actual cost data has been reviewed for a typical underground residential subdivision in Whitehorse. The actual average cost per lot of two of the most recent Residential subdivision extensions in Whitehorse, escalated to 2011 dollars using the 10 year average Electric Utility Construction Price Index (distribution), V735224,

Table 327-0011, (EUCPI) increase (reference Appendix A, Table 1), was $4,373 per lot. Refer to Table 3 for details.

Table 3: Cost of Residential extensions in Whitehorse (2011$)

Year	Project Cost (Year $) (A)	EUCPI Inflation Factor(1) (B)	Project Cost (2011$) (C)=(A)*(B)	Number of lots (D)	Cost per Lot (2011$) (E)=(C)/(D)
2005	$ 304,967	1.162	$ 354,372	75	
2006	$ 404,978	1.090	$ 441,426	107	
			$ 795,798	182	$ 4,373

Based on the EUCPI, the cost of a Residential extension has increased 63% since 1989, from an estimated $2,689 per site to $4,373 per site, while the Residential MIL has had no corresponding increase during the same period. Table 4 indicates that 21% of the projected Residential average cost of $4,373 would be covered by the Companies' current MIL of $900, while 33% of the average cost of $2,689 was covered in 1989. This demonstrates that, since 1989, costs have increased disproportionately to the investment level, thus an intergenerational inequity exists whereby today's new Residential customers are experiencing a 94% percent increase in their contribution to the cost of a new extension than new Residential customers did in 1989.

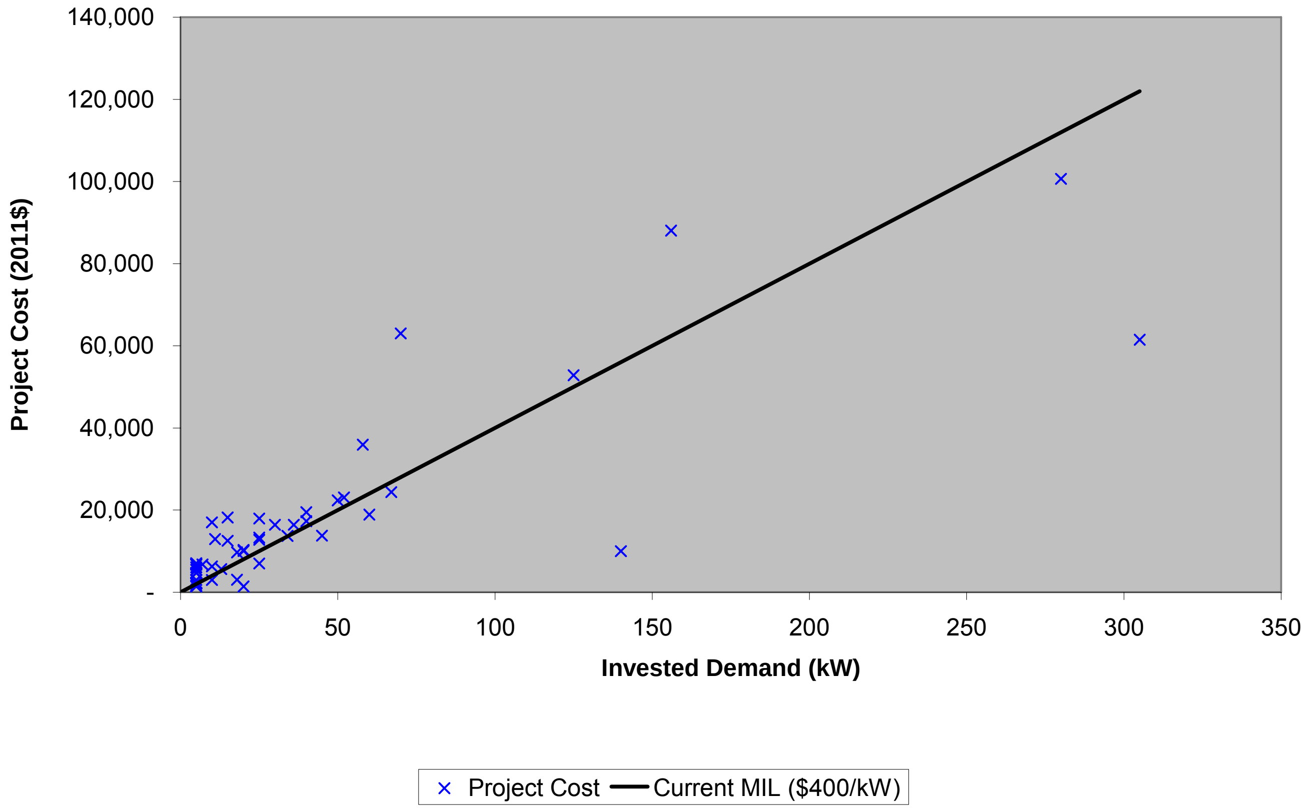
Table 4: Residential Costs and MIL (1989 vs 2011)

Year	MIL per Site	Average Cost per Site	% of Cost Covered by MIL
1989	$ 900	$ 2,689	33%
2011	$ 900	$ 4,373	21%
Increase	0%	63%	

ii) General Service

Unlike the Residential MIL, the General Service MIL has been adjusted more recently. It increased from $180 per kW to $400 per kW in 2005. For the analysis of the General Service MIL, cost and demand data from 48 General Service projects in Whitehorse, from 2006 to 2008, was gathered, representing approximately 89% of all the General Service extensions in that time period. This cost data was then converted to 2011 dollars using the EUCPI. Appendix A, Table 2 provides specific project data. The average demand of the representative sample projects is 39 kW and the average cost per project is $17,627 (2011$) resulting in an average cost of $454 per kW per project. The current General Service MIL of $400 per kW covers 77% of the sum of the 48 projects' total cost, however only 25% of the 48 projects were fully covered by the company investment thus 75% of the customers were required to make a contribution to the project cost. Graph 1 provides a comparison of the General Service project costs and the current MIL used in the analysis.

Graph 1: Whitehorse Historical General Service Project Costs (2011$) and Invested Demand



YECL records indicate that the cost for a typical General Service 10 kW extension in Whitehorse was $5,964 in 2005 and $10,167 in 2009. General Service extension costs have increased by an estimated 70% since 2005 while the General Service MIL has had no corresponding increase during the same period (refer to Table 5 for details). Thus an intergenerational inequity exists whereby today's new General Service customers are currently bearing a greater percentage of the cost of a new extension than new General Service customers did in 2005.

Table 5: General Service Average Costs and MIL of a 10kW extension (2005 vs 2009)

Year	MIL per kW	Typical Cost per Project	% of Cost Covered by MIL
2005	$ 400	$ 5,964	67%
2009	$ 400	$ 10,167	39%
Increase	0%	70%	

iii) Street Lights

Using the same two subdivisions from the residential analysis, the actual average cost per light, escalated to 2011 dollars, was $2,772 per light. Refer to Table 6 for details on the Street Lighting costs.

Table 6: Costs of Street Light extensions in Whitehorse (2011$)

Project	Year	Cost (A)	EUCPI Inflation Factor [(1)] (B)	Cost (2011$) (C)=(A)*(B)	# of lights (D)	Cost Per Light (2011$) (E)=(C)/(D)
1	2005	$ 68,509	1.162	$ 79,607	28	
2	2006	$ 69,358	1.090	$ 75,600	28	
				$ 155,208	56	$ 2,772

[(1)] Refer to Appendix A, Table 1 for EUCPI data

YECL records indicate that in 1989 the cost for a typical Street Lighting extension in Whitehorse was $749, thus 93% of Street Light costs was covered with the $700 investment. As Table 7 demonstrates, 25% of the cost of a typical Street Light extension of $2,772 (2011$) are currently covered by the existing MIL. Street Light extension costs have increased 270% since 1989 while the Street Lighting MIL has had no corresponding increase during the same period. This demonstrates that, since 1989, costs have increased disproportionately to the investment level, thus an intergenerational inequity exists whereby developers are experiencing a substantial increase in their contribution to the cost of new street lights compared to 1989.

Table 7: Street Lighting Costs and MIL (1989 vs 2011)

Year	MIL per Site	Average Cost per Light ($)	% of Cost Covered by MIL
1989	$ 700	$ 749	93%
2011	$ 700	$ 2,772	25%
Increase	0%	270%	

E. Proposal

Similar to neighbouring utilities, such as Northland Utilities, Fortis Alberta and ATCO Electric, YECL is using a cost based approach as the basis for establishing target investment levels, while also considering the Guiding Principles in Section C. In all customer classes, the cost target is based on the costs for new extensions in Whitehorse as the majority of the Companies' customer additions occur in Whitehorse. Having a common MIL among all the communities is consistent with historical MILs and is further supported by the fact that all customers of the respective rate classes pay the same fixed charges which go toward recovery of the investment throughout the various communities.

The following sections describe the approach taken to derive the proposed MIL within each customer class. To simplify the future practical application of the MILs, the proposed MILs have been rounded to the nearest 5 dollars.

i) Residential

In keeping with the Guiding Principles and the cost analysis discussed in Sections C and D respectively, YECL is proposing to gradually increase the current Residential MIL from $900 per site to a target equal to the average cost of a new residential extension in Whitehorse of $4,373 (2011$) per site over a period of 5 years (2011 to 2015). The target MIL is proposed to be simultaneously indexed to keep pace with ongoing inflationary cost pressures. Using the 10 year (2000 – 2009) average change in the EUCPI of 1.8% (refer to Appendix A, Table 1) to escalate the MIL annually, the target MIL in 2015 will be $4,700.

YECL proposes to standardize the method of deriving the Residential MIL by basing the proposed level on the average cost of a new extension on a going forward basis. By setting the target Residential MIL to the average cost, customers with costs greater than average will continue to be required to make a cost contribution and customers with costs below the average will continue to receive investment up to the full cost of their extension.

Table 8 illustrates the proposed annual transition for the increase to residential MIL. The MIL is increased by approximately 39% each year, for five years, until the inflation adjusted target MIL is achieved.

Table 8: Proposed Changes to Residential MIL

Year		Inflation Adjusted Target (1)	MIL (Per Site)	Proposed Chg MIL
Existing			$ 900	
Proposed	2011	$ 4,373	$ 1,250	39%
	2012	$ 4,451	$ 1,740	39%
	2013	$ 4,531	$ 2,420	39%
	2014	$ 4,613	$ 3,360	39%
	2015	$ 4,700	$ 4,700	40%

(1) Increased each year by 10 Year Average Change in EUCPI of 1.8%

Note that the Proposed MIL is equivalent to the Target MIL by the fifth year.

Consistent with the current MIL structure, YECL proposes to set the MIL for Multi-Dwelling units at half that of the Residential MIL. Table 9 illustrates the proposed transition from $450 to $2,350 per site by 2015.

