BOARD ORDER 2010-13

APPENDIX A: REASONS FOR DECISION

IN THE MATTER OF THE *PUBLIC UTILITIES ACT*

REVISED STATUTES OF YUKON, 2002, C.186, AS AMENDED

AND

AN APPLICATION BY YUKON ENERGY CORPORATION AND

YUKON ELECTRICAL COMPANY LIMITED FOR

APPROVAL OF THEIR 2009 PHASE II RATE APPLICATION

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1 INTRODUCTION

1. On February 19, 2010, Yukon Electrical Company Limited (YECL) and Yukon Energy Corporation (YEC) (jointly "the Companies") filed with the Yukon Utilities Board (YUB or Board), pursuant to the *Public Utilities Act* (Act), and Order-In-Council (OIC) 1995/90, the 2009 Phase II Rate Application (Application). The Companies requested an Order approving adjustments to rates (on a prospective basis), to be effective September 1, 2010, and to collect an approved 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million.

2. YECL, separately, is seeking approval of a proposed Diesel Generation Energy Cost Recovery Rider (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 and had not been forecast.

3. The Application also proposes updates to the Terms and Conditions of Service (previously known as Electric Service Regulations) including a review of investment levels.

4. The Board through Board Order 2010-6 issued a process schedule and requested Parties intending to participate in the review process to register in writing with the Board Secretary no later than May 17, 2010. Board Order 2010-6 directed the Companies to arrange for publication, not later than May 7, 2010, the Notice of Application, in such appropriate local news publications in the service area of the Companies so as to provide adequate notice to the public. The Companies were ordered to make the Application and supporting materials available for inspection at the Head Offices of the Companies and the District Offices of each respective company, as well as Yukon community and public libraries.

5. The Board through Board Order 2010-7, dated May 21, 2010, revised the proceeding schedule based on a request by YEC due to witness availability, provided an issues list from the submissions of interested parties, and granted Intervenor status to the following persons:

City of Whitehorse
John Maissan (Leading Edge)
Peter Percival
Keith Lay
Utilities Consumers' Group

6. The proceeding schedule was further revised through Board Order 2010-8, dated July 13, 2010, when the Board approved the request received from the Companies on July 7, 2010, requesting an extension for information responses from July 12, 2010, to July 23, 2010. No Parties objected to the request of the Companies.

7. On October 5, 2010, the Board held an oral public hearing in the Whitehorse, Yukon. The Board was comprised of Chair Bruce McLennan, Vice-Chair Robert Laking, and members Richard Hancock and Jody Woodland.

8. During the oral public hearing the Companies requested that the date for Final Argument be changed to October 22, 2010, and the date for Reply Argument be changed to November 5, 2010. The Board approved this request [1]. The Board considers this proceeding closed on November 5, 2010.

9. In reaching the determinations contained within this Decision, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each Party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 BACKGROUND

10. The Companies filed the Application with a Tab 4YEC and Tab 4YECL. Tab 5, Terms and Conditions of Service, was subsequently filed on March 1, 2010.

11. Each company had previously separately filed a General Rate Application (GRA) in 2008, for forecast revenue requirements for 2008 and 2009. Board Orders 2009-2 and 2009-5 approved YECL's revenue requirements for the test period and Board Orders 2009-8 and 2009-10 approved YEC's revenue requirements for the 2008 and 2009 test period.

12. The Companies were directed in Board Order 2009-8 to jointly file a complete Phase II Application with the Board within 60 days of the date of the Decision on the YEC compliance filing. A Phase II Application was to provide accurate revenue to cost ratios for all rate classes, provide rate design recommendations that comply with previous Board directions and current OICs, provide updated Terms and Conditions of Service, and contain a review on investment levels. The Board expected the Application to contain stakeholder input. YEC filed its compliance filing for its 2008 and 2009 revenue requirements on October 8, 2009, and the compliance filing was approved by the Board in Board Order 2009-10 dated November 18, 2009. The Companies advised the Board through correspondence on December 10, 2009, that they would be unable to meet the January 17, 2010, filing date for the Phase II Application.

13. The Board informed the Companies, by way of letter dated January 21, 2010, that a Party who cannot meet a direction of the Board must file a request for an extension of time to comply with the direction. As the Companies had not done so, they were in non-compliance with the Board's direction. The Companies were directed to provide a detailed explanation of the reasons for the failure to file the Phase II

[1] Transcript, Volume 3A, October 7, 2010, page 531, line 20 to page 532, line 7.

Application and to propose a date, no later than 30 days from the date of the Board's letter, for the filing of the Phase II Application.

14. In correspondence dated January 29, 2010, the Companies replied that the Phase II Application would be filed by February 19, 2010.

3 DISCUSSION OF ISSUES

3.1 Consolidated Revenue Requirements

15. The Companies provided the 2009 consolidated revenue requirement in Table 2.1 2009 Consolidated Revenue Requirement[2] of the Application. The table is reproduced as follows:

Table 1. Table 2.1: 2009 Consolidated Revenue Requirements

	YEC	YECL	Total
	($000s)		
Fuel Expense	443	5,397	5,840
Purchase Power	54	23,910	0
Purchase Power - cap. Fish Lake1		- 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

16. The consolidated firm rate revenue requirement was presented in Table 2.2: Consolidated Firm Rate Revenue Requirements[3] of the Application. The table is as follows:

Table 2. Table 2.2: Consolidated Firm Rate Revenue Requirements

	($000s)
Consolidated Revenue Requirement	52,331
Less: YEC Revenue Offsets	125
Less: YECL Revenue Offsets	827
Less Secondary Retail Sales	546
Total	50,833

17. No issues were identified with the 2009 Consolidated Revenue Requirement. The Board, upon review of Table 2.1 and Table 2.2, accepts the 2009 Consolidated Revenue Requirement as the basis for the cost of service and rate design for the Companies.

[2] Application, page 2-1.
[3] Application, page 2-2.

3.2 Approved Sales Forecasts

The Phase II Application includes a consolidated sales forecast of 338,175 MW.h for firm sales. The following table shows the breakdown of the sales forecast into customer classes:

Table 3. Table 2.3: YEC/YECL 2009 Consolidated Customer, Demand and Energy Forecast[4]

Customer Class	# of Customers	Demand (kW)	Energy (kW.h)
Res-Non Gov't	14,128		137,637,626
Res-Gov't	252		2,160,438
Gen Serv-Non Gov't	2,539	484,399	113,497,895
Gen Serv-Gov't	547	165,716	51,410,733
Industrial	1	62,400	29,023,000
Street Lights (61/66)	5,392	9,264,080 (W)	3,712,124
Street Lights (67)	64	222,600 (W)	87,660
Sentinel Lights (75/76)	977	1,666,600 (W)	645,700
Sub-total	23,900		338,175,176
Secondary Sales	23		7,584,000
Total	23,923		345,759,176

18. Other than issues raised with respect to the Energy Demand and Loss Analysis (EDLA) study as discussed in the Cost of Service Section of this Decision, no Parties objected to the aggregated totals of the consolidated sales forecast for 2009. The Board approves the aggregate 2009 consolidated sales forecast for the Companies.

3.3 Cost of Service (COS)

19. In Tab 3 of the Application, the Companies provided a single COS study[5] with updated revenue/cost (R/C) ratios for all rate classes receiving firm service. The Companies submitted that the methodology for the 2009 COS study largely reflects past principles and methods adopted by the Companies and approved by the Board.

20. The COS study followed a standard approach typically used by other Canadian utilities, wherein embedded costs (Consolidated Revenue Requirement) are divided/allocated among the rate classes according to principles of cost causation. The approach used a three-step process:

a. Functionalization: the costs were separated according to function, i.e. Generation, Transmission or Distribution;
b. Classification of functionalized costs: the functionalized costs were separated into components of utility service in the manner they are incurred, i.e. customer costs, demand costs or energy costs; and

[4] From Rate Design models (Excel Worksheets) – YEC and YECL 2009 Phase II Application Schedule of Determinants on Proposed Rates
[5] The COS was based on the 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million for the Companies.

c. Allocation: the classified costs were allocated to the various customer rate classes.

21. Based on the above approach, the cost of service for each rate class, adhering to the requirements of OIC 1995/90, was determined on a Yukon-wide basis with no differentiation between the utilities or between communities.

22. Methodology changes proposed by the Companies related to bulk power cost classification (generation and transmission), distribution cost classification and cost allocation methodologies. The proposals are reviewed in the following sections.

23. There were two issues on which the Companies were not in agreement. The issues "relate[d] to the allocation of distribution-related costs to the industrial class, and to the load characteristics calculated for the General Service classes (Government and Non-Government)."[6] These matters are also reviewed in the following sections.

Views of the Parties

24. Considering that the majority of the major rate classes had not seen material changes with respect to revenue to cost ratios since the last COS study, the Companies questioned whether updated COS studies are required for each future Phase II Application, or whether periodic updates would be sufficient.[7]

25. City of Whitehorse submitted that OIC 2008/149 prevented the Board from accepting a rate design proposal whereby rate classes would more adequately reflect the costs associated with servicing them until December 31, 2012. Nonetheless, City of Whitehorse submitted that:

> [It] expects another COS study will be performed by the Companies at or around the expiry of the OIC, which will allow for a more precise allocation of costs to rate classes in the cost environment of that time, and assist the utilities in creating a rate design with more reasonable revenue to cost ratios.[8]

26. Notwithstanding that OIC 2008/149 prevents rate changes, the Companies submitted that the OIC does not restrict, limit or hinder the Board's ability to review and approve an updated COS at this time, the results of which would guide the Board, the Companies and interested persons in the future.

[6] Exhibit B-9, page 3.
[7] YEC Argument, page 9. YECL Argument, page 4.
[8] City of Whitehorse Argument, paragraph 38.

27. City of Whitehorse submitted that the expiry of OIC 2008/149 should drive a new COS study, which is essential to any future rate restructuring process. Moreover, because of the constraints of the OIC, City of Whitehorse submitted that rate design issues in this proceeding were addressed independent of the COS study.

> …the Utilities and LE advanced rate designs without any reference to the cost of service study.[9]

Further, because of the separation between the COS study and the larger issue of rate design, Intervenors may not have pursued all of the issues that the joint COS study raised.

28. UCG expressed concern that the Companies were considering avoiding the filing of COS studies when rate adjustments were being considered. Accordingly, UCG submitted that no ad hoc rate adjustments should be considered:

> …a full public review of the joint revenues and costs as well as the allocation of these costs is required before any fair and reasonable rate adjustment should be considered.[10]

Views of the Board

29. The Board notes that the last COS study approved by the Board was completed in 1997. The Board does not accept the COS study as filed by the Companies. The Board agrees with the City of Whitehorse's view that an updated COS study approved by the Board is essential to establishing a future rate restructuring process. Therefore, the Board directs the Companies to file a joint COS study within six months of the expiry of OIC 2008/149. The Board further directs the Companies to incorporate all findings and directions of this Decision into the next COS study.

3.3.1 Bulk Power Classification Methods (Production and Transmission)

30. The Companies submitted that the methods used to classify bulk power costs (generation and transmission) incorporated standard approaches adopted by similar Canadian utilities and for the most part reflected the principles and methods adopted by the Companies in previous COS studies approved by the Board.

31. By and large, the methodologies which were used to classify bulk power costs reflected consideration of a number of factors such as:

a. How a given asset or class of assets is used;
b. What type of loads on the system increase the required level of investment in the particular type of asset (what is the basis for the investment); and
c. What would be the alternative system cost profile absent the assets (what are the benefits of the asset to the system).[11]

[9] City of Whitehorse Reply Argument, paragraph 28.
[10] UCG Reply Argument, paragraph 21.
[11] Application, Section 3.2.1.

32. Since 1996/97, the emphasis of utility cost changes has been focused on the increased costs of generating the energy demands on the hydro grid systems, in particular as load growth continues to drive the requirement for diesel fuel to be used for base load purposes.[12]

33. The Companies determined the appropriate 2009 generation and transmission classification factors taking into account the relationship between capacity and energy, and applying careful consideration of the relative energy benefit of each asset and ensuring there is no excessive focus on its capacity benefits.[13]

34. On this basis, the Companies proposed that the classification of all bulk power generation and transmission assets remain as classified in the 1996/97 COS except for the following adjustments reflected in the table below.

Table 4. Classification of Transmission and Production Assets

Description	Proposed Split (%)		Previous COS (%)	
	Demand	Energy	Demand	Energy
Aishihik Hydro Plant	0%	100%	40%	60%
Mayo Hydro Plant	0%	100%	40%	60%
Transmission Assets***	0%	100%	100%	0%

Source: YEC Final Argument, Page 9

***Excluding specific assignment to the Faro mine, transmission costs in previous COS were classified 100% to demand at the time of system peak, without any consideration as to assigning any share to energy (Appendix 3.4, Footnote 29)

35. In support of their submission, the Companies stated that the proposed changes reflect new developments in the Yukon since the 1996/97 GRA, while continuing to reflect standard approaches utilized by similar utilities in Canada.

3.3.1.1 Aishihik Hydro Plant

36. As noted above, the classification of the Aishihik hydro plant in the 1996/96 GRA was 60% to energy and 40% to demand. The Companies proposed to change the classification of the existing Aishihik generation plant to 100% energy, because

> Under the new capacity planning criteria recently adopted in YEC's 20-Year Resource Plan, 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.[14]

Views of the Parties

37. Notwithstanding that the Aishihik plant normally contributes to carrying loads at peak times, YEC submitted that it was not precluded from the requirement to invest in other reliable demand capacity in order to meet WAF grid winter peak loads.

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[12] Application, page 3-4.
[13] Application, page 3-4.
[14] Application, page 3-5.

Furthermore, given the capacity planning criteria, YEC submitted that it was reasonable to treat the Aishihik plant similar to other facilities such as wind or independent power producers (IPPs) that are not relied upon to provide demand under all contingencies and classify it as 100% energy.[15]

38. Leading Edge pointed out that Aishihik is completely dispatchable and furthermore it stores summer energy for dispatch in winter to meet winter peak demands and energy requirements."[16] Citing evidence that the Aishihik plant was consistently used as one of the main sources to meet winter peak demands on the WAF system, Leading Edge viewed the historical 60% energy and 40% demand allocation as the minimum appropriate demand allocation. Moreover, when the third turbine is added to the Aishihik plant, Leading Edge submitted that the demand allocation could be higher.

