YUKON
ENERGY

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August 19, 2014

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

Dear Mr. McLennan:

Re: Application to Revise the Diesel Contingency Fund ("DCF") & Related Amendments to the Energy Reconciliation Adjustment ("ERA") – YEC Interrogatory Responses

In accordance with direction in Board Order 2014-08 and the date extension granted on August 13, 2014, please find attached responses to interrogatories in the above referenced matter.

Please note the following:

- The response to YUB-YEC-1-25 provides final versions of Tables 1, 2 and 3 from Yukon Energy's January 31, 2014 filing, based on final actuals for 2012 and 2013, including modifications to the ERA determinations in Table 2 to better reflect Fish Lake impacts as well as the determination of expected diesel in Table 1 for actual grid loads (i.e., for the DCF); and
- Throughout interrogatory responses ATCO Electric Yukon has been referenced as "YECL" or "AEY" depending on the context of the discussion and the IR.

Yukon Energy has provided cross references in a number of responses – as in past proceedings, in order to assist in review of cross referenced IR response, Yukon Energy will provide the Board with an electronic consolidation with hyperlinks embedded where there are cross references to other IRs. An electronic consolidation will be provided by August 25th. As in past, it is expected that Board can make this document publicly available on its website to assist interested parties in review of the material.

Yukon Energy requests any intervenor who wishes to receive a paper copy of interrogatory responses notify YEC as soon as possible to permit production and distribution process.

If you have any questions regarding the above please contact the undersigned.

Yours truly,

Ed Mollard
Chief Financial Officer



YUKON ENERGY CORPORATION

APPLICATION TO REVISE THE DIESEL CONTINGENCY FUND ("DCF")
AND
RELATED AMENDMENTS TO THE ENERGY RECONCILIATION ADJUSTMENT
("ERA")

INTERROGATORY RESPONSES FILED

August 19, 2014

ATCO Electric Yukon (AEY)

REFERENCE:

Line		Approved Forecast		Approved Forecast Adjusted for Actual Wholesale Sales		Δ	
		MWh	$000s	MWh	$000s	MWh	$000s
1	Wholesale	296.000	24.662	310.264	25.746	14.264	1.184
2	Untested Forecast Incremental Expected Actual Diesel Due to Wholesale	6.268	1.805	12.136	3.484	5.848	1.679
3 = 2 - 1	Additional Revenue Requirement for Wholesale Variance only						495
4	Consolidated Revenues of Non-Industrial		51.188		52.372		1.184
5	Consolidated Revenues of Industrial		4.955		4.955		-
6 = 4 + 5	Total Consolidated Revenues		56.143		57.327		1.184
7	Revenue Requirement		59.815		61.494		1.679
8 = 7 - 6	Shortfall		3.672		4.167		495
Formula	Rider J - Non-Industrial		6.65%		7.57%		0.72%
Formula	Rider J - Industrial		3.34%		4.04%		0.70%
9 = 4 * Rider J	Recovery of Shortfall from Non-Industrial		3.507		3.967		461
10 = 5 * Rider J	Recovery of Shortfall from Industrial		165		200		35
11	Total Shortfall Recovery		3.672		4.167		495
	Conclusion: If Wholesale Sales forecast had been equal to actuals. 100% of the cost would be recovered from Ratepayers						

PREAMBLE:

The above table was included in ATCO Electric Yukon (AEY)'s original submission and demonstrates the following:

i) If YEC's GRA forecasts had been equal to actuals, then
ii) There would be no ERA charge from YEC to AEY.

QUESTION:

a) Please confirm that there would have been no ERA charge to AEY in either 2012 or 2013 if YEC's GRA forecast wholesale sales to AEY had been equal to YEC's actual wholesale sales to AEY in 2012 and 2013, respectively. If not confirmed, please fully explain.

b) Please complete the table below which compares Yukon Energy's approved 2012 and 2013 shortfalls and % rate increases over existing (pre-2012/13 GRA)

rates to what they would have been if YEC's GRA forecast wholesale sales to AEY had been equal to actual wholesale sales to AEY for 2012 and 2013. Please include back-up calculations for all numbers in Excel.

	2012		2013	
	Shortfall	**% Rate Increase Over Existing Rates**	**Shortfall**	**% Rate Increase Over Existing Rates**
As approved in Board Order 2013-04				
If YEC's GRA forecast wholesale sales to AEY had been equal to YEC's actual wholesale sales to AEY				

ANSWER:

(a)

Confirmed. There would have been no ERA charges to AEY in either 2012 or 2013 if the actual YEC wholesale sales to AEY had been equal to YEC's GRA approved wholesale forecast for 2012 and 2013, after consideration of Fish Lake impacts. However, as reviewed in Table 2 of the YEC January 31, 2014 filing (and YUB-YEC-1-25), actual AEY wholesale purchases after consideration of Fish Lake impacts in each year exceeded YEC's GRA approved wholesale forecast.

As regards the approved wholesale forecasts in the YEC 2012-2013 GRA per Order 2013-01, the record confirms that YEC's forecasts were approved by the Board notwithstanding arguments from YECL and others suggesting that YEC's forecasts should be reduced.[1]

(b)

YEC has prepared rate increase estimates replacing the forecast wholesale sales for 2012 and 2013 with actual wholesale sales, adjusted per Table 2 of YEC's January 31,

[1] See Order 2013-01, Section 2.2.1; also see YEC 2012/13 GRA Reply Argument, pages 6 through 9.

2014 filing for Fish Lake variances from expected generation (GRA forecasts assume expected Fish Lake generation). Please see Table 1 below for summary estimates and Attachment 1 for the excel version of the table with back-up calculations.

Table 1: Required Rate Increases to Recover Revenue Requirement Shortfall[2]

	2012			2013	
	Shortfall ($000)	% Rate Increase		Shortfall ($000)	% Rate Increase
		Non-industrial	Industrial		
As approved in Board Order 2013-04	3,672	6.85%	3.34%	6,163	3.89%
If YEC's GRA forecast wholesale sales to AEY had been equal to YEC's actual wholesale sales to AEY	4,309	7.76%	4.21%	6,168	3.24%

[2] The actual wholesale sales for 2012 were 14.264 GW.h higher than 2012 GRA forecast, 2013 actuals were 0.780 GW.h higher than 2013 GRA forecast; after adjustment for Fish Lake variances, wholesale variances are 13,272 MW.h for 2012 and 86 MW.h for 2013 (see Table 2 of YEC January 31, 2014 filing). The long-term average diesel estimates for actual sales are based on DCF table (Table 1.1-1) per Table 2 of YEC January 31, 2014 filing), with a diesel cost at 28.71 cents/kW.h. The required rate increases are estimated based on Table 1.3 from 2012/13 GRA Compliance Filing, after adjustment of revenue at existing rates to reflect the added retail revenues related to the added wholesales (assumed incremental retail rates per note 6 of Table 2, YEC January 31, 2014 filing).

REFERENCE: "Charges to YECL will be adjusted on a **monthly basis** to reconcile actual wholesale purchases to **Yukon Energy's most recent test year forecast purchases** during the months when Yukon Energy diesel generation is modified by such variances in wholesale purchases. To the extent that actual wholesale purchases fall short or exceed Yukon Energy's most recent test year forecast wholesale purchases, an adjustment to the YECL bills will be made based on the **variance in diesel generation costs incurred by Yukon Energy** as a **direct result of actual wholesale purchases falling short or exceeding forecast wholesale purchases**."

(YEC January 31, 2014 DCF/ERA Submission, Attachment 2-1 – Proposed Rate Schedule 42)

"The DCF account will be managed on a monthly basis to permit financial reporting through use of a simple pre-determined monthly percentage distribution. **However, due to imprecision in forecast long-term average hydro monthly distributions it is possible that inappropriate values may arise during monthly estimating but these will not be part of final annual DCF calculations.** Monthly calculations will be a placeholder with ultimate final calculations performed only on the annual calendar year values."

(YEC January 31, 2014 DCF/ERA Submission, Appendix 1, p. 1-5.)

PREAMBLE:

QUESTION:

a) Please fully explain the "imprecision in forecast long-term average hydro monthly distributions".

b) Please confirm that YEC intends on calculating a monthly ERA invoice to AEY based on "imprecise" monthly forecast long-term average hydro distributions. If not confirmed, please fully explain.

c) Please confirm that, absent a YEC GRA in 2014 or 2015, YEC will use its 2013 GRA-approved forecasts for its ERA & DCF calculations in 2014 and 2015. If not confirmed, please fully explain.

d) Absent a YEC filing a GRA for 2014 or 2015, please provide the calculations for what YEC's ERA charge to AEY will be in 2014 and 2015 if AEY Wholesale purchases from YEC are 314,125 MWh in 2014 and 320,965 MWh in 2015. Please keep all other variables constant at YEC GRA-approved forecast levels for 2013.

e) Please confirm the ERA charge can vary depending on other factors besides wholesale sales variance. In particular, please confirm whether YEC retail and industrial sales variance and YEC's system losses have influence on the ERA calculation. If not confirmed, please fully explain.

ANSWER:

(a)

The referenced statement from page 1-5 of the YEC filing addresses the DCF determinations affecting YEC (rather than ERA determinations affecting YECL), limitations on monthly reporting of same, and the resulting fact that monthly calculations will be a placeholder with ultimate final calculations performed only on the annual calendar year basis.

Reliance on final annual determinations occurred with past DCF implementation, reflecting the inherent imprecision associated with allocating as between months any long-term average annual hydro generation number. In addition, the YECSIM model assessments used to vary the long-term average diesel generation (and cost) estimates at different grid loads for the test years as approved in Order 2013-01 and for ongoing DCF determinations ultimately rely on an annual assessment even though the model has a weekly time step analysis. Please also see response to YUB-YEC-1-1 (d).

(b)

Not confirmed.

To clarify, Yukon Energy intends that monthly calculations for the ERA (as well as for the DCF) will be a placeholder with ultimate final calculations performed for both only on the annual calendar year basis.

However, the issues related to monthly ERA determinations affecting YECL differ materially from the issues related to monthly DCF determinations affecting YEC (as addressed in (a) above).

- DCF monthly calculations affecting YEC depend on month-by-month assessments of long-term average expected diesel generation versus actual diesel generation; aside from month-to-month expected diesel forecast issues for any specific annual load forecast, it is also necessary in the DCF determination to consider adjustments to the annual grid load forecast (to reflect actual loads experienced) and how this will affect the long-term average expected diesel determination.

- In contrast, ERA monthly determinations affecting YECL are driven initially by factors which have nothing to do with the DCF, namely the variance between actual and forecasts for wholesales by month, the adjustments to this variance as needed to reflect Fish Lake variances between actual and long-term average generation by month, and the related estimates of the wholesale variance impact on YEC generation.

- The DCF related impact on the ERA does not depend at all on consideration of YEC month-by-month DCF determinations and any impression related thereto.

- The DCF related impact on the ERA in the end depends only on the overall annual assessment of the percent share of the wholesale-related YEC generation variance that is accounted for by expected diesel, i.e., line "L" in Table 2 of the January 31, 2014 YEC filing. For monthly assessments of this DCF factor, YEC will assume a placeholder percent share (for the generation variance accounted for by expected diesel) that is reasonable in the circumstances taking into

account the likely annual determination,[1] i.e., the final ERA determination for each year will be as set out in Table 2 of the YEC filing.

(c)

Confirmed for ERA; not confirmed for DCF load forecasts, i.e., DCF adjusts expected diesel as required each year based on actual load (for test year or any other subsequent year), and relevant tables for this determination are to be adjusted (subject to Board review and approval) as required to reflect material changes in load shape and/or capacity of renewable generation.

(d)

With assumed actual wholesale sales at 314,125 MWh in 2014 and 320,965 MWh in 2015 (other variables at 2013 GRA forecast level, including connection of WHCT) the ERA estimate as per approach used for Table 2 in YEC's January 2014 filing (as revised per YUB-YEC-1-25) would be $0.304 million for 2014 and $0.716 million for 2015. Please see detailed calculations in Attachment 1 to this response.

(e)

The ERA charge can vary depending on the following factors besides YECL wholesale purchase variance:

- YECL Fish Lake generation variance from approved long-term average forecast (including related impacts on changes to YEC revenues and YECL costs).

- YEC's system losses as a percent of sales (this factor affects determination of overall generation change due to wholesale variance).

- Factors affecting line "L" percentage in Table 2 of YEC's January 31, 2014 filing (incremental diesel percentage share of generation variance due to wholesale

[1] In a year such as 2012, reference to the GRA Table 1.1-1 would suggest a relevant percentage to assume for the placeholder in any month. In a year such as 2013, Table 2 demonstrates the need to include a material adjustment in the placeholder percentage to reflect the anticipated change related to the GRA forecast for this test year (due to the absence of WHCT, expected diesel for YEC related to actual annual loads will be determined by reference to Table 1.1-1 rather than Table 1.1-2 as assumed in the GRA for determining 2013 rates).

variance); this percentage is an annual determination based on the change in expected diesel generation as a share of the change in total YEC generation for firm sales (any impact on this factor from YEC retail and industrial sales variance is likely to be minimal[2] - the major factor affecting the 2013 percentage relates to AEY's loads, including AEY's forecast industrial customer [WHCT] not being connected, and the fact that this specific industrial load was expected to have minimal impact on expected diesel).

Responses to AEY-YEC-1-3(a) and AEY-YEC-1-4(a) demonstrate ERA variations related to higher YEC system losses (increase in ERA), higher wholesales (increase ERA), and variances in YEC industrial sales (ERA changes in same direction as the change in YEC industrial sales). Regardless of change in any of the above factors, no ERA applies when there is no change in wholesales from forecast (after Fish Lake impacts) and Option A ensures that the YECL deferral account addresses any unrecovered cost impact on YECL.

[2] Assuming YEC losses at 8.7% of sales, the YECL wholesale variance (including Fish Lake impacts) accounts for 82% of the YEC generation variance in 2012 and only 30% in 2013; however, in 2013 YEC retail and industrial sales variance did not drive the change in expected diesel compared to GRA forecast (line "J" in Table 2) - the increase in expected diesel is driven by the forecast YECL industrial (WHCT) not being connected and the need to use Table 1.1-1 rather than Table 1.1-2 to determine expected diesel (see note 6 to Table 2).