Table 9: Proposed Changes to Residential Multi-Dwelling Unit MIL

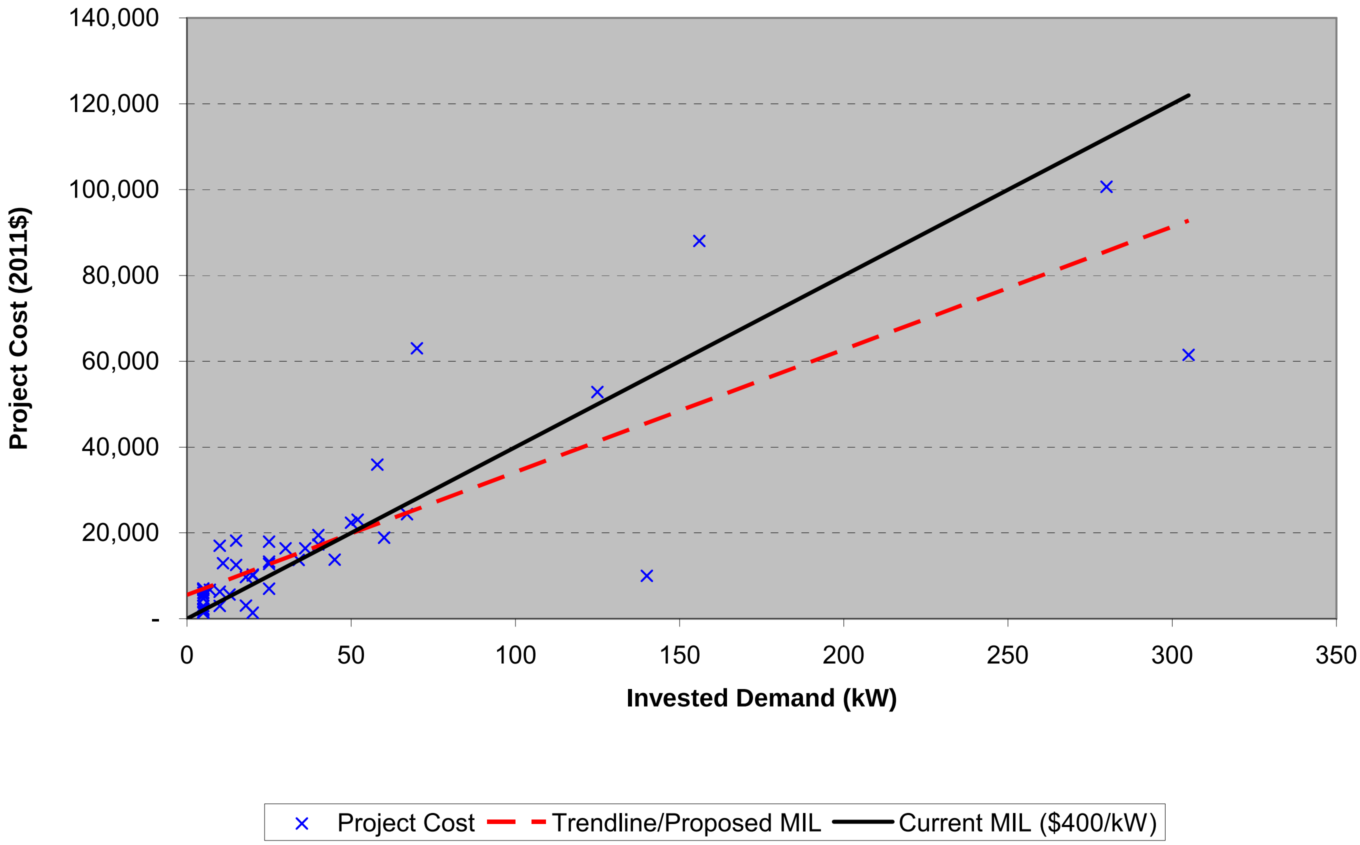
Year		MIL (Per Site)	Proposed Chg MIL
Existing		$ 450	
Proposed	2011	$ 625	39%
	2012	$ 870	39%
	2013	$ 1,210	39%
	2014	$ 1,680	39%
	2015	$ 2,350	40%

ii) General Service

In keeping with the Guiding Principles, and the cost analysis discussed in Sections C and D respectively, YECL is proposing to change the current General Service MIL from a single variable MIL of $400 per kW to a fixed and variable MIL of $5,545 per site plus $285 per kW (in 2011$). YECL proposes to achieve the target MIL over a period of 5 years (2011 to 2015). The annual target MILs are proposed to be simultaneously indexed to keep pace with ongoing inflationary cost pressures, using the 10 year (2000 – 2009) average change in the EUCPI of 1.8% (refer to Appendix A, Table 1) to escalate the MIL. By 2015 the target MIL will be $5,955 per site plus $305 per kW.

The 2011$ target MIL is based on a regression of the historical General Service project data shown in Appendix A, Table 2 and discussed in Section D. Please refer to Graph 2.

Graph 2: Whitehorse Historical General Service Project Costs (2011$) and Proposed MIL



The corresponding equation from the regression analysis is:

y = 285.95x + 5544,

where y = Project Cost $; and

x = Invested Demand (kW)

Using this equation as the basis of the proposed MIL, 60% of the projects and 81% of total project costs will be covered whereas, as mentioned in Section D, only 25% of the projects and 77% of the total project costs are covered with the current General Service MIL. By moving to a fixed and variable component to the MIL more projects are covered by the MIL.

Table 10 illustrates the proposed fixed and variable annual General Service MILs and the resulting investment based on the average General Service load of 39 kW as indicated by the project data in Appendix A, Table 2.

Table 10: Proposed Changes to General Service MIL

	Year	Target MIL Fixed (Per Site) [1]	Target MIL Variable (Per kW) [1]	Proposed MIL Fixed (Per Site) (A)	Proposed MIL Variable (Per kW) (B)	Maximum Investment [2] (A)+(39*(B))	Proposed Chg MIL
Existing				$ -	$ 400	$ 15,600	
Proposed	2011	$ 5,545	$ 285	$ 5,355	$ 275	$ 16,080	3.1%
	2012	$ 5,645	$ 290	$ 5,500	$ 280	$ 16,420	2.1%
	2013	$ 5,745	$ 295	$ 5,650	$ 290	$ 16,960	3.3%
	2014	$ 5,850	$ 300	$ 5,800	$ 295	$ 17,305	2.0%
	2015	$ 5,955	$ 305	$ 5,955	$ 305	$ 17,850	3.1%

(1) Increased each year by 10 Year Average Change in EUCPI of 1.8%

(2) Maximum Investment based on average project load of 39kW

iii) Street Lights

In keeping with the Guiding Principles and the cost analysis discussed in Sections C and D respectively, YECL is proposing to increase the current Street Light MIL from $700 per light to a target equal to the average cost of a new street light extension of $2,772 per light. As with the residential rate class, YECL is proposing a five year phase-in (2011 to 2015), simultaneously indexed for inflation. Using the 10 year (2000 – 2009) average change in the EUCPI of 1.8% (refer to Appendix A, Table 1) to escalate the MIL annually, the target MIL in 2015 will be $2,975 per light. Table 11 illustrates the proposed transitions for the increase to the Street Light MIL. The MIL is proposed to be increased by approximately 33.5% each year, until the inflation adjusted target is achieved.

Table 11: Proposed Changes to Street Lighting MIL

	Year	Inflation Adjusted Target [1]	MIL (Per Site)	Proposed Chg MIL
Existing			$ 700	
Proposed	2011	$ 2,772	$ 930	33.5%
	2012	$ 2,821	$ 1,240	33.5%
	2013	$ 2,872	$ 1,660	33.5%
	2014	$ 2,924	$ 2,220	33.5%
	2015	$ 2,975	$ 2,975	34.0%

(1) Increased each year by 10 Year Average Change in EUCPI of 1.8%

As with the residential rate class, the Proposed MIL is equivalent to the Target MIL by the fifth year.

F. Summary

After consideration of the principles summarized earlier in this document, as well as the review of the available data, this study concludes that increases to the Companies' investment levels are warranted. The current MILs have not kept pace with the cost of new extensions.

The proposed investment levels for residential, general service and street light customers resulting from this study are summarized in Table 12.

Table 12: Summary of Proposed Changes to YECL/YEC Maximum Investment Levels

Year	Residential Single Family Dwelling (Per Site)	Residential Multi Dwelling Unit (Per Site)	General Service Fixed (Per Site)	General Service Variable (Per kW)	Street Lighting (Per Light)
Current	$ 900	$ 450	$ -	$ 400	$ 700
2011	$ 1,250	$ 625	$ 5,355	$ 275	$ 930
2012	$ 1,740	$ 870	$ 5,500	$ 280	$ 1,240
2013	$ 2,420	$ 1,210	$ 5,650	$ 290	$ 1,660
2014	$ 3,360	$ 1,680	$ 5,800	$ 295	$ 2,220
2015	$ 4,700	$ 2,350	$ 5,955	$ 305	$ 2,975

YECL has forecast the overall impact on the total revenue requirement if the new investment levels are implemented in 2011. The resulting rate impact is illustrated in Table 13.

Table 13: Forecast Rate Impact with Proposed Changes to YECL/YEC Maximum Investment Levels

Rate Class	2011	2012	2013	2014	2015
Residential	0.02%	0.06%	0.12%	0.19%	0.28%
General Service	0.03%	0.08%	0.13%	0.17%	0.22%
Street Lighting	0.07%	0.22%	0.41%	0.65%	0.95%

APPENDIX A

Table 1: EUCPI Data

EUCPI
Electric Utility Construction Price Index (distribution)
V735224, Table 327-0011

Year	Index	% Change	Inflation Factor
1989	95.5		1.626
1990	98.5	3.14%	1.576
1991	97.7	-0.81%	1.589
1992	100.0	2.35%	1.552
1993	102.5	2.50%	1.515
1994	108.2	5.56%	1.435
1995	116.7	7.86%	1.330
1996	116.6	-0.09%	1.331
1997	118.0	1.20%	1.316
1998	122.8	4.07%	1.264
1999	126.1	2.69%	1.231
2000	128.7	2.06%	1.206
2001	129.6	0.70%	1.198
2002	130.5	0.69%	1.190
2003	130.6	0.08%	1.189
2004	131.1	0.38%	1.184
2005	133.6	1.91%	1.162
2006	142.4	6.59%	1.090
2007	148.8	4.49%	1.043
2008	150.2	0.94%	1.034
2009	149.8	-0.27%	1.036
2010*	152.5	1.80%	1.018
2011*	155.2	1.80%	1

* Forecast based on average annual change from 2000 to 2009 of 1.8%

1 **Table 2: YECL General Service Project Data**

Year	Invested Demand kW	Project Costs (2011$)	Cost per kW (2011$)
2006	140	10,006	71
2006	20	1,429	71
2006	18	3,036	169
2006	20	10,335	517
2006	18	9,742	541
2006	305	61,493	202
2006	5	2,979	596
2006	5	2,097	419
2006	156	88,055	564
2006	10	17,042	1,704
2006	13	5,655	435
2006	5	5,477	1,095
2006	5	4,721	944
2006	67	24,375	364
2006	280	100,631	359
2006	70	62,993	900
2006	58	35,909	619
2006	40	17,338	433
2006	50	22,372	447
2006	25	17,964	719
2006	5	2,324	465
2006	25	6,986	279
2006	7	6,786	969
2006	5	2,127	425
2007	52	23,080	444
2007	125	52,807	422
2007	10	2,997	300
2007	15	12,518	835
2007	5	1,406	281
2007	5	2,273	455
2007	5	7,052	1,410
2007	40	19,512	488
2007	5	6,037	1,207
2007	60	18,892	315
2007	5	1,596	319
2007	5	6,706	1,341
2007	30	16,449	548
2007	25	13,310	532
2008	45	13,770	306
2008	15	18,186	1,212
2008	10	6,296	630
2008	36	16,436	457
2008	20	10,053	503
2008	25	12,798	512
2008	5	6,846	1,369
2008	34	13,710	403
2008	5	4,730	946
2008	11	12,951	1,177
Average	**39**	**17,627**	**454**

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TAB 6
BOARD DIRECTIVES

6.0 BOARD DIRECTIVES

This Tab reviews directives on cost of service, rate design and other related matters contained in Board Decisions since the Companies' 1996/97 GRA, and (where relevant) the Companies' response.