39. UCG submitted that there is continued justification for the current 60/40 energy/demand split in the Yukon.

40. YEC submitted that Leading Edge's classification recommendations would not be appropriate because

> …none of [the Aishihik] plant capacity can be relied upon (under the approved capacity planning criteria that drives ongoing investment in demand assets) to meet the system's winter peak demand capacity requirement [and]
> …prior to adoption of the N-1 capacity planning criteria, Yukon Energy did in fact rely on this plant's capacity to meet the system's winter peak and the 40% classification [to demand] was therefore appropriate at that time.[17]

41. Leading Edge submitted that hydro plants were built to serve both demand and energy requirements. The N-1 emergency planning criteria adopted in 2006 should not be used as a COS classification methodology for hydro plants; what one does in planning for emergencies should not drive COS classifications.

Views of the Board

42. With respect to the classification of hydro facilities as 100% energy, the Board considered the evidence that:

a) Manitoba Hydro classifies generation assets 100% to energy but use a time differentiated energy allocator based on marginal cost weighted energy, such that energy consumption during high surplus energy program price time periods attracts more costs than energy consumption during low surplus energy program price time periods;
b) British Columbia Hydro classifies its IPP purchases 100% to energy; and

[15] YEC Argument, page 14.
[16] Leading Edge Argument, pages 4 to 5.
[17] YEC, Reply Argument, page 9.

c) Ontario Power Generation and Hydro Quebec generation assets are not regulated on a traditional COS basis, but costs related to regulated or heritage generation facilities in both jurisdictions are recovered through an energy charge.[18]

43. The Board further notes that BC Hydro assets owned by BC Hydro are classified 55/45 demand/energy, which is consistent with the British Columbia Utilities Commission's decision respecting BC Hydro's 2007 rate design application. BC Hydro had applied for a 50/50 demand/energy classification submitting that

> It is not possible to develop an accurate, planning based classification of hydro plant between demand and energy. When hydro plant is built, it provides both energy and capacity and one cannot be obtained without the other.[19]

44. In respect of the Aishihik plant contributing to peak loads, the Companies' submission indicates that over "the past 5 years Aishihik has provided, on average 45% of the WAF winter peak load and would be expected to contribute at this same level for the winter peak for 2010."[20] The Board took note that the Aishihik plant was classified as 60% to energy and 40% to demand prior to the adoption of the N-1 capacity planning criteria.

45. Furthermore, the Board points to YEC's statement that it is "not aware of any utilities that changed their generation COS classification on the basis of adopting an N-1 planning criteria."[21]

46. As a result, the Board finds there is no compelling evidence that supports the classification of the Aishihik plant as 100% energy from its present classification of 60% energy and 40% demand. The Board therefore denies the Companies' proposal to change the Aishihik plant classification to 100% energy. Furthermore, the Board directs the Companies to classify the Aishihik hydro plant 60% energy and 40% demand in the next COS study.

3.3.1.2 Mayo Hydro Plant

47. Material changes in the system since the 1996/97 GRA led the Companies to propose a change to the classification of the Mayo hydro plant from 60% energy and 40% demand to a 100% energy classification. In support of their position, the Companies submitted that:

> … the construction of Mayo Dawson [MD] 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."[22]

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[18] Exhibit B-4, YUB-YEC/YECL-1-5.
[19] Ibid.
[20] CW-YEC/YECL-1-2.
[21] LE-YEC/YECL-1-4.
[22] Application, page 3-6.

Views of the Parties

48. The Companies added that the MD system loads, if required, could be supplied by diesel generation assets which were located in Mayo, Stewart Crossing and Dawson. Also, the Companies submitted that the Mayo hydro system's primary function was to offset the requirement to rely on local diesel generation in isolated communities with resident diesel units.

49. The Companies explained that the Mayo hydro plant typically supplies both products, energy and demand, but the presence of the hydro plant does not drive any cost savings in terms of diesel plant — i.e. you still need a diesel plant in Mayo and Dawson — but does drive material savings in diesel fuel in respect of not having to run these plants. Further, since the commissioning of the MD transmission line in 2003, Mayo hydro generation has provided, on average, 95% of the MD winter peak load and is expected to contribute approximately 94% of the 2010 winter peak.[23]

50. YEC submitted that the economic benefit profile of having the hydro plant versus not having this plant was "heavily dependent today on energy cost savings (kW.h) and not its capacity contribution (MW)."[24]

51. Leading Edge argued that hydro plant classification should remain 60% energy and 40% demand, submitting:

> Hydro plant assets were built to service both demand and energy requirements. One simply cannot serve one without serving the other…Simply because one alternative supply to hydro plants is diesel generation, which has a high energy cost, is no reason to classify such assets 100% to energy.[25]

Views of the Board

52. The Board considers important YEC's submission that the primary function of the Mayo hydro plant "is to provide energy that offsets the need to rely on local diesel generation with resident diesel, while these units remain available to provide capacity benefits as required."[26] From the Board's perspective, it is clear from this passage that the Mayo hydro plant is supplying both capacity and demand. Furthermore, the resident diesel generation in local communities will serve to provide the necessary capacity benefits if the Mayo hydro plant is out of service or loads are greater than the available plant capacity.

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[23] Exhibit B-4, CW-YEC/YECL-1-3.
[24] YEC Argument, page 15.
[25] Leading Edge Reply Argument, page 3.
[26] Exhibit B-4, LE-YEC/YECL-1-7.

53. This, in the Board's view, underscores the BC Hydro statement in evidence that:

> It is not possible to develop an accurate, planning based classification of hydro plant between demand and energy. When hydro plant is built, it provides both energy and capacity and one cannot be obtained without the other.[27]

54. The Board took note of the Companies' submission, indicating that the Mayo hydro "plant no longer only services the local Mayo and Keno loads but now serve a larger complement of formerly isolated communities that previously relied upon resident diesel generation to supply base load requirements."[28] The Board understands that the available capacity, i.e. demand and energy, of the Mayo hydro facility is now more fully utilized. That being said, the Board finds that because a plant is more fully utilized does not suggest a reclassification of the facility.

55. In addition, the Board finds no compelling evidence that justifies the reclassification of the Mayo hydro plant from 60% energy and 40% demand to 100% energy. The Board therefore denies the Companies proposal to change the Mayo hydro plant classification to 100% energy. Accordingly, the Board directs the Companies to classify Mayo hydro plant 60% energy and 40% demand in the next COS study.

3.3.1.3 Transmission

56. The Companies submitted that the proposed change to classify all current transmission from 100% demand to 100% energy was based on the following considerations:

- The Faro mine closure removed the basis for specifically assigning to the Industrial class (i.e. Faro mine) 85% of the Whitehorse-Faro transmission costs.
- 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.
- The remainder of the WAF 138kV 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.[29]

57. The Companies further stated that if it were determined that some portion of transmission merits a capacity component, i.e. the portion of the 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 as 100 percent energy, since under the current capacity planning criteria Aishihik does not contribute to the system firm load carrying capability

[27] Ibid.
[28] Exhibit B-4, LE-YEC/YECL-1-7.
[29] Application, pages 3-8 to 3-9.

(due to N-1) and MD and CSTP were built almost entirely to displace diesel generation."[30]

Views of the Parties

58. YEC argued that transmission infrastructure changes drove how transmission assets were considered and classified in the 2009 COS study. Important considerations in this regard included:

- transmission classification was not a priority in 1996/97 as 85% of the transmission line costs from Whitehorse to Faro were assigned to the Faro mine;
- new transmission assets were justified based on the economics of supplying loads that would otherwise rely on costly diesel generation with lower cost hydro; and
- transmission assets were viewed as "generation integration transmission"; hence, the classification of transmission lines mirrored the generation asset classification.[31]

59. When asked to provide examples of other Canadian utilities that make use of a 100% energy classification in respect of transmission line, the Companies responded that Manitoba Hydro's treatment of its high-voltage direct current (HVDC) facilities is analogous to the proposed treatment of assets in the Yukon. Supporting their submission, the Companies pointed out that:

> Manitoba Hydro stated the primary benefit of the energy-only method is that it is more reflective of electricity value in interconnected markets and therefore the opportunity value of Manitoba Hydro supply.[32]

60. Leading Edge indicated that the MD transmission line should have a classification wherein the demand portion is less than the energy portion. However, in respect of the WAF or integrated hydro system, Leading Edge submitted that "there is a greater rationale for allocating at least a portion of the transmission assets to energy, but considers 100% energy to be an overstatement."[33] Leading Edge therefore recommended that the Board order that transmission lines be classified 60% to energy and 40% to demand.

61. UCG submitted that the utilities failed to provide evidence that the Yukon's transmission lines should be classified 100% energy:

> While they have suggested (without backup evidence) that Manitoba Hydro conducts such a classification, they have not provided evidence that this is the "normal practice" with utilities or that it is used "in many places".[34]

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[30] Application, page 3-9.
[31] YEC Argument, pages 15-16.
[32] Exhibit B-4, YUB-YEC/YECL-1-6.
[33] Leading Edge Argument, page 5.
[34] UCG Argument, paragraph 28.

62. YEC submitted that UCG's arguments were made without regard for the extensive evidence made available during the proceedings. Rejecting UCG's and Leading Edge's arguments, YEC submitted that rejection of the bulk power classification measures, as presented in the Application, ignores implications regarding Industrial R/C ratios; the Industrial R/C ratios will move further above 100%.[35] Moreover, transmission assets, i.e. the new Mayo-Dawson and CSTP Stage One transmission assets, are viewed as generation integration transmission, and as such:

> … these … transmission assets were justified almost entirely (MD line) or entirely (CSTP line) based on savings of diesel energy costs rather than diesel demand costs.[36]

Views of the Board

63. In respect of transmission lines, the Board agrees that changes in circumstances warrant changes to the COS or rate design principles from those established in 1996/97. The Board observes that the reasons underlying the Companies' proposal to change transmission line classification to 100% include the closure of Faro mine, the construction of the MD transmission line, and the relative importance of the transmission system in respect of providing the benefit of avoiding expensive diesel generation. The Board has considered each of these changes in turn.

64. With respect to the Faro mine closure, the Board took note that, other than the 85% that was directly assigned to the Faro mine, the remainder of the Whitehorse to Faro transmission line was allocated to customers on the basis of 100% demand in 1996/97.

65. The Board is not convinced that classification of transmission lines in the Yukon should not contain a demand component. The Board also notes that the example in the preceding paragraph relates to interconnected markets and is not analogous with the Yukon environment. The Board notes YEC's submission:

> In general, when you're dealing with the transmission lines that the people have been dealing with in Yukon, the driving characteristics for a line for the type - - for needing a line for the type of line, for the sizing of the line, for the voltage of the line, has been the peak loads.[37]

66. The Board finds that the submission highlights the finding that the grid system(s) in the Yukon currently provides both energy and capacity.

67. Further, the Board understands the intrinsic capacity of the Yukon transmission lines and their connections to the hydro plants allows for the resident diesel unit capacity to supply energy and demand to be redundant. Accordingly, the resident diesel unit capacity is not required unless the transmission lines are down, the hydro plants cannot provide the capacity that is required to meet the customer demand, or a

[35] YEC Reply Argument, pages 9, 12.
[36] YEC Reply Argument, page 9.
[37] Transcript, Volume 1B, October 5, 2010, page 182, lines 8-13

combination of the two. The Board is therefore not convinced that “these lines exist solely to supply hydro energy to displace the need for diesel generation to supply loads in Whitehorse and elsewhere.”[38]

68. With respect to what demand/energy split is reasonable, the Board considers important the YEC submission that transmission lines can be thought of as an extension of the generation plant:

> That’s a relatively accepted method in cost of service. It’s cited in the types of manuals you’ll see for preparing costs of service, and it’s used in - - in many places.[39]

69. The Board accepts the view that transmission is “effectively an extension of the generation plant.”[40] Being that the Board directed that Yukon hydro plant be classified 60% energy and 40% demand, the Board finds that a transmission line classification of 60% energy and 40% demand is reasonable. The Board denies the Companies’ proposal to classification transmission lines 100% energy and directs the Companies to reflect a 60% energy and 40% demand transmission line classification in the next COS study.

3.3.1.4 Distribution Cost Allocation to Transmission

70. When asked to confirm that the Industrial class had been allocated its fair share of distribution system related costs, YECL submitted that the Industrial class “was appropriately allocated $154,000 in Distribution classified costs.”[41] However, YEC responded that the Minto mine, which is connected to the system by transmission assets, was incorrectly assigned certain distribution O&M costs and credits.

71. In a subsequent letter dated September 30, 2010, the Companies agreed that costs functionalized as distribution that relate to activities that are in fact beneficial to the overall system and all customers should be allocated in part to the Industrial class (e.g. Public Information, Customer Accounting, General Plant and General), but not costs that relate to assets functionalized as distribution (e.g. poles and wires).[42] The estimated reduction in costs allocated to the industrial customer is $79,000.[43]

Views of the Board

72. The Board notes that customers did not comment on this issue. With respect to the 1997 COS study, the Board notes that the Industrial class was allocated a small degree of distribution assets, as the former United Keno Mine site was connected to the Mayo system via distribution assets.[44] The Board agrees with the Companies that costs functionalized as distribution that are purely related to the distribution system, i.e.

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[38] Ibid.
[39] YEC Argument, page 15.
[40] Transcript, Volume 1A, October 5, 2010, page 73, line 14-15
[41] Exhibit B-4; UCG-YEC/YECL-1-15.
[42] Exhibit B-9, page 3.
[43] Exhibit B-16.
[44] Exhibit B-4; UCG-YEC/YECL-1-15.

are not beneficial to the overall system and to all customers, should not be allocated to customers connected to the grid via transmission assets.

3.3.1.5 Secondary Sales Revenues

73. The Companies did not include secondary sales as a separate rate class in the COS study. In support of their position, the Companies stated that secondary sales, by definition, are based solely on surplus hydro generation, and have terms and conditions that require interruption of these sales whenever surplus hydro is not or is not expected to be available.[45]

Views of the Parties

74. The Companies argued that secondary sales are not a component of firm rate service. Furthermore, the rates charged are determined on a quarterly basis to reflect customer savings relative to use of alternative oil or propane energy supplies.

> 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.
> …
> Based on normal rate principles, these secondary sales are assigned to reduce overall Consolidated Revenue Requirement costs… recovered through rates from customers receiving firm power service.[46]

75. The Companies submitted that Secondary Sales be treated as incidental revenues in the COS study. Moreover, the Companies proposed that the benchmark price "for setting the secondary sales rate is what would be the alternative available to the customer to get the same BTUs out of heating oil."[47]

76. City of Whitehorse expressed the following concerns with the Companies' value-of-service method of setting rates:

a. City of Whitehorse considers that assuming the true value of Secondary Sales is related to retail heating oil leads to sub-optimal uses of surplus energy.
b. The value-of-service criterion is not recognized among Bonbright's 10 attributes of a sound rate structure.
c. Basing the Secondary Sales rate on the retail price of a volatile commodity such as fuel oil creates rate instability; therefore, the Companies, being price-regulated industries, should not be charging rates that are based on retail unregulated commodity prices.