REFERENCE: Table 1: Revised DCF Calculation for Actual 2012 and Preliminary Actual 2013 (YEC January 31, 2014 DCF/ERA Submission, p.8)

Table 2: Option A: Revised ERA Calculation for Actual 2012 and Preliminary Actual 2013

(YEC January 31, 2014 DCF/ERA Submission, p.9)

PREAMBLE:

QUESTION:

a) Please provide complete DCF and ERA calculations in the same format as Tables 1 and 2 referenced above for 2012 based on the following scenarios. Apart from the factors as shown in the table below, please hold all other variables (such as the impact of Fish Lake and system losses) at the levels in Table 2.

	Scenario 1 – Actual Data	**Scenario 2 – Losses higher than expected**
YEC Retail and Industrial Sales (MWh)	79,861	79,861
Wholesale Sales (MWh)	310,264	310,264
Losses	8.8217%	12.00%

b) Please provide YEC's approved system loss percentages for the years 2008, 2009, 2012, and 2013.

c) Please provide YEC's actual system loss percentages for the years 2008-2013.

d) Please fully explain all factors that impact YEC system losses.

ANSWER:

(a)

Please see Attachment 1 to this response for requested analysis. Please note that both scenarios use the same information as per Tables 1 and 2 of YEC's filing as revised in YUB-YEC-1-25, except losses and subsequent calculations as per AEY's request noted above. Table 1 also varies assumed actual hydro as required to provide the assumed added generation required.

(b)

YEC's approved system loss percentages (per GRAs) are as noted in the table below.

Year	Losses (%)
2008	8.66
2009	8.42
2012	8.70
2013	8.70

(c)

YEC's actual system loss percentages are as noted in the table below.

Year	Losses (%)
2008	8.91
2009	8.17
2010	8.75
2011	8.71
2012	8.82
2013	9.01

(d)

The following factors impact system line losses:

1. **Distance from generation to use** - The longer the distance energy has to travel via the grid system the more line loss occurs.

2. **Location of generation** - If an area on the grid cannot meet their demands for energy, energy from other areas on the grid has to be transferred in to meet that demand. This transfer of energy results in line loss (distance).

3. **Age and size of line** - The older and smaller the line the more loss will occur when energy is transferred along these lines.

4. **Reporting** - Due to the billing cycle of CIS, the Residential and General Service customer numbers for YEC are a month behind resulting in a small impact on reported line loss vs actual. This will often result in a low line loss one month and a high loss the following month (or vice versa).

Over the period addressed above, YEC has been gaining actual experience with operation of new facilities related to the Carmacks-Stewart Transmission Project (connection of the two grids) and Mayo B.

REFERENCE: Table 1: Revised DCF Calculation for Actual 2012 and Preliminary Actual 2013

(YEC January 31, 2014 DCF/ERA Submission, p.8)

Table 2: Option A: Revised ERA Calculation for Actual 2012 and Preliminary Actual 2013

(YEC January 31, 2014 DCF/ERA Submission, p.9)

PREAMBLE:

QUESTION:

a) Please provide full calculations (in Excel) in the same format as Table 1 and Table 2 referenced above for 2012 to show what the ERA charge from YEC to AEY would be for each of the scenarios below. Other than the changes in YEC industrial sales and/or YEC wholesale sales noted below, please hold all other variables (such as the impact of Fish Lake and system losses) at the levels in Table 1 and Table 2.

Scenario	YEC Retail (Change in GWh from 2012 GRA Forecast)	YEC Industrial (Change in GWh from 2012 GRA Forecast)	YEC Wholesale Sales (Change in GWh from 2012 GRA Forecast)
i)	No change	No change	No change
ii)	No change	No change	+15
iii)	No change	+5	+15
iv)	No change	-5	+15
v)	No change	+5	No change
vi)	No change	-5	No change
vii)	No change	No change	-15
viii)	No change	5	-15
ix)	No change	-5	-15

ANSWER:

(a)

Please see Attachment 1 to this response which provides the Excel file. The file has been prepared based on the revisions to ERA assessments as reviewed in response to YUB-YEC-1-25.

Please note that for scenarios vi) through ix) the load relevant to expected diesel determinations is less than 400 GW.h and as per Note #6 to Table 1.1-1 of YEC's January 2014 Filing the DCF table in the filing does not address load less than 400 GW.h. The expected diesel generation for these scenarios has been estimated based on YECSIM model output outside of Table 1.1-1 of the January 31, 2014 filing.

Table 1: DCF Calculation for Actual 2012 per AEY-YEC-1-4 (a)

Variable cost of YEC diesel calculation

Line No												Notes
L1	Fuel Cost per kW.h	28.71	28.71	28.71	28.71	28.71	28.71	28.71	28.71	28.71	cents/kW.h	Compliance Filing Average Fuel cost

Calculation of Diesel Cost to Charge (Refund) DCF

	Assumptions	**2012** AEY-YEC-1-4 Scenario i) No change from GRA re Sales	**2012** AEY-YEC-1-4 Scenario ii) Wholesale sales are higher by 15 GW.h over GRA	**2012** AEY-YEC-1-4 Scenario iii) Wholesale sales are higher by 15 GW.h over GRA, YEC industrial higher by 5 GW.h over GRA	**2012** AEY-YEC-1-4 Scenario iv) Wholesale sales are higher by 15 GW.h over GRA, YEC industrial lower by 5 GW.h than GRA	**2012** AEY-YEC-1-4 Scenario v) No change in Wholesale sales, YEC industrial higher by 5 GW.h over GRA	**2012** AEY-YEC-1-4 Scenario vi) No change in Wholesale sales, YEC industrial lower by 5 GW.h than GRA	**2012** AEY-YEC-1-4 Scenario vii) Wholesale sales are lower by 15 GW.h than GRA, no change in YEC retail and industrial	**2012** AEY-YEC-1-4 Scenario viii) Wholesale sales are lower by 15 GW.h than GRA, YEC industrial increase by 5 GW.h	**2012** AEY-YEC-1-4 Scenario ix) Wholesale sales are lower by 15 GW.h than GRA, YEC industrial increase by 5 GW.h		
L2	YEC Grid load	405,553	421,873	427,313	416,433	410,993	400,113	389,233	394,673	383,793	MW.h	per AEY-YEC-1-4 (a)
L3	Fish Lake	3,388	3,388	3,388	3,388	3,388	3,388	3,388	3,388	3,388	MW.h	Fish Lake actual
L4=L2+L3	Total Grid load	408,941	425,261	430,701	419,821	414,381	403,501	392,621	398,061	387,181	MW.h	
	Assumed Actual Generation Sources											
L5	YECL Fish Lake	3,388	3,388	3,388	3,388	3,388	3,388	3,388	3,388	3,388	MW.h	Fish Lake actual
L6	YEC Hydro	402,052	418,231	423,624	412,838	407,445	396,659	385,873	391,266	380,480	MW.h	Prorated based on Scenario i)
L7	YEC Diesel	3,057	3,198	3,245	3,151	3,104	3,010	2,916	2,963	2,869	MW.h	Scenario i) is actual for 2012. Other scenarios are residual of hydro and wind from total load.
L7a	*YEC Diesel charged to capital*	*373*	-	-	-	-	-	-	-	-		Assume no diesel charged to capital
L7b	*YEC Net Diesel*	*2,683*	*3,198*	*3,245*	*3,151*	*3,104*	*3,010*	*2,916*	*2,963*	*2,869*		
L8	YEC Wind	445	445	445	445	445	445	445	445	445	MW.h	Assume at 2012 level
L9	Total Grid load	408,941	425,261	430,701	419,821	414,381	403,501	392,621	398,061	387,181	MW.h	
	Expected Generation Sources											
L10	YECL Fish Lake (expected)	4,380	4,380	4,380	4,380	4,380	4,380	4,380	4,380	4,380	MW.h	Unit #2 at 4.380 GW.h - assume no Unit #1 generation.
L11	YEC Wind (expected)	239	239	239	239	239	239	239	239	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	404,322	420,642	426,082	415,202	409,762	398,882	388,002	393,442	382,562	MW.h	
L13	Expected Base Diesel Generation	6,000	14,100	16,400	11,800	7,800	5,600	2,800	3,900	2,000	MW.h	Derived from Table 1.1-1, Revised DCF Proposal
L14=(L12- X GW.h)x X%	Expected Incremental Diesel Generation	1,556	295	541	93	1,905					MW.h	Derived from Table 1.1-1, Revised DCF Proposal
L15=L13+L14	Total Expected YEC Diesel Generation	7,556	14,395	16,941	11,893	9,705	5,600	2,800	3,900	2,000	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	7,556	14,395	16,941	11,893	9,705	5,600	2,800	3,900	2,000	MW.h	100% of long-term average
L17=L7	YEC Diesel Generation	2,683	3,198	3,245	3,151	3,104	3,010	2,916	2,963	2,869	MW.h	Net of capital diesel
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 4,873	- 11,198	- 13,697	- 8,742	- 6,601	- 2,590	116	- 937	869	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($1,399)	($3,215)	($3,932)	($2,510)	($1,895)	($744)	$33	($269)	$249		

Note:

1. Under the scenarios vi) through ix) the load relevant to expected diesel determinations is less than 400 GW.h and as per Note #6 to Table 1.1-1 of YEC's January 2014 Filing the DCF table would need to be updated if the load is less than 400 GW.h. Therefore, the expected diesel generations are estimated based on YECSIM model outside of Table 1.1-1.

Table 2: ERA Calculation for 2012 per AEY-YEC-1-4 (a)

	2012										
	AEY-YEC-1-4 Scenario i)	AEY-YEC-1-4 Scenario ii)	AEY-YEC-1-4 Scenario iii)	AEY-YEC-1-4 Scenario iv)	AEY-YEC-1-4 Scenario v)	AEY-YEC-1-4 Scenario vi)	AEY-YEC-1-4 Scenario vii)	AEY-YEC-1-4 Scenario viii)	AEY-YEC-1-4 Scenario ix)		
	No change from GRA re Sales	Wholesale sales are higher by 15 GW.h over GRA	Wholesale sales are higher by 15 GW.h over GRA, YEC industrial higher by 5 GW.h over GRA	Wholesale sales are higher by 15 GW.h over GRA, YEC industrial lower by 5 GW.h than GRA	No change in Wholesale sales, YEC industrial higher by 5 GW.h over GRA	No change in Wholesale sales, YEC industrial lower by 5 GW.h than GRA	Wholesale sales are lower by 15 GW.h than GRA, no change in YEC retail and industrial	Wholesale sales are lower by 15 GW.h than GRA, YEC industrial increase by 5 GW.h	Wholesale sales are lower by 15 GW.h than GRA, YEC industrial lower by 5 GW.h		
GRA approved wholesales	296,000	296,000	296,000	296,000	296,000	296,000	296,000	296,000	296,000	MW.h	A
Actual wholesales	296,000	311,000	311,000	311,000	296,000	296,000	281,000	281,000	281,000	MW.h	B
Incremental	0	15,000	15,000	15,000	0	0	-15,000	-15,000	-15,000	MW.h	C=B-A
Less: Fish Lake Impact	992	992	992	992	992	992	992	992	992	MW.h	D
Incremental net of Fish Lake	-992	14,008	14,008	14,008	-992	-992	-15,992	-15,992	-15,992	MW.h	E=C-D
Total YEC's generation net of secondary, LTA wind & FL	404,322	420,642	426,082	415,202	409,762	398,882	388,002	393,442	382,562	MW.h	F - per Table 1 (DCF), L12
GRA approved load forecast, net of expected wind	405,314	405,314	405,314	405,314	405,314	405,314	405,314	405,314	405,314	MW.h	G
Total YEC incremental generation relative to GRA approved	-992	15,328	20,768	9,888	4,448	-6,432	-17,312	-11,872	-22,752	MW.h	H=F-G
Expected diesel generation at actual load	7,556	14,395	16,941	11,893	9,705	5,600	2,800	3,900	2,000	MW.h	I
Expected diesel generation at GRA load (approved)	7,926	7,926	7,926	7,926	7,926	7,926	7,926	7,926	7,926	MW.h	J
Total YEC expected incremental diesel generation	-370	6,469	9,015	3,967	1,779	-2,326	-5,126	-4,026	-5,926	MW.h	K=I-J
Incremental Diesel in Base Rates	37.3%	42.2%	43.4%	40.1%	40.0%	36.2%	29.6%	33.9%	26.0%		L=K/H
Generation Variance Charged for Diesel Cost	-402	6,433	6,616	6,115	-432	-390	-5,152	-5,900	-4,532	MW.h	M=E*L*Losses
Impacts on YEC	ERA Based on All Incremental Wholesale (100%)										
Added Revenue	-	1,403	1,403	1,403	-	-	1,403 -	1,403 -	1,403	$000	N=C*(8.298+average rider)
Added Cost	- 116	1,847	1,899	1,756 -	124 -	112 -	1,479 -	1,694 -	1,301	$000	O=M*28.71
Net Impact on YEC	116 -	443 -	496 -	352	124	112	76	291 -	102	$000	P=N-O
ERA charge to YECL	- 116	443	496	352 -	124 -	112 -	76 -	291	102	$000	Q=(-P)
Impacts on YECL											
Added Revenue	- 125	1,765	1,765	1,765 -	125 -	125 -	2,015 -	2,015 -	2,015	$000	R=E/1.062*average energy rate
Added Cost	- 116	1,688	1,741	1,597 -	124 -	112 -	1,320 -	1,535 -	1,142	$000	S=C*8.298 +Q
Impact on YECL	- 9	77	24	168 -	1 -	13 -	694 -	480 -	872	$000	T=R-S
YECL Deferral Account - Rider charge (Rebate)	-	-	-	-	-	-	-	-	-	$000	U=If S>0 then 0 if T>0; otherwise (-T) U=If S<0 then 0 if T<0: otherwise (-T)
Net Impact on YECL after Deferral Charge (Rebate)	**- 9**	**77**	**24**	**168 -**	**1 -**	**13 -**	**694 -**	**480 -**	**872**	$000	V=T+U

Note:

1. Under the scenarios vi) through ix) the load relevant to expected diesel determinations is less than 400 GW.h and as per Note #6 to Table 1.1-1 of YEC's January 2014 Filing the DCF table would need to be updated if the load is less than 400 GW.h. Therefore, the expected diesel generations are estimated based on YECSIM model outside of Table 1.1-1.

REFERENCE: "[…] actual diesel costs" [as] are reflected in its accounts are currently determined in any year based on long-term average hydro generation (not actual hydro generation) requirements at the actual grid generation level in that year, i.e., under the proposed DCF in YEC's filing, the difference in diesel generation costs between actual and long-term average requirements is the amount that goes into (or comes out of) the DCF such that in 2012 and subsequent years YEC's "actual diesel costs" are based on long-term average hydro generation."