6.1 1996/97 GRA

Order 1996-7 directed YEC and YECL to design a rate rebalancing program that would target all customer class revenue/cost ratios (R/C) of 90% to 110% over a ten year period.

- In Yukon Energy's 2005 Required Revenues and Related Matters Application, Yukon Energy noted that no action had been taken on the directive as of the date of filing.
- The Board addressed the issue during the 2005 hearing in Order 2005-1.
- In response, the Companies jointly filed a required report with the Board in August 2005 that provided information on the revenue to cost ratios by customer class for both Companies using the most recent cost of service allocation study, including comments on the implementation of a rate shift program over 10 years. Intervenors provided comments to the Board on this report, and on October 27, 2005 the Companies jointly responded to the Board on these comments. Submissions from the Companies included the following:
    - In 1997, the R/C ratios for the Residential Non-Government and General Service Government were the only two results that were outside the 90:110% range.
    - Overall, there is no reason to believe that changes since 1997 have reduced materially since the 1997 GRA the extent to which R/C ratios for the Residential Non-Government and General Service Government remain outside the 90:110% target range. These two customer classes are currently far outside the range targeted by the Board. Accordingly, in order to prevent giving rise to concerns over rate shock, it will likely take a number of years in any rate shift program to begin to approach the target range.
    - The Companies identified issues to be addressed in any rate shift program, including the status of government rate relief (a factor noted in Order 1996-7) and rate shock impact implications (including bill impact implications when considered together with reductions/removal of government rate relief).
    - The Companies noted that when a rate shift program is designed and implemented, a key first task will be to determine the rate design approach to be used in implementing the rate shift, including the related requirements of OIC 1995/90. Based on previous rate

designs, rate shift impacts as between customer classes would focus, after the runoff rates are established, on first block energy rates and customer charges or demand charges. A possible first assessment then would be the impact of adjusting the runoff block to move towards incorporating the current price of diesel fuel (which would affect all customers as runoff rates in each rate zone currently are equal between the various classes). This level of detail regarding rate design has not been considered by the Companies in recent years, and would likely be a necessary precondition to implementing a differential rate shift program at this time.

  - Preparation of a new cost of service study will require a number of matters to be addressed. First, there will need to be an approved revenue requirement for each of the two utilities on a consistent test year basis as well as the determination of billing determinants and load characteristics by customer class. The key methods (such as classification of generation and transmission assets) will also need to be reviewed to ensure that the cost of service approach properly tracks the cost imposed on the current system (with its adjustments since 1997) on each customer class.

- Yukon Energy and Yukon Electrical each filed separate revenue requirement applications with the Board in 2008 for the test years 2008 and 2009. These submissions, which provided the basis for preparing an updated COS for 2009, did not address cost of service or rate design work related to any rate shift program or rate rebalancing as between customer classes. Such matters were to be addressed, as required by the Board, in future submissions following consideration of the revenue requirement applications.

In addressing these matters today, the Application has referenced OIC 2008/149 that amends OIC 1995/90 to add immediately after section (2) of that directive, the following regarding retail rate adjustments:

> 2.1(1) The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

> Section 2.1(2) adds that this section will expire on December 31, 2012, effectively preventing any rate rebalancing for retail customers until after that date.

The updated COS as provided in this Application (Table 3.2) confirms that the current 2009 R/C ratios for the Residential Non Government and General Service Government have shown minimal change since 1997 and remain outside the 90:110% range (with respective R/C ratios at 79% [versus 81% in 1997] and 144% [versus 143% in 1997]). In addition, unlike 1997, the R/C ratios for General Service Non-Government, Street Lights and Sentinel Lights are also outside the 90:110% range (with respective R/C ratios at 117%, 69% and 148%). These COS results remain to be tested in the current proceeding. Thereafter, the Companies have noted in their August 2005 submission to the Board (see above) the issues that would need to be addressed when a rate shift program is designed and implemented at some future time.

6.2 DECISION 2007-5

On February 9, 2007, Yukon Energy filed the Minto PPA for review and approval by the Board. Order 2007-5 denied the Minto Power Purchase Agreement ("PPA") as filed, and directed Yukon Energy to file a revised PPA Agreement by May 31, 2007. On May 14, 2007, Yukon Energy subsequently reached an agreement with Minto Mine to amend the PPA to incorporate the changes desired by the Board. In Order 2007-6 (dated May 25, 2007) the Board approved the PPA as amended on May 14, 2007 and noted that it had "reviewed the filing and agrees that it meets the intent of Board Order 2007-5."

Outstanding matters related to Board Order 2007-5 are as follows:

Board Finding 3: COS Models

- ***The Board reiterates its earlier direction that YEC and YECL provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators and to look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further the Board expects to see justification on the allocation of transmission assets. For the next GRA the Board directs both YEC and YECL to provide their electronic COS models and to distinctly show costs as being related to generation, transmission, and distribution. Further, generation costs are to be separated based on each generation type (i.e., hydro, diesel, wind etc). This will enable testing of costs to serve all rate classes, including Rate 35.***

A full Cost of Service as directed is provided as Tab 3 of this Application. Electronic COS models are also being provided.

Board Finding 5: Rate 35 Audit and Control Measures

- ***Should Minto pursue Rate 35, proposed audit and control measures and reporting requirements must be established between YEC and Minto, and then YEC is to file these with the Board. YEC is not to implement Rate Schedule 35 until such approval has been granted.***

This was addressed in Tab 4 of Yukon Energy's 2008/2009 GRA and in response to directives provided in Tab 6 of that GRA.[1] YEC cannot implement this rate until audit and control measures and reporting requirements have been proposed by Minto, reviewed and agreed upon by Yukon Energy, and approved by the Board. As of the date of filing Minto Explorations has yet to provide further information to YEC regarding specific proposed auditable reporting and control mechanisms. In the event this service was requested by Minto Explorations, and there was anticipated power to be made available, YEC and Minto Explorations intend to work together to determine acceptable auditable reporting and controls. However, the forecast quantities of power available for such service are very limited.[2]

Minto mine has yet to pursue service under Rate Schedule 35.

Board Finding 6: Rate 35 Amendment

- ***The board directs YEC to amend the wording for Rate Schedule 35 when such an opportunity arises.***

This was addressed in Tab 4 of Yukon Energy's 2008/2009 GRA and in response to directives provided in Tab 6 of that GRA. Minto mine has yet to pursue service under Rate Schedule 35.

Board Finding 10: Maximum Utility Investment

- ***The Board directs both YEC and YECL to review and refine their investment policies for industrial customers and to include recommendations within their next GRA, which is expected to be filed by October 31, 2007. The policies should***

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[1] The Board also reviewed this issue and reiterated its earlier comments in Order 2008-13 approving Rate Schedule 39 as final.

[2] This rate is to be served at a lower priority than Rate Schedule 32 secondary sales. Rate Schedule 32 sales are presently constrained and approaching the limits of the system. Accordingly, no material energy is expected to be further "surplus" to Rate Schedule 32 needs for service under Rate Schedule 35, except possibly in limited years during summer.

clarify to potential industrial customers what the utility will invest in new facilities and provide consistency in the approach when construction facilities to serve new loads.

Maximum Investment Policies for industrial customers are reviewed in Tab 5 of this Application, and address the need for consistency in approach on this matter over time.

Board Finding 19: Ratchet and Demand Rate Issues

- ***Ratchet issues and changes to demand rate should be addressed in YEC's next GRA.***

Rate design issues are reviewed in Tab 4 of this Application.

6.3 DECISION 2009-8

On October 6, 2008, Yukon Energy Corporation (YEC) filed with the Yukon Utilities Board (Board) an Application, pursuant to the *Public Utilities Act* and Order-In-Council 1995/90, requesting an Order approving forecast revenue requirements for the 2008 and 2009 test years of $29.217 million for 2008 and $31.599 million for 2009 (General Rate Application or Application).

Following an oral hearing in May 2009, the Board determined as follows:

- YEC's 2008 and 2009 revenue requirement was approved with the changes directed by the YUB in the Reasons for Decision (Appendix A attached to Order 2009-8).
- YEC was directed to, in conjunction with YECL, file a complete Phase II (rate design and cost of services) with the Board within 60 days of the date of the decision on the above ordered compliance filing.

YEC and YECL wrote to the Board on the December 10, 2009 noting that they would not be able to file by the January 17, 2010 deadline date (60 days from the date of the order approving the YEC compliance filing) due to the time required to work through the "logistics of having two companies work on one filing, the volume of work and the need and commitment to complete sufficient and appropriate consultation…".

In correspondence provided January 21, 2010 to Yukon Energy (YEC) and Yukon Electrical (YECL) the Board indicated receipt of the Companies' letter dated December 10, 2009, and noted that the Companies did not provide details regarding the reason for not meeting the Board's direction to file a joint Phase II application by January 17, 2010 (as provided in Order 2009-8). YEC and YECL were consequently directed to "provide a detailed explanation by January 29, 2010 of the reasons for failure to file the joint Phase II application and propose a date no later than 30 days from the date of this letter for the filing of the Phase II application".

The Companies responded January 29, 2010 providing greater detail related to their inability to meet the January 17, 2010 filing date and noting their intention to file a joint Phase II application with the Board by February 19, 2010.

Board Finding 13: Cost Allocation and Revenue to Cost Ratios

- ***The Board directs YEC and YECL as agreed to file a joint Phase II application containing an up-to-date cost of service study (with electronic models attached) within 60 days of the issuance of the decision on the compliance filing by YEC as directed in this Board Order. The Phase II application is to provide accurate revenue to cost ratios for all rate classes, provide rate design recommendations that comply with previous Board directions and comply with current OICs, provide updated terms and conditions of service, and contain a review on investment levels. As supported by both utilities, the Board expects the application to contain stakeholder input.***

An up to date cost of service study, including revenue to cost ratios for all rate classes is discussed and provided as Tab 3 of this Application. Rate design recommendations that comply with previous Board direction and current OICs are provided in Tab 4 of the Application. Up to date terms and conditions of service and a review of utility investment levels are provided in Tab 5 of this Application. Tab 7 reviews the consultation process used by the utilities to gain stakeholder input.

Secondary Sales Rate Design

- ***The Board expects that Rate Schedule 32 will be included in the full review of rate design and cost of service study that will be jointly filed by YEC and YECL. It is noted that the Environment Canada update provided by CW was not provided***

during the evidentiary part of the hearing. Consistent with the Board's views expressed in Section 4.2 above, the Board will defer this issue to the joint Phase II proceeding.

Secondary Sales Rates are discussed in Tab 4 (section 4.3). Given the fact that Environment Canada now provides a 7 day forecast as opposed to a 5 day forecast, the Companies have not pursued amendments to Rate Schedule 32 as were originally proposed in Yukon Energy's 2008/2009 GRA.

TAB 7
CONSULTATION

7.0 CONSULTATION

This Tab provides an overview of the stakeholder consultation process undertaken by the Companies in relation to the preparation and filing of the Phase II Application.

This Tab consists of the following items:

- Summary of Consultation; and
- Summary of Comments Heard.

Materials distributed to intervenors and comments received from intervenors are provided in Appendix 7.1.

7.1 SUMMARY OF CONSULTATION

Board Order 2009-8 directed YEC and YECL to file a joint Phase II Application containing an up-to-date cost of service study (with electronic modes attached) within 60 days of the issuance of the decision approving the Compliance Filing by YEC as directed in the Order. The Board noted that it expected the application to contain stakeholder input.