77. In light of its concerns, City of Whitehorse submitted that the Secondary Sales rate (Rate 32) should be based on a fixed percentage of the first energy block of the General Service rate, not on volatile, retail commodity prices. Noting that the assumed

[45] Application, page 3-9.
[46] Application, pages 3-9 to 3-10.
[47] Transcript, Volume 1A, October 5, 2010, page 26, line 24 to page 27, line 1.

Secondary Sales energy cost in the Application of $0.072/KW.h was approximately 87% of both the current and proposed first block for General Service customers, City of Whitehorse proposed that the Secondary Sales rate be set at $0.072/KW.h. [48]

78. Noting the Companies' submission that there were almost no incremental cost of servicing the secondary customers, UCG submitted that "there are still some very specific costs (billing, transformers, etc.) that should be directly allocated to this service and deemed to be recovered specifically through secondary rates charged rather than through the rates charged to other ratepayers for other services."[49]

Views of the Board

79. The Board took note of the following YEC submission that incremental costs associated with providing Secondary Sales are insignificant:

> …the value concept that we've talked about this morning on secondary sales is the basis for the price. There are some incremental costs. They would be accounted for, and if you were looking at sort of the cost that would be offset against that value, if you were trying to figure out what the net value is, those incremental costs are trivial compared to the value. So, it's not a question of a cost-based consideration at all.[50]

80. The Board finds that secondary sales 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. Accordingly, the Board finds the Companies' proposal to be reasonable and directs the Companies in the next COS to use these secondary sales revenues to reduce the firm rate revenues required to be collected from all distribution connected rate classes.

3.3.2 Distribution Cost Classification Methods

81. The Companies reviewed and updated the customer/demand classification factors for Distribution Plant using Yukon specific data and the same methodologies that were used in ATCO Electric's 2010 Distribution Tariff Application. The table below shows the 2009 Distribution classification factors proposed by the Companies; for purposes of comparison, the Companies also provided the classification factors that were approved in Board Order 1996-7.

[48] City of Whitehorse Argument, pages 22-24.
[49] UCG Argument, paragraph 31.
[50] Transcript, Volume 1A, October 5, 2010, page 51, lines 9-16.

Table 5. Classification of Distribution Expenses

Description	Proposed Split (%)		Board Order 1996-7 Split (%)	
	Customer	Demand	Customer	Demand
Land and Land Rights	0	100	NO CHANGE	
Poles, Towers & Fixtures	56	44	75	25
Overhead (OH) Conductors Underground (UG) Conduits (Wires)	52	48	30	70
Line Transformers	28	72	30	70
Services	100	0	NO CHANGE	
Meters and Metering Equipment	100	0	NO CHANGE	
Streetlights/Space Lights	Directly assigned to rate classes (NO CHANGE)			

Source: Application, Page 3-11.

82. The Distribution classification factors were previously based on ATCO Electric's material costs, installed quantities and labour rates; for this study the classification factors were updated using YECL specific data because

> YECL considers that the refinement of using YECL specific PP&E and cost data results in classification factors that are more accurate and consistent with the goal of aligning cost with causation.[51]

83. YECL explained that significant change in Distribution Classification Factors would have negligible impact on rates. A sensitivity analysis that was provided by YECL, showed the impact of using Yukon specific data on cost allocation to be less than 1% for all rate classes.[52]

84. Also, YECL studied the results of the zero-intercept and minimum plant studies and considered that:

> 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.[53]

85. The Companies provided the following table which shows the impact of the zero-intercept method, the minimum-plant method, or an average of the two.

[51] Exhibit B-4, YUB-YEC/YECL-1-7 (c).
[52] Exhibit B-4, YUB-YEC/YECL-1-7 (b).
[53] Application, Appendix 3.2, page 3.2A-6.

Table 6. Comparison Zero-Intercept and Minimum-Plant Distribution Classification Methods

Rate Class	Zero-Intercept Method	Minimum Plant Method	Average of Methods
Residential Government	$392	$411	$401
Residential Non-Gov't	$24,187	$25,031	$24,592
General Service Gov't	$6,587	$6,287	$6,442
General Service Non-Gov't	$15,134	$14,663	$14,909
Industrial	$2,965	$2,923	$2,946
Street Light	$1,453	$1,411	$1,432
Sentinel Light	$116	$108	$112

Source: Exhibit B-4, UCG-YEC/YECL-1-14 (d)

Views of the Parties

86. YECL submitted that the minimum-plant and zero-intercept studies are the only two methodologies contained in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual. YECL added that it was not aware of any other utility in Alberta or the Northwest Territories that averages the results of the two classification methods. However, YECL believed that the use of those two studies are supported and recommended by NARUC.[54]

87. The Companies proposed that the treatment of YECL revenue offsets be revised to use Distribution Plant classifications to classify revenue offsets in order to match how revenue was derived.[55]

88. UCG submitted that without corroborating evidence from experts such as Foster & Associates, referred to during the hearing, there is limited value in the Companies' proposal to update the Distribution classification factors.[56]

89. YECL submitted that, "while it is acknowledged that each of the methodologies may have certain inherent shortcomings, the bias or impact of such factors has been minimized by conducting an analysis using each methodology and then averaging the results."[57] Moreover, in respect of UCG's suggestion that expert evidence should have been presented, YECL did "not consider that the additional expense associated with presenting such expert evidence would have been justified in the circumstances."[58]

Views of the Board

90. The Board considers that the minimum-system and zero-intercept methods are well-recognized methods of classifying between customer and demand. Therefore, there is no need for further expert evidence, as suggested by UCG. Furthermore, no evidence was presented that YECL carried out the studies in an inappropriate manner. The Board finds that the results of averaging the zero-intercept and minimum-plant Distribution classification methodologies as proposed by the Companies for this COS

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[54] Exhibit B-4, UCG-YEC/YECL-1-13.
[55] Application, page 3-11.
[56] UCG Argument, paragraph 29.
[57] YECL Argument, page 5.
[58] YECL Reply Argument, page 6.

study are not substantially different than those that were approved by the Board in 1996/97.

91. As a result, the Board agrees with YECL that extra costs associated with presenting expert evidence to justify the proposal to average the methodologies is not warranted. Further, the Board finds the use of Yukon-specific data represents an improvement over previous cost of service studies. Accordingly, the Board approves the use of Yukon specific data, the use of average results of the zero-intercept and minimum-plant methodologies and the results of the studies as applied to poles, towers and fixtures, overhead conductors, underground wires, and transformer costs.

3.3.3 Allocation Methods

92. The Companies stated that classified costs were allocated to each firm rate class using methods adopted in past COS studies and updated forecasts for the numbers of customers, peak demand, and energy use for each rate class. The Companies added that:

> 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).[59]

93. However, the notable exception to the above, was the allocation of demand costs which were according to the Companies:

> … based on an estimate of each class' contribution to the overall system coincident peak ("CP"), and to the distribution system non-coincident peak ("NCP").[60]

94. In this regard, the updated EDLA study, provided in Appendix 3.3, was used to estimate class aggregate demands. Based on the approaches adopted in the EDLA study, the major demand load metrics which the Companies used in 2009 are shown in the following table and compared to those which were approved in 1996/97.

[59] Application, page 3-12.
[60] Ibid.

Table 7. Demand Load Characteristics at the Meter, by Class

Customer Class	Load Factors (CP, NCP)	2009	1996/97
Residential Non-Government	CP	56.5%	53.0%
	NCP	48.2%	45.6%
Residential Government	CP	56.5%	49.2%
	NCP	48.2%	42.3%
General Service Non-Government	CP	77.4%	61.5%
	NCP	63.6%	49.2%
General Service Government	CP	77.4%	66.5%
	NCP	63.6%	53.2%
Industrial	CP	77.4%	99.9%
	NCP	N/A	N/A
Streetlights	CP	46.7%	48.0%
	NCP	46.7%	48.0%
Space Lights	CP	46.7%	47.7%
	NCP	46.7%	47.7%

Source: Application, Page 3-12.

95. The Companies stated that three rate classes: Industrial; General Service Government; and General Service Non-Government, experienced a significant change in respect of demand load characteristics since the 1996/97 GRA. With respect to industrial customers, the Companies submitted that the change in load factor resulted because the Minto mine load was forecast "to be of a lower load factor and a much smaller size [than the Faro mine load] relative to the overall system."[61]

Views of the Parties

96. The Companies submitted that no Yukon-specific load studies had been conducted in support of the proposed 2009 load factors. Consequently, the new load factors were derived from recent load studies on ATCO Electric customers in Alberta. The Companies explained that the 1996/97 load factors were also based on earlier analyses of ATCO Electric customers in Alberta.[62]

97. Responding to an information request, YEC stated that:

> Yukon Energy cannot identify a reasonable underlying Yukon-based explanation for ATCO's calculation that the Yukon General Service load factors have increased so materially since 1996/97 (from 61.5% to 77.4% at coincident peak, and from 49.2% to 63.6% at non-coincident peak). The error appears to arise due to reliance on ATCO data from Alberta that is difficult to analyze or assess, and is of questionable value in determining the load characteristics of Yukon customers.[63]

[61] Application, page 3-13.
[62] Ibid.
[63] Exhibit B-4, YUB-YEC/YECL-1-8 (i).

98. YEC highlighted in its response to information request YUB-YEC/YECL-1-8 that:

1) The load factors calculated exceed any range for load factors for major classes of General Service customers reviewed elsewhere in Canada (including ATCO Electric, who appear to use only a 72% coincident peak load factor in their cost of service studies, and this is among the highest values identified). Most other jurisdictions reviewed, including hydro based jurisdictions in Manitoba and Newfoundland, appear to be in the range of 60-64%, consistent with Yukon's 1997 values.
2) YEC was not able to identify any cited references to other jurisdictions implementing major changes to the cost-of-service load characteristics of General Service customers in the last 10 years. YEC also cannot identify any underlying Yukon specific reason for ATCO to draw this conclusion about material load characteristic changes.
3) If the ATCO values are correct, and General Service customers are operating at such a high load factor (meaning they peak relatively low for their quantity of energy used) the overall calculated CP-based estimate of the system peak does not accord with the known system peaks. In particular, the sum of the calculated system peaks, as compared to the forecast system peak would infer that the system experiences losses at peak times approximate 25%, which does not accord with known system values. With General Service load factor values from 1997 inserted, the calculated peaks suggest a system demand loss at peak times of approximately 18% which, while still very high, is directionally closer to expectations.[64]

99. Because of its concerns, YEC pointed out that the General Service class of customers is being allocated too low a share of costs, while other classes are being allocated too high a share. In the absence of any Yukon-specific data to support such a material change, YEC submitted that the 1996/97 General Service CP and NCP values should be retained.[65]

100. Subsequently, YEC changed its position because the Companies agreed to request that the Board accept the COS ratios proposed in this proceeding because:

a) the ratios are based on the most readily available data; and
b) the COS study will not determine rate changes at this time.

Also, in their next COS study, the Companies proposed to re-evaluate this issue to ensure the results are consistent with the load characteristics in Yukon.[66]

101. YEC reiterated concerns that the proposed General Service demand load factors may not reflect Yukon realities. Additionally, in respect of developing a Yukon-specific energy, demand and loss analysis, YEC submitted that the significant costs associated with such an undertaking were not warranted. Furthermore, YEC did acknowledge that cross-checks, which were undertaken in the previous COS studies to ensure that results were consistent with load characteristics in the Yukon, were not done in the

[64] Ibid.
[65] Ibid.
[66] Exhibit B-9; Appendix A, Joint Agreement on Outstanding Matters.

current study. Notwithstanding the Companies' varying opinions in respect of the EDLA study, "the Companies have committed to work together to resolve that issue prior to the next COS study".[67]

102. YECL noted that questions were raised with respect to the use of ATCO Electric's Alberta-based data and submitted that "it is simply not practical to incur the costs that would be required to obtain equivalent data for Yukon customers…it is sensible and logical to adopt a proxy that provides useful information for use in the subject Cost of Service Study."[68] The data that is used for the EDLA study was from customers who share similar characteristics and covers a period of 20 years. The current EDLA approach and methodology is the same as used in the previous study.

103. City of Whitehorse expressed concerns that there may be a fundamental difference between load data from ATCO Electric and the Yukon system. For example:

> The City understands that electric heating is much more uncommon in Alberta than it is in the Yukon.[69]

104. Accordingly, City of Whitehorse requested that the Board direct the Companies to verify the suitability of that ATCO Electric load information for use in the Yukon by the time of the next GRA.

105. Addressing concerns regarding the cost of a Yukon-specific load study, City of Whitehorse also submitted that statistical sampling of Yukon loads might be an economical alternative and provide a means of testing the validity of the ATCO Electric load information.[70]

106. Given the differences between the Alberta electric and Yukon systems, Leading Edge submitted that:

> It is our view that there are practical and cost effective checks that can be carried out to check or "truth" the Alberta data so that the adjustments made to the Alberta models will reasonably accurately reflect Yukon realities…These may include demand (amperage) readings on portions of various feeders that serve primarily one type of customer, for example residential, downtown small business, large box stores, and large government facilities of various types.[71]

107. Accordingly, Leading Edge submitted that the Board should order the Companies to collaborate to identify and select appropriate cost effective measures to measure adequately actual Yukon specific customer loads so that the ATCO Alberta models can be calibrated to provide reliable Yukon specific information, and to implement these measures prior to the next Phase II Application.

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[67] YEC Argument, pages 19-20.
[68] YECL Argument, page 7.
[69] City of Whitehorse Argument, paragraph 39.
[70] City of Whitehorse Reply Argument, paragraph 25.
[71] Leading Edge Argument, page 6.

Views of the Board

108. In regard to the significant change in the General Service load factors since 1996/97, the Board considered important YEC's submission, wherein YEC indicated that it could not:

> … identify a reasonable underlying Yukon-based explanation for ATCO's calculation that the Yukon General Service load factors have increased so materially since 1996/97 (from 61.5% to 77.4% at coincident peak, and from 49.2% to 63.6% at non-coincident peak). The error appears to arise due to reliance on ATCO data from Alberta that is difficult to analyze or assess, and is of questionable value in determining the load characteristics of Yukon customers.[72]

109. The Board further took note that the "same methods and approaches used in the 1997 approved COS study, including reliance…on then current load data from ATCO Electric in Alberta,"[73] were adopted for this analysis, albeit "cross-checks that were done in Yukon at the time of the earlier joint COS studies to address such concerns … were not done in the current study".[74]

110. The Board is concerned that, if the current study were approved and rates were to be based on the COS study, the General Service class of customers may be allocated too low a share of costs, while the other customer classes may be allocated too high a share.