(YEC June 30, 2014 Supplemental filing, p. 1-2)

"The YECSIM model is a planning model that is designed to provide an accurate representation of the YEC power system under a variety of hydrologic conditions. It has been custom made to accommodate all significant factors that affect the operation of the YEC power system, including the complex rules of operation and the regulatory demands on YEC. It is not designed to forecast actual diesel expected to be incurred in a particular year. It is designed to provide what the diesel requirement would be under long-term average water conditions at a particular load level and under assumed licence and generation installation conditions."

(YEC June 30, 2014 Supplemental Filing, p. 2-3)

PREAMBLE:

AEY wishes to test the data and assumptions underlying the YECSIM model that is being used to calculate the DCF and ERA.

QUESTION:

a) Please confirm that YEC's "Actual Diesel Costs" as referenced above are, in fact, derived from the YECSIM model.

b) Please confirm that YEC has not applied for and obtained Board approval of the YECSIM. If not confirmed, please explain in what Board decision and for what purposes the YECSIM was approved.

c) Please fully explain how YEC's YECSIM model "accommodate[s] all significant factors that affect the operation of the YEC power system, including the complex rules of operation and the regulatory demands on YEC." Are the assumptions regarding YEC's operation of its power system incorporated in YECSIM based on YEC's historical operation of the system?

d) Please provide a copy of all data, calculations and assumptions used to derive the YECSIM model(s) used to calculate the DCF/ERA amounts for 2012 and 2013 as filed by YEC in its January 31, 2014 submission.

ANSWER:

(a)

Confirmed, in the sense that YEC's expense costs for diesel fuel with the DCF, in 2012 and subsequent years, are based on "expected diesel" generation volumes and not actual diesel generation that occurred in the year. "Expected diesel" generation for the actual generation loads in each year is derived from the YECSIM model determination of long-term average hydro generation water conditions as set out in Table 1 of the January 31, 2014 filing and YUB-YEC-1-25.

The reference above is actually part of a sentence that in full reads as follows, and fully explains how the process is implemented:

> "YEC understands that this ["actual diesel costs"] is defined by YECL as actual YEC generation, without regard to the fact that YEC's "actual diesel costs" as reflected in its accounts are currently determined in any year based on long-term average hydro generation (not actual hydro generation) requirements at the actual grid generation level in that year, i.e., under the proposed DCF in YEC's filing, the difference in diesel generation costs between actual and long-term average requirements is the amount that goes into (or comes out of) the DCF

such that in 2012 and subsequent years YEC's "actual diesel costs" are based on long-term average hydro generation."

Under the proposed DCF in YEC's filing, the difference in diesel generation costs between actual and long-term average requirements [determined based on YECSIM, as per Order 2013-01] is the amount that goes into (or comes out of) the DCF such that in 2012 and subsequent years YEC's "actual diesel costs" for its accounts are based on long-term average hydro generation.

(b)

YECSIM is one of many models used by Yukon Energy for capital planning and assessing future revenue requirements. Such models continue to be used by YEC and other utilities in regulatory filings, without seeking or requiring separate formal approvals from regulators.

YEC has consistently utilized YECSIM for recent assessments of planning and revenue requirement applications that the Board has ultimately recommended or approved (as appropriate for the proceeding), including recent Part 3 project applications that the Board has reviewed (namely, the Mayo B Project application and the Whitehorse Diesel-Natural Gas Conversion Project application), as well as for forecasts of long-term average hydro generation and diesel generation requirements as approved by the Board in Order 2013-01 for the YEC 2012-13 GRA.

(c)

For an overview of the YECSIM model's development and approach, please see YUB-YEC-1-3(a). As reviewed below, the assumptions in the model regarding YEC's operation of its power system reflect the full range of relevant considerations.

The YECSIM model incorporates the operation rules and license requirements that specifically apply to each site. This includes minimum flow requirements for each river, and each segment of the river when the requirements change along the same water course, as well as the maximum and minimum levels of operation of each lake in the system, in accordance to the license. The model also includes seasonal changes, when these apply, as well as the necessary provisions to adjust during a simulation (for

instance, in the operation of Aishihik Lake for which minimum levels are based on the 10-year rolling average of minimum spring levels). Rule curves are developed at the beginning of each simulation to ensure satisfaction of the input requirements.

The model also includes conditions that derive from YEC's operation, such as the priority sequence for drawing water from the lakes in the system. These are based on discussions with YEC, and have been derived from experience and knowledge of the sites.

Other conditions that relate to the physical characteristics of the stations and reservoirs, such as tailwater rating curves and discharge rating curves, storage capacity, were included in the model based on the data that YEC provided. The characteristics of each plant (flow capacity, head, head losses, efficiencies) are also consistent with records.

As an example of the model reflecting the condition and historical water levels and outflows for each generating station and/or reservoir, the power generated at the Whitehorse Rapids Generating Station is calculated from the differential water levels (reservoir level minus tailwater level) that exist at that structure. It requires an accurate algorithm that computes the tailwater level as a function of the river flow, and acknowledges the fact that in winter there can be some increases in tailwater due to ice. The algorithms that are built into the model have been based on surveyed water levels and known plant outflows.

The YECSIM model has the capability of making changes to the elements listed above. This allows adjusting the model to potential changes on these conditions or to evaluate alternatives.

The historical operation of the system was revised at the developing stages to obtain a general understanding of YEC's operation. At those stages, simulations were carried out to verify in general that the model results properly corresponded to the operation of the WAF system. Model results were discussed with YEC at that stage. However, the YECSIM model is not set to replicate the past; but to simulate the system operation within the conditions imposed by physics, regulation and operational priorities, in order to supply the estimated loads with the available hydrologic inputs.

(d)

YEC cannot provide all the data, calculations and assumptions used to derive the YECSIM model without actually providing the model, which is proprietary. To assist in understanding what is included in YECSIM, a list of key elements is provided below

The calculations in the model are based on general rules of physics (such as energy derived from flow and head, head loss calculations) or in available data (rating curves, storage curves).

The data that constitutes the input to the YECSIM model includes:

- Hydrologic Inputs:
    - Inflows Available for Outflows (total inflows minus ground water outflows and evaporation) to all the reservoirs in the system.
- Reservoirs:
    - Elevation-Storage Volume Curves;
    - Minimum and maximum water levels as per operation license;
    - Initial water level;
    - Minimum riparian outflows at each structure;
    - Discharge rating curves (water elevation vs. flow) for spillways and control structures;
    - Priorities for drawdown of reservoir levels; and
    - Limits to maximum winter draw-down if applicable.

- Generating Stations:
    - Efficiency curves (efficiency vs flow);
    - Station service loss;
    - Transmission losses;
    - Forced outages losses;
    - Tailwater rating curve (s) and seasonal changes;
    - Maximum plant flows per week;
    - Head loss as a function of flow; and
    - Minimum allowable outflows flows at each site.
- Energy Inputs:
    - Total load for each simulated year;
    - Weekly factors to estimate weekly loads;
    - Load duration curve to estimate hourly peaks within each week;
    - Maximum diesel capacity;
    - Other energy sources (optional); and
    - System configuration to be used in the simulation: WAF, MD, individual stations, interconnected.

The user can define inputs to the model, including the following:

- Rules of operation and the regulatory demands for each lake/reservoir, including minimum and maximum allowed water levels, minimum and maximum outflows;

- Minimum and maximum outflows for each generating station, flow rates and generation unit efficiencies, tailwater and head loss coefficients;

- Load data, including weekly distribution and load duration curve for the week; and

- Inflows Available for Outflows, the inflows estimated based on historical water levels and outflows.

REFERENCE:

Table 2: Option A: Revised ERA Calculation for Actual 2012 and Preliminary Actual 2013

ERA forecast for 2012 and 2013

	2012	2013 Preliminary		
GRA approved wholesales	296,000	307,147	MW.h	A
Actual wholesales	310,264	307,927	MW.h	B
Incremental	14,264	780	MW.h	C=B-A
Less: Fish Lake Impact	992	693	MW.h	D
Incremental net of Fish Lake	13,272	86	MW.h	E=C-D
Total YEC's actual generation net of secondary	424,541	419,349	MW.h	F
GRA approved load forecast	405,553	416,387	MW.h	G
Total YEC incremental generation relative to GRA approved	18,987	2,962	MW.h	H=F-G
Expected diesel generation at actual load	15,622	13,326	MW.h	I
Expected diesel generation at GRA load (approved)	7,926	11,006	MW.h	J
Total YEC expected incremental diesel generation	7,696	2,320	MW.h	K=I-J
Incremental Diesel in Base Rates (see Note 6)	49.5%	81.1%		L=K/H
Generation Variance Charged for Diesel Cost	5,853	76	MW.h	M=E*L*Losses
Impacts on YEC				
	ERA Based on All Incremental Wholesale (100%)			
Added Revenue	1,242	9	$000	N=E*(8.298+average rider)
Added Cost	1,680	22	$000	O=M*28.71
Net Impact on YEC	- 439	- 13	$000	P=N-O
ERA charge to YECL	439	13	$000	Q=(-P)
Impacts on YECL				
Added Revenue	1,672	11	$000	R=E/1.062*average energy rate
Added Cost	1,540	20	$000	S=E*8.298 +Q
Impact on YECL	132	- 9	$000	T=R-S
YECL Deferral Account - Rider charge (Rebate)	-	9	$000	U=if T>0 then 0, otherwise (-T)
Net Impact on YECL after Deferral Charge (Rebate)	132	-	$000	V=T+U

"Change in expected diesel generation **reflects no WHCT load** in 2013, and resulting need to retain updated Table 4.1-1 for GRA Compliance Filing Proposal (2012 DCF), which has higher expected diesel for load without WHCT than forecast in Table 4.1-2 (2013 GRA with WHCT load)."

(YEC January 31, 2014 DCF/ERA Submission, Table 2, p. 9, Footnote 6)

"In YEC's 2012/13 GRA, the YUB approved YEC forecast diesel generation (GW.h) and diesel generation costs ($000) based on long-term average (LTA) hydro generation determined using the YECSIM model6. Based on Order 2013-04, diesel generation was included in rates for 2012 at 7.926 GW.h and for 2013

at 11.006 GW.h (reflecting the total YEC generation as then forecast). These are the diesel costs actually included in rates."

(YEC June 30, 2014 Supplemental Filing, Attachment 1, p 1-3)

PREAMBLE:

QUESTION:

a) Please confirm that "Table 4.1-1" in Footnote 6 referenced above is actually referring to Table 1.1-1 from page A1.1-8 of YEC's January 31, 2014 DCF/ERA Submission. If not confirmed, please fully explain.

b) Please confirm that "Table 4.1-2" in Footnote 6 referenced above is actually referring to Table 1.1-2 from page A1.1-9 of YEC's January 31, 2014 DCF/ERA Submission. If not confirmed, please fully explain.

c) Please confirm that Table 1.1-1, which assumed only Minto & Alexco mine loads, was used to calculate the "Expected diesel generation at actual load" for 2012 on line I of Table 2 above. If not confirmed, please fully explain.

d) Please confirm that Table 1.1-2, which assumed WHCT and other industrial loads for 2013, was used to calculate the "Expected diesel generation at GRA load (approved)" in line J of Table 2 above. If not confirmed, please fully explain.

e) Please detail under what circumstances and how frequently YEC proposes to update the YECSIM model in the future.

f) Please confirm that YEC's proposed incremental diesel included in base rates in 2013 on line L of Table 2 above (81.1%) is higher than incremental diesel in rates at the highest grid loads included in both Tables 1.1-1 and 1.1-2 (78%). If confirmed, please justify how the calculation of 81.1% can be correct. If not confirmed, please fully explain.

ANSWER:

(a) and **(b)**

Confirmed. Tables 4.1-1 and 4.1-2 from YEC's 2012/13 GRA Compliance Filing are the same as Tables 1.1-1 and 1.1-2 of YEC's January 31, 2014 Revised DCF/ERA filing.

(c)

Confirmed.

(d)

The expected diesel generation numbers in line J of Table 2 are approved diesel generation forecasts for 2012 and 2013 Test Years from YEC's 2012/13 GRA, including (for 2013) forecast WHCT loads served by YECL with impacts on YEC wholesales. The expected diesel generation in line J of Table 2 of 7.9 GW.h for 2012 was calculated on the basis of Table 1.1-1, while the expected diesel generation of 11.0 GW.h for 2013 was calculated on the basis of Table 1.1-2 of YEC's January 31, 2014 Revised DCF/ERA Filing (see Table 1, line L13).

(e)

The expected diesel generation numbers in the Tables 1.1-1 and 1.1-2 are based on YEC's current renewable generation resources, license and operation requirements. Any new additional renewable generation resources, or changes to the existing license and operation requirements (e.g. reservoir levels, outflows, etc.) will require updates to these tables. Also, updates will be required when there is any new mine or industrial loads that are connected to the grid, and/or when the load exceeds assumed load range in the tables (please see notes to the tables). Please also see response to YUB-YEC-1-26 and YUB-YEC-1-27.

(f)

It is confirmed that incremental diesel included in base rates in 2013 on line L of Table 2 above (81.1%) is higher than incremental diesel in rates at the highest grid loads

included in both Tables 1.1-1 and 1.1-2 (78%). The percentage at line L, however, is not directly derived from these tables – it is derived for 2013, as shown at Table 2, based on "expected diesel" as per the approved GRA (derived from Table 1.1-2, assuming WHCT load as forecast in the approved GRA to be supplied by YECL through wholesales from YEC) and "expected diesel" as per Table 1 based on preliminary actual grid generation and actual YECL wholesales for 2013 and derived from Table 1.1-1 [not Table 1.1-2] which, as specified in the GRA, is required to be done until such time as WHCT is connected with a notable load on the grid.

This was explained in Note #6 to Table 2, where change in expected diesel generation for 2013 reflects no WHCT load in 2013, and the resulting need to retain Table 1.1-1 for 2013, which has higher expected diesel for the load without WHCT than forecast in Table 1.1-2 (with WHCT load).

Please also see YUB-YEC-1-16 which reviews the specific 2013 impact on expected diesel due to the actual load not including WHCT as forecast in the approved GRA (and included as part of the forecast wholesales in the approved GRA).

REFERENCE: "It is readily apparent that there is a very big difference in 2012 between the proposed DCF and YECL's proposal as regards 2012 funds going into the DCF to protect ratepayers against future drought impacts, i.e., the YECL proposal results in payments into the DCF in 2012 related to increased grid generation (above GRA forecast) at less than 10% of what is proposed in the YEC filing based on actual generation requirements in that year."