The Companies undertook a stakeholder involvement program leading up to the filing, as follows:

1. **Briefing with Yukon Government** - The Companies met and presented background information related to its application to representatives of Yukon Government (Energy, Mines and Resources and the Energy Solutions Center) on November 4, 2009. Copies of the presentations provided to the Yukon Government by YEC and YECL are provided in Appendix 7.1 Attachment A.

2. **Open House with Stakeholders** - The Companies met with stakeholders at an Open House on December 15, 2009, to gather input related to cost of service, rate design and terms and conditions of service to be considered in light of the Companies' joint application to be filed in early 2010.

Prior to the Open House some stakeholders provided the Companies with issues lists; the Companies considered these in their presentation of materials. Issues lists provided by the following attendees are provided as Appendix 7.1 Attachment B:

i. Utilities Consumers Group
ii. City of Whitehorse
iii. Leading Edge

The Open House was held from 1:00 p.m. until 8:00 p.m., and involved wide ranging discussion on cost of service and rate design issues in Yukon. The Companies provided a joint presentation (Provided in Appendix 7.1 Attachment B) and provided attendees with a copy of the power point presentation used along with a copy of one presentation used at the November 4, 2009 briefing with the Yukon Government (Current Rate Policy, Board Directives and Rate Design).

Meeting minutes from the Open House are provided in Appendix 7.1 Attachment B. Meeting Minutes were distributed to attendees on January 13, 2010, requesting that those copied provide any edits or comments.

3. **Follow up correspondence** – Following the Open House, further background materials were provided to attendees and further written submissions were provided by attendees:

   a. At the Open House representatives of the Companies committed to provide attendees with electronic copies of the following materials (which were subsequently distributed to attendees on January 4, 2010 and are provided as Appendix 7.1 Attachment C):

      i. The 1992 YUB Cost of Service and Rate Design Report (filed during YEC 2008/2009 GRA as response to YUB-YEC-1-21(d)).
      ii. The 1993/94 GRA response to recommendations in the 1992 YUB Cost of Service and Rate Design Report.
      iii. A copy of the 1997 Cost of Service Study.
      iv. A copy of the November 4 presentation provided to YG on Current Rate Policy, Board Directives and Rate Design (handed out at workshop).
      v. Load analysis slides for the General Service Municipal rate class; reproducing slides 34, 35, and 36 of the Dec.15 presentation for General Service Municipal.

vi. Writing Tablet Notes.

b. At the Open House on December 15, 2009, the Companies encouraged stakeholders to provide any further comments in writing after the session (to be provided by January 15, 2010). Many of the attendees provided written submissions, or emails relating further views and considerations related to rate design and cost of service issues for Yukon. These materials are provided in Appendix 7.1 Attachment D and include the following:

i. Submission from Utilities Consumer Group dated December 29, 2009.
ii. Submission from Leading Edge dated January 14, 2010.
iii. Submission from City of Whitehorse dated January 15, 2010.
iv. Submission from Yukon Conservation Society dated January 15, 2010.
v. Email correspondence copied to all attendees over January 13 and January 14, 2010.

c. An undertaking was made for representatives of both Companies to discuss issues related the Electric Service Regulations/ Terms and Conditions of Service and provision for a "customer bill of rights" separately with a representative of the Utilities Consumer Group. Due to scheduling issues, this undertaking is outstanding at the time of filing, but is expected to be completed shortly. Any required further update will be provide as required.

7.2 SUMMARY OF COMMENTS HEARD AND RESPONSE

A high level summary of comments provided by stakeholders during the consultation process and a summary of how these have been responded to by the Companies is provided in the Table 7.2 below:

Table 7.2
Summary of Stakeholder Comments and Response

No.	Intervenor	Submission Date	Issue	Response
1	Leading Edge (John Maissan)	11-Dec-09	(1) Churches different from other General Service customers: Churches are included in the General Service rate class yet their demand and consumption pattern is far different from a normal business. Typically peak loads occur after business / office hours or on weekends, and typically peak loads occur on a very infrequent basis (a few times per year) as opposed to 5 or 6 days per week. Alternative rate class treatment for these customers should be considered.	The Companies have not considered creating a separate general service rate class for religious facilities or any other particular group institution. The companies are not aware of any utility that maintains such a rate schedule specific to churches.
2	Leading Edge (John Maissan)	11-Dec-09	(2) Cost sharing period for infrastructure paid for by customer contributions: The period of time for capital cost sharing for new customers connecting to a line paid for previously by one or more other customers needs to be reconsidered. YECL and Yukon Energy limit this time period to 5 years whereas the Yukon Government's Rural Electrification Program uses 15 years. This can result in a free ride for new customers while the originating customer(s) are still paying thousands of dollars per year.	The existing cost sharing policy provides a reasonable balance between customer rights and obligations, and the amount of administration required by YEC and YECL to track cost sharing applications. YEC and YECL have no role in determining the time periods applied by the cited government programs.

No.	Intervenor	Submission Date	Issue	Response
3	City of Whitehorse	10-Dec-09	(1) Existing and Proposed Revenue to Cost Ratios for each customer class and the rationale to support any that do not fall within the range 95% to 105%.	The results of the COS study are provided in Tab 3; OIC 2008/149. prevents inter-class rebalancing at this time.
4	City of Whitehorse	10-Dec-09	(2) Existing and Proposed Revenue to Cost Ratios relating to costs allocated to demand, customer and commodity and the rationale to support any that do not fall within the range 95% to 105%.	Please refer to discussion in Tab 4 of Application.
5	City of Whitehorse	10-Dec-09	(3) Discussion of seasonal rates as one form of time-of-use rates that fit into current residential metering capabilities.	The Companies have not proposed seasonal or time of use rates in this Application. The implementation of seasonal rates would only be considered in light of appropriate studies to indicate some form of sustained cost-based rationale that provided benefits in excess of the costs and administrative issues of implementing a more intricate or complex rate structure.
6	City of Whitehorse	10-Dec-09	(4) Demand elasticity information to measure the efficacy of DSM initiatives.	The Application does not review DSM programs. Order 2009-8 directs the Companies, to consult with stakeholders and develop a policy paper with respect to DSM initiatives. YEC and YECL are to jointly lead this process and submit a policy paper (Plan) in their next GRA (Directive # 3).
7	City of Whitehorse	10-Dec-09	(5) Discussion of the rationale of adopting inverted block rates, particularly regarding the recovery of allocated costs by each rate block.	Please refer to discussion in Tab 4 of Application.
8	City of Whitehorse	10-Dec-09	(6) Discussion of the appropriateness of using marginal costs in an embedded cost of service study.	The embedded cost of service study does not use marginal costs.

No.	Intervenor	Submission Date	Issue	Response
9	City of Whitehorse	10-Dec-09	(7) YEC's and YECL's joint interpretation of pertinent OICs and their effects on the Phase 2 Application and cost of service study.	Please see discussion in Tab 4 of Application.
10	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(1) Proposed time line of COS proceedings i.e. future workshops/ meetings, etc.	Schedule of Phase II Application proceedings and provision for any further workshop to be determined by the Board.
11	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(2) Provide and discuss last COS methodology approved by the Yukon Utilities Board.	Please see Tab 3. A copy of the 1996/97 COS was provided to stakeholders after the December 15, 2009 Open House and is included in Appendix 7.1. Past COS reviews and methodology are discussed in Tab 3, Appendix 3.4: Background and Past Practice.
12	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(3) How to deal with plant additions since last COS, as well as future plant additions.	Please see Tab 3, section 3.2.
13	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(4) Need for an independent non-utility (YEC/YECL) consultant to run COS study.	The COS study has been conducted by the Companies in this Application.
14	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(5) Secondary energy rate; i.e., fair customer classification rather than revenue offset.	Please see Tab 3; discussion of Bulk Power Classification Methods. (Transmission and Generation) is provided in Section 3.2.
15	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(6) Explain how classification of a plant to energy or to demand impacts each category of customers.	Please refer to Tab 3, section 3.2. It was noted in discussion during the December 15 Open House (see workshop notes page 18-19 provided in Appendix 7.1) that the tendency is for residential customers to be allocated more demand-related costs and industrials to be allocated a larger share of energy-related costs. In the 1997 COS study (Tab 5 of Appendix to 1996/97

No.	Intervenor	Submission Date	Issue	Response
				GRA), residential non-government customers had 35.7% of the costs of demand and 26.6% of the energy cost.
16	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(7) Explain how the proposed load data was collected/determined.	Please refer to YEC and YECL Phase I General Rate Applications, as well as Tab 3.
17	Utility Consumers Group (UCG) (Roger Rondeau)	8Dec -09	(8) Explain which specific load data will be used in cost allocation study.	Please refer to Tab 3, section 3.2 of this Application.
18	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(9) Provide for discussion yearly load factors for each year since last COS.	Please refer to EDLA study set out in the Application, Tab 3 Appendix 3.3.
19	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(10) Provide for discussion study for determining appropriate method of classifying generation operation and maintenance expenses.	Please refer to Tab 3, Review of Methodology for Application Section 3.2 of this Application.
20	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(11) Provide for discussion study for the purpose of identifying long-run marginal costs to be included in run-out rates.	The Companies have not included a study of long-run marginal costs in this Application. Based on established practice, run-off rates are based on short-run incremental costs.
21	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(12) Provide for discussion study for possibilities of using interruptible rates, time-of-use rates and special electrical heating rate for purpose of increasing economy and efficiency.	With respect to time-of-use and seasonal rates, please see item 5. Special interruptible electrical hearing rates are presently in place, under Rate Schedule 32 Secondary Energy.
22	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(13) Provide for discussion study to determine the optimum size of the first energy block and usefulness of multiple energy blocks.	Please refer to Application, Tab 4.

No.	Intervenor	Submission Date	Issue	Response
23	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(14) Consider demand side management or energy management at this time, if plan is to introduce energy blocks.	With respect to DSM, see item 6.
24	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(15) Use of PPAs or government OICs for determining COS allocation i.e. need to know real and fair costs of all customer groups using approved cost allocation model.	The consolidated COS for the Companies is provided in Tab 3 of this Application (Appendix 3.1). Cost of service results are summarized in Section 3.3.
25	Utility Consumers Group (UCG) (Roger Rondeau)	8-Dec-09	(16) Need to include a Consumer Bill of Rights in the ESR. A code of ethics identifying a step-by-step procedure a customer or the utility must comply when having a dispute.	Please refer to the proposed ESR, (commonly called Terms and Conditions of Service). The ESRs, or terms and conditions, set out the rights and responsibilities of customer and utility with regard to the provision of service. Discussions with concerned stakeholders on this issue are being undertaken but have not been completed at time of filing.
26	Leading Edge (John Maissan)	14-Jan-10	(3) Recalculate monthly energy blocks and subsidies on a daily basis: billing periods between 27 to 34 days the variation on the high side (often the Christmas period) can unnecessarily push customers into a higher rate (and lower subsidy) category.	Currently, energy consumption is prorated into Block 1 and Block 2 when falling outside billing periods of 25 to 31 days when it is an initial or final bill only.