111. As a result, the Board finds the validity of data underpinning the EDLA to be questionable in determining the load factors of Yukon customers. Furthermore, the Board does not find it reasonable to accept the Companies' recommendation to approve the COS ratios in this proceeding because the ratios are based on the most readily available data and the COS study will not determine rate changes at this time. Accordingly, the Board does not accept the Companies' proposed 2009 COS demand load metrics (CP and NCP load factors).

112. Respecting the issue of adopting a Yukon-specific load study to derive demand load metrics, the Board agrees with the Companies that it is not, at this time, economical or practical to attempt to put in place the necessary infrastructure to gather the detailed information that would be required for such a study. As such, the Board acknowledges that a valid proxy that relies upon comparable data from ATCO Electric, which has been scaled for Yukon using established formulae from the Demand Tables developed by the U.S. Department of Agriculture, may be appropriate.

113. Notwithstanding the above acknowledgement, the Board is concerned that the Companies prepared and filed the 2009 COS study without verifying the EDLA results with corresponding Yukon-specific load information. The Board understands that there are practical and cost-effective checks that can be carried out to adjust the Alberta data

[72] Exhibit B-4, YUB-YEC/YECL-1-8.
[73] YECL Argument, page 6
[74] YEC Argument, pages 19 and 20.

if necessary to ensure that the Alberta EDLA model reasonably and accurately reflects Yukon realities.

114. A verification process was undertaken in respect of previous COS studies: "people were organized…to come out during the coldest period and do some spot checks…"[75] The Board further notes that YEC agreed that a similar type of process (proxy study) as was done previously "would seem to …be the type of thing that we should look into."[76] Moreover, the Board notes the Companies submitted to "re-evaluate this issue to ensure the results are consistent with the load characteristics in Yukon"[77] in the next COS study.

115. Therefore, in respect of the next COS study, the Board directs the Companies to collaborate to identify and select appropriate cost-effective measures that will effectively measure actual Yukon-specific customer loads (proxy study) so that the ATCO Alberta models can be calibrated to provide reliable Yukon-specific load information, and to implement these measures prior to the next Phase II Application.

116. The Companies are further directed in the next Phase II Application to provide an explanation of and accompanying reasons as to why the measures are appropriate in calibrating the ATCO Alberta EDLA study in order to provide reliable Yukon-specific load information.

117. The Board further directs the Companies to confirm the appropriateness of using the demand tables from REA Bulletin 45-2, and to affirm that the document has never been updated.

118. In terms of losses, if the simplified model is used to provide EDLA results in the next COS study, the Board directs the companies to provide details regarding the differences and the impacts respecting the results of the EDLA. Further, the Board directs the Companies to provide details that support the transmission line loss calculation in EDLA, considering the different transmission voltages in the Yukon (69kV and 138kV) and Alberta (144kV).

119. In respect of the creation of two General Service classes,[78] the Board agrees with the Companies' proposal to separate "the non-homogeneous general service class into two subclasses at a future date."[79] The Board believes that split General Service rate classes, i.e. small and large, may serve to explain the divergence of load factors since 1996/97 and contribute to the goal of allocating costs according to cost causation. The Board therefore directs the Companies to create and incorporate two General Service rate classes, i.e. small and large General Service customer rate classes, into the next COS study.

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[75] Transcript, Volume 1B, October 5, 2010, page 159, lines 1-2.
[76] Transcript, Volume 1B, October 5, 2010, page 159, lines 8-9.
[77] Exhibit B-9, page 4.
[78] Exhibit B-1, page 4YEC-21, page 4YECL-12.
[79] Exhibit B-4, CW-YEC/YECL-1-15.

3.3.4 COS Study; Direct Assignment

120. The Companies explained that they have only been able to identify direct assignable costs for the Street and Sentinel customer rate classes.[80]

Views of the Parties

121. UCG submitted that:

> … it is a rare occurrence in cost of service analysis that costs, especially the costs to serve the larger customers, cannot be specifically identified for direct assignment.[81]

122. Noting that the Companies had already identified higher specific costs required to serve the Commercial customer rate class, UCG added that the Companies should be directed to review their operations to directly assign more costs to larger customers.

Views of the Board

123. The Board considers that, ideally, a cost of service should be 100% assigned costs, as this would represent 100% cost responsibility. The reality is that with functions that are shared by different rate classes, a reasonable method of allocating costs must be found. The Board agrees that the costs to serve the larger customers may be more identifiable for the purposes of being directly assigned. However, considering the size of the Yukon customer base and the unique setting in Yukon, the Board is not convinced that the costs of such an undertaking would outweigh the benefits.

[80] Exhibit B-4, YUB-YEC/YECL-1-2.
[81] UCG Argument, paragraph 30.

3.4 Rate Design

124. The Board received five recommendations with respect to rate design (for Residential and General Service customers) which are summarized in the following table (each option will be discussed in further detail in later sections):

Table 8. Proposed Rate Designs

Option	Description	Comment
A	Initial Proposal in Tab 4YEC in Application- Eliminates Rate Riders, adjusts runoff rates and recognizes the inability to "rebalance".	Option C later (October 1, 2010) preferred by YEC.
B	Proposed in Tab 4YECL in Application. Eliminates Rate Riders, addresses economy and efficiency rate principles, and recognizes the inability to "rebalance".	Preferred by YECL.
C	YEC Proposal, October 1, 2010 – blocking structure matches Option B, runoff rate at $0.2/kW.h (Old Crow at $0.4/kW.h) for residential non-government. Accepts Option B demand charge.	Option C (Mod) later proposed in Argument (October 22, 2010) and preferred by YEC.
C(Mod)	YEC Proposal in argument, October 22, 2010 – Modification for residential customer classes where the block 2 rate changes from 13.75 cents per kW.h to 13.00 cents per kW.h and an increase in the block 1 rate.	Final proposed option by YEC.
LE	Covers only non-government residential rate class. Two of three versions have a run out rate at $0.2/kW.h (Old Crow at $0.4/kW.h), same block structure as Option A.	Only covers residential non-government rate class.

125. This section summarizes the different rate options for Residential and General Service in a tabular format. From the tables, the proposed rate and block structures for each rate class are readily apparent.

3.4.1 Options A and B (Residential and General Service)

126. Table 4.1 Summary of Residential Rate Options A and B from page 4YEC-3 of the Application set out the following:

Table 9. 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	$0.1399
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	$0.1399

127. Table 4.2 Summary of General Service Rate Options A and B from page 4YEC-5 of the Application set out the following:

Table 10. 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	$0.1286	$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

128. For Residential customers (both non-government and government residential), Options A and B are designed to remove Riders J and R, introduce a new equalized second energy block and increase the base customer charge to $14.65 for non-government Residential and to $18.47 for government residential customers. As is evident in Table 4.1 the options differ in terms of the blocking structures and the energy rates for each block.

129. For General Service customers (non-government, municipal government and federal and territorial governments), Options A and B are designed to adjust base rates, introduce a new equalized second energy block (2,001 kW.h to 15,000 kW.h per month), a new equalized third energy block (15,001 kW.h to 20,000 kW.h per month) and a runoff energy block (>20,000 kW.h per month for large users and for future consideration of a General Service Large User rate class.[82] For General Service, Options A and B provide the same blocking structure but do not provide the same prices (except for the runoff rate block) in terms of the demand charges and the energy charges for each of the blocks.

130. As shown in Tab 4YEC and Tab 4YECL of the Application, three rate design matters were identified:

- eliminate riders (remove Riders J and R and adjust retail base rates accordingly)
- adjust runoff rates (adjust economy and efficiency rate principles) and bring runoff rates toward the approved 2009 incremental (diesel) costs
- inability to "rebalance" (limitations, in principle, due to OIC 2008/149)

131. On October 1, 2010 YEC in presented Option C, and then later presented a modified Option C in its Argument of October 22, 2010. Thee options are presented in the following tables:

Table 11. Table 4.3: Residential Rate Options C and C(Mod)

Rate Class		Option C			Option C(Mod)		
	Customer Charge per month	Energy 1 (0-1000) kWh	Energy 2 (1001-2500) kWh	Energy 3 >2500 kWh	Energy 1 (0-1000) kWh	Energy 2 (1001-2500) kWh	Energy 3 >2500 kWh
1160 Hydro Non-Gov	$14.65	$0.1177	$0.1375	$0.20	$0.1193	$0.1300	$0.20
1260 Sm Diesel Non-Gov	$14.65	$0.1177	$0.1375	$0.20	$0.1193	$0.1300	$0.20
1360 Lg Diesel Non-Gov	$14.65	$0.1177	$0.1375	$0.20	$0.1193	$0.1300	$0.20
1460 Old Crow Non-Gov	$14.65	$0.1177	$0.1375	$0.4398	$0.1193	$0.1300	$0.4398
1180 Hydro Gov	$18.47	$0.1735	$0.1375	$0.20	$0.1754	$0.1300	$0.20
1280 Sm Diesel Gov	$18.47	$0.1735	$0.1375	$0.20	$0.1754	$0.1300	$0.20
1380 Lg Diesel Gov	$18.47	$0.1735	$0.1375	$0.0	$0.1754	$0.1300	$0.20
1480 Old Crow Gov	$18.47	$0.1735	$0.1375	$0.4398	$0.1754	$0.1300	$0.4398

[82] Application, page 4YEC-3

Table 12. Table 4.4: General Service Rate Option C

Rate Class	Option C				
	Dem. Charge /kW	Energy 0-2000 kWh	Energy 2001-15000 kWh	Energy 15001-20000 kWh	Energy >20000 kWh
2160 Hydro NG	$7.39	$0.0941	$0.1288	$0.2000	$0.1286
2260 Sm Diesel NG	$7.39	$0.0941	$0.1288	$0.2000	$0.1522
2360 Lg Diesel NG	$7.39	$0.0941	$0.1288	$0.2000	$0.1286
2460 Old Crow NG	$7.39	$0.0941	$0.1288	$0.2000	$0.3172
2170 Hydro Municipal	$7.39	$0.0941	$0.1288	$0.2000	$0.1286
2270 Sm Diesel Municipal	$7.39	$0.0941	$0.1288	$0.2000	$0.1522
2370 Lg Diesel Municipal	$7.39	$0.0941	$0.1288	$0.2000	$0.1286
2470 Old Crow Municipal	$7.39	$0.0941	$0.1288	$0.2000	$0.3172
2180 Hydro Gov	$12.31	$0.1888	$0.1297	$0.2000	$0.1286
2280 Sm Diesel Gov	$12.31	$0.1888	$0.1297	$0.2000	$0.1522
2380 Lg Diesel Gov	$12.31	$0.1888	$0.1297	$0.2000	$0.1286
2480 Old Crow Gov	$12.31	$0.1888	$0.1297	$0.2000	$0.3172

132. For the General Service rate classes there were no changes from Option C to Option C(Mod).

133. Leading Edge presented the following alternative for non-government residential rates in its evidence:

Table 13. Table 4.5: Leading Edge Residential Rate Option (non-government only)

Rate Class		LE Option		
	Customer Charge per month	Energy 1 (0-1000) kWh	Energy 2 (1001-1500) kWh	Energy 3 >1500 kWh
1160 Hydro Non-Gov	$14.65	$0.1101	$0.1600	$0.2000
1260 Sm Diesel Non-Gov	$14.65	$0.1101	$0.1600	$0.2000
1360 Lg Diesel Non-Gov	$14.65	$0.1101	$0.1600	$0.2000
1460 Old Crow Non-Gov	$14.65	$0.1101	$0.1600	$0.4000

134. Based on the submission of YEC that Option C(Mod) was its preferred choice,[83] the Board will not give further consideration to Options A and C with respect to residential rates. Option C will be discussed in terms of General Service rates.

[83] YEC Argument, page 28 "Attachment A provides updated bill comparison tables (residential and general service non-government), with and without IER, that includes the modified Option C as now recommended by Yukon Energy in this Argument. (underlining added)

Positions of Parties

135. YEC and YECL, in terms of rate design were able to agree on the following items:[84]

- Residential customer charges of $14.65 for non-government and $18.47 for government (see Table 4.1 – Option B).
- Residential energy block structure as shown in Table 4.1 above for Option B.
- Updated incremental cost of diesel generation and the proposed consolidation of the hydro, large diesel and small diesel zones (incremental cost of 27.99 cents/kW.h).
- Seasonal or time-of-use rates not recommended.[85]
- General Service energy block structure as shown in Table 4.2 (Option B) or Table 4.4 (Option C) above.
- General Service demand charges as shown in Table 4.2, Option B.
- General Service energy rates for energy blocks 2 and 4.
- Elimination of Riders J and R.
- Amendments to Rate Schedules 61, 66, 67 (Street Lighting) and 75, 76 (Sentinel Lighting).
- Amendment to Industrial Rate Schedule 39 (to clarify the operation of Rider F for this customer class).
- Amendment to Wholesale Rate Schedule 42 (as required to reflect adjusted retail base rates and removal of Riders J and R) and Energy Reconciliation Adjustment (ERA) confirming ERA charges to YECL will be adjusted monthly only during months when diesel generation is on the margin at normal long-term average water flows on the hydro zone.
- Amendment to Wholesale Rate Schedule 51 (single energy only rate at the same level as the base Rate Schedule 42 for YEC purchases from YECL.
- Cancellation of Rate Schedules 33, 38 and 40.
- No changes to rate schedules 32 and 43 (Secondary Energy) or to Riders A and B (Multiple Residence Service and Unmetered General Service Flat Rate).

136. YEC and YECL were unable to agree on the following issues:

- Energy rates for each energy block for residential customers.
- General Service energy rates for energy blocks 1 and 3.

137. Intervenors expressed the following with respect to the rate proposals of the Companies and other Phase II rate design issues:

- UCG submitted that the Board should direct the utilities to undertake studies on seasonal and time-of-use rates to determine if such rates would or would not be beneficial to the Yukon.[86]

[84] YEC Argument, pages 2 to 5 inclusive, confirmed in YECL Reply (Joint YECL/YEC Phase II Issues), page 3.
[85] YEC Argument, page 25.
[86] UCG Argument, paragraph 86.