(YEC June 30, 2014Supplemental Filing, p. 1-4)

"2012 – YEC [proposal] to refund DCF $3.715 million"

(YEC June 30, 2014 Supplemental Filing, Appendix 1-B, P. B-1)

"2012 – [Under AEY's proposal] YEC to refund new Diesel Deferral Account $1.609 million;"

(YEC June 30, 2014 Supplemental Filing, Appendix 1-B, P. B-1)

PREAMBLE:

QUESTION:

a) Please provide YEC's calculation which shows that AEY's proposal results in payments into the DCF in 2012 "at less than 10%" of YEC's contribution.

ANSWER:

(a)

Please note the percentage reference in the quote relates to "increased grid generation (above GRA forecast)", which affects only a portion of the total DCF or Diesel Deferral Account calculations referenced for 2012.

As was noted on page 1-4 of YEC's June 30, 2014 Supplementary Filing, the YECL proposal assumes "% Fuel included in rates" at 2.12%[1] [which is applied to any "increased grid generation (above GRA forecast)"], compared to 40.5% under YEC's proposal to be charged to DCF for incremental generation. 2.12% is less than 10% of YEC's proposal at 40.5%.

[1] AEY January 2014 Filing, Table 3.1 Excel file.

REFERENCE: "The question assumes that each new mine is "responsible" for the incremental diesel generation that is expected, on a long term average basis, to be required from overall growth of the integrated grid. The question ignores any similar suggestion regarding any other source of growth on this grid, e.g., Whistle Bend or other major new subdivisions to accommodate strong and ongoing non-industrial growth.

Attempts to assign responsibility for new "incremental" diesel generation to specific customers or customer classes are fraught with serious issues of principle.

In principle, each customer and each customer class contributes to load on the grid, and to the current "incremental" load at any time of day or season of the year. Every kW.h consumed is a part of the load that must be served from existing and new resources, regardless as to the length of time that customer has been on the system (e.g., old house versus new house, old industry versus new industry)."

(YEC 2012-2013 GRA proceeding, YEC IR response to LE-YEC-1-38)

PREAMBLE:

AEY is seeking further understanding about the above statement.

QUESTION:

a) Please confirm that YEC believes diesel costs should not be attributable to specific customers. If not confirmed, please fully explain.

b) Please confirm that the ERA calculation attributes specific diesel costs to a specific customer, i.e. AEY. If not confirmed, please fully explain.

ANSWER:

(a) and **(b)**

The reference above to a response to the earlier YEC 2012/2013 GRA IR has no relevance to the past approved ERA or the current proposal to update the ERA to reflect current conditions.

YEC's earlier response to LE-YEC-1-38 addressed a question asserting that individual new industrial loads connecting to the grid, or the industrial class overall, should be responsible for the full cost of the incremental increase in diesel generation associated with connecting such loads to the grid. Such an approach would be rate discrimination, charging one retail or industrial class or customer for firm service on an entirely different basis than all other customers or customer classes.

However, the ERA does not do what was being asserted in the earlier LE IR and does not result in rate discrimination; YECL also is a regulated utility recovering its prudently incurred costs from its customers, and not a typical retail or industrial customer.

The ERA was created to ensure that YECL's retail WAF loads are served by YECL under the same risk profile as all other YEC and YECL retail and industrial loads in Yukon, i.e., when YEC or YECL's retail loads vary, and this variation in load drives changes in the quantities of diesel generation required, YEC or YECL carries the cost of that added diesel generation needed to supply its retail customers. However, if the diesel generation is driven by water variability rather than by changing load requirements, YEC and YECL do not carry the risk, i.e., ratepayers bear the risk through the Diesel Contingency Fund mechanism.

Separate from this distinctive wholesale rate example, it can also be noted that run-out rates applied in the past to incremental use by individual retail and industrial customers on the Hydro grid also reflected YEC incremental diesel generation costs – and the application of such run out rates to all classes for incremental use (beyond block 1 rate use levels) has been viewed as sound rate design and not an example of rate discrimination. In this context, the past and currently proposed ERA is similar to a run out retail rate in that it applies only to incremental changes in use and not total use by YECL.

REFERENCE: "However, since diesel is now forecast to be on the margin in the test years these mechanisms once again become relevant and important."

(YEC 2012-2013 GRA Application, p. 2-12)

"The Fund does not currently deal with secondary sales conditions or revenues, since the Fund only is active when diesel is on the margin (i.e., when secondary sales are not allowed).

UPDATE: Secondary revenues remain highly variable component of YEC's income structure and fundamentally are made feasible from time to time based on water flows. For this reason a logical connection exists to the updated DCF and the overall objective of facilitating rate stability. In order to have stability in GRA rate revenues it is proposed that YEC will forecast 0 GWh of secondary sales in any GRA for the purposes of setting rates whenever annual long-term average hydro forecasts indicate the need for forecast baseload diesel/gas generation costs to be included in rates. In the event secondary sales arise secondary revenues will then be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), thereby helping to fund the long-term risks related to hydro generation water condition fluctuation."

(YEC 2012-2013 GRA Application, Attachment 3.2, Page 6)

"Secondary energy is available from time to time to General Service or Industrial customers in parts of the WAF and Mayo-Dawson systems as determined by Yukon Energy based on the availability of surplus hydro."

(Rate Schedule 32)

	For Standard metered Secondary Service Customers	
Year	**Secondary Sales 'ON'**	**Secondary Sales 'OFF'**
2012	July 10, 2012	October 21, 2012
2013	July 31, 2013	October 31, 2013
2014	June 19, 2014	

PREAMBLE:

AEY is seeking further understanding about the concept of "diesel on the margin."

QUESTION:

a) Please provide the dates and times of YEC's activation of secondary sales for its SCADA customers from 2012 to today.

b) Please explain why diesel should be considered "on-the-margin" all of the time in 2012 and 2013 when secondary sales were "on" for a substantial part of the year.

c) Please list any new customers engaged by YEC in 2012, 2013 or 2014 that have been offered secondary sales.

ANSWER:

(a)

YEC secondary sales were activated for YEC's SCADA customers during the following time periods:

- 2012: July 10 to October 24.
- 2013: August 1 to October 1.
- 2014: June 9 to current.

(b)

As approved in Board Order 2013-01, diesel has been considered "on the margin" for 2012 and 2013 total loads based on the forecast needed in each test year for material firm diesel generation at 100% of long-term average (LTA) hydro generation water conditions. These determinations were made for the test years when (based on the GRA as filed in April 2012) actual hydro generation water conditions were forecast to be well above LTA (see for example YUB-YEC-1-1(a)). Actual diesel generation (or its absence) has no bearing today or in the past on the determination as to whether diesel is "on the margin (see YUB-YEC-1-1, YUB-YEC-1-4), whereas actual access to secondary sales is determined based on actual surplus hydro generation due to actual water conditions.

In each of the above years from 2012 to 2014 (current) secondary sales were available over the summer period only (i.e., from June or July until October). The availability of secondary sales over the summer periods noted relates to the fact that over this period there was higher than annual average hydro generation as well as (for much of this seasonal period) lower than annual average grid loads. Secondary sales were not available over the winter months for any of the years noted in response to (a) above.

The 2012/2013 General Rate Application noted that system growth since the closure of the Faro mine, and resulting depletion of surplus hydro, meant that secondary sales revenue benefits were no longer available on a reliable forecast basis going forward to reduce total revenues required to be collected in rates. Secondary sales (and related revenues) were not forecast to be available in the test years and were not expected to be available on more than a limited basis going forward.

The 2012-13 GRA also recognized that, notwithstanding that diesel is now on the margin for annual generation forecasts, secondary sales could still occur during high water years or seasons – and, in order to enhance rate stability and augment the DCF funds available for future low water years, the 2012-13 GRA proposed that any future secondary revenues be fully assigned to the DCF (which benefits ratepayers in dealing with future fossil fuel generation costs resulting from lower than average hydro generation) rather than be included as revenues to YEC. The Board rejected this approach in Order 2013-1.

(c)

New customers engaged by YEC in 2012, 2013 or 2014 that have been offered secondary sales are as follows:

- 2012: Chilkoot Brewing, Quadra Equities, City of Whitehorse, YTG Law Centre.
- 2013: Chilkoot Brewing, City of Whitehorse (all year), YTG Law Centre.
- 2014: City of Whitehorse (January 1-current).

REFERENCE: "253. The Board is concerned that the DCF masks market signals and that, in times of a drought, consumers will be removed from the signal to reduce consumption. The problem with smoothing rates is that it mutes market signals and hence consumer behavior.

254. In addition, the Board notes that the use of the fund in the past has been sporadic as evidenced by the fact that the fund has not been active since 1999. Such periods of infrequent use raise issues of intergenerational inequity in that a consumer contributing to a fund today may benefit another consumer several years later."

(Appendix A to Board Order 2013-01, p. 54)

PREAMBLE:

QUESTION:

a) Please explain how YEC's proposed DCF/ERA mechanism addresses the Board's concerns regarding masked market signals.

b) Please explain how YEC's proposed DCF/ERA mechanism addresses the Board's concerns regarding intergenerational inequity.

ANSWER:

(a)

The proposed DCF/ERA addresses market signal concerns in the same way as such concerns were addressed in the DCF/ERA as previously approved by the Board. In reviewing this issue, the DCF is the key mechanism, i.e., the ERA primarily addresses cost sharing between the two utilities with little if any impact on ratepayers.

The DCF was established specifically to smooth out short term price variability related to water availability and to instead provide firm rate customers with stable and appropriate longer term price signals. Further, due to lack of any interconnection with external grids,

there is no broader "market" signal as such to be communicated to consumers as regards such cost variances, similar to what might otherwise apply on interconnected southern grids.

Yukon Energy addressed this issue in Attachment 2 (pages 2-6 to 2-7) of the June 30, 2014 Supplementary Filing, noting as follows (see also response to (b) below):

- Rate design criteria are inherently competing, most notably "economic and price signals" (i.e., economic efficiency) versus "rate stability and predictability".

- From the outset of YEC's rates being regulated by the Board, it has been accepted as a basic principle that diesel cost variances from forecast due to water availability variances are a ratepayer risk and not a utility risk. Similar to other hydro-based systems, the system in place in Yukon to deal with water flow variation since the 1990's has been intended to maximize rate stability and predictability and mute the harsh short-term economic efficiency criteria as it arises with respect to diesel cost changes related only to water availability variances from approved forecasts used to set rates.

- If economic efficiency criteria principles had been favoured principles in relation to addressing water flow variation, a DCF (or similar mechanism) would not have been adopted to stabilize rates and rates would have varied based on short term water conditions at the time of each GRA. For example, when water conditions were above average, rates would have been relatively low, and in the case of low water, or drought conditions, there would have been harsh (and likely impractical) rate increases or special riders required to recover higher diesel costs. In short, the very concept of including long-term average water and a DCF in the rate system (as approved in Board Order 2013-01 as well as in the 1996/97 GRA in response to the joint submission of YEC and YECL) is intended to increase the rate stability of the system and decrease the harshness of the short-term economic efficiency outcome.

If an alternative approach was to be considered, providing price signals related to water availability would create many new concerns.

For example, as noted under (b) below, it is not realistic to assume that the "cost of a severe drought" could ever be borne by only those ratepayers using power at the time of the drought. As reviewed in YUB-YEC-1-14, YUB-YEC-1-31(b), and Attachment 1 to YUB-YEC-1-1(b and c), the worst year drought condition is currently expected to require more than 100 GW.h of diesel with single year fuel costs at current approved diesel fuel prices exceeding $30 million - and with prospects for extended low water conditions to occur over six consecutive years. Such conditions would create several practical issues for any attempt to set prices based on actual annual diesel fuel costs, including:

- The difficulty of preparing, reviewing and approving in a timely way (i.e., to be operative in the year of the drought) the necessary GRA submissions needed to approve the needed rate changes.

- Aside from time needed for regulatory processes, assessment of actual water conditions affecting any given year can be subject to its own issues, i.e., forecasts for a subsequent year are subject to material change up to the end of the previous summer, and actual water conditions during any given year can also obviously change water conditions for that year.

- In addition to the above issues, imposing such added drought costs in rates for the affected year (or even spread over "a few" years) would result in "rate shock" for all Yukon ratepayers. In practice, one way or the other, drought-related cost impacts would need to be charged to ratepayers over many years, i.e., including many years beyond when the actual drought water conditions occurred.

Looking beyond issues related to trying to charge drought costs only during drought conditions, providing price signals related to water availability would also create issues for a range of consumer and utility investments and tend to frustrate rather than enhance effective long-term planning by ratepayers and the utility. Basic examples of such issues would include:

- In high water years, ratepayers would be given low prices for power, encouraging increased power use, investment in electric heating, minimizing of DSM, etc.; high water years would also mask any rate impacts related to major increases in fuel prices, increased need for thermal generation at LTA conditions, and the benefit of investing in new renewable resources to displace fossil fuels.

- In low water years, ratepayers would be given much higher prices for power, encouraging (to the extent feasible) reduced power use, switching to other heat sources, maximizing DSM, etc.; low water years would send price signals of long-term power costs well above the likely long term requirement, inhibiting business and consumer confidence in Yukon's ability to provide affordable and competitive power costs.

In summary, the DCF allows the Board to set rates that display rather than mask the expected long-term cost of thermal generation based on current thermal fuel prices, grid renewable generation capability, and forecast grid loads. The ability to provide such price signals is particularly timely and important today when LTA thermal generation requirements are notably growing (due to "diesel on the margin" once again being relevant) at a time when high water conditions mask the underlying change that is taking place.

(b)

The proposed DCF/ERA addresses intergenerational inequity concerns in the same way as such concerns were addressed in the DCF/ERA as previously approved by the Board. In reviewing this issue, the DCF is the key mechanism, i.e., the ERA primarily addresses cost sharing between the two utilities with little if any impact on ratepayers.

Yukon Energy addressed this issue in Attachment 2 (pages 2-7 to 2-8) of the June 30, 2014 Supplemental Filing, noting as follows:

- When considering the impacts of an extreme drought, some intergenerational inequity will exist whether funds are collected before the event occurring or funds are collected after the event through required rate increases that must of necessity be spread over many years (due to the magnitude of the cost recovery required). Either way, ratepayers not present at the time of the drought will be required to pay part of the costs of the drought.