No.	Intervenor	Submission Date	Issue	Response
27	Leading Edge (John Maissan)	14-Jan-10	(4) Rate signals required for economy and efficiency: strongly in support of rate design that sends meaningful cost signals that promote economy and efficiency to all customers as required by YTG Order in Council (OIC) 1995-90. Whitehorse, like the rest of Yukon, has had generous government subsidy programs both directly (on the utility power bills) and indirectly (capital subsidies on electrical infrastructure). The fact that increasing cost drives consumption downwards is well known and recognized. However, the signal that all customers are getting from Yukon Housing Corporation, a YTG Crown Corporation, is that electric heating is as cheap, if not cheaper than oil heating (See Attachment D)! How can the utilities or the government or the YUB or anyone expect consumers to make the right choices when they are getting all the "wrong" signals? The consumers are simply following the signals that they are getting, they are normal consumers.	Please refer to Tab 4 of Application. Rate design options considered for Residential and General Service classes are discussed in Section 4.2.4. Rate proposals for 2009 are discussed in section 4.4. The proposals for 2009 rate design address the need to provide runoff rates for residential and general service customers that reflect "economy and efficiency", and sending a fair efficiency price signal for some level of consumption above a stipulated threshold for each class.

No.	Intervenor	Submission Date	Issue	Response
28	Leading Edge (John Maissan)	14-Jan-10	(5) Residential rate design: With respect to residential customers, I consider the 1000 kWh per month first block to be out of date and too high 700 kWh is more appropriate the 1000 kWh per month is set by YTG (OIC 1995-90). Given the OIC stipulations in this respect in place at present, the author suggests that the first block be subdivided into two sub-blocks, with the lower block rate lower and the upper block rate higher. In the residential runoff rates there need to be signals too, but there may be challenges in setting meaningful rates without undervaluing first block energy due to OIC 2008-149 stipulations (inability to make inter-class adjustments) and due to government subsidies on capital infrastructure that has shielded customers from actual power cost increases. The runoff block should also be subdivided into two or more blocks. The appropriate monthly consumption level for this block requires some analysis may well need to be in the 2000 to3000 kWh per month range.	Please refer to Tab 4 of Application. Rate design options considered for Residential and General Service classes are discussed in Section 4.2.4. Rate proposals for 2009 are discussed in section 4.4. The utilities did consider a first block of up to 700 kWh per month but determined a 1,000 kWh first block to be appropriate at this time. Rate designs based on a 700 kW.h first block can be calculated within the constraints of OIC 2008/149.

No.	Intervenor	Submission Date	Issue	Response
29	Leading Edge (John Maissan)	14-Jan-10	(6) General Service rate design: all customers should get rate signals that promote economy and efficiency. At present the runoff block (over 2000 kWh per month) appears to be too low for most GS customers to ever hope to reduce their consumption down to that level consider a mechanism such as load factor based rates for the runoff block so that all customers will get the economy and efficiency signal utilities will need to perform analyses on the GS class to determine what practical measures could be put in place with respect to demand charge adjustments and/or runoff rate block energy charges, as a function of load factor, to determine appropriate adjustments. Some adjustments to the first energy block may also be required to enable price signals to be added to the new runoff block (or blocks).	Please refer to Tab 4 of Application. Rate design options considered for Residential and General Service classes are discussed in Section 4.2.4. Rate proposals for 2009 are discussed in section 4.4. A variety of options for providing fair and reasonable economy and efficiency price signals to the general service rate class. A load factor based rate was not considered feasible for implementation due to the complexities involved in determining such a rate and ensuring it provided for fair and reasonable rates that reflected utility ratemaking principles and met the requirements of Yukon rate policy OICs.
30	Leading Edge (John Maissan)	14-Jan-10	(7) Industrial rate design: the Industrial rate class should also receive an economy and efficiency signal in their rates, but I do not have any particular suggestions as to the best method for doing this (if in fact it would be possible within OIC 2007-94 stipulations).	Please refer to **Major Industrial Rate Schedule 39** which provides for a price signal in circumstances when diesel is on the margin: "A Base Load Energy amount per month may be established for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount." At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for

No.	Intervenor	Submission Date	Issue	Response
				amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.
31	Leading Edge (John Maissan)	14-Jan-10	(8) Seasonal rates: seasonal rates would be beneficial in providing to customers signals of the high cost of marginal winter generation (diesel, or hydro with significant storage) and the lower summer generation cost simpler to administer than time of use rates with hourly changes. Seasonal rates would reflect Yukon's realities. Winter seasonal rates may also be a way of discouraging electric heating. I believe that the summer season definition needs to reflect hydro power (water) availability, and not just air temperatures or daylight hours. A two season rate composed of June through October as summer (for bills issues in those months which would include consumption in the previous month), and November through May as winter may work well the diesel rate zones do not require seasonal rates but whether it is practical to have seasonal	Introducing seasonal or TOU rates would introduce complications (including complications related to billing customers such as additional costs, cancelled or re-bill implications,) and also introduce a level of complexity and confusion into Yukon rates that needs to be fully considered and tested before such rates could reasonably be advanced in any proposal to the YUB for review.

No.	Intervenor	Submission Date	Issue	Response
			rates in the hydro zone and not in the three diesel zones would have to be considered by the utilities.	
32	Leading Edge (John Maissan)	14-Jan-10	(9) Classification of Aishihik power plant costs: The 1996-1997 GRA Cost of Service (COS) study classified 40% of the cost of hydro plants (with the exception of Whitehorse No. 4) to demand and 60% to energy a Yukon Energy representative stated that the N-1 planning criterion may result in more of Aishihik being classified to energy and less to demand. I do not support an increased classification of the Aishihik power plant to energy. Since diesel plant is classified entirely to demand it would logically follow that a smaller portion of the Aishihik plant should be classified to energy than is at present.	Please see discussion of bulk power methods in Tab 3 of Application. See section 3.2.1 and discussion at page 3-5 and 3-6 for treatment of Aishihik and Aishihik 3rd Turbine in the 2009 COS.

No.	Intervenor	Submission Date	Issue	Response
			The addition of the third turbine with a presumed capacity of about 7 MW, a project which is now underway. The plant without the third turbine has only a 40% capacity factor (assuming no water license restrictions) and with the third turbine this will drop to 38.4%. Furthermore, according to the COS study for the Minto PPA the Aishihik to Whitehorse transmission line is classified to demand at the time of system peak. These facts and figures indicate that even an allocation of 60% to energy is questionable.	
33	Leading Edge (John Maissan)	14-Jan-10	(10) Government power subsidy thwarts economy and efficiency: direct government subsidies on power bills and excessive indirect subsidies on electrical infrastructure (no cost capital contributions beyond those required to make projects justifiable from a normal utility perspective) are counterproductive, and frustrate the utilities' and the YUB's ability to send appropriate economy and efficiency signals to consumers as required by OIC 1995-90. These subsidies keep the cost of power artificially low and undermine the government's own OIC	The items noted are Revenue Requirement matters.

No.	Intervenor	Submission Date	Issue	Response
			1995-90 by preventing the utilities and the YUB from sending appropriate and meaningful economy and efficiency cost signals to consumers.	
34	Leading Edge (John Maissan)	14-Jan-10	(11) Residential class first block of 1000 kWh per month too high: The first block of the Residential class was raised from 700 kWh per month to 1,000 kWh per month by OIC in 1989 it is now appropriate to re-set the OIC limit for the first block of the Residential class to 700 kWh or thereabouts. While it is acknowledged that the utilities and the YUB cannot directly change the OIC, they can recommend and encourage the YTG to do so.	See item 28
35	Leading Edge (John Maissan)	14-Jan-10	(12) Clarification required on amount and timing of diesel energy in 2010 and beyond: Slide 17 of the utilities' presentation indicates that by 2012 (in 2 years time) with Mayo B in place, there is a forecasted requirement for 30 GWh per year of diesel energy. It is not clear from this slide whether this forecast assumes	The noted items are issues that can properly be addressed in the Mayo B Part III application, not the joint YEC/YECL 2009 Phase II GRA.

No.	Intervenor	Submission Date	Issue	Response
			the addition of the Aishihik third turbine, which we understand is underway. The Aishihik third turbine will provide about 5 GWh per year more energy and about 7 MW more winter hydro peaking capacity, both of which would be expected to reduce diesel generation and diesel peaking requirements.	
36	Leading Edge (John Maissan)	14-Jan-10	(13) Customer bill of rights: A suggestion was put forward that the new "Terms and Conditions of Service" (up to now called the "Electric Service Regulations") contain a "Customer Bill of Rights". I support clearly articulated rights and responsibilities of both the customers and the utilities in the Terms and Conditions of Service, regardless of whether it is called a "Bill of Rights" or something else or just embedded but clearly articulated.	See item 25
37	Leading Edge (John Maissan)	14-Jan-10	(14) Diesel and new hydro like Mayo B driving costs: Slide 22 of the utilities presentation seems to indicate that increases in diesel prices are the main long term and future cost driver on the system. Incremental diesel costs are also discussed on slide 27. In my view it is important to note that the diesel fuel price assumption underlying these figures is the YUB	Please see Tab 4 of the Application; section 4.3 addresses the incremental cost of diesel and explains how this was calculated for 2009 rates.

No.	Intervenor	Submission Date	Issue	Response
			approved fuel cost which is higher than the actual present fuel cost. In view of the fact that it will be difficult enough to develop meaningful rate economy and efficiency signals to consumers (in all classes), it may be adequate to consider actual present diesel costs in rate design.	
38	Leading Edge (John Maissan)	14-Jan-10	(15) Maximum utility investment levels: I am in support of an increase in the maximum utility investment level (MIL) for all classes of customers. The MIL should be set with reference to other utilities in western Canada. Raising the MIL for residential customers in Whitehorse to the full cost of an underground service is, in my view, inappropriate. I consider that it would be appropriate to have a proportionally higher MIL in communities outside the Whitehorse area where the costs of providing similar services are higher.	Please refer to Tab 5 and the MIL study provided as Appendix to Tab 5 of Application. MIL levels are proposed to remain equal throughout Yukon.

No.	Intervenor	Submission Date	Issue	Response
39	Leading Edge (John Maissan)	14-Jan-10	(16) Opportunistic approach to long-term infrastructure development: With regard to the MIL for industrial customers the utilities in slide 42 say in part: ***"Where "common" facilities are constructed to interconnect customer, need to look at opportunity to put in place cost-effective long-term infrastructure (e.g., Carmacks-Stewart Transmission) rather than what just needed to connect customer"***. I fully supports this approach...In the case of the Carmacks-Stewart Transmission Project the $17 million in government and YDC subsidies has helped to frustrate the utilities' ability to send appropriate economy and efficiency rate signals and thus the government's own OIC 1995-90. The same situation is developing with the Mayo B and Aishihik third turbine project.	The noted items are issues that can properly be addressed in the Mayo B Part III application, not the joint YEC/YECL 2009 Phase II GRA.
40	City of Whitehorse	15-Jan-10	Optimal Mix of Generation: No specific discussions have taken place regarding what the most appropriate or "optimal" level of diesel generation in the Yukon should be and how the Utilities should attain that level.	Near term and long term system planning issues were addressed in the Yukon Energy 2006 20-Year Resource Plan. The current Application is intended to provide a 2009 COS and address rate issues for 2009.

No.	Intervenor	Submission Date	Issue	Response
41	City of Whitehorse	15-Jan-10	Optimal Mix of Generation: The Utilities should develop policies to target this optimal hydro/diesel generation mix on an ongoing basis.	See item 40.
42	City of Whitehorse	15-Jan-10	Optimal Mix of Generation: This exercise should also include a determination of the optimal level of alternative generation green technology including additional hydro facilities where appropriate.	See item 40
43	City of Whitehorse	15-Jan-10	Optimal Mix of Generation: The Utilities should provide a study into the appropriateness and feasibility of the development of optional "green rates" to support the growth of environmentally responsible generation and consumption.	The Companies have not considered "green" rates or programs in this Application. With respect to "environmentally responsible generation" can best be addressed in the Mayo B Part III application, not the joint YEC/YECL 2009 Phase II GRA.
44	City of Whitehorse	15-Jan-10	Optimal Mix of Generation: new diesel generating units should not be located in proximity to the Whitehorse area.	See item 40
45	City of Whitehorse	15-Jan-10	"Price Signal" Proposal for Residential Non-government Rate Class: The Utilities propose to increase the residential non-government second block rate because it would send the "right price signal referenced in OIC 1995/90. No studies have been done to analyze whether or not the proposal is fair to customers, what effect it will have on customers demand in the short-term or long-term, or whether it	Please refer to Tab 4 of the Application. Electricity is generally inelastic over the short term, so no material adverse effects on revenue are anticipated.