- City of Whitehorse submitted Option B is slightly superior to the other proposed options but asked the Board to approve the current rate design with Riders J and R included in base rates.[87]
- Leading Edge submitted that now is not the time for seasonal rates[88]; it supports the creation of a large General Service rate class in the future[89] and preferred Option C[90] over Options A and B.
- In Reply, UCG supported the Argument of City of Whitehorse that the current rate structure should be maintained.[91]
- Leading Edge, in Reply Argument, said that the proposal by City of Whitehorse (to maintain the existing rate structure) is not without merit[92]. Leading Edge also commented that the Revised Option C proposed by YEC in Argument [Option C(Mod)] had a runoff rate that Leading Edge was comfortable with but needed stronger pricing signals in the block 2 consumption bracket.[93]
- City of Whitehorse submitted in Reply Argument[94] that if the short-term price elasticity for Residential and General Service customers is zero, then all the options proposed are faulty. That is, nothing changes, and if nothing changes why change the rate design?

Views of the Board

138. As a point of reference, Table 4.4 from the Application is shown below as Table 4.6:[95]

Table 14. Table 4.6: 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**		**Gov't**			**NG & Mun**		**Gov't**	
	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

[87] City of Whitehorse Argument, paragraph 33.
[88] Leading Edge Argument, page 7.
[89] Leading Edge Argument, page 7.
[90] Leading Edge Argument, page 9
[91] UCG Reply Argument, paragraphs 34 and 39.
[92] Leading Edge Reply Argument, page 6.
[93] Leading Edge Reply Argument, page 7.
[94] City of Whitehorse Reply Argument, paragraph 22.
[95] Application, page 4YEC-15.

139. With the applicable Riders J and R added to the base rates the rates become:

Table 15. Table 4.7: Existing "Base" Firm Energy Rates (with riders and before taxes) in $/kW.h

First Block Res=1,000 kWh/m; GS= 2,000kWh/m — Second Block (run-out rates)

Rate Zone	NG & Mun		Gov't			NG & Mun		Gov't	
	res	GS	res	GS		res	GS	res	GS
Hydro (WAF, MD)	0.1213	0.1022	0.1764	0.2146		0.1285	0.1285	0.1285	0.1285
Large diesel (Watson)	0.1213	0.1022	0.1764	0.2146		0.1285	0.1285	0.1285	0.1285
Small diesel (YECL)	0.1213	0.1022	0.1764	0.2146		0.1520	0.1520	0.1520	0.1520
Old Crow (YECL)	0.1213	0.1022	0.1764	0.2146		0.3169	0.3169	0.3169	0.3169

140. At page 4.1B-2 of Appendix 4.1B, YECL provides revenue-to-cost ratios for Option B. Although the Board has provided several comments with respect to the COS study in earlier sections, it is clear from this table that, due to the inability to rebalance rates because of the existing OICs, regardless of the option chosen, Residential (non-government) and Street Light rates are significantly below unity. That is, the revenues from these classes are considerably below the costs to serve those rate classes. Therefore, when OIC 2008/149 expires, and as referred to in the Cost of Service section, the Board expects that both utilities will jointly come before this Board with a new Phase II Application to correct the current imbalances.

3.4.2 Residential Rates (Government and Non-Government)

141. Options B, C and C(Mod) offer similar energy block structures. As noted above, City of Whitehorse, UCG and to some extent Leading Edge support using the existing two-block energy structure. The Intervenors are not opposed to the creation of the second equalized energy block. Their arguments focus on the inability of the Companies to arrive at a consensus on one rate design model[96] and the possible effect of the proposed rate designs, given that the Companies see the demand for electricity to be inelastic,[97] especially in the short term.

142. The Board agrees with the introduction of the second equalized energy block for the Residential rate class. The Board views the addition of this block as introducing flexibility to the rate design. Also, the addition may assist is sending proper economic signals to customers, and is a step forward in promoting conservation. For these reasons the Board approves the residential rate energy blocking structure as proposed in Options B, C and C(Mod).

[96] City of Whitehorse Reply Argument, paragraphs 6, 9, 15 and 22; UCG Argument, paragraph 75.
[97] Transcript, Volume 2A, October 6, 2010, page 319, lines 17-18; City of Whitehorse Reply Argument, paragraph 22. Leading Edge (Argument, page 8) disagrees with the utilities and states that a Whitehorse Yellowknife comparison shows definite price elasticity in the short term.

143. In terms of the rates for each of the energy blocks, the Companies were unable to agree on a joint proposal. As noted above, the Intervenors to some extent support the existing rate structures escalated to include Riders J and R into the base rates. For non-government residential customers Option B proposed a first-block energy rate more closely aligned with the views of the Intervenors,[98] that is, first energy block rates close to those shown in Table 4.7 above. Given that for this rate class, the revenues are below costs and that this issue should be corrected when OIC 2008/149 expires, the Board is of the view that a reduction in first-energy block rates is not warranted[99] and agrees with YECL that such a design is inefficient.[100] The Board also considers that for this rate class, Option B provides an inclining rate structure that would in the longer term promote economy and efficiency and send appropriate economic signals to customers. Therefore, the Board approves Option B for the rate design and rates for each of the energy blocks for residential non-government customers.

144. The Board has a different view for Residential-Government customers. Again, based on the philosophies of economic efficiency and conservation espoused by the Companies and supported by the Board, the Board supports an inclining energy block structure. None of the options preferred by the applicants or provided by the Intervenors support this type of structure for government residential customers. As is the case of residential non-government rates, the Board considers that the revenue-to-cost ratio for the Residential-Government rate class exceeds unity, and if rate rebalancing were possible, the rates for this rate class could potentially go down. As rebalancing is not possible, for reasons provided in residential non-government rates, the Board supports an inclining rate structure for this rate class. To meet this direction, and to retain the revenue levels for this rate class, the Board proposes the following rates for each of the Residential-Government energy blocks (the block 2 energy charge before rounding is 17.57479 cents/kW.h):

Table 16. Board Proposed Energy Block Rates – Residential-Government

Proposed Rate	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)
1160 G - H	16.57	17.57	18.85
1260 G - SD	16.57	17.57	18.85
1360 G - LD	16.57	17.57	18.85
1460 G - OC	16.57	17.57	30.77

98 City of Whitehorse Argument, paragraph 33, UCG Argument, paragraph 61 wherein UCG says "the YEC approach fails to adequately consider the wider issues and related impacts to ratepayers" and tacitly by supporting the incorporation of Riders J and R into the current rate structure. This equates to the first block energy rate supported by YECL.

99 City of Whitehorse also disagreed with a decrease in 1st block rates; City of Whitehorse Argument, paragraph 6.

100 YECL Separate Argument on Phase II Issues (page 3), wherein YECL says "it is counter-intuitive to establish a Rate Design today, that sends a group of customers within a particular rate class a signal that their rates will decrease, even though the circumstances which are supposedly being addressed are associated with a significant increase in costs." YECL later states: "Such a price signal is seen as being perverse in the circumstances."

145. However, the Board will not set this rate structure because it wants to afford the Companies the opportunity, in the compliance filing, to jointly propose one rate structure for Residential-Government customers based on inclining rate blocks. Further, the Board finds the proposed customer charges as presented in Options A, B, and C(Mod) reasonable, as the charges reflect the incorporation of Riders J and R. Therefore, the Board accepts the customer charges for Residential-Government customers, as proposed.

3.4.3 General Service Rates (Government and Non-Government)

146. Three options, Options A, B and C, were provided with respect to General Service rates. The rate design includes new equalized second and third energy blocks and an adjusted runoff energy block designed to address large users as a step toward a potential Large General Service rate class.[101] YEC subsequently moved away from Option A and provided Option C as its preferred choice in correspondence to the Board dated October 1, 2010. In a comparison of Options B and C, the Board finds that the energy block structures are the same, the demand charges are the same, and the fourth block energy rates are the same.

147. The Board also finds, based on Table 4.7 above and page 4.1B-2 of Appendix 4.1B (YECL revenue –to-cost ratios for Option B), that, even looking at the escalated current rate design, the revenue-to-cost ratios for this rate class exceed unity. The implication of this is that when rebalancing between the rate classes resumes, there is likely to be some downward movement on the rates.

148. For General Service Non-Government and General Service Municipal, the Board does not accept Option B, as it does not provide an appropriate signal in the first energy block as to the direction rates are likely to go when rebalancing resumes. The Board does not accept Option C as there is a concern of rate shock over third energy block rates. As was stated above for Residential-Government rates, the Board supports an inclining rate structure, and is attempting to both provide an appropriate economic signal to General Service rate class consumers and to mitigate the potential of rate shock to consumers in the third energy block. The Board proposes the following rates[102] for the General Service Non-Government and Municipal Government rate classes (the block 3 energy charge before rounding is 15.67642 cents/kW.h):

[101] Application, page 4YEC-3.
[102] The proposed rate structure maintains the revenue levels as proposed for these rate classes.

Table 17. Board Proposed Energy Block Rates - General Service (Non-Government and Municipal Government)

Proposed Rate	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)	Block 4 Energy Chg (¢ / kW.h)
2160 NG - H 2170 GM - H	10.00	12.88	15.68	12.86
2260 NG - SD 2270 GM - SD	10.00	12.88	15.68	15.22
2360 NG - LD 2370 GM - LD	10.00	12.88	15.68	12.86
2460 NG - OC 2470 GM - OC	10.00	12.88	15.68	31.72

149. The Board accepts the rates for energy blocks 2 and 4 as jointly agreed to by the Companies. The Board also recognizes that the fourth energy block may be an initial step toward the transition to a new Large General Service rate class which the Board directs the Companies to put forth in their next Phase II Application.

150. However, the Board will not set this rate structure but will give the Companies the opportunity in the compliance filing, to jointly propose <u>one</u> rate structure for General Service Non-Government and General Service Municipal Government based on the determined inclining rate blocks, proper economic signals and rate shock considerations. Further, the Board finds the proposed demand charges as presented in Options B and C reasonable, and therefore accepts the demand charges, as proposed for these two General Service rate classes.

151. For the General Service Government rate class, the Board is of a similar mind as with the other General Service rate classes. That is, three options have been presented (Options A, B and C). The Companies agree on the demand charge (Options B and C) and the Companies agree on the second and fourth energy block rates.

152. The Board further finds, based on Table 4.7 above and page 4.1B-2 of Appendix 4.1B (YECL revenue-to-cost ratios for Option B) that, even looking at the escalated current rate design, the revenue-to-cost ratios for this rate class exceed unity; only the Street Lighting rate class is more out of balance than this General Service rate class. The implication of this is that when rebalancing between the rate classes resumes, there is likely to be some downward movement on the rates.

153. For General Service Government, the Board does not accept Option B as it does not provide an appropriate signal in the first energy block as to the direction rates are likely to go when rebalancing resumes. The Board does not accept Option C, as it does not present the inclining energy block rate structure that the Board supports. However, there is no concern regarding rate shock, as the rate for the proposed third energy rate block is less than the rate proposed for the first energy block under Option B and the proposed rate is also less than the first block rate if the current rate structure was escalated to incorporate Riders J and R. As was stated above for the General Service Non-Government and General Service Municipal Government rates, the Board supports an inclining rate structure, and is attempting to provide an appropriate

economic signal to General Service Government rate class consumers. Therefore, the Board proposes the following rates[103] for the General Service Government rate class (the block 1 energy charge before rounding is 13.81068 cents/kW.h):

Table 18. Board Proposed Energy Block Rates – General Service (Government)

Proposed Rate	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Block 3 Energy Chg (¢ / kW.h)	Block 4 Energy Chg (¢ / kW.h)
2180 GFT - H	13.81	15.00	20.00	12.86
2280 GFT - SD	13.81	15.00	20.00	15.22
2380 GFT - LD	13.81	15.00	20.00	12.86
2480 GFT - OC	13.81	15.00	20.00	31.72

154. The Board accepts the rates for energy block 4 as jointly agreed to by the Companies. The Board also recognizes that the fourth energy block may be an initial step toward the transition to a new Large General Service rate class which the Board directs the Companies to put forth in their next Phase II Application.

155. However, the Board will not set this rate structure, but affords the Companies the opportunity, in the compliance filing, to jointly propose one rate structure for General Service Government based on the determined inclining rate blocks and proper economic signals. Further, the Board finds the proposed demand charges as presented in Options B and C reasonable, and therefore accepts the demand charges as proposed for the General Service Government rate class.

156. The rate model used to determine these rates is attached to this Decision as a reference for all Parties (Appendix 2).

3.4.4 Street and Sentinel Lighting

157. The Companies proposed to adjust the rates for Street Lighting (Rate Schedules 61, 66, and 67) and Sentinel Lighting (Rate Schedules 75 and 76) by an equal percentage of 23.126% to reflect the proposed elimination of Riders J and R. This was not opposed by any Party. The Board agrees that the escalation of the rates for these schedules is reasonable as it pertains to the elimination of Riders J and R and therefore accepts the rates for Rate Schedules 61, 66, 67, 75 and 76 as filed.

3.4.5 Rate Schedule 32 (Secondary Sales)

158. The Companies did not seek any changes to Rate Schedule 32 (Secondary Sales) in the Application.[104] The Board sees this as reasonable since at this date secondary sales have been suspended.

[103] The proposed rates maintain the revenues as applied for in this rate class.
[104] Application, page 4YEC-31.

3.4.6 Rate Schedule 39 (Industrial)

159. YEC proposed to amend Rate Schedule 39 Industrial to provide for fixed Rider F as approved in Board Order 2009-10. YEC later stated:

> 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 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 compliance filing.[105]

160. The Board concludes the request by YEC is reasonable and directs YEC to highlight the proposed wording change for Rate Schedule 39 by YEC in the compliance filing.

3.4.7 Rate Schedule 42 (Wholesale sales to YECL)

161. Rate Schedule 42 is described as the rate provided for YEC sales to YECL.[106] YEC is unable to give a precise rate as it is dependent upon the ultimate rate design selected.

162. The Board agrees with the Companies that Rate Schedule 42 should be updated. However, the Board cannot approve this proposed rate schedule as it currently is indeterminate. Therefore, based on the previous directions under rate design, the Companies are to provide one proposal for Rate Schedule 42 that both companies endorse, in the compliance filing arising from this Decision.