- The DCF was inactive over the last decade largely due to the material surplus hydro generation on the system due to the closure of the Faro mine in 1998. However, with surplus hydro generation largely fully absorbed due to ongoing load growth on the integrated grid over the past decade, the system has returned

to a point where diesel is on the margin. This fact was confirmed by the Board when it directed that LTA diesel generation costs be included in YEC's 2012/13 GRA revenue requirements.

- The basic premise behind the DCF/rate setting method is that ratepayers pay the same during drought periods (when massive quantities of diesel may be required) as they do during floods (when very small quantities of diesel, if any, are required). To work effectively, this premise requires a DCF that is robust in terms of threshold limits (maximum and minimum levels allowed before funds are dispersed or replenished by any rate rider).

- The approach advanced by YECL would mandate that the account be disbursed in a timely manner. However, "timely disbursal" is not aligned with the underlying purpose that a DCF-type account serves, i.e., the point of having a DCF is to establish and build a fund that is available to stabilize rates when there is material variation in water availability. During higher than average water years the fund is built up and during extreme low water years the fund is drawn down in order to stabilize rates and reduce impacts of drought events. Timely dispersal would prevent the fund from being built up and available to stabilize rates during low water years.

Hydro generation facilities are capital intensive and very long-term assets. Development planning and assessment of the economic value of such assets requires focus on long-term average water conditions as well as expected loads over the economic life of the facilities. In this context, the DCF mechanism facilitates rather than frustrates intergenerational equity and fair treatment related to the benefits provided by hydro generation over the long-term (i.e., under LTA water conditions).

REFERENCE: "Yukon Energy notes that in fact the relevant forecasts for ERA purposes in the past, and today, are the forecasts as approved by the Board - and that the ERA is required and appropriate, in the past and today, to comply with OIC 1995/90, which provides that wholesale rates approved for YEC "must be sufficient to recover its costs that are not recovered from its other customers".

(YEC January 31, 2014 DCF/ERA Submission, Attachment 2, p. 2-5)

"Option B provides for the Revised DCF as proposed in the 2012/13 GRA (with adjustments essentially as outlined in the May 1, 2013 Compliance Filing), but amends Rate Schedule 42 as requested by YECL to remove reference to an ERA mechanism; in place of an ERA, a new YEC Diesel Deferral Account (DDA) would be administered to address YEC's net thermal generation cost changes at LTA related to variances in firm YEC sales from GRA approved forecasts (after consideration of all revenue changes related to such variances in firm YEC sales)."

(YEC January 31, 2014 DCF/ERA Submission, p. 4)

PREAMBLE:

QUESTION:

a) Please outline how YEC has modified its DCF/ERA proposal from that filed in its 2012/13 GRA proceeding in an effort to arrive at a joint utility proposal.

b) Please confirm that Option B as described in YEC's January 31, 2014 submission complies with the requirements of OIC 1995/90. If not confirmed, please fully explain.

c) Please confirm whether or not YEC is proposing Option B as an alternative solution in this proceeding. Please confirm that YEC did not propose Option B to AEY during the utilities' discussions prior to the January 31, 2014 submissions.

ANSWER:

For the record, it is noted that the first quote above comes from YEC's June 30, 2014 supplementary filing (Attachment 2, page 2-5) and not from the January 31, 2014 filing.

(a)

Please see response to YUB-YEC-1-13(a).

(b)

Please see response to YUB-YEC-1-13(e).

(c) and **(d)**

Option B was provided as an option to YEC's preferred and recommended Option (Option A), that YEC understood would address the main concerns raised by YECL. YEC in its January 31, 2014 filing outlined in detail how Option B could be implemented (i.e., required approvals, including details regarding how the Diesel Deferral Account would be operated). Please see response to YUB-YEC-1-6(c) for further discussion.

Option B was developed and provided to YECL for review and comment on January 17, 2014, prior to YEC's January 31, 2014 Filing, as an option that reflected YEC's understanding of YECL's position as outlined through prior discussions regarding the DCF and ERA. The draft was developed to provide a potential framework for a joint YEC/YECL submission as directed by the Board wherein the key difference between the two utilities would be defined and clarified to the maximum extent possible.

In the cover letter provided along with the material, YEC noted as follows to YECL:

> "In recognition of the concerns raised by YECL regarding the ERA, the attached application summarizes and assesses two options that have been defined through the consultation process undertaken by the Companies:
>
> - **Option A**: Proposed Revised DCF Fund and Updated ERA (with adjustments essentially as outlined to YECL in September 2014).

- **Option B:** Proposed Revised DCF Fund with a new YEC administered deferral account and no ERA mechanism.

In Yukon Energy's view Option A is to be preferred and recommended to the Board for the reasons set out in the attached draft submission, including its lower ratepayer impacts compared to Option B. We note, however, that Option B does reflect our understanding of Yukon Electrical's position to date.

We are providing this as draft in the event that Yukon Electrical may have any comments or discussion prior to finalization and filing by the January 31st deadline. To the extent possible, we understand that the Board would like to receive the position of each company - and to that end, if YECL intends to provide a submission, we would appreciate as well the opportunity for review and comment prior to January 31st."

Utilities Consumers’ Group (UCG)

REFERENCE: YEC DCF-ERA Filing

YECL Revised Proposals on the DCF and Rate Schedule 42 ERA

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) In YEC's and YECL's views, what are the specific purposes of the Diesel Contingency Fund, the Energy Reconciliation Adjustment and the Fuel Adjustment Rider?

b) Does YEC and YECL believe that the current electricity cost paid by ratepayers is affordable in the short and long term?

c) If stable and affordable electricity rates are a long term goal, what do these three mechanisms accomplish toward implementing a plan to ultimately reach that goal?

ANSWER:

(a) to **(c)**

The purpose of the DCF and the ERA are summarized in response to YUB-YEC-1-11(b). Rider F, established and maintained pursuant to Order in Council 1995/90, Section 8, is an account that captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel prices. Pursuant to Board Order 2005-12, Yukon Energy also credits this account with all variations (positive or negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price.

In summary, the referenced mechanisms are not specifically implemented or designed to achieve affordability objectives. The DCF and Rider F are designed to meet rate stability objectives, i.e., to mute short term rate impacts and provide longer

term rate stability for ratepayers. The ERA addresses specific flow through of incremental costs as required between YEC and YECL - under YEC's Option A proposal, this flow though will have minimal, if any, impact on ratepayers.

The main mechanism relevant to ratepayers in the current proceeding is the DCF and its use to smooth out thermal generation cost impacts on ratepayers from water variability affecting hydro generation. The relevance of the DCF to ratepayers is reviewed in YUB-YEC-1-14.

The Yukon Utilities Board regulates the costs to be recovered through rates, focusing on need, justification and prudency of costs incurred – and with a clear objective to minimize costs required to serve customers today and in the future. The YUB must ensure that utility rates charged are just and reasonable and that utility decisions are made prudently. As last reviewed in Appendix 4.2 of YEC 2012-13 GRA submission, Yukon electric utility retail (residential and commercial) rates are lower than rates approved for other northern utilities in Canada, and are also competitive with rates charged in many cities in southern Canada.

REFERENCE: YEC DCF-ERA Filing

YECL Revised Proposals on the DCF and Rate Schedule 42 ERA

PREAMBLE:

Request to YEC:

QUESTION:

a) Please provide a copy of all YUB decisions / orders and Orders in Council that address the Diesel Contingency Fund, the Energy Reconciliation Adjustment, and other similar proposed adjustment mechanisms and provide specifics of references.

ANSWER:

(a)

Board Orders from 1980 to present are available on the Yukon Utilities Board website. Links to relevant Board Orders and specifics of references are provided in Attachment 1 and Attachment 2 to this response. These attachments address decisions up to the end of 2012 and do not address Order 2013-1 and 2013-2.

Please also see response to YUB-YEC-1-24.

ATTACHMENT 1: DIESEL CONTINGENCY FUND ("DCF")

Order 1989-4 Establishment of Reserve for Contingencies as part of the 1989/90 General Rate Application
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201980/16_boardorder1989_4.pdf

The Order notes as follows (at page 19):

> A reserve of $2.250 million was established out of retained earnings in 1987. Of this amount $250 thousand was established to protect against injury and property claims and $2 million was established to protect against increased costs to produce electricity by diesel generation at times of low water conditions and shutdowns of hydro facilities. It was noted that the reserve of $2 million would enable the Company to cushion the impact of low water conditions before having to ask the Board for an increase in consumer rates.
>
> The Companies explained that in the event that the reserves were drawn down as a result of such events, it would be the intention to replenish the reserve. It was also explained that the reserve would be replenished, either by charges against retained earnings, the inclusion of the amount required to replenish the reserve as a portion of YEC's revenue requirement at a generation rate application, or by an application to the Board for a special surcharge rider.

Order 1992-1 [pages 47-52] Approving implementation of a low water financial reserve as part of the 1991/92 General Rate Application
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/23_boardorder1992_1.pdf

The 1991/92 GRA proposed implementation of a low water financial reserve (and adoption of an approximate $4 million maximum amount[1]).

In Order 1992-1 the Board noted its understanding of the proposed LWRF as follows [page 49-50]:

> On the basis of evidence adduced during the hearing, it is the Board's understanding that the low water reserve will be implemented by the Company in the following manner:
>
> 1. The Company will determine the level of the lake at the time the forecast is prepared.

[1] Order 1992-1, page 48.

2. The Company will forecast average water inflows during the year.

3. Based on Steps (1) and (2) the Company will forecast the amount of hydro generation and thus the required amount of diesel generation.

4. At the end of the year the Company will determine if the forecast diesel generation differed from actual experience due to water flows and if so the reserve will be increased or decreased accordingly.

The Board noted its understanding that:

> Based on the above procedures it is the Board's understanding that no direct charge will be included in the forecast revenue requirement for the low water reserve. Rather, if the Company over earns in a year because the actual diesel generation is less than the forecast diesel generation due to higher than forecast water flows, the reserve would be increased to the extent of the difference between forecast and actual diesel generation up to a maximum of $4 million. Similarly, if the Company under earns in a year because actual diesel generation exceeds forecast diesel generation due to lower than forecast water flows, the reserve would be decreased.

The Board noted (page 52) concern that:

> The use of the "level of lake at the time the (hydro) forecast is prepared" as proposed in the October 1991 update, rather than using a hydro generation forecast based upon long term average hydro generation, may lead to rate instability.

The Board indicated its expectation that all matters relating to the LWRF would be re-examined at the next GRA and that the Company would "present evidence relating to the advantages and disadvantages of using current water levels as compared to long term average hydro generation."

Order 1993-8 approving the 1993/94 GRA [pages 68-70]
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/40_boardorder1993_8.pdf

In the revised 1993/94 General Rate Application, the Companies did not propose adding or withdrawing funds from the reserve during the test years. As Curragh was not forecast to be on the system during the test years (and little diesel would be required for the test years), intervenors proposed that the reserve be reduced by $1 million over the period from July 1, 1993 to December 31, 1994 to help mitigate proposed rate increases.

YEC reviewed the possibility of reducing the LWRF under the assumption that the Faro mine did not reopen, and determined that the existing level of the reserve at $2.3 million could be reduced to $500,000 over the Test Years.

The Companies did not propose a reduction in revenue requirement, but instead proposed to allocate $400,000 and $1,400,000 of the total reduction to the reserve to 1993 and 1994, respectively. The rate relief as proposed by the Companies would entail a one-time reduction in bill increases of approximately 14 to 16 percentage points for eligible sales.

The Board determined as follows at page 70:

> The Board agrees with the parties that, under the circumstances, a reasonable drawdown of the Low Water Reserve Fund can be effective to reduce rates in the current Test Years without creating undue risk for future customers. The Board accepted the Companies' proposal to reduce the Low Water Reserve by $400,000 in 1993 and $1,400,000 in 1994. However, the Board does not agree with the Companies' proposal to use the drawdown directly in the form of rate relief. The Board directs that the reduction in the Low Water Reserve be applied as a reduction to the revenue requirement.

Decision 1994-5 [Page 48]
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/47_boardorder1994_5.pdf
The Companies submitted that in Paragraph 5.1.4.3 of Decision 1993-8 the Board erred in fact or law when it determined that the reduction in the LWRF of $1.4 million in 1994 be applied as a reduction to YEC's 1994 revenue requirement and that the appropriate way to implement the reduction is by use of a rider.

The Board concurred with the Companies' position that a one-time refund, such as the $1.4 million relating to 1994, can be best accomplished by way of a general rider rather than through an adjustment to base rates.

Order 1994-8 - Implements Rider J – 1994 Low Water Reserve Interim Refund Rider
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/50_boardorder1994_8.pdf
The Order approved a refund of 8.726% applied to all customer energy and demand charges for bills issued from July 1, 1994 until an amount of $1,400,000 has been refunded.

1996/97 GRA Negotiated Settlement [Orders 1996-6 and 1996-7]
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/62_boardorder1996_6.pdf
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/63_boardorder1996_7.pdf

YUB-YEC-1-1(f) Attachment 3 provides an excerpt from the 1996/97 GRA Application which summarizes the proposed low water reserve fund.

The 1996/97 GRA consisted of a workshop negotiated settlement process and public hearing in March 1996. A negotiated settlement was reached on most, but not all issues, and included the establishment of a Diesel Contingency Fund (in place of the proposed Rate Stabilization Fund). The settlement was considered by the Board at an oral public hearing commencing March 18, 1996. The Board heard submissions regarding the Settlement from proponents of the Settlement. Parties that did not agree with certain aspects of the Settlement were allowed to present evidence and cross-examine witnesses. UCG dissented on certain aspects of the Settlement, including the ROE.

Order 1996-6 approved the revenue requirements for the companies as set out in Exhibit 148. Written reasons were provided in Order 1996-7 which included review of the Diesel Contingency Fund included in the Negotiated Settlement package. The Negotiated Settlement set out the following rules for operation of the DCF [attached to Order 1996-7]:

> This fund is to replace the proposed rate stabilization fund. The fund will operate to smooth customer rate changes and offset forecast diesel costs. Rates and the fund will be determined using the long term average water expected to be available for generation (105+246 GWh). The initial funding will be determined based upon the funds available as at December 31, 1995. If additional funding becomes available due to other determinations with respect to diesel costs or other utility costs in 1995, the fund will be adjusted. The fund is only to be used for the purposes of stabilizing customer rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.
>
> The cap on the fund is set at the initial contribution level. If the fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider to customers over the following two years. If the fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and negative cap levels. The fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.
>
> The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund.