No.	Intervenor	Submission Date	Issue	Response
			will influence the collection of revenue requirement. A full study and understanding of the proposal's effect on customer consumption in the residential non-government rate class is a prerequisite for the City's acceptance.	
46	City of Whitehorse	15-Jan-10	Demand Side Management: the Utilities should facilitate and encourage the retrofitting of appliances and lighting and upgrading of the insulation of electric heating customers in the residential non-government rate class, with similar programs tailored to the general service customer. The goal should be to incent efficiency amongst all rate payers in an effort to reduce the amount of diesel generation necessary for the system.	See item 6
47	City of Whitehorse	15-Jan-10	The Utilities have brought forward no strategies to reduce the consumption of any other rate class and rate blocks, whether short-term or long-term. The City expects the Utilities will propose short-term and long-term strategies for all rate classes to reduce consumption and peak demand.	Please refer to Tab 4 of Application with respect to price signals. Also see item 6.

No.	Intervenor	Submission Date	Issue	Response
48	City of Whitehorse	15-Jan-10	Cost of Service Study: A cost service study could undertaken without the constraint of the OIC's to reflect customers' true cost of service. The City is supportive of the idea.	The 2009 consolidated COS study is provided in Tab 3, Appendix 3.1.
49	City of Whitehorse	15-Jan-10	Cost of Service Study: YEC stated that the cost of service study may allocate proportionately more transmission costs to "energy" than to "demand" as compared to other jurisdictions. The City generally does not oppose.	Please see discussion in Tab 3 of Application, section 3.2.
50	City of Whitehorse	15-Jan-10	Cost of Service Study: As part of any cost of service study, the Utilities need to provide a full explanation and rationale for any Mayo B related costs allocated to customers located in the City.	Please see discussion in Tab 3 of Application, section 3.2.
51	City of Whitehorse	15-Jan-10	Cost of Service Study: The City awaits the Utilities' new Cost of Service Study incorporating new industrial customers.	Please Tab 3 and COS study provided as Appendix 3.1 which provides the consolidated COS study for 2009. There is only one industrial customer in the 2009 test year.
52	City of Whitehorse	15-Jan-10	Rate Design: "Reasonableness zone" as set by the YUB is 90% to 110%. The City believes that in the long-term the revenue to cost ratios for all rate classes should lie within this reasonableness zone.	Please refer to Tab 3. A summary of COS results is provided in section 3.3.
53	City of Whitehorse	15-Jan-10	Rate Design: The City supports eliminating as many rate riders as possible.	Please refer to Tab 4 (section 4.2). The rate design approach followed in the Application includes terminating current general purpose Rate Riders (Riders J and R) and adjust retail base rates to fully reflect approved 2009 costs.

No.	Intervenor	Submission Date	Issue	Response
54	City of Whitehorse	15-Jan-10	Rate Design: The City believes that the rate for secondary power should be capped at a percentage of the base General Service power rate rather than based on the cost of diesel fuel. Given that secondary power is not derived from diesel, but rather surplus hydro generation.	See Tab 4, section 4.5.1 no changes to the secondary sales rates are proposed at this time.
55	City of Whitehorse	15-Jan-10	Rate Design: The City recommends a rate design for street lighting that encourages energy efficient street lighting.	Please see Tab 4. Rate Schedules for Street Lighting (61, 66, 67) and Sentinel Lighting (75, 76) to adjust base rates. No other changes are proposed at this time. The rates for streetlight vary by lamp type.
56	City of Whitehorse	15-Jan-10	Rate Design: The City notes that electric utilities in BC and Alberta offer investment (by customers) and non-investment rates for streetlights and sentinel lights should be made available to customers in the Yukon.	The Companies were not able to consider this option in this Application.
57	City of Whitehorse	15-Jan-10	Seasonal Rates: The City is concerned that the potential implementation of a multiple block rate creates little or no incentive for customers to reduce consumption, given that the effect on consumer demand is unknown and has not been studied. The City's position is that an understanding of the effect on consumption by any proposed rate structure change is a prerequisite.	Please refer to Tab 4 (section 4.2). Within the context of a single test year, no material effects on consumption (within the context of the overall revenue requirement) are expected.

No.	Intervenor	Submission Date	Issue	Response
58	City of Whitehorse	15-Jan-10	Terms and Conditions of Service: The Utilities are proposing an increase to the residential MIL to cover a bigger proportion of this cost the City does not oppose the Utilities' proposal in this matter providing that the evidence supports these current costs the City believes that the level of MIL for street lighting may require reassessment as well.	Please see Tab 5. The MIL Study addresses MILs for Residential, General Service and Street Lighting.
59	City of Whitehorse	15-Jan-10	Terms and Conditions of Service: A "Customer Bill of Rights" has been proposed by the UCG the City does not oppose such an undertaking.	Please refer to the proposed ESRs provided in Tab 5. The ESRs, or terms and conditions, set out the rights and responsibilities of customer and utility with regard to the provision of service. Discussions with concerned stakeholders on this issue are being undertaken but have not been completed at time of filing.
60	City of Whitehorse	15-Jan-10	Terms and Conditions of Service: The City encourages the Utilities to rewrite the Terms and Conditions in plain English format the City believes that the matters covered by an approved "Bill of Rights" should be incorporated in the Terms and Conditions.	Please refer to the proposed ESR's provided in Tab 5. The ESRs, or terms and conditions, set out the rights and responsibilities of customer and utility with regard to the provision of service. Discussions with concerned stakeholders on this issue are being undertaken but have not been completed at time of filing.
61	City of Whitehorse	15-Jan-10	Utility Consultation Meetings with Customers: The City welcomes any opportunity to participate in further consultations.	Further opportunities to review stakeholder issues may be available during the YUB Phase II review process.

No.	Intervenor	Submission Date	Issue	Response
62	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(1) Although some UCG issues of concern were brought forward at the first workshop, others were not given the due time.	Further opportunities to review stakeholder issues may be available during the YUB Phase II review process.
63	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(2) One such issue was that of having an independent consultant to incorporate an agreed to methodology and run the COS study.	An electronic copy of the Companies COS is provided with the Application. Intervenors as part of the review process may have independent experts test the Companies' COS study and results and may advance their own evidence or arguments as part of the hearing process.
64	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(3i + 3ii + 4) It is our understanding that the starting point would be the last Board approved COS study. The option of an agreed upon impartial methodology would be the UCG preferred first step. We therefore suggest another workshop studying and setting up a COS methodology. From there, we can debate how to deal with proposed changes, plant additions since last COS, as well as future plant additions should be open to the new order. After a well thought out cost of service is completed in this forum, then the government philosophy can be applied.	The methodology used by the Utility Companies is as recommended in the NARUC Manual and represent industry standard methodologies that are fair to all rate classes. The embedded cost of service methodology uses the accounting records to provide plant information and the information is then functionalized into the correct asset category of Production (Wind, Hydro, Other Hydro, Diesel), Transmission (Transmission line, Transmission line other), Distribution Plant and General Plant. The methodology in the NARUC Manual is then followed to allocate costs. Plant additions have already been approved in the Phase I filing. Further opportunities to review stakeholder issues may be available during the YUB Phase II review process.
65	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(5) It is important to note that the other interested parties present at the first workshop do not represent any particular rate group; simply private interest. It is to their competitive advantage to have a set	Workshop on December 15 was to obtain input into COS and rate design from interested stakeholders. OIC 2008/149 prevents inter-class rebalancing at this time thus each unit cost of electricity is set for each rate class. Please note

No.	Intervenor	Submission Date	Issue	Response
			higher unit cost of electricity, especially for residential consumers as they are the bread and butter of the industry.	the residential rate class revenue to cost ratio is below 100%.
66	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(6) UCG would yet again strongly recommend, is that a Green Energy Rate be implemented, so that individuals with this perspective can volunteer to pay top dollar for their electricity into a Fund for subsidizing renewable power.	The Companies have not considered "green" rates or programs in this Application. Further study is required with respect to the feasibility and benefits of other rate structures and programs.
67	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(9) It was mentioned somewhere in the first workshop that it should not be up to the utilities to invest in social programs for those in need. Then why do other jurisdictions have just such programs, provided by the utilities and sanctioned by their regulator?	The Companies and the YUB act within the government rate policy direction provided.
68	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(11) UCG cannot support the initiation of further energy rate blocks, at this time, without the implementation of the necessary solutions to these two issues above. As such, we submit the run-off rates are sufficient to send the message these individuals propose.	Please refer to Tab 4 (rate design approach and principles are discussed in section 4.2).

No.	Intervenor	Submission Date	Issue	Response
69	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(12) We suggest that the second portion of this requested workshop be given to load data: • Provide for discussion yearly load factors for each year since last COS; • Explain how the proposed load data was collected/determined; and • Explain which specific load data proposed to be used in cost allocation study.	The load data was derived from the YEC and YECL sales forecast data that was approved in the Phase I filings. The load factor profiles are derived from ATCO Electric's load profile to develop the CP and NCP. A significant amount of time and resources would be required to collect and analyze any Yukon specific data.
70	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(13) The following studies were recommended by the Board in the 1992 capital hearing: • Study for determining appropriate method of classifying generation operation and maintenance expenses.	These studies were recommended after the 1992 COS and Rate Design review. They were responded either during the Capital Hearing that followed in 1992 or in response to recommendations provided in the 1993/94 GRA. Appendix 3.4 of Tab 3 of the Application notes as follows: The Board in its 1992 report recommended the utilities perform a study to determine a more appropriate method of classifying generation O&M expenses. In response to recommendations (provided in the 1993/94 GRA), it was noted by the Companies that for the "average" plant factor, the ratio of the maximum demand to average demand of generating units is a commonly used guide to the allocation of operation and maintenance expenses between demand and energy. Plant factors are averaged over a number of years to smooth out period variations associated with load changes and expansion of generation capacity. The seven year rolling average of generating units in

No.	Intervenor	Submission Date	Issue	Response
				the Hydro, large diesel and small diesel zones...suggest that an allocation very close to 50% is appropriate. A similar result was obtained for YECL's sister company in the NWT".
71	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(13) • Study for the purpose of identifying long-run marginal costs to be including run-out rates; • Study for possibilities of using interruptible rates, time-of-use rates and special electrical heating rate for purpose of increasing economy and efficiency; and • Study to determine the optimum size of the first energy block and usefulness of multiple energy blocks.	These studies were recommended after the 1992 COS and Rate Design review. They were responded either during the Capital Hearing that followed in 1992 or in response to recommendations provided in the 1993/94 GRA. - The companies provided their response re: runout rates at page 5.2-18 of the 1993/94 GRA. The method of setting the runout rate (based on accepted past practice) is set out in Tab 4, section 4.3. The Companies do not propose to deviate from this tested and accepted precedent for determining incremental costs at this time. - The Companies provided their response re: interruptible and TOU rates at page 5.2-18 and 19 of the 1993/94 GRA. Interruptible rates are currently provided per under Rate Schedule 32 (Secondary Sales). - The Companies provided their response re: optimum size of the first energy block and usefulness of multiple blocks at page 5.2-19 and 20 of the 1993/94 GRA. Please see discussion in Tab 4; the approach to rate design and proposals provided for 2009 provide for multiple rate blocks and have considered alternate rate block sizes.
72	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(15) UCG submits that the consensus at the first workshop was to disregard PPAs or government OICs for determining COS allocation i.e. need to know real and fair costs of all customer groups using	See Tab 3. The PPAs and OICs affect rate design, not cost of service.