3.4.8 Rate Schedule 51 (Wholesale sales to YEC)

163. In Tab 4-YEC the following was said:

> 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 (approximately 8.3 cents/kW.h).[107]

164. The amount indicated by YECL is 8.299 cents/kW.h.[108] The Board agrees that Rate Schedule 51 should be an energy-only rate, applicable throughout Yukon and that it should be at the same level as the base for Rate Schedule 42. However, as noted above, since Rate Schedule 42 is indeterminate, the Board concludes the same for Rate Schedule 51. Therefore, similar to the direction given for Rate Schedule 42, the Board directs the Companies to provide one proposal for Rate Schedule 51 that both

105 Application, page 4YEC-31.
106 Application, page 4YEC-31.
107 Application, page 4YEC-32.
108 Application, page 4YECL-20. YECL notes that this rate is dependent upon Option B assumptions.

companies endorse, in the compliance filing arising from this Decision. In addition, in the compliance filing, the Companies are to provide copies of all rate schedules for those rates the Companies share and for those rates unique to each company.

3.4.9 Rate Schedules 33, 38 and 40

165. The Companies, in their Application, proposed to cancel Rate Schedules 33, 38, and 40 as each schedule does not have any applicable customers and the unique circumstances that existed when the schedules were created no longer exist. The Board finds this request by the Companies reasonable and accepts the cancellation of Rate Schedules 33, 38 and 40 as proposed by the Companies.

3.4.10 Secondary Energy Rate Schedules 32 and 43 and Riders A and B

166. No changes were proposed to the Secondary Energy Rate Schedules (32 and 43) nor to Riders A and B. The Board approves Secondary Energy Rate Schedules 32 and 43 and Riders A and B as filed.

3.4.11 Rider D

167. Pursuant to the *Public Utilities Act*, YECL sought approval of its proposed Rider D, Diesel Generation Energy Cost Recovery Rider; to facilitate the dispensation of the balances tracked in the Board approved wholesale purchase power deferral account. YECL proposed that the rider would apply to all Yukon customers, except for customers served on Rate Schedule 32, Secondary Energy and Rate Schedule 40, Maintenance Energy.

168. In Board Order 2009-2,[109] the Board approved YECL's wholesale purchase power deferral account that dealt with the treatment of variances between the actual and forecast cost of purchase power for the hydro zone during the period when diesel generation was on the margin and when the approved run-out rate set out under the Energy Reconciliation Adjustment (ERA) in Schedule 42 was different than the rates used to determine the forecast cost of purchase power for diesel generation.

Views of the Parties

169. Subject to review of the monthly deferral account balance, YECL proposed that any reconciliation of Rider D would occur on an annual basis and would be applied as an adjustment to the monthly retail rates based on a ¢/kW.h charge or refund. To facilitate the implementation of Rider D, YECL proposed to amend the ERA provision set out in Rate Schedule 42, to clarify the manner in which Rate Schedule 42 is intended to operate with the new Rider D.[110]

[109] Order 2009-2, YECL 2008-09 GRA, Issued February 12, 2009
[110] Exhibit B-2, page 3.

170. YECL stated that a similar rider mechanism was approved by the Northwest Territories Public Utilities Commission (NWTPUB); since 1999, the NWTPUB has allowed Northland Utilities to capture the ongoing variances in diesel volumes.[111]

171. YECL stated that there is a significant disconnection between how the ERA and Rate Schedule 42 is linked to rate design. The current rates are collecting production costs of $0.083 per kW.h while the current incremental cost of diesel is approximately $0.27 per kW.h. The significant change in circumstances which has occurred is the reason why YECL is proposing Rider D to act as a mechanism to clear the deferral account.[112]

172. Moreover, YECL submitted that, were it to face circumstances beyond its control where it incurred significant costs because the proposed rider was not in place, YECL would have no choice but to trigger a Phase I Rate Application and force the incurrence of additional costs associated with a rate proceeding.

173. YEC stated that there is no forecast basis to consider Rider D or any other mechanism to dispose of any future deferral account balance related to Rate 42 ERA charges or refunds to YECL. It also stated:

> YECL further confirmed that the details of the Rider D mechanism and the calculation of the rider amount "will be explained in detail in a [future] Rider D application."[113]

174. In respect of the rate adjustment formula that YECL provided, YEC submitted that the information, which was provided after close of the oral hearing, must be given no material weight by the Board as to what the appropriate mechanics should be for any Rider D in the future. Furthermore, YEC submitted that the placeholder Rider D application does not adequately address the amounts to be determined for flow through to customers. It stated:

> YECL revenue offsets related to the load variance from forecast must also be addressed.
> …
> the Rider D application will ensure that YECL can avoid the need to address load forecast variance derived ERA cost changes.[114]

175. YEC also pointed out that YECL's proposal to charge all customers, other than secondary energy customers, was not consistent with OIC 2007/94 in that no such rider can be charged to Industrial Rate 39 customers at this time.

[111] Exhibit B-4, UCG-YEC/YECL-1-21.
[112] YECL Separate Argument on Phase II Issues, page 9.
[113] YEC Argument, Page 43.
[114] YEC Argument, Page 45.

176. Leading Edge noted that YECL acknowledged that diesel was not forecast to be on the margin in the test year for which the Application applies. Furthermore, it stated:

> … it was clear that YECL had not yet fully worked out the mechanics of exactly how the monies would flow into and out of the account, nor was this process yet before the Board for review.[115]

177. Therefore, Leading Edge recommended that the Board defer a decision on Rider D until the next GRA when the issues and mechanics of the deferral account can be discussed by all Parties.

178. UCG submitted that YECL's proposed Rider D should be denied given that the current forecasts do not indicate a need for risk compensation beyond base rates.

Views of the Board

179. The Board took note of YECL's submission that details of the Rider D mechanism, including the period in which the balance will be collected or refunded to customers and the calculation of the rider amount will be explained in detail in a Rider D Application. Further, if "within a 12 month period YECL accumulates balances (plus or minus) in excess of 0.5% of total revenue requirement, YECL anticipates that it will file a Rider D Application to true-up balances in order to avoid material rate swings to Yukon customers."[116]

180. The Board, in Board Order 2009-2, approved YECL's wholesale purchase power deferral account:

> The Board acknowledges that there was little debate regarding the deferral accounts described in the Application, i.e. the Diesel Contingency Fund and Rate from YEC. Therefore, the Board approves YECL's…deferral accounts.[117]
> [Footnote omitted]

181. Implicit in the Board's approval of the purchase power deferral account is the approval of a future rider to dispense of the accumulated balances in the deferral account.

182. The Board acknowledges that diesel is not forecast to be on the margin during the 2009 period and given the deferral account exists, Rider D may be applied for in the next YECL GRA when the issues of the deferral account and the mechanics of money flowing into and out of the account can be addressed. Conversely, if YECL determines that the balance in the deferral account is too large, YECL may file a separate Rider D Application at that time, providing all assumptions and calculations (including in electronic form), and over what term YECL proposes to dispense with the balance in the deferral account.

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[115] Leading Edge Argument, Page 11.
[116] Exhibit B-26, Undertakings 4, 5, and 7, page 6.
[117] Order 2009-2, page 11 of 49.

183. In respect of YECL's 2008-09 GRA, the Board notes that YECL's proposed purchase power deferral account request refers to "non-governmental residential service for the hydro zone."[118] In this Application, YECL submitted that Rider D is applicable to all classes of service.[119] Accordingly, the Board directs YECL, when it files its Rider D Application, to clarify for which rate class or classes the rider is applicable.

184. The Board denies YECL's proposed Rider D and proposed amendments to the ERA provision. The Board directs YECL to re-file its proposed amendments at the time of its Rider D filing.

3.4.12 Rider F

185. Fuel Adjustment Rider F is applicable to all electric service throughout Yukon. When questioned on the operation of Rider F, the YEC panel stated that the Companies endeavored to not let the balance for Rider F exceed +/- $200,000.[120] YEC also stated that there was no written policy with respect to the Rider F account balance.[121] Exhibit B23, which was a response to an undertaking to Board counsel at Transcript page 440,[122] shows the balance in the Rider F account ranging from a negative $635,000 to a positive $600,000.

Views of the Board

186. Given the large swings in the balance of the Rider F account, the Board directs the Companies to provide a written policy, for approval by the Board, on how Rider F is to be managed at the time of the next filing to adjust the rate for Rider F, or at the latest by June 30, 2011. Secondly, to allow all interested parties to monitor the balance in the Rider F account, the Companies are to provide to the Board quarterly acknowledgement filings stating the balance in the Rider F account and concurrently posting those filings on each company's website for easy public access.

3.4.13 Other Issues

3.4.13.1 Incremental Cost of Diesel Generation

187. The Companies submitted evidence on the incremental cost of diesel generation for each rate zone and further proposed that this incremental cost be merged for the hydro, small diesel and large diesel rate zones (the consolidated cost of incremental diesel generation being 27.99 cents /kW.h).

Views of the Board

188. The calculation of the incremental cost of diesel generation was not contested by any Party. The Board approves the incremental diesel generation cost calculation and the consolidation of this incremental cost for the three rate zones (hydro, small diesel,

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[118] YECL 2008 General Rate Application, Dated April 30, 2008; Exhibit B-1, page 3-2.
[119] Exhibit B-2, YECL Rider D – Diesel Generation Recovery Rider (March 1, 2010); Attachment 1.
[120] Transcript, Volume 2B, October 6, 2010, page 440 lines 1-4.
[121] Transcript, Volume 2B, October 6, 2010, page 440 lines 14-15.
[122] Transcript, Volume 2B, October 6, 2010, page 440-441 lines 23-1

large diesel) providing a consolidated incremental cost of diesel generation for those three rate zones of 27.99 cents/kW.h.

3.4.13.2 Economy and Efficiency Rate Principles in Rate Design

189. Considerable discussion was included in this process regarding economy and efficiency principles within the rate design of the runoff rates. YEC's view was to adjust runoff rates toward the incremental cost of diesel generation based on the approved forecast of fuel prices (2009) and consistent with Yukon practice.[123] Economy and efficiency, YEC submitted, 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.[124]

190. YECL concurred with YEC's position in that rate design principles, where practicable, and based on the level of incremental diesel generation that is being used due to increasing consumption, that retail runoff rates, by reflecting short term incremental generation costs, provide economy and efficiency as a price signal at higher levels of consumption.[125]

191. YECL added:

> 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.[126]

192. In argument, YECL stated:

> The Rate Design should be reflective of the economic implications associated with the incremental cost of diesel generation based on the facts as we know them today[127].
>
> …
>
> As noted by YECL during the proceeding, it has been unable to find a clear definition for the term "economy and efficiency" as it currently relates to Yukon.[128]

But acknowledged:

> Nonetheless, YECL understands that in the past Rate Design was linked to the short-term incremental costs of diesel, in order to provide signals to customers that as consumption increases so do costs.[129]

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[123] Application, page 4YEC-10.
[124] Application, page 4YEC-18.
[125] Application, page 4YECL-4.
[126] Application, page 4YECL-10.
[127] YECL Separate Argument on Phase II Issues, page 4
[128] YECL Separate Argument on Phase II Issues, page 4
[129] YECL Separate Argument on Phase II Issues, page 5

193. In its Argument, YEC said:

> It was noted that at this time, given the length of time since the last runoff rate adjustment and the reality that the runoff rate today is less than 50% of incremental diesel generation costs in the hydro/large diesel zone, the runoff block rate did not need to move immediately to 100% of incremental costs, but should make notable progress today in this direction. In the 2008/2009 GRA YEC identified a range of 20-22 cents/kWh as a reasonable step towards reflecting full incremental costs at the time; Option A identified in Tab4 YEC provided a rate of 22 cents per kWh.h (reflecting 80% of incremental cost) and YEC Option C filed on October 1 provided a runoff rate of 20 cents/kWh (at 71.5% of incremental cost). Yukon Energy's recommended roadmap is that a decision be made today that this initial runoff rate will be moved as soon as is reasonable back up to reflect 100% of incremental short term supply costs in each rate zone. It was noted in the hearing that moving the runoff rate within a reasonable period of time to 100% of incremental supply costs will enhance customer conservation incentives and enhance their own long term purchase decisions.[130]

194. City of Whitehorse argued:

> The City notes that in OIC 1995/90 the only requirement is that the runoff rates for the non-government retail customer class be fixed "on the basis of rate design principles to promote economy and efficiency" – it is not a requirement that the runoff rate fully reflect the incremental cost of diesel on the system.[131]

City of Whitehorse further submitted that the movement toward 100% incremental cost of diesel generation for the Hydro Rate Zone was unjustifiable and discriminatory.[132]

195. In Reply Argument, City of Whitehorse stated that, with respect to runoff rates, no specification (percentage terms) has been made as to what ratio of incremental cost of diesel generation should be reflected in runoff rates. City of Whitehorse added that the Board is not bound by its own precedents and that the Companies have not demonstrated that the factors that were relevant in the past concerning runoff rates are still relevant.[133]

Views of the Board

196. The Board has considered the views of all the Parties and notes that there clearly is no consensus on this issue. However, it is clear that the Companies agree that in the past, economy and efficiency has been linked to the incremental cost of diesel generation.

[130] YEC Argument, page 31.
[131] City of Whitehorse Argument, paragraph 11.
[132] City of Whitehorse Argument, paragraph 12.
[133] City of Whitehorse Reply Argument, paragraph 12.

197. In terms of pricing signals, the Board is of the view that the best pricing signals to customers are those prices that reflect the full cost to serve those customers. Arguments on incremental cost of diesel generation, or what portion of the incremental cost of diesel generation should be reflected in runoff rates should take a distant backseat to the proper alignment of costs to revenues for each rate class. Once rebalancing has occurred for the rate classes, then issues relating to runoff can be examined in greater detail.

198. Nonetheless, runoff rates are part of the required rate structure and based on current OICs must reflect economy and efficiency. Therefore, for this Application, the Board has determined that runoff rates shall be defined as being on the order of 50% of the incremental cost of diesel generation or greater.

3.4.13.3 Seasonal Rates/Time of Use Rates

199. Both Companies recognized that a possible option to address the present need for transition was to consider seasonal or time-of-use rates; however, after review of the logistical issues that arise, the Companies agree these options were not a practical or preferred approach at this time.[134]

200. City of Whitehorse and Leading Edge did not support the use of seasonal rates at this time.[135]

Views of the Board

201. The desire on the part of customers to get some understanding of the costs and benefits of seasonal rates has been noted by the Board. The Board also considers that all Parties recognize that seasonal rates cannot be offered at this time. To obtain further information on this issue, the Board directs the Companies to undertake a study of seasonal rates and report the results of that study to the Board at the time of the next Phase II Rate Application.