The annual report to the Board will also include a forecast of available water for the following year.

Order 1996-9 – UCG Complaint

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/65_boardorder1996_9.pdf

UCG filed a complaint with the Board May 2, 1995, alleging that YECL and YEC mismanaged the storage of the Aishihik Reservoir in 1993 and 1994. Specifically, UCG alleged that the Companies wasted approximately two feet of water in Aishihik Lake in 1993 and 1994 and estimated the loss to be approximately $3 million.

The YUB retained BC Hydro International Limited to provide a preliminary opinion and assistance in determining what information is required regarding the complaint filed by UCG against YEC alleging negligence in its management of its water resources at Aishihik Lake.

The Board heard the complaint in conjunction with the hearing for the 1996/97 GRA filed by YEC and YECL. Specifically, at the March 1996 hearing, the Board heard testimony related to the Water Complaint. The Board determined that:

- YECL and YEC did not act imprudently with respect to the management of the storage of water in Aishihik Reservoir as alleged in the complaint.

- The quality of information and decision support tools used by YECL and YEC for making water management decisions was inadequate to maximize the management of stored water for the customers' benefit.

Mr. Kerslake committed YEC/YECL to the development of a plan to implement hydraulic forecasting and decision support systems and to report that plan to the Board by November of 1996. The Board accepted this commitment and ordered the plan to be filed by November 30, 1996. The Board ordered YECL and YEC to file by November 30 1996, for approval a plan to address the inadequacies identified in the Reasons for Decision attached as Appendix A to Order 1996-9.

Order 1996-11

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/57_boardorder1996_11.pdf

Order 1996-11 addressed the method for recovering from ratepayers' revenue flowing from an appeal of the YEC/ YECL 1993/94 General Rate Application.

The Board invited the Companies and intervenors to comment on the alternatives for recovery proposed by the companies; Anvil Range Mine (ARM) and the City of Whitehorse, indicated a preference for reducing the DCF by the amount of the appeal impact, while UCG submitted that the recovery should not be made by way of a reduction in the DCF but rather by a rate rider surcharge in 1997.

The Board noted Decision 1996-7 wherein it accepted a settlement package entered into by the Companies and intervenors respecting rate increases effective January 1, 1996 and January 1, 1997. Order 1996-11 notes, the terms of the settlement stipulated that with respect to the DCF "the fund is only to be used for the purposes of stabilizing rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates"

The Board considered that the amount of $1,952,912 should be recovered from customers by way of a rider on all billings rendered on or after January 1, 1997 until such time as the amount of $1,952,912 is attained. The Board also notes in Order 1996-11, "this method to be fair, in the public interest and consistent with the terms of the settlement package previously accepted by the Board".

Order 1997-4 – Appeal of Order 1996-11

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/73_boardorder1997_4.pdf

Appeal by Anvil Range Mine to Order 1996-11. The Board re-affirmed its decision, noting regarding the DCF (page 8):

> Based on the submissions of the parties, the Settlement Package and the transcripts of evidence from the GRA, the Board finds as a matter of fact that the purpose of the Fund was to offset costs when the Utilities had to rely on diesel generation. It was not intended to pay for costs incurred in the past. In fact, the Diesel Contingency Fund was established before the Court of Appeal decision had been rendered. The Board is of the view that the parties to the 1996/97 GRA did not anticipate the Fund to be used to recover the Appeal revenue.

Order 1997-7

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/76_boardorder1997_7.pdf

On May 26, 1997, the YUB issued Order 1997-6 to YEC and YECL directing that (at page 1) "An interim refundable general rider surcharge of 20% be applied to the base rates for all customer classes of service effective for billings issued on or after June 1, 1997, and continuing thereafter until such time as the Faro mine resumes as a Rate Schedule 39 customer of YEC, or until the Board determines final rates for 1997."

The Commissioner in Executive Council, pursuant to Section 17(1) of the PUA issued a direction to the Board.[1]

> The Commissioner in Executive council directs the Yukon Utilities Board to determine and order by July 1, 1997 a method for providing rate stabilization from the Diesel Contingency Fund established by the Board in Decision 1996-7 in the form of a minimum 25 per cent reduction for all customers in the general rider surcharge approved by the Board in Decision 1997-6. The method determined by the Board shall provide that the rate stabilization be effective on June 1, 1997 and shall continue until such time as the surcharge is removed.

The Board ordered a credit of 25% to be applied to the interim refundable general rider surcharge approved in Order 1997-6 for all customer classes of service effective for billings issued on or after June 1, 1997, and continuing thereafter until such time as the Faro mine resumes as a Rate Schedule 39 customer of YEC, or until the Board determines the final rates for 1997; and the operation of the Diesel Contingency Fund established by the Board in Order 1996-7 shall be amended to allow the recovery of the above credit from the amounts in the fund.

Order 1998-5
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/85_boardorder1998_5.pdf

The Revised Application requested an order approving the establishment of a Rate Adjustment and Stabilization Fund on a pilot basis, including a method for providing rate stabilization from the Diesel Contingency Fund (DCF). This provided for a 50% reduction for all residential and commercial customers in the proposed rider surcharge until January 31, 1999, with reduced reductions thereafter, and with provisions for replenishing the Fund.

In Appendix A to its decision, the Board notes (at page 9):

> The Diesel Contingency Fund was created from the Low Water Reserve Fund, and excess customer revenues received in relation to the Faro mine. It is used to smooth rate adjustments caused by diesel generation cost instabilities due to fluctuations in hydro generation from long-term average capabilities and currently has a balance in excess of $2.2 million (Exhibit 19, page 20).

[1] See OIC 1997-090 on the Board's website at the following link:
http://yukonutilitiesboard.yk.ca/pdf/OICs/447_oic1997_090.pdf

> The Board requested submissions on its jurisdiction and general consensus was that there is nothing in the Act or the OICs that limits or restricts the jurisdiction of the Board to utilize the DCF.

The Board did not approve the establishment of a Rate Adjustment and Stabilization Fund, but directed that the balance in the DCF be used to make contributions to all eligible customers to offset 100% of the net rider increase over the next 12 months.

Order 1998-9
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/89_boardorder1998_9.pdf

By letter dated January 15, 1997, UCG made two applications to the Board (at page 1).

1. The first was an application for a review and variance of Board Order 1996-7 pursuant to s. 62 and a request for a Board investigation pursuant to s. 48 of the *Public Utilities Act*.

2. The second was a complaint regarding the Low Water Reserve Fund pursuant to ss. 44, 45 and 46 of the Act.

UCG requested an investigation as to whether the Companies saved money by using less diesel generation than forecast in 1995 and, if so, why those savings were not placed in the Low Water Reserve Fund. The Board reviewed all previous Orders with respect to the Low Water Reserve Fund and the Diesel Contingency Fund and requested additional information from the Companies and denied the request for an investigation with respect to the LWRF.

Order 1998-10 – UCG Complaint
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/80_boardorder1998_10.pdf

By letter dated June 30, 1998, the UCG filed a complaint with the Board pursuant to s. 44(1)(c) of the *Public Utilities Act* and a request for a Board investigation of the Complaint pursuant to s. 46 of the Act. UCG alleged that information in the Company's' filing of the 1997 annual forecast with the Yukon Territorial Water Board (YTWB) and transcript excerpts from the 1996/97 GRA hearing provided evidence that the Companies had a secret internal policy to keep Aishihik two feet above the licensed water level, consciously misleading intervenors and the Board.

The complaint was rooted in the May 2, 1995 complaint in which UCG alleged that the decision by utility management to make early releases of water in 1993 and 1994 was imprudent and cost ratepayers $3 million. The Board addressed the issue as part of the General Rate Application and

heard extensive testimony at the March 1996 hearing. Subsequently, the Board issued Order 1996-9 which noted that the early releases were made to avoid high water levels and subsequent shoreline erosion in Aishihik Lake, to calibrate the release valves and to compensate for restrictions at the Whitehorse Rapids Plant. The Reasons for Decision (at page 2) stated that the issues to be considered were:

1. Were the forecasts of water inflow and load requirements reasonable at the time? (the Board accepted that the shortfall could not have been reasonably forecast).

2. Were the non-power producing objectives reasonable? (the Board believed that the objectives were not unreasonable).

3. Did YEC/YECL unreasonably restrict the operation of WH#4? (the Board found that the restrictions were forced outages).

The complaint was served on the utilities and their reply was received. The Board reviewed the complaint, supporting arguments and related documents and dismissed the complaint.

The Board reiterated that the Companies did not act in an imprudent manner during the water releases and no penalties are appropriate. Issues of regulatory risk and pre-approvals of utility actions were fully discussed in the 1996 UCG Submission and no new material had been presented. With respect to the complaint's reference to the value of water, this was also fully canvassed in the hearing. While the Board agreed that, in hindsight, the water had value, it took note of the uncertainties, stated that management's actions were not imprudent, and that, therefore, issues regarding the precise quantities and cost of the water were not relevant.

Order 1999-3 [Diesel Contingency Fund Reports] [Pages 1-2]
http://yukonutilitiesboard.yk.ca/pdf/Board_Order_1999-3.pdf

The terms of the 1996/97 Negotiated Settlement approved by Board Order 1996-6 provided for the creation of a Diesel Contingency Fund to smooth customer rate changes and offset forecast diesel costs. The terms also provided that an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board is to direct the companies on the additions and deletions to the fund.

On June 6, 1999 YEC filed a report, detailing the changes to the DCF in 1998, together with revised reports for 1996 and 1997. The filing also included, for convenience, copies of relevant DCF tables for YECL. On July 4, 1999 UCG responded with some preliminary concerns and requested a full review of

this report with a similar process to rate hearings; interrogatories and responses to/from the Companies to the various intervenor concerns.

The Board forwarded the UCG concerns to the Companies but noted that the Board had the ultimate jurisdiction over the DCF. On October 7, 1999 YEC provided comments on the submission from UCG and additional information to assist the Board review. The Board [has] reviewed the material and finds that the approval of the report was [is] in the public interest. The Board approved [s] the additions and deletions to the DCF or 1996 to 1998 as filed.

Order 2000-1 [UCG Applications to Review and Vary Board Orders 1999-3 and 1999-5]
http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/437_Board%20Order%202000-1.pdf

By letters dated December 3, 1999 and December 10, 1999 UCG made two applications to the Board to review and vary Board Orders 1999-3 and Board Orders 1999-5 respectively. The Applications for review and variance of Board Orders 1999-3 and 1999-5 were dismissed.

With regard to Order 1999-3 UCG (at page 3 of Order 2000-1) alleged that the Board made an error in jurisdiction "by not acting in the public interest by not holding a full public review and debate on the Diesel Contingency Fund". Order 2000-1 notes as follows (at page 4):

- On June 6, 1999 Yukon Energy Corporation ("YEC") filed a report, detailing the changes to the Diesel Contingency Fund in 1998, together with revised reports for 1996 ad 1997. The filing also included for convenience copies of relevant DC tables for the Yukon Electrical Company Limited ("YECL"). The Board found that approval of the report was in the public interest, and issued Board Order 1999-3 approving the additions and deletions to the Diesel Contingency Fund for 1996 to 1998 as filed.

- After receiving the DCF report filed by YEC, the Board distributed copies of the report to interested parties for comment. On July 4, 1999 the Utilities Consumers' Group responded with some preliminary concerns and requested a full review of this report with a similar process similar to rate hearings; interrogatories and responses to/from Companies to various intervenor concerns. No other comments were received. The Board forwarded the UCG concerns to the Companies but noted that the Board had the ultimate jurisdiction of the DCF. On October 7, 1999 Yukon Energy Corporation provided comments on the submission from the Utilities Consumers' Group and additional information to assist the Board in its review. On October 10, 1999 UCG again argued for a "public review", in part because the "1996/97 Settlement Agreement was very general in terms of reference for the operation." The Board

considered that it had provided for a sufficient public review and Order 1999-3 was signed on November 3, 1999 after its review of all the material received.

The Board notes in its reasons (at page 5) for decision that:

- Board Order 1999-3 simply approved the additions and deletions to the Diesel Contingency Fund for 1996 to 1998 as filed.

- The report prepared by the Yukon Energy Corporation was filed in accordance with the Board's directions under Board Orders 1996-6, 1997-7 and 1998-5. UCG appears to be taking issue with the provisions of the latter two orders, to the extent that they amend the operation of the DCF. As well, the UCG January 31, 2000 Rebuttal points to Board Orders 1996-11 and 1997-4 as supporting its position.

The Board reviewed in detail its reasons for decision in 1996-11, 1997-4, 1997-7 and 1998-5:

- With regard to **1996-11** – The Board determined (at page 5) that "Board Order 1996-11 did not preclude the use of the DCF for stabilizing rates at another time."

- With regard to **1997-4** - The Board determined (at page 7) that "in deciding that the DCF should not be used to recover the Appeal revenue, it did not preclude its later use to smooth rate changes."

- With regard to **1997-7** – The Board summarized (at page 7) "that it complied with the Order-in-Council and Board Order 1997-7 amended the operation of the Diesel Contingency Fund to allow the recovery of the above credit from the amounts in the fund. No request for variance of this order was received."

- With regard to **1998-5** – The Board concluded (at page 8) that "the purpose of the July 1998 hearing was to see what could be done to deal with the fact that the Faro mine had shut down and was not expected to return in the foreseeable future. The hearing established that there was nothing in the Act or Orders-in-Council that limited or restricted the jurisdiction of the board to utilize the DCF to help stabilize rates and mitigate the impact of what would have been a rate increase of almost 30%."

Order 2002-3

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/100_boardorder2002_3.pdf

On April 26, 2002, YEC reported that it had reached a settlement with its insurance companies and filed a final report on the impacts relating to the far at the Whitehorse Rapids Generating Station ("Fire Report"). YEC requested an Order that, with the filing of the Fire Report, it has complied with the reporting requirements directed by the Board and that an insurance gain of $744,000 be placed into a deferral account for the benefit of ratepayers pending further direction of the Board. YEC also requested an Order approving that the December 31, 2000 DCF balance be changed as outlined in Section IV of the Fire Report.

On May 27, 2002 the Board provided interested parties with an opportunity to comment. After a series of information requests to YEC the Utilities Consumers' Group and The Yukon Electrical Company Limited provided their comments, to which YEC replied on September 3, 2002.

The Board reviewed the material and noted as follows (at page 3):

- "YEC has complied with the reporting requirements directed by the Board relating to the October 1997 fire."

- "The insurance gain of $744,000 realized as part of the settlement of the insurance claim arising for the fire is to be placed into a deferral account as an offset to rate base for the benefit of ratepayers pending further direction of the Board."