No.	Intervenor	Submission Date	Issue	Response
			approved cost allocation model. We suggest this proceed.	
73	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(16) This fundamental cost analysis should be made available for review by all parties and be part and parcel of the application process to the Board. This program can then go forward with the modifications incorporating the government directions.	See Tab 3.
74	Utility Consumers Group (UCG) (Roger Rondeau)	29-Dec-09	(17) UCG plans on meeting with Yukon Electrical staff and sets out a draft Consumer Bill of Rights to be included in the ESR.	Discussions with concerned stakeholders on this issue are being undertaken but have not been completed at time of filing.
75	Yukon Conservation Society (Sally Wright and JP Pinard) (YCS)	15-Jan-10	We feel that it is important to implement proper price signals to maximize the use of renewable energy and to discourage the use of fossil fuel. We recognize that the highest monetary and environmental cost of producing electricity occurs in the coldest winter period when diesel is burned to meet the peak loads. To avoid using diesel we would like to see a seasonally adjusted rate that is increased during the period of sparse hydropower availability and decreased during the period of excess hydro.	The rate designs in Tab 4 are based on establishing "proper price signals". With respect to seasonal rates, see item 5.

No.	Intervenor	Submission Date	Issue	Response
76	Yukon Conservation Society (Sally Wright and JP Pinard) (YCS)	15-Jan-10	YCS believes the most effective way to avoid using diesel in the winter is to send a strong price signal to the mining industry. We would like the mining industry winter rate to be high enough that the mine would consider reducing or shifting their operations away from the winter period when hydro is sparse.	Rates to industrial customers are set in Rate Schedule 39. This rate schedule provides the opportunity for establishing diesel-linked price signals for incremental use once diesel is on the margin on the WAF system, and also for customer peak load shedding during cold periods, where relevant.

TAB 8
ORDERS IN COUNCIL

YUKON

CANADA

Whitehorse, Yukon

ORDER-IN-COUNCIL 2008/149

PUBLIC UTILITIES ACT

Pursuant to section 17 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed Directive to amend the *Rate Policy Directive (1995)* is hereby made.

Dated at Whitehorse, Yukon, this October 3 2008.

YUKON

CANADA

Whitehorse, Yukon

DÉCRET 2008/ 149

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

Le commissaire en conseil exécutif, conformément à l'article 17 de la *Loi sur les entreprises de service public*, décrète :

1 Sont établies *les Instructions modifiant les Instructions sur la politique tarifaire (1995)* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 3 octobre 2008.

Administrator of Yukon/Administrateur du Yukon

Directive amending the Rate Policy Directive (1995).doc

PUBLIC UTILITIES ACT

DIRECTIVE TO AMEND THE RATE POLICY DIRECTIVE (1995)

1 This Directive amends the *Rate Policy Directive (1995)*.

2 The following section is added immediately after section 2 of the said Directive.

"Retail rate adjustments

2.1(1) The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

(2) This section expires on December 31, 2012."

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

INSTRUCTIONS MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 Les présentes instructions modifient les *Instructions sur la politique tarifaire (1995)*.

2 L'article suivant est ajouté après l'article 2 des mêmes instructions.

« Ajustements des tarifs de détail

2.1(1) La Commission s'assure que les ajustements tarifaires pour les clients au détail s'appliquent uniformément en termes de pourcentage à toutes les catégories de clients au détail.

(2) Le présent article vient à échéance le 31 décembre 2012. »

YUKON

CANADA

Whitehorse, Yukon

ORDER-IN-COUNCIL 2007/94

PUBLIC UTILITIES ACT

Pursuant to section 17 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed *Major Industrial Customer Rate Directive* is hereby made.

Dated at Whitehorse, Yukon,
this 04 June 2007.

YUKON

CANADA

Whitehorse, Yukon

DÉCRET 2007/94

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

Le commissaire en conseil exécutif, conformément à l'article 17 de la *Loi sur les entreprises de services publics*, décrète :

1 Les *Instructions sur les clients industriels majeurs* paraissant en annexe sont établies

Fait à Whitehorse, au Yukon,
le 4 juin 2007.

Commissioner of Yukon/Commissaire du Yukon

PUBLIC UTILITIES ACT

MAJOR INDUSTRIAL CUSTOMER DIRECTIVE

1 This order amends the Rate Policy Directive (1995).

2 The following subsection is added immediately after subsection 6(2) of the said Directive.

“(3) Despite subsection (1), the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary, attached hereto as Schedule A.**”**

3 This Order expires on January 1, 2013.

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

RÈGLEMENT SUR LES INSTRUCTIONS SUR LES CLIENTS INDUSTRIELS MAJEURS

1 Le présent décret modifie les Instructions sur la politique tarifaire (1995).

2 L’article 6 est modifié par adjonction, après le paragraphe (2), de ce qui suit :

« (3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs du 1er janvier 2008 au 31 décembre 2012 respectent l’annexe tarifaire no 39, Clients industriels, paraissant à l’annexe A. **»**

3 Le présent décret expire le 1er janvier 2013.

SCHEDULE A

INDUSTRIAL PRIMARY

RATE SCHEDULE 39

Available

Throughout the service areas of Yukon Energy Corporation (**"YEC"**) and The Yukon Electrical Company Limited ("**YECL**") served by the Whitehorse-Aishihik-Faro and Mayo-Dawson systems.

Applicable

To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

Rate

Charges in any one billing month shall be the sum of the following:

(a) Demand Charge of $15.00/kV.A of Billing Demand

(b) Energy Charge of 7.60¢/kW.h for all energy used.

(c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments then required under the amended Power Purchase Agreement (the **"PPA"**) dated May 14, 2007, between YEC and Minto Explorations Ltd. (**"Minto"**) for monthly Capital Cost Contributions for transmission connection to the mine.

Peak shaving credit

For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month equal to 50% of the Demand Charge times the Peak Shaved Load.

Minimum Monthly Bill

The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

Peak Shaved Load

Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

Billing Demand

The Billing Demand shall be the greater of:

(a) the highest metered kV.A demand recorded in the current billing month; or

(b) the highest metered kV.A demand recorded in the previous 12-month period including the current billing month, excluding the months April through September; or

(c) the contract minimum demand.

Winter Contract Load

A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

(a) the customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);

(b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kV.A demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;

(c) the customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by written notice of not less than 12 months by the customer to YEC;

(d) if during such contract period for the Winter Contract Load the customer's metered kV.A demand recorded, after YEC has provided notice as specified in paragraph (b), exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kV.A demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than -30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

Base Load Energy

A Base Load Energy amount per month may be established for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

Rate Modifications Applicable:

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to $0.0 for fuel price forecast filed November 20, 2006.

***Electric Service Regulations*:**

The *Electric Service Regulations* approved by the Yukon Utilities Board form part of this rate schedule and apply to YEC and every customer supplied with electric service by YEC in the Yukon Territory. Copies of the *Electric Service Regulations* are available for inspection in the offices of YEC during normal working hours.

Escalation of demand and energy charges

Demand and Energy charges for the directed changes are to be escalated once each calendar year, starting January 1, 2010, based on the latest percentage increase in the 12 month implicit chain price index for gross domestic product at market prices for Canada as reported by Statistics Canada.

Adjustment of fixed charge

The Fixed Charge is to be adjusted to provide for fixed monthly charges as set out in any Power Purchase Agreement, or amendments thereto, between a Major Industrial Customer and either Yukon Energy Corporation or the Yukon Electrical Company Limited, as approved by the Board.

ANNEXE A

CLIENTS INDUSTRIELS

ANNEXE TARIFAIRE N° 39

Offert

Dans l'ensemble des régions desservies par la Société d'énergie du Yukon (« **SEY** ») et la Yukon Electrical Company Limited («**YECL** »), desservie par les systèmes de Whitehorse-Aishihik-Faro et Mayo-Dawson.

Applicable

À tous les clients industriels majeurs dont les activités sont la fabrication, le traitement ou l'exploitation d'une mine dont l'approvisionnement en électricité excède 1000 kW.

Tarif

Les tarifs facturés pour un mois de facturation sont la somme de ce qui suit :

a) une prime de puissance de 15.00 $/kVA de la demande facturée;

b) le coût de l'énergie établi à 7,60¢/kWh pour toute l'énergie consommée;

c) des frais fixes

Pour l'approvisionnement du site de la mine Minto, les frais fixes sont égaux aux paiements exigés en vertu de la convention d'achat intitulée *Power Purchase Agreement* (la « **PPA** »), avec ses modifications, datée du 14 mai 2007, conclue entre YEC et Minto Explorations Ltd. («**Minto** ») pour la contribution mensuelle des coûts d'investissement pour le branchement de l'approvisionnement de la mine.

Crédit d'écrêtement de la demande de pointe

Pour les clients dont la charge hivernale maximale est en règle, le crédit d'écrêtement de la demande de pointe de chaque mois de facturation représente 50 % de la prime de puissance multipliée par la charge réduite pour la demande de pointe.

Facture mensuelle minimale

La facture mensuelle minimale est égale au total de la prime de puissance et des frais fixes mensuels, desquels est soustrait tout crédit d'écrêtement de la demande de pointe.

Charge réduite pour la demande de pointe

La charge réduite pour la demande de pointe pour un mois de facturation, représente la différence entre la charge hivernale maximale et la demande facturée pour le mois.

Demande facturée

La demande facturée est le montant le plus élevé de :

a) la demande la plus élevée en kVA enregistrée au cours du mois de facturation courant;

b) la demande la plus élevée en kVA enregistrée au cours des 12 derniers mois, y compris le mois de facturation courant, mais à l'exclusion des mois d'avril à septembre;

(c) la demande minimale fixée par contrat.

Charge hivernale maximale

Un client peut, en donnant un préavis de six mois à la SEY, adopter une charge hivernale maximale qui représente au moins deux tiers de la demande maximale du client fixée par contrat, sous réserve des conditions suivantes :

a) le client s'engage envers la SEY à ne pas excéder la charge hivernale maximale adoptée lorsque la température à Whitehorse est inférieure à -30 degrés Celsius d'après les renseignements fournis au client par la SEY par téléphone, télécopieur ou courriel relativement aux prévisions météorologiques et la température hivernale véritable à Whitehorse, en conformité avec l'alinéa b);

b) YEC s'engage à informer le client au moins une heure à l'avance et au plus une journée à l'avance, si les prévisions météorologiques pour Whitehorse sont inférieures à -30 degrés Celcius. Dès lors et jusqu'à ce que la SEY l'avise du contraire, il incombe au client de veiller à ce que les kVA mesurés au compteur n'excèdent pas la charge hivernale au cours d'une heure pendant laquelle la température véritable à Whitehorse est inférieure à -30 degrés Celcius. La SEY informera immédiatement le client lorsque les prévisions météorologiques pour Whitehorse ne sont plus inférieures à -30 degrés Celcius pour les prochaines 24 heures;

c) le client consent à ce que le contrat relatif à la charge hivernale maximale demeure en vigueur jusqu'à ce qu'il soit annulé par le client avec un préavis écrit d'au mois 12 mois à la SEY;

d) si au cours de la période fixée par contrat pour la charge hivernale maximale, la demande en kVA mesurée au compteur du client excède la charge hivernale maximale, alors qu'un avis a été donné par la SEY en conformité avec l'alinéa b) et que la température à Whitehorse est inférieure à -30 degrés Celcius, le contrat relatif à la charge hivernale maximale est immédiatement résilié. Le client est dès lors tenu de rembourser immédiatement à la SEY tous les crédits d'écrêtement de la demande de pointe accordés au cours des 12 derniers mois de facturation, ainsi que qu'une pénalité pour le mois courant qui représente quatre fois la prime de puissance sur la demande du client en kVA mesurée au compteur qui excède la charge hivernale maximale. De plus, la SEY se réserve le droit, si cela est nécessaire pour satisfaire aux besoins du système lorsque la température à Whitehorse est inférieure à -30 degrés Celcius au cours du mois alors en cours et les 12 mois suivants, d'interrompre l'alimentation en électricité du client qui excède la charge hivernale maximale.