3.5 Terms and Conditions of Service

3.5.1 Overview

202. In Section 5 of the Application, the Companies proposed changes to the Terms and Conditions of Service. There were three notable updates included:

a. Revised Terms and Conditions Service Document: primarily changes to clarify wording and to more fully communicate the rights and obligations of the utility and the customer.

b. Changes to Schedule B, Maximum Company Investment: the Companies proposed changes to all customer classes as well as non-standard customers for 2011 as well as incremental increases over the period of 2012 to 2015. A Maximum Investment Level (MIL) study was provided by YECL, which was not

[134] YEC Argument, page 25.
[135] City of Whitehorse Argument, paragraph 74 and Leading Edge Argument, page 7.

supported by YEC. In their submission on September 30, 2010, the Companies revised their proposal to include only an incremental increase for 2012.

c. Changes to Schedule D Fees and Service Charge Summary: All fees and service charges that were previously stated with their respective articles in the Terms and Conditions document are proposed to all be located in Schedule D – Fees and Service Charge Summary.[136]

3.5.2 Updated Terms and Conditions of Service

3.5.2.1 Changes to Schedule D Fees and Service Charge Summary

203. The Board notes that no Parties raised any issue with the proposed changes to Schedule D. The Board considers that the proposed changes, which will provide a single point of reference for all fees and service charges, will enhance the Terms and Conditions of Service. Therefore, Board approves the proposed changes to Schedule D: Fees and Service Charges Summary.

3.5.2.2 Customer Bill of Rights and Simple Language in the Terms and Conditions of Service

Views of Parties

204. UCG submitted that the current wording in the Terms and Conditions of Service are difficult to understand for most customers.[137] Consequently, UCG requested that the Board make some conclusions on how the Terms and Conditions of Service can be presented to ratepayers in a more understandable format. Specifically, UCG recommended a customer bill of rights be developed which would explain in clear understandable language the rights of customers.

205. The Companies argued that the issues to be covered in a customer bill of rights are already comprehensively addressed in the proposed Terms and Conditions.[138] The Companies also submitted that the Terms and Conditions are a legal contract between the Companies and their customers, and as such, must clearly lay out the legal rights of both. Therefore, the Companies submitted that a separate document containing such rights is not needed.

206. Board counsel asked the Companies during the hearing whether or not section 9.4 of the proposed Terms and Conditions, which relates to Company liability, could be rewritten to simplify the language and therefore, clarify the meaning of this clause.[139] The Companies undertook to consider the question and respond in writing.[140]

[136] Application, page 5-2.
[137] UCG Argument, Paragraph 91
[138] YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 12.
[139] Transcript, Volume 2A, October 6, 2010, at pages 268-273.
[140] Transcript, Volume 2C, October 6, 2010, at pages 525-526.

207. On October 12, 2010, YEC and YECL replied that they had examined the proposed wording of this provision and determined, on the advice of counsel, that the wording should not be changed. This provision deals with the liability of the Companies They submitted that it is one of the most important provisions of the Terms and Conditions, as it establishes the scope of the potential liability to which the Companies could be exposed. As such, it is critical that this provision be concise and clear from a legal point of view. If the interpretation of this provision is ever called into question, it would likely be in the context of a legal dispute. Furthermore, this provision is patterned on similar longstanding provisions from other jurisdictions that have been accepted and approved by other regulators. They submitted that the provision should be approved, as filed.

Views of the Board

208. The Board is not convinced by the argument put forward by UCG that the current wording of the Terms and Conditions of Service overall is unclear and that customers cannot understand the rights and obligations of both the Companies and the customer. The Board will not direct the Companies to modify the language in the Terms and Conditions of Service, except as specified below. The Board finds there is no need for the Companies to develop a customer bill of rights.

209. The Board is not persuaded by the Companies' argument that clause 9.4 of the Terms and Conditions cannot be clarified. It is for the very reason cited by the Companies that clause 9.4 must be rewritten. The Board agrees that it is one of the most important provisions of the Terms and Conditions and it should be made clear what each company is liable for in the event of loss or damages by a customer. The Board finds that a badly written clause should not be continued because it was accepted in the past or has been accepted by other regulators. The Board is of the view that the clause can be rewritten as follows:

> 9.4 For the purpose of this clause, "direct physical loss, injury or damage" excludes 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, 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.
>
> Except as described below in this clause, 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, arising out of or in any way connected with the provision of Service by the Company to its Customers including any failure, defect, fluctuation, reduction or interruption in the provision of Service by the Company to its Customers.
>
> The Company shall be liable for 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.

210. Unless the Companies can provide detailed reasons as to why the above-mentioned wording is not acceptable in the compliance filing, the Board directs that the clause 9.4 as rewritten above be inserted in the Terms and Conditions.

3.5.2.3 Demand Side Management (DSM)

Views of the Parties

211. UCG recommended that a joint interested-party panel be implemented to promote more efficient use of energy over the longer term and that YEC be directed to work with YECL, the Yukon government and other stakeholders to implement a DSM program for all electricity ratepayers in the Yukon.[141]

212. In support of the recommendation by UCG, City of Whitehorse requested that the Board direct the Companies to provide exact plans and timelines in their compliance filings for both consultations with stakeholders in the development of the policy paper regarding DSM initiatives and negotiating with Intervenor groups, environmental organizations, government environmental professionals, and communities on the range of energy efficiency and conservation measures to be adopted.[142] City of Whitehorse also requested that the Board set a series of deadlines for the Companies to provide update reports on programs with DSM initiatives, or establish a process that will otherwise ensure that the utilities comply with Board Order 2009-8.

213. The Companies submitted that DSM discussions are progressing as anticipated and no further action from the Board is required at this time.[143]

Views of the Board

214. The Board is of the view that the directions provided in Board Order 2009-8 are clear and no further direction is needed at this time.

3.5.2.4 Cost Sharing Period

Views of the Parties

215. Leading Edge requested that the Board direct the Companies to extend the cost-sharing period to 10 years for distribution-extension projects in which customers pay individual customer contributions of $10,000 or more each, and to 15 years for distribution projects in which individual customers pay $15,000 or more each.[144]

216. City of Whitehorse supported the request by Leading Edge and argued that the Companies' five-year rule results in unfair treatment of customers and supports the proposal of Leading Edge to extend the period over which contributions can be refunded.[145] City of Whitehorse submitted that the Terms and Conditions should be

[141] UCG Argument, paragraph 105
[142] City of Whitehorse Argument, page 30.
[143] YECL Argument on Joint YECL/YEC Phase II Issues, page 12.
[144] Leading Edge Argument, page 4.
[145] City of Whitehorse Argument, page 28.

amended to state that the period over which contributions are refundable to customers corresponds to the period over which the contribution is amortized.[146]

217. The Companies argued that the cost of developing the systems and processes to track all forms of new extensions and implement systems to refund a portion of the initial contribution, should another customer share some of the facilities for an extended period is simply not appropriate.[147] The current practice has been effective and continues to work well. The Companies submitted that the requested five-year cost-sharing period is reasonable.

Views of the Board

218. The Board has considered the proposal to extend the cost-sharing period to 10 and 15 years as proposed by Leading Edge and City of Whitehorse. While the Board does not intend to impose an administrative burden on the Companies, the Board has not been convinced by the Companies that this proposal actually represents such a burden because the number of customers who would qualify for such cost-sharing is relatively low. The Board considers that the proposal represents fairness to customers that far outweighs any potential administrative burden. Therefore, the Board directs the Companies to revise the Terms and Conditions of Service to extend the cost-sharing period to 10 years for distribution-extension projects for which customers pay individual customer contributions of $10,000 or more each.

3.5.2.5 Late Payment Fees

219. UCG submitted that Late Payment and Dishonoured Payment Fees should be based on the actual costs incurred.[148] In response, the Companies argued that there is no evidence to suggest that customers are abusing the late payment process because the fees are low.[149] The Companies submit that the current proposal reflected in the Terms and Conditions is reasonable.

220. The Board does not agree with UCG that the Late Payment and Dishonoured Payment Fees should be modified from the current proposed levels. There has been no evidence presented to indicate that the current fees are not reasonable. Therefore, the Board will not direct the companies to modify the charges for Late Payment and Dishonoured Payment Fees.

[146] City of Whitehorse Reply Argument, page 19.
[147] YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 14.
[148] UCG Argument, , pages 17-18, paragraph 94
[149] YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 14.

3.5.2.6 Totalized Metering

221. In Section 5 of the Application, the Companies proposed to move the section on totalized metering from Section 4.7 to Section 7.7. The Companies also proposed to changing wording of the clause as follows by referring to a contract for 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.[150] [emphasis added]

Views of the Board

222. While no Party raised totalized metering as a concern in the proceeding, the Board has the following concerns. Totalized metering provides an advantage to the company receiving it in that it levels the demand between the meters being totalized. This results in a revenue advantage to the customer that must be made up among the other customers in that category. The half-mile radius was introduced to prevent over-use of totalized metering by customers. The Board is of the view that by allowing a contract to supersede the intention of the clause, abuses of the privilege of totalized metering may result. Consequently, the Board directs the Companies to modify Section 7.7 and remove the words, “or where specified by a contract”.

3.5.3 Maximum Company Investment

3.5.3.1 Guiding Principles

223. In the Application, the Companies provided a Study on Maximum Investment Levels in Appendix 5.4. The study detailed 10 guiding principles that underlay the approach to determining MILs.[151] While no Parties objected to these principles, the Companies requested that the Board confirm the appropriateness of examining MIL levels in the context of these principles.[152]

224. The Board has considered the 10 guiding principles proposed by the Companies for the basis of examination of MILs. The Board considers that the study provided is an excellent consideration of MILs and confirms that the principles set forward are a reasonable basis on which to examine MILs in the Yukon.

[150] Application, page 5.1-22.
[151] Application, pages 5.4-3 -5.4-4.
[152] YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 8.

3.5.3.2 Energy Efficient Street Lights in Municipalities

225. City of Whitehorse proposed that Terms and Conditions for street lighting add a provision that the Companies will share 50% of the cost of installing energy-efficient streetlights with the municipality.[153]

226. UCG did not support this proposal by City of Whitehorse and submitted that if a municipality will be the only beneficiary of an action, then the municipality should pay the full cost of installing energy-efficient streetlights within the municipality.[154]

227. The Companies did not support the proposal by City of Whitehorse and argued that it would be difficult to know the outcome of the proposal by City of Whitehorse.[155] The Companies submitted that the proposed investment levels for street lighting are adequate at this time.

228. The Board agrees with UCG and the Companies in that any proposal for energy-efficient street lighting by City of Whitehorse should be paid for by City of Whitehorse. Consequently, the Board will not direct the Companies to add a provision that the Companies will share 50% of the cost of installing energy-efficient streetlights with the municipality.

3.5.3.3 MIL Recovery of Actual Costs

229. UCG submitted that customer contributions should be based on the actual cost to connect new customers rather than on a cost estimate.[156]

230. The Companies argued that UCG's proposal was inconsistent with the average cost approach underlying the MIL recommendations. The Companies also noted that this approach is completely inconsistent with commonly accepted practice and was only introduced to the proceeding during the Argument phase. The Companies also argued that the proposed MILs align with cost causation and standards of service.[157]

231. The Board notes that the proposal to base MILs on actual costs rather than cost estimates was introduced during the Argument phase of the proceeding and, consequently, has not been properly tested in the course of the proceeding. Therefore, the Board will not direct the Companies to base MILs on actual costs rather than cost estimates.

3.5.3.4 Single Step Approach to 2012 Levels of MILs

232. In the Application, the Companies proposed a gradual increase in MILs from 2011 to 2015.[158] This was later revised by the Companies to 2011 to 2012.[159] The

153 City of Whitehorse Argument, page 20.
154 UCG Reply Argument, paragraph 68.
155 YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 11.
156 UCG Argument, October 24, 2010, page 3.
157 YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 11.
158 Application, page 5-6.
159 Exhibit B-9, page 7.

Intervenor groups, with the exception of Leading Edge, proposed a single-step increase in MILs to the proposed 2012 levels. In reply, the Companies indicated support for this approach and modified their proposal accordingly.[160]

233. The Board has reviewed the arguments regarding a single-step approach to MILs. The Board notes the broad agreement among the Intervenors for a single-step approach. The Board agrees with the Intervenors that a single-step approach will provide more certainty for new customers and for the construction industry. The Board therefore approves a single-step approach to the MILs, raising them effective January 1, 2011.

3.5.3.5 Fixed/Variable Component for General Service

234. In its Application, the Companies proposed a change in the calculation for General Service from a straight variable component to a fixed and variable component.[161] The Companies proposed that the first $5,500 would be covered by the MIL and after that $280/kWh of demand would be covered by the MIL in this customer category. The Companies argued that this approach for the General Service rate class would benefit a greater number of customers.[162] The Companies also submitted that the majority of general service customers would see an increase in investment.

235. City of Whitehorse argued that this proposal would result in some customers in the General Service rate category paying less while others would see an increase in the customer contributions.[163] UCG submitted that the change to a fixed/variable component of the MIL for the General Service rate category would introduce an unjustified inequity in the general service customer category which contains both small and large industrial customers.[164]

236. The Board has not been persuaded by the evidence presented by the Companies that more customers would benefit from a fixed/variable MIL structure for the General Service rate category. The Board agrees that some customers under this proposal may be required to contribute more under this policy than under the current MILs, which is not the intention of the change. Accordingly, the Board approves the MILs as submitted by City of Whitehorse and directs the Companies to revise the MILs to the following:

Year	Residential Single Family Dwelling (per site)	Residential Multi-Dwelling Unit (per site)	General Service (per kW)	Street Lighting (per light)
2011-2012	$1,500	$725	$690	$1,240

[160] YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 9.
[161] Application, page 5-6.
[162] YECL Reply Argument on Joint YECL/YEC Phase II Issues, page 10.
[163] City of Whitehorse Argument, page 19.
[164] UCG Argument, Oct 24, 2010, page 4.