- "The additions and deletions to the Diesel Contingency Fund for 1999 and 2000 are approved as filed, except that het December 31, 2000 balance is to be changed from ($61,744.29) to $681,721.92 as outlined in section IV of the Fire Report."

Order 2011-15 (and Appendix A)

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1306_Board%20Order%202011-15.pdf

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1307_Board%20Order%202011-15%20Appendix%20A%20Reasons%20for%20Decision.pdf

The Order and Appendix A to the Order notes [at pages 8-9]:

> In further response to DCF issues, the Companies submitted that diesel was not forecast to be "on the margin". Also, changes in operating rules are required for the DCF and those changes require Board review and approval. Furthermore, any DCF transactions are at the

GRA-approved fuel price thus have no impact on the DFPVA, and that there is no interrelationship between the administration of the DFPVA and the DCF.

YEC committed to addressing DCF issues and any changes in the operating rules for the DCF in its next GRA.

As noted above, the Policy was filed in response to a direction in Board Order 2010-13.

At the time the direction was given, the Board did not contemplate issues respecting Rider D and the DCF. To strengthen the record in this proceeding, the Board issued Order 2011-12. Appendix A of that Order directed the Companies to provide adequate responses to certain information requests of LE and UCG.

Through Appendix B of Order 2011-12, the Board asked further information requests regarding the detailed calculations for the DFPVA, company risk, historical regulatory process, and the DCF. The information was needed to clarify the issues pertaining to the DCF.

The Board is satisfied with the responses of the Companies. The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA. Also, the Board requires that YEC provide a specific definition of the term "diesel on the margin". The Board directs that YEC complete its review and bring the necessary changes before the Board at the earliest of its next GRA or July 1, 2012.

Based on the evidence presently available to the Board, the Board accepts the submissions of the Companies that there is no interrelationship between the DFPVA and the DCF and no interrelationship between the DFPVA and Rider D.

ATTACHMENT 2: ENERGY RECONCILIATION ADJUSTMENT

1.0 RATE POLICY ORDERS IN COUNCIL

OIC 1995/90 (Rate Policy Directive) is available on the Board's website at the link below.

http://yukonutilitiesboard.yk.ca/pdf/OICs/446_oic1995_090.pdf

Copies of earlier rate policy OICs [OIC 1988/150 and OIC 1991/62] are provided as Attachment 3 to UCG-YEC-1-2(a). Provisions relevant to the ERA are as follows:

- **Directives regarding Wholesale Rates** - were provided in Section 4 of OIC 1988/150; Section 9 of OIC 1991/62 and Section 7 of OIC 1995/90.
- **Directives regarding Normal Utility Principles** – were provided in Section 3(f) of OIC 1988/150; Section 4 of OIC 1991/62 and Section 3 of OIC 1995/90.

2.0 APPLICATIONS AND BOARD ORDERS

Order 1992-4 [pages 9-10]

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/27_boardorder1992_4.pdf

Board Order 1992-4 at page 10 notes:

> At page 2-6 of YECL's Application it states:
>
> > "The wholesale rate, for the purposes of this Application, has been based on an inter-utility transfer which allows YECL and YEC each to meet their respective revenue requirements based on the retail rates as applied for and the assumptions set out above with respect to Curragh rates."
>
> The Board views the wholesale rate as a method of balancing revenues to costs as between YECL and YEC and, accordingly, approves the Companies' method of determining the wholesale rate and the structure of the proposed wholesale rate.

Decision 1993-1-6 and 1993-1-7

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/38_boardorder1993_6.pdf

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/39_boardorder1993_7.pdf

The Joint YEC/YECL 1993/94 General Rate Application noted as follows regarding the changes to the wholesale rate included in the Application [page 3-9]:

> The wholesale rate applicable to transfers between YEC and YECL has been restructured to provide a more stable balance of costs and revenues between the two companies.

> The move to increase retail run-out rates to incremental energy costs has also increased revenue volatility of YEC and YECL. As YEC is responsible for most energy production and YECL is responsible for most retail sales, fluctuations of retail sales now cause revenue changes at an incremental cost level for YECL that is not balanced by a corresponding cost change in the current single block wholesale energy rate. The converse problem occurs for YEC. Restructuring the wholesale rate to allow periodic adjustments between forecast and actual wholesale transfers at a rate equal to the retail run out rate restores the balance. The new wholesale rate will cause adjustments in transfers between YECL and YEC that balance the changes in revenues and costs caused by sales fluctuations and will have no effect on retail sales.

Order 1993-1-6 approved revenue requirement amounts for 1993 and 1994 and ordered the companies to design rates to collect these amounts. Order 1993-7 approved the rate schedules requested in Decision 1993-1-6. Section 5 of Order 1993-1-7 [page 5-1] notes as follows:

> Section 9 of OIC 1991/62 requires that YEC wholesale rates charged to YECL be sufficient to recover YEC costs that are not recovered from its other customers. Rate Schedule 42 (Wholesale) has been calculated in accordance with this requirement, based on proposed rates and forecast rate revenues for each year.
>
> The proposed wholesale rate applicable to transfers from YECL to YEC (Rate Schedule 42) has also been restructured, as described in the revised June 1993 GRA, to provide a more stable balance of costs and revenues between the two companies in the event that YEC power sales to YECL vary from forecasts on an annual basis.
>
> In 1993, a determination of the total wholesale charge under Rate Schedule 42 will be made at year end, based on forecast wholesale sales at the annualized rate of 7.502 c/kWh, and the reconciliation adjustment to reflect variances from the forecast wholesale sales. A portion of the 1993 wholesale charge under Rate Schedule 42, equal to $1,590,300, will be accrued for payment to YEC on Rider K, starting January 1, 1994 (the accrued amount reflects YECL's forecast retail revenue shortfall in 1993, after recover of Rider H amounts in November and December 1993).
>
> The 7.765 c/kWh is the transfer wholesale rate for 1994, prior to any reconciliation adjustment. Rider K will also be charged in addition to the 1994 wholesale rate until an amount of $1,590,300 has been collected.

The Order 1993-1-7 attached Rate Schedules (referred to as Schedule "A") which included the revised Rate Schedule 42 (including the Energy Reconciliation Adjustment). The Order approved Rate Schedule 42 which included the following provision for the Energy Reconciliation Adjustment.

Order 1994-8 and Order 1996-8

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/50_boardorder1994_8.pdf

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/64_boardorder1996_8.pdf

Rate Schedule 42 (in the same form as approved in Order 1993-1-7) was approved in Order 1994-8 and Order 1996-8.

> Charges to YECL will be periodically adjusted to reconcile actual wholesale purchases to test year forecast purchases. To the extent that actual wholesale purchase fall short or exceed forecast wholesale purchases, an adjustment to the YECL bills will be made at a rate equal to the approved run out rate for non-government residential service for the Hydro zone. Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

Order 1999-4 – Rate Schedule 42 Settlement

http://yukonutilitiesboard.yk.ca/pdf/Board_Order_1999-4.pdf

The Board approved the Energy Charge Rate under Wholesale Rate 42 as applied for and the terms of the Settlement Agreement. The Order notes as background (on page 1) as follows:

> Yukon Energy Corporation's April 28, 1998 Revised Application requested that certain amendments be approved with respect to the wholesale rate applicable during 1996 and 1997.
>
> As this matter directly affects amounts paid to Yukon Energy Corporation and The Yukon Electrical Company Limited pursuant to Rate Schedule 42 (Wholesale Primary) for 1996 and 1997, and does not affect other ratepayers, Board Order 1998-5 agreed that the matter should be dealt with in a separate process after the public hearing.

The Board agreed that the outstanding issues be resolved between the Companies utilizing the British Columbia Utilities Commission negotiated settlement process guidelines. The Companies reached a settlement on October 7, 1999 and requested as follows (as summarized in Order 1999-4):

> [That] Energy Charge Rate under Wholesale Rate Schedule 42 be approved at the amount reflected in the Revised Application, being:
>
> - 1996 – 6.755 cents/kWh; and
> - 1997 – 6.840 cents/kWh.

The Companies provided a copy of the Settlement Agreement, clarifying certain items in the Energy Reconciliation Adjustment mechanism in Rate Schedule 42 (The Settlement Agreement and Mutual Release Concerning Outstanding Rate Schedule 42 Issues provided as Appendix A to Order 1999-4).

The Board reviewed the Settlement Agreement and determined as follows (at page 1):

> That no changes to the wording of Rate Schedule 42 are required but that the clarifications are consistent with the intent of Rate Schedule 42.

Order 2010-13 [page 38, page 41-42]

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1159_Board%20Order%202010-13.pdf

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1158_Board%20Order%202010-13%20Appendix%20A.pdf

Page 38 of Order 2010-13 notes as follows regarding Rate Schedule 42:

> 161. Rate Schedule 42 is described as the rate provided for YEC sales to YECL. 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.

Page 41-42 of Order 2010-13 notes as follows regarding YECL's proposed Rider D mechanism:

> 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."
>
> 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. [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.

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.

Order 2011-05 – 2009 Joint Phase II Rate Application Rate Schedules [Pages 1-2]

http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1227_Board%20Order%202011-05.pdf

On February 28, 2011, the Companies filed with the Board their compliance filing in respect of their 2009 Phase II Rate Application. The Board determined that the compliance filing was consistent with the directions given to the Companies in the Reasons for Decision attached as Appendix A to Board Order 2010-13, and the Board approved the Rate Schedules attached as Appendix A to this Board Order effective June 1, 2011.

YUKON TERRITORY

C A N A D A

Whitehorse, Yukon

ORDER-IN-COUNCIL 1988/150

PUBLIC UTILITIES ACT

Pursuant to section 17 of the Public Utilities Act, the Commissioner in Executive Council orders:

1. The annexed Rate Policy Directive is hereby made and established.

Dated at Whitehorse, in the Yukon Territory, this 12 day of *September*, A.D., 1988.

Filed: 88 09 12

I hereby certify that the foregoing is a true copy of the original instrument of which it purports to be a copy.

Registrar of Regulations

Commissioner of the Yukon

O.I.C. 1988/150

PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE

1. The Board shall regulate rates of Yukon Energy Corporation subject to the terms and conditions of the Purchase and Sale Agreement between Yukon Energy Corporation, Canada, Yukon and Northern Canada Power Commission, dated March 31, 1987, including the valuation therein of assets acquired by Yukon Energy Corporation, the constraints therein on Yukon Energy Corporation rates up to March 31, 1989, and the terms and conditions of any contracts entered into by Yukon Energy Corporation as contemplated hy the Agreement of Purchase and Sale or therein assigned to Yukon Energy Corporation.

2. The Board shall deem the equity of Yukon Energy Corporation as at March 31, 1987, to be the sum o $39,000,000.00, and shall include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity as such equity may vary from time to time.

3. The Board shall regulate retail power rates of Yukon Energy Corporation and The Yukon Electrical Company Limited with respect to residential, general service and street lighting power customers in accordance with the following power rate policy for Yukon, effective for rates after April 1, 1989:

   (a) one rate zone shall apply for all Yukon power customers other than government accounts;

   (b) retail rates for non-government accounts of Yukon Energy Corporation shall equal the same rates approved for The Yukon Electrical Company Limited, such rates to be determined based on The Yukon Electrical Company Limited's costs of service;

(c) excluding government accounts, The Yukon Electrical Company Limited rates within each customer class shall be the same throughout Yukon, subject only to provision of separate energy run-off rates reflecting short term incremental energy costs in communities supplied primarily by generation other than hydro, such run-off rates to be applicable only to levels of use in excess of 1,000 kWh per month for residential customers and 2,000 kWh per month for general service customers;

(d) the Board shall not authorize any increase in average retail rates charged to residential customers by The Yukon Electrical Company Limited in excess of the increase in the average retail rate charged by The Yukon Electrical Company Limited to all of its customers;

(e) the Board shall permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates so as to reflect fluctuations in the prices for which they contract for the supply of diesel fuel from time to time, without the requirement for specific application to and approval of the Board. Subject to the foregoing, the procedures respecting such rate adjustments shall be determined by the Board;

(f) within the policy framework set out herein, retail rates other than those applicable for government accounts shall be reviewed and approved by the Board in accordance with normal regulatory principles applicable in Canada for similar power utilities, and the Board shall aim to review rates once every two years, with an initial hearing to occur during 1988 or early 1989 to approve rates applicable starting on April 1, 1989 or such earlier date as may be agreed upon between the Government of the Yukon and the Government of Canada;

(g) Yukon Energy Corporation and The Yukon Electrical Company Limited rates applicable to government accounts shall be excluded from retail rate equalization and shall continue as at present, with adjustments in future to reflect changes in applicable costs and any increases in rates approved for all retail customers.

4. The Board shall regulate bulk power rates of Yukon Energy Corporation affecting wholesale and industrial power customers in accordance with the following power rate policy for Yukon, effective for rates after April 1, 1989:

   (a) all wholesale charges to The Yukon Electrical Company Limited shall be pooled to provide one demand rate and one energy rate applicable throughout Yukon and such rates shall be sufficient to recover Yukon Energy Corporation's regulated costs not otherwise recovered from other Yukon Energy Corporation customers;

   (b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail power service with adoption of The Yukon Electrical Company Limited rates as specified herein;

   (c) the rates charged to major industrial customers shall be in conformance with any contract between such industrial customers and Yukon Energy Corporation, and no increase or decrease in the existing rates charged to such industrial customers shall occur unless such modification is requested by Yukon Energy Corporation and is in conformance with such contract.

5. The Board shall treat any monies to be received by The Yukon Electrical Company Limited from the Government of the Yukon, pursuant to the Government of the Yukon's prevailing policy with respect to rebate of income tax paid by The Yukon Electrical Company Limited, as acting in corresponding reduction, in the year in which such income tax is paid, of The Yukon Electrical Company Limited's revenue requirements as determined from time to time by the Board.

YUKON TERRITORY

CANADA

Whitehorse, Yukon

ORDER-IN-COUNCIL 1991/62

PUBLIC UTILITIES ACT

Pursuant to sections 17 and 18 of the Public Utilities Act, the Commissioner in Executive Council orders as follows:

1. Order-in-Council 1988/150 is hereby revoked.

2. The annexed Rate Policy Directive (1991) is hereby made.

Dated at Whitehorse, in the Yukon Territory, this 27 day of Mar , 1991.