Charge de base de l'énergie

Un montant de charge de base de l'énergie par mois peut être fixé pour le client qui consomme 90 % de la consommation anticipée lorsque la SEY prévoit devoir faire appel à la production d'énergie au carburant diesel pour alimenter l'usage qui excède ce montant de charge de base de l'énergie. L'annexe tarifaire n° 39 est alors soumise à la Régie des entreprises de service public du Yukon pour être modifiée afin d'ajuster le tarif de l'énergie de façon à établir un tarif à deux paliers qui permet la même charge d'énergie pour la consommation d'énergie anticipée, avec un taux qui tient compte du coût additionnel pour la production d'énergie au carburant diesel applicable à toute l'énergie consommée en plus de la charge de base. Le tarif réduit nécessaire pour permettre la même charge d'énergie pour la consommation anticipée est applicable à l'énergie restante.

Modifications des tarifs applicables :

Pour la clause additionnelle relative au coût du carburant, consulter la clause additionnelle F. La clause additionnelle F s'applique exclusivement aux coûts de l'énergie, fixés à 0,0$ pour la prévision des prix de l'essence déposée le 20 novembre 2006.

***Electric Service Regulations* :**

Les *Electric Service Regulations*, approuvés par la Régie des entreprises de service public du Yukon font partie intégrante de la présente annexe relative aux tarifs et s'appliquent à la SEY et à tous les clients qui reçoivent des services d'approvisionnement en électricité de la SEY au Yukon. Il est possible de consulter les *Electric Service Regulations* aux bureaux de la SEY pendant les heures normales d'ouverture.

Augmentation de la prime de puissance et du coût de l'énergie

La prime de puissance et le coût de l'énergie pour les modifications exigées font l'objet d'une augmentation par année civile à compter du 1er janvier 2010 et reposent sur la plus récente augmentation de l'indice de prix en chaîne pour les 12 mois inclusivement, pour le produit intérieur brut aux prix du marché pour le Canada, établi par Statistique Canada.

Ajustement des frais fixes

Les frais fixes sont ajustés pour tenir compte des coûts mensuels fixes établis dans toute convention d'achat d'énergie, ou dans les modifications à celle-ci, conclue entre un client industriel majeur d'une part et la SEY ou la YECL, d'autre part et qui a été approuvée par la Régie.

O.I.C. 1995/090
PUBLIC UTILITIES ACT

PUBLIC UTILITIES ACT

Pursuant to sections 17 and 18 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows:

1. Order-in-Council 1991/062 is hereby revoked.

2. The annexed Rate Policy Directive (1995) is hereby made.

Dated at Whitehorse, in the Yukon Territory, this 29th day of May, 1995.

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Commissioner of the Yukon

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

Le Commissaire en conseil exécutif, conformément aux articles 17 et 18 de la *Loi sur les entreprises de service public*, décrète ce qui suit :

1. Le décret 1991/062 est, par les présentes, abrogé.

2. Les instructions sur la politique tarifaire (1995), paraissant en annexe, sont par les présentes adoptées.

Fait à Whitehorse, dans le territoire du Yukon, ce 29 mai 1995.

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Commissaire du Yukon

O.I.C. 1995/090
PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE (1995)

Interpretation

1. In this Directive

"customer" refers to a purchaser of electricity; *«client»*

"government customer" means a retail customer

(a) who is a federal or territorial department or agency;

(b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a); *«client gouvernemental»*

"isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer; *«client industriel isolé»*

"major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer; *«client industriel majeur»*

"province" has the same meaning as in the *Interpretation Act*; *«province»*

"retail customer" means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer, an isolated industrial customer, or a wholesale customer; *«client au détail»*

"wholesale customer" means the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation. *«client en gros»*

Normal return on equity

2.(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

Définitions

1. Les définitions qui suivent s'appliquent aux présentes instructions :

«client» Acheteur d'électricité; *"client"*

«client au détail» Client de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited qui n'est ni un client industriel majeur, ni un client industriel isolé, ni un client en gros; *"retail Customer"*

«client en gros» La Yukon Electrical Company Limited lorsqu'elle achète de l'énergie de la Société d'énergie du Yukon; *"wholesale customer"*

«client gouvernemental» Client au détail qui est:

a) soit un organisme gouvernemental, un ministère fédéral ou territorial;

b) soit un organisme qui n'exploite aucune entreprise à des fins lucratives et dont le financement provient en totalité, ou pour l'essentiel, d'un organisme décrit à l'alinéa a); *"government customer"*

«client industriel isolé» Client qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont l'approvisionnement en électricité est indépendant de celui de tout autre client; *"isolated industrial customer"*

«client industriel majeur» Client autre qu'un client industriel isolé qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont la demande de pointe d'électricité dépasse 1 MW. *"major industrial customer"*

«province» S'entend d'une province au sens de la *Loi d'interprétation*. *"province"*

Rendement normal sur la valeur nette

2.(1) Sous réserve du paragraphe 2, la Commission doit prévoir dans les tarifs de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited les mesures pour réaliser un rendement équitable sur leur valeur nette utilisé pour financer leurs tarifs de base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

(3) When finalizing the interim 1997 rates made by Board Order 1997-6, the Board may adjust the 1997 fair return provided on Yukon Energy Corporation's equity and on Yukon Electrical Company Limited's equity."

(Section 2 replaced by O.I.C. 1998/32)

Normal principles to apply

3. Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.

Retail rates: non-government customers

4.(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

(a) the rates for non-government retail customers must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;

(b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

(3) The Board must fix runoff rates for each non-

(2) La Commission doit inclure dans les tarifs de la Société d'énergie du Yukon des mesures pour réaliser un rendement équitable sur la valeur nette de cette dernière, moins 5 dixièmes pour cent (,5 %).

(3) Lorsqu'elle met au point les tarifs intérimaires de 1997 établis par l'ordonnance 1997-6 de la Commission, cette dernière peut rajuster le rendement équitable de 1997 découlant de la valeur nette de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited.

(Article 2 remplacé par décret 1998/32)

Application des principes normaux

3. Sauf indication contraire dans les présentes instructions ou dans la Loi, la Commission examine et approuve les tarifs aux clients selon les principes établis au Canada pour des services publics, y compris les principes établis par les organismes régulateurs des gouvernements fédéral et provinciaux réglementant les entreprises de services publics, que ces derniers soient reliés à l'électricité ou pas.

Tarifs au détail pour les clients non-gouvernementaux

4.(1) La Commission fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire suivante pour le Yukon :

a) les tarifs pour les clients non-gouvernementaux doivent suffire à générer les recettes nécessaires afin de recouvrer les coûts, lesquels ne doivent pas être récupérés des clients gouvernementaux ou des clients industriels majeurs;

b) les tarifs pour chaque catégorie de clients au détail non-gouvernementaux s'appliquent uniformément à la grandeur du Yukon et sans distinction entre la Société d'énergie du Yukon et la Yukon Electrical Company Limited.

(2) La Commission doit déterminer une série de primes de dépassement pour chaque catégorie visée de clients au détail non-gouvernementaux, lesquelles s'appliquent à la consommation de chaque client qui excède un niveau de consommation déterminée, au cours d'une période de facturation et un tel niveau de consommation déterminé par client ne peut s'appliquer qu'à la consommation atteignant 1 000 kWh ou plus pour la catégorie résidentielle de clients au détail non-gouvernementaux et de 2 000 kWh pour la catégorie de services généraux de clients au détail non-gouvernementaux.

(3) La Commission doit déterminer des primes de

government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non-government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

dépassement pour chaque catégorie de clients au détail non-gouvernementaux sur la base de principes pour l'élaboration des taux afin de favoriser l'efficacité et l'économie et, dans cette optique, des primes de dépassement peuvent être permises à l'intention de clients demeurant dans différentes communautés ou dans des zones où les taux diffèrent, en autant que ces primes de dépassement dans chaque catégorie de clients au détail non-gouvernementaux soient les mêmes pour chaque communauté ou chaque zone tarifaire à travers le Yukon, conformément aux principes pour l'élaboration des tarifs.

Retail rates: government customers

5.(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

(a) rates for government customers may be adjusted so as to simplify the rate structure and make the rates more consistent throughout Yukon;

(b) the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

Tarifs au détail pour les clients gouvernementaux

5.(1) La Commission fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit :

a) les tarifs pour les clients gouvernementaux peuvent être ajustés aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;

b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited, ou d'un client, la Commission prend une décision sur le statut de client gouvernemental d'un client.

Rates - major and isolated industrial customers

6.(1) The Board must ensure that the rates charged to major industrial power customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

(2) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

Tarifs pour les clients industriels majeurs et isolés

6.(1) La Commission doit s'assurer que les tarifs facturés aux clients industriels majeurs, en vertu d'un contrat ou autrement, suffisent à recouvrer les coûts du service pour cette catégorie de clients. Ces coûts sont déterminés en considérant tout le Yukon comme une zone tarifaire unique et les tarifs facturés par les deux services publics doivent être les mêmes.

(2) Les tarifs s'appliquant aux clients industriels et isolés desservis par la Société d'énergie du Yukon ou la Yukon Electrical Company Limited doivent être conformes à tout contrat entre le client et ces sociétés; les coûts et les revenus reliés à ces contrats ne peuvent être considérés par la Commission lorsqu'elle établit les tarifs pour d'autres clients.

Wholesale rates

7. The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

Fuel Price adjustment

8. The Board must permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates to retail customers, major industrial customers, and isolated industrial customers so as to reflect fluctuations in the prices for which the two utilities pay for diesel fuel, without the requirement for specific application to and approval of the Board.

Tarifs de gros

7. La Commission doit déterminer les tarifs facturés par la Société d'énergie du Yukon au client en gros selon la politique tarifaire du Yukon qui suit :

a) la Société d'énergie du Yukon vend de l'électricité à la Yukon Electrical Company Limited au même tarif de demande et au même tarif d'énergie à la grandeur du Yukon et ces tarifs doivent suffire à la Société d'énergie du Yukon pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

b) le tarif de gros facturé à la Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Société d'énergie du Yukon de recouvrer ses coûts de service au détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s'appliquent à ces services en vertu des présentes.

Ajustement du prix du combustible

8. La Commission permet à la Société d'énergie du Yukon et à la Yukon Electrical Company Limited d'ajuster les tarifs facturés aux clients au détail, aux clients industriels majeurs et aux clients industriels isolés de manière à refléter les fluctuations des prix payés pour le mazout par ces deux sociétés, sans avoir à faire une demande particulière à la Commission pour obtenir son autorisation.