APPENDIX 1: SELECTIVE SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board directs the Companies to file a joint cost of service study at the expiry of OIC 2008/149. The COS study must incorporate the directions in this Decision. .... Paragraph 29

2. The Board finds there is no compelling evidence on the record of this proceeding to persuade it that the classification of the Aishihik plant should be changed to 100% energy from its present classification of 60% energy and 40% demand. The Board therefore denies the Companies' proposal to change the Aishihik plant classification to 100% energy. Furthermore, the Board directs the Companies to classify the Aishihik hydro plant 60% energy and 40% demand in the next COS study. .... Paragraph 46

3. The Board can find no compelling evidence that justifies the reclassification of the Mayo hydro plant from 60% energy and 40% demand to 100% energy. The Board therefore denies the Companies' proposal to change the Aishihik plant classification to 100% energy. Accordingly, the Board directs the Companies to classify Mayo hydro plant 60% energy and 40% demand in the next COS study. .... Paragraph 55

4. The Board accepts the view that transmission is "effectively an extension of the generation plant." Being that the Board directed that Yukon hydro plant be classified 60% energy and 40% demand, the Board finds that a Transmission Line classification of 60% energy and 40% demand to be reasonable. The Board denies the Companies' proposal to classification transmission lines 100% energy and directs the Companies to reflect a 60% energy and 40% demand Transmission Line classification in the next COS study. .... Paragraph 69

5. The Board finds that secondary sales 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. Accordingly, the Board finds the Companies' proposal to be reasonable and directs the Companies in the next COS to use these secondary sales revenues to reduce the firm rate revenues required to be collected from all distribution connected rate classes. .... Paragraph 80

6. In respect of the next COS study, the Board directs the Companies to collaborate to identify and select appropriate cost-effective measures that will effectively measure actual Yukon-specific customer loads so that the ATCO Alberta models can be calibrated to provide reliable Yukon-specific load information, and to implement these measures prior to the next Phase II Application…Paragraph 115

7. The Companies are directed in the next Phase II Application to provide an explanation of and accompanying reasons as to why the measures are appropriate in calibrating the ATCO Alberta EDLA study in order to provide reliable Yukon-specific load information. This will enable Parties to the proceeding and the Board to examine the results of the EDLA study. ….. .... Paragraph 116

8. The Board directs the Companies to confirm the appropriateness of using the demand tables from REA Bulletin 45-2, and to affirm that the document has never been updated. .... Paragraph 117

9. If the simplified model is used to provide EDLA results in the next COS study, the Board directs the companies to provide details regarding the differences and the impacts respecting the results of the EDLA. Further, in respect of losses, the Board directs the Companies to provide details that support the transmission line loss calculation in EDLA, considering the different transmission voltages in the Yukon (69kV and 138kV) and Alberta (144kV). .... Paragraph 118

10. In respect of the creation of two General Service classes, the Board acknowledges and agrees with the Companies' proposal to separate "the non-homogeneous general service class into two subclasses at a future date." The Board believes that a split General Service rate classes, i.e. small and large, may serve to explain the divergence of load factors since 1996/97 and contribute to the goal of allocating costs according to cost causation. The Board therefore directs the Companies to create and to incorporate two General Service rate classes, i.e. small and large General Service customer rate classes, into the next COS study. .... Paragraph 119

11. The Board accepts the rates for energy blocks 2 and 4 as jointly agreed to by the Companies. The Board also recognizes that the fourth energy block may be an initial step toward the transition to a new Large General Service rate class which the Board directs the Companies to put forth in their next Phase II Application. .... Paragraph 149

12. The Board accepts the rates for energy block 4 as jointly agreed to by the Companies. The Board also recognizes that the fourth energy block may be an initial step toward the transition to a new Large General Service rate class which the Board directs the Companies to put forth in their next Phase II Application. .... Paragraph 154

13. The Board concludes the request by YEC appears to be reasonable and directs YEC to highlight the proposed wording change for Rate Schedule 39 by YEC in the compliance filing. .... Paragraph 160

14. The Board agrees with the Companies that Rate Schedule 42 should be updated. However, the Board cannot approve this proposed rate schedule as it currently is indeterminate. Therefore, based on the previous directions under rate design, the Companies are to provide one proposal for Rate Schedule 42 that both companies endorse, in the compliance filing arising from this Decision. …… .... Paragraph 162

15. The amount indicated by YECL is 8.299 cents/kW.h. The Board does agree that Rate Schedule 51 should be an energy-only rate, applicable throughout the Yukon and that it should be at the same level as the base for Rate Schedule 42. However, since Rate Schedule 42 is indeterminate, the Board concludes the same for Rate Schedule 51. Therefore, similar to the direction given for Rate Schedule 42, the Board directs the Companies to provide one proposal for Rate Schedule 51 (that both companies endorse) in the compliance filing arising from this Decision. In addition, in the compliance filing, the Companies are to provide copies of all rate schedules for those rates the Companies share and for those rates unique to each company. .... Paragraph 164

16. In respect of YECL's 2008-09 GRA, the Board notes that YECL's proposed purchase power deferral account request refers to "non-governmental residential service for the hydro zone." In this Application, YECL submitted that Rider D is applicable to all classes of service. Accordingly, the Board directs YECL, when it files its Rider D Application, to clarify for which rate class or classes the rider is applicable. .... Paragraph 183

17. The Board denies YECL's proposed Rider D and proposed amendments to the ERA provision. The Board directs YECL to re-file its proposed amendments at the time of its Rider D filing. .... Paragraph 184

18. Given the large swings in the balance of the Rider F account, the Board directs the Companies to provide a written policy, for approval by the Board, on how Rider F is to be managed at the time of the next filing to adjust the rate for Rider F, or at the latest by June 30, 2011. Secondly, to allow all interested parties to monitor the balance in the Rider F account, the Companies are to provide to the Board quarterly acknowledgement filings stating the balance in the Rider F account and concurrently posting those filings on each company's website for easy public access. .... Paragraph 186

19. The desire on the part of customers to get some understanding on the costs and benefits of seasonal rates has been noted by the Board. The Board also notes that all Parties recognize that seasonal rates cannot be offered at this time. To obtain further understanding on this issue, the Board directs the Companies to undertake a study of seasonal rates and report the results of that study to the Board at the time of the next Phase II Rate Application. .... Paragraph 201

20. While no Party raised totalized metering as a concern in the proceeding, the Board will address this issue here. The Board notes that totalized metering provides an advantage to the company receiving it in that it levels the demand between the meters being totalized. This results in a revenue advantage to the customer which must be made up among the other customers in that category. The half-mile radius was introduced to prevent over-use of totalized metering by customers. The Board is concerned that by allowing a contract to supersede the intention of the clause, abuses of the privilege of totalized metering may result. Consequently, the Board directs the Companies to modify Section 7.7 and remove the words, "or where specified by a contract". .... Paragraph 219

21. The Board has not been persuaded by the evidence presented by the Companies that more customers would benefit from a fixed/variable MIL structure for the general service rate category. The Board agrees that some customers under this proposal may be required to contribute more under this policy than under the current MILs, which is not the intention of the change. Accordingly, the Board approves the MILs as submitted by City of Whitehorse and directs the Companies to revise the MILs to the following: ..... Paragraph 236

Year	Residential Single Family Dwelling (per site)	Residential Multi-Dwelling Unit (per site)	General Service (per kW)	Street Lighting (per light)
2011-2012	$1,500	$725	$690	$1,240

APPENDIX 2: RATE DESIGN MODEL

Board Order 2010-13 Appendix A Reasons for Decision (Appendix 2 - Rate Design Model)

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**

Residential-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						
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		16.57	17.57	18.85	0.000%	0.000%
1260 G - SD	18.47		16.57	17.57	18.85	0.000%	0.000%
1360 G - LD	18.47		16.57	17.57	18.85	0.000%	0.000%
1460 G - OC	18.47		16.57	17.57	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		164,789	54,425	6,045	0	0	**259,642**
1260 G - SD	5,763		28,531	6,887	281	0	0	**41,462**
1360 G - LD	6,657		30,881	4,464	0	0	0	**42,001**
1460 G - OC	2,660		13,491	3,454	5,968	0	0	**25,573**
Revenue - YEC								
1160 G - H	6,483		38,630	5,135	3,157	0	0	**53,404**
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		203,419	59,559	9,202	0	0	**313,046**
1260 G - SD	5,763		28,531	6,887	281	0	0	**41,462**
1360 G - LD	6,657		30,881	4,464	0	0	0	**42,001**
1460 G - OC	2,660		13,491	3,454	5,968	0	0	**25,573**
Revenue ($)	55,945		276,321	74,365	15,451	0	0	**422,083**

General Service-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)	Block 3A Energy (kW.h)	Total Energy (kW.h)
				2009			
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
			0.288637642	0.403192463	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 3A Energy Chg (¢/kW.h)	Rider J Charge (%)	Rider R Charge (%)
2160 NG - H 2170 GM - H	0.00	7.39	10.00	12.88	15.68	12.86	0.000%	0.000%
2260 NG - SD 2270 GM - SD	0.00	7.39	10.00	12.88	15.68	15.22	0.000%	0.000%
2360 NG - LD 2370 GM - LD	0.00	7.39	10.00	12.88	15.68	12.86	0.000%	0.000%
2460 NG - OC 2470 GM - OC	0.00	7.39	10.00	12.88	15.68	31.72	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Block 3A Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	Total Rate Revenue
Revenue - YECL									
2160 NG - H	0	2,485,992	2,482,071	4,117,702	460,797	2,533,693	0	0	**12,080,255**
2260 NG - SD	0	54,030	83,001	102,963	256	0	0	0	**240,250**
2360 NG - LD	0	137,771	185,557	225,499	22,303	55,964	0	0	**627,094**
2460 NG - OC	0	11,466	17,766	24,092	0	0	0	0	**53,323**
2170 GM - H	0	390,250	200,848	505,719	106,162	1,002,445	0	0	**2,205,424**
2270 GM - SD	0	0	0	0	0	0	0	0	**0**
2370 GM - LD	0	35,110	25,630	87,470	6,126	14,238	0	0	**168,575**
2470 GM - OC	0	0	0	0	0	0	0	0	**0**
Revenue - YEC									
2160 NG - H	0	342,563	235,815	576,845	55,745	247,411	0	0	**1,458,380**
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	45,288	251,572	50,614	68,362	0	0	**538,362**
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	2,717,886	4,694,547	516,543	2,781,104	0	0	**13,538,634**
2260 NG - SD	0	54,030	83,001	102,963	256	0	0	0	**240,250**
2360 NG - LD	0	137,771	185,557	225,499	22,303	55,964	0	0	**627,094**
2460 NG - OC	0	11,466	17,766	24,092	0	0	0	0	**53,323**
2170 GM - H	0	512,776	246,137	757,291	156,775	1,070,807	0	0	**2,743,786**
2270 GM - SD	0	0	0	0	0	0	0	0	**0**
2370 GM - LD	0	35,110	25,630	87,470	6,126	14,238	0	0	**168,575**
2470 GM - OC	0	0	0	0	0	0	0	0	**0**
Revenue ($)	0	3,579,709	3,275,976	5,891,861	702,002	3,922,114	0	0	**17,371,663**

General Service-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							
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
			0.128726238	0.321246335	0.05576677	0.494260657	

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 3A Energy Chg (¢/kW.h)	Rider J Charge (%)	Rider R Charge (%)
2180 GFT - H	0.00	12.31	13.81	15.00	20.00	12.86	0.000%	0.000%
2280 GFT - SD	0.00	12.31	13.81	15.00	20.00	15.22	0.000%	0.000%
2380 GFT - LD	0.00	12.31	13.81	15.00	20.00	12.86	0.000%	0.000%
2480 GFT - OC	0.00	12.31	13.81	15.00	20.00	31.72	0.000%	0.000%

	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Block 3A Energy Revenue	Rider J Charge Revenue	Rider R Charge Revenue	**Total Rate Revenue**
Revenue - YECL									
2180 GFT - H	0	1,586,757	637,763	1,893,892	475,127	2,744,294	0	0	**7,337,832**
2280 GFT - SD	0	48,891	56,137	51,693	0	0	0	0	**156,721**
2380 GFT - LD	0	104,246	74,002	158,563	36,662	42,542	0	0	**416,016**
2480 GFT - OC	0	31,050	30,453	31,293	0	0	0	0	**92,795**
Revenue - YEC									
2180 GFT - H	0	269,017	115,624	341,886	61,612	480,930	0	0	**1,269,068**
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	753,387	2,235,777	536,740	3,225,223	0	0	**8,606,901**
2280 GFT - SD	0	48,891	56,137	51,693	0	0	0	0	**156,721**
2380 GFT - LD	0	104,246	74,002	158,563	36,662	42,542	0	0	**416,016**
2480 GFT - OC	0	31,050	30,453	31,293	0	0	0	0	**92,795**
Revenue ($)	0	2,039,961	913,978	2,477,326	573,402	3,267,765	0	0	**9,272,433**

Industrial

Billing Determinants		Number of Customers Billed/year	Demand kVA	Total Energy (kW.h)
		2009		
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**

Street Lights - Rate 61/66

Billing Determinants		Number of Customers Billed/year	Demand W	Total Energy (kW.h)	Highmast Customers Billed/year
		2009			
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

Billing Determinants		Number of Customers Billed/year	Demand W	Total Energy (kW.h)
2009				
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**

Sentinal Lights - Rate 75/76

Billing Determinants	Number of Customers Billed/year	Demand W	Total Energy (kW.h)
2009			
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**

Secondary Sales

Billing Determinants		Number of Customers Billed/year	Demand kW	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	2009 Total Energy (kW.h)
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**

TOTAL RATE REVENUE - PROPOSED RATE

Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Block 3 Energy Revenue	Block 3A Energy Revenue	Rider J & R Charge Revenue	Rider F Charge Revenue		Total Rate Revenue
						2009				
Revenues - YECL										
Residential										
Non-Government	2,229,994		12,330,642	2,869,008	389,639		0			**17,819,283**
Government	49,462		237,691	69,230	12,294		0			**368,678**
General Service										
Non-Government	0	3,114,619	2,994,874	5,063,444	595,643	3,606,341	0			**15,374,921**
Government	0	1,770,945	798,354	2,135,441	511,790	2,786,835	0			**8,003,365**
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	16,361,561	10,137,123	1,509,367	6,393,176				**42,626,462**
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	16,862,253	10,137,123	1,509,367	6,393,176	0	0	827,000	**43,954,154**
Revenues - YEC										
Residential										
Non-Government	253,738		1,114,425	183,281	41,199		0			**1,592,643**
Government	6,483		38,630	5,135	3,157		0			**53,404**
General Service										
Non-Government	0	465,090	281,103	828,417	106,359	315,773	0			**1,996,742**
Government	0	269,017	115,624	341,886	61,612	480,930	0			**1,269,068**
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	1,549,782	1,358,719	212,327	796,703				**5,003,503**
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	3,800,886	1,358,719	212,327	796,703	0	61,239	125,000	**8,376,846**
Revenues - Total										
Residential										
Non-Government	2,483,732		13,445,067	3,052,290	430,838		0			**19,411,927**
Government	55,945		276,321	74,365	15,451		0			**422,083**
General Service										
Non-Government	0	3,579,709	3,275,976	5,891,861	702,002	3,922,114	0			**17,371,663**
Government	0	2,039,961	913,978	2,477,326	573,402	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			**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	17,911,343	11,495,842	1,721,693	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	20,663,139	11,495,842	1,721,693	7,189,879	0	61,239	952,000	**52,331,000**