Florence E Whyard

Administrator of Yukon

TERRITOIRE DU YUKON

CANADA

Whitehorse, Yukon

DÉCRET 1991/62

LOI SUR LES SERVICES PUBLICS

Le Commissaire en conseil exécutif, conformément aux articles 17 et 18 de la loi sur les services publics, décrète ce qui suit:

1. Le Décret 1988/150 est par les présentes révoqué.

2. Les instructions sur la politique tarifaire (1991) paraissant en annexe sont par les présentes adoptées.

Fait à Whitehorse, dans le territoire du Yukon, ce 27 jour de mars 1991.

Florence E Whyard

Administrateur du Yukon

PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE (1991)

Interpretation

1. In this Directive

"customer" refers to a purchaser of electricity; ("Client")

"government customer" means a retail customer

(a) who is a federal or territorial department or agency, a municipality, a hamlet, or the governing body of a Yukon First Nation;

(b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a); ("Client gouvernemental")

"isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer; ("Client industriel isolé")

"major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer; ("Client industriel majeur")

"retail customer" means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer, an isolated industrial customer, or a wholesale customer; ("Client au détail")

"wholesale customer" means The Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation. ("Client en gros")

LOI SUR LES SERVICES PUBLICS

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE

Définitions

1. Les définitions qui suivent s'appliquent aux présentes instructions:

"Client" Acheteur d'électricité; ("customer")

"Client au détail" Client de la Yukon Energy Corporation ou de The Yukon Electrical Company Limited qui n'est ni un client industriel majeur, ni un client industriel isolé, ni un client en gros; ("retail customer")

"Client en gros" The Yukon Electrical Company Limited lorsqu'elle achète de l'énergie de la Yukon Energy Corporation. ("wholesale customer")

"Client gouvernemental" Client au détail qui est:

(a) soit un organisme gouvernemental, un ministère fédéral ou territorial, une municipalité, un hameau ou le corps dirigeant d'une Première nation du Yukon;

(b) soit un organisme qui n'exploite aucune entreprise à des fins lucratives et dont le financement provient en totalité, ou pour l'essentiel, d'un organisme décrit à l'alinéa 1(a). ("government customer")

"Client industriel isolé" Client qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont l'approvisionnement en électricité est indépendant de celui de tout autre client; ("isolated industrial customer")

"Client industriel majeur" Client autre qu'un client industriel isolé qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont la demande de pointe d'électricité dépasse 1 MW; ("major industrial customer")

Normal return on equity

2. The Board must include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity, less one half of one percent (.5 %).

Retail rate adjustments

3. The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

Normal principles to apply

4. Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with normal principles applicable in Canada for similar utilities.

Demand-side management

5.(1) The Board shall encourage Yukon Energy Corporation and The Yukon Electrical Company Limited to promote economy and efficiency in the generation, transmission, and use of electricity.

(2) The Board shall allow Yukon Energy Corporation and The Yukon Electrical Company Limited to recover, through rates, the expenditures reasonably incurred by them for the purposes set out in subsection (1).

Retail rates: non-government customers

6.(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon

(a) subject to subsection (2), the rates for non-government retail customers must be the same throughout the Yukon and must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;

Rendement normal sur la valeur nette

2. La Commission prévoit dans les tarifs de la Yukon Energy Corporation les mesures pour réaliser un rendement commercial normal sur sa valeur nette, moins 5 dixièmes pour cent (.5 %).

Ajustements des tarifs de détail

3. La Commission s'assure que les ajustements tarifaires pour les clients au détail s'appliquent uniformément en termes de pourcentage à toutes les catégories de clients au détail.

Application des principes ordinaires

4. La Commission examine et approuve, sauf indication contraire dans les présentes instructions ou dans la Loi, les tarifs aux clients selon les principes ordinaires de réglementation en application au Canada pour des services publics semblables.

Gestion de la demande

5.(1) La Commission encourage la Yukon Energy Corporation et The Yukon Electrical Company Limited à produire, transmettre et utiliser l'électricité de façon plus efficace et plus économique.

(2) La Commission permet à la Yukon Energy Corporation et à The Yukon Electrical Company Limited de recouvrer, au moyen des tarifs, les dépenses raisonnables qu'elles encourent pour les programmes décrits au paragraphe (1).

Tarifs au détail pour les clients non-gouvernementaux

6.(1) La Commission fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire du Yukon suivante:

(a) les tarifs pour les clients non-gouvernementaux s'appliquent, sous réserve du paragraphe (2), uniformément à la grandeur du Yukon et doivent suffire à générer les recettes pour recouvrer les coûts qui ne sont pas recouvrés des clients gouverne-

(b) subject to subsection (2), rates for each class of non-government retail customer must be the same throughout Yukon and without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) Separate runoff rates must be allowed for non-government retail customers to reflect short-term incremental energy costs in communities supplied primarily by generation other than hydro, but

(a) for residential non-government retail customers, the runoff rate may be applied only to consumption in excess of 1,000 kWh per month, and

(b) for general service non-government retail customers, the runoff rate may be applied only to whichever of the following the Board approves:

(i) consumption in excess of 2,000 kWh per month, or

(ii) consumption in excess of a level which would, for an average customer of that class, be equivalent to 2,000 kWh per month for general service non-government retail power customers.

Retail rates: government customers

7.(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

(a) subject to section 3, rates for government customers may be adjusted so as simplify the rate structure and make the rates more consistent throughout Yukon;

mentaux ou des clients industriels majeurs;

(b) les tarifs pour chaque catégorie de client au détail non-gouvernemental s'appliquent, sous réserve du paragraphe (2), uniformément à la grandeur du Yukon et sans distinction entre la Yukon Energy Corporation et The Yukon Electrical Company Limited;

(2) Des primes de dépassement différentes sont permises à l'égard des clients au détail non-gouvernementaux pour refléter les coûts d'énergie supplémentaires à court terme dans les agglomérations approvisionnées principalement d'une autre source d'énergie que l'hydro-électricité. Toutefois,

(a) pour les clients résidentiels au détail non-gouvernementaux, la prime ne peut s'appliquer qu'à la consommation dépassant 1 000 kWh par mois;

(b) pour les autres clients au détail non-gouvernementaux, la prime s'applique à un des niveaux de consommation suivants qu'approuve la Commission:

(i) soit une consommation qui dépasse 2 000 kWh par mois;

(ii) soit une consommation dépassant le niveau qui serait, pour un client moyen de cette catégorie, l'équivalent de 2 000 kWh par mois pour les clients au détail non-gouvernementaux desservis par le service général.

Tarifs au détail pour les clients gouvernementaux

7.(1) La Commission fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit:

(a) les tarifs pour les clients gouvernementaux peuvent être ajustés, sous réserve de l'article 3, aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;

(b) the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

Rates — major and isolated industrial customers

8. (1) The Board must ensure that the rates charged to major industrial power customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

(2) Notwithstanding subsection (1), the Board must ensure that rates charged to Curragh Resources Inc. and United Keno Hill Mines Limited by Yukon Energy Corporation conform with any contract between Yukon Energy Corporation and Curragh Resources Inc. or United Keno Hill Mines Limited.

(3) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

Wholesale rates

9. The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate

(b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Yukon Energy Corporation ou de The Yukon Electrical Company Limited, ou d'un client, la Commission prend une décision sur le statut de client gouvernemental d'un client.

Tarifs pour les clients industriels majeurs et isolés

8. (1) La Commission doit s'assurer que les tarifs facturés aux clients industriels majeurs, en vertu d'un contrat ou autrement, suffisent à recouvrer les coûts du service pour cette catégorie de clients. Ces coûts sont déterminés en considérant tout le Yukon comme une zone tarifaire unique et les tarifs facturés par les deux services publics doivent être les mêmes;

(2) Sous réserve du paragraphe (2), la Commission doit s'assurer que les tarifs facturés à Curragh Resources Inc. et à United Keno Hill Mines Limited par la Yukon Energy Corporation se conforment à tout contrat intervenu entre la Yukon Energy Corporation et Curragh Resources Inc. ou United Keno Hill Mines Limited.

(3) Les tarifs pour les clients industriels isolés desservis par la Yukon Energy Corporation ou The Yukon Electrical Company Limited doivent être conformes à tout contrat intervenu entre le client et ces sociétés, et les coûts et les recettes dérivant de ces contrats ne sont pas pris en compte par la Commission aux fins de la fixation des tarifs pour les autres clients.

Tarifs de gros

9. La Commission doit réglementer les tarifs facturés par la Yukon Energy Corporation au client en gros selon la politique tarifaire du Yukon qui suit:

(a) la Yukon Energy Corporation vend de l'électricité à The Yukon Electrical Company Limited au même tarif de demande et au même tarif d'énergie à la

throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

Fuel price adjustment

10. The Board must permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates to retail customers, major industrial customers, and isolated industrial customers so as to reflect fluctuations in the prices for which the two utilities pay for diesel fuel, without the requirement for specific application to and approval of the Board.

Cost of service and rate design review and report

11.(1) The Board shall conduct a full review of costs of service to and of rates charged to all classes of customers within the Yukon and shall recommend appropriate methods of determining costs of service and appropriate principles for establishing rates to be used for rate applications made after 1991.

(2) When conducting its review and making its recommendations the Board shall observe the following guidelines:

(a) cost of service for each customer class must be determined on a Yukon-wide basis that is consistent with Yukon's rate policy, having the same rate for the same class of customer throughout the Yukon, no rate differentiation between utilities, and provision for runoff rate variations in accordance with the principles set out in subsection 6(2);

grandeur du Yukon et ces tarifs doivent suffire à la Yukon Energy Corporation pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

(b) le tarif de gros facturé à The Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Yukon Energy Corporation de recouvrer ses coûts de service au détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s'appliquent à ces services en vertu des présentes.

Ajustement du prix du combustible

10. La Commission permet à la Yukon Energy Corporation et à The Yukon Electrical Company Limited d'ajuster les tarifs facturés aux clients au détail, aux clients industriels majeurs et aux clients industriels isolés de manière à refléter les fluctuations des prix payés pour le mazout par ces deux sociétés, sans avoir à faire une demande particulière à la Commission pour obtenir son autorisation.

Révision et rapport sur le coût du service et la structure de tarifs

11.(1) La Commission procède à l'examen complet du coût de service en ce qui concerne les tarifs facturés à toutes les catégories de clients d'électricité du Yukon. Elle recommande une méthodologie pour fixer le coût de service et des principes appropriés pour établir une structure tarifaire applicable aux demandes de tarifs faites après 1991.

(2) La Commission suit, dans le cours de son examen et au moment de rédiger ses recommandations, les lignes directrices suivantes:

(a) le coût de service pour chaque catégorie de client est déterminé à la grandeur du Yukon d'une façon compatible avec la politique tarifaire du Yukon qui comporte un tarif unique pour les clients d'une même catégorie, un tarif unique pour tous les services publics et une disposition couvrant les variations entre les primes de dépas-

(b) customer classes examined must include each class currently used for rate making purposes;

(c) costs must be determined on a prospective basis for a test period conforming to the period for which the Board approves rates as a result of Yukon Energy Corporation's and The Yukon Electrical Company Limited's 1991 general rate applications;

(d) the review must investigate principles and methods currently applicable in Canada for similar hydro based and northern diesel service areas and must examine the implications of any options in this regard that may merit adoption in Yukon;

(e) the review must investigate the extent to which regulated rates reflect cost of service for different customer classes in Yukon and in other Canadian jurisdictions;

(f) the review must examine implications of adjusting future rates in order to bring rates closer to costs for all customer classes in Yukon.

(3) The review must also investigate the extent to which rate design should respond to factors other than cost of service for each customer class such as:

(a) promotion of economy and efficiency in the generation, transmission, distribution, and use of power;

(b) environmental or other costs that are not currently included in cost of service for the utilities;

(c) current cost required to develop new power supplies; and

sement, conformément aux principes énoncés au paragraphe 6(2);

(b) les catégories de clients sous examen comprennent toute catégorie utilisée présentement aux fins de fixer les tarifs;

(c) les coûts sont déterminés de façon prospective pour une période d'essai correspondant à celle pour laquelle la Commission approuve les tarifs suivant les demandes de tarifs de la Yukon Energy Corporation et de The Yukon Electrical Company Limited, pour l'année 1991;

(d) l'examen comprend l'étude des principes et méthodes en application au Canada pour des services dans des régions similaires desservies par l'hydro-électricité et dans des régions nordiques desservies par le combustible diesel. La Commission étudie les conséquences de toute option valable pour son implantation au Yukon;

(e) l'examen étudie jusqu'où les tarifs réglementés d'électricité réflètent le coût de service pour les différentes catégories de clients du Yukon et des régions relevant d'autres compétences au Canada;

(f) l'examen étudie les conséquences d'un ajustement des tarifs futurs en vue de rétrécir l'écart entre les tarifs et les coûts pour toutes les catégories de clients du Yukon.

(3) L'examen étudie également dans quelle mesure des facteurs autres que le coût de service pour chaque catégorie de client doivent être pris en compte aux fins de la structure tarifaire, notamment:

(a) la promotion d'une plus grande économie et d'une plus grande efficacité dans la production, la transmission et l'utilisation de l'électricité;

(b) les coûts environnementaux ou autres qui n'apparaissent pas dans le coût actuel de service pour les services publics;

(d) demand-side management activities carried out in accordance with the principles set out in subsections 5(1) and (2).

(4) The Board must begin its review by soliciting submissions from Yukon Energy Corporation and The Yukon Electrical Company Limited as part of their 1991 general rate applications and shall direct the companies to prepare such submissions in accordance with the guidelines set forth in subsection 11(2).

(5) The Board shall deliver its report to the Executive Council Member on or before June 1, 1992.

(c) le coût actuel exigé pour développer de nouveaux approvisionnements d'électricité;

(d) les activités pour gérer la demande exécutées en conformité avec les principes énoncés aux paragraphes 5(1) et 5(2).

(4) La Commission débute son examen en sollicitant les représentations de la Yukon Energy Corporation et de The Yukon Electrical Company Limited qui figurent dans leur demande de tarifs généraux pour l'année 1991; elle leur enjoint de soumettre leurs représentations en respectant les lignes directrices énoncées au paragraphe 11(2).

(5) La Commission remet son rapport au membre du Conseil exécutif le 1 juin 1992 au plus tard.

REFERENCE: Board Order 2013-03, Page 2, Paragraph 5

"In future, YEC must file Excel versions, with formulae intact of all schedules and tables used to support its filings."

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) Given the content of its current application, please explain what part of this direction from the YUB that YEC does not understand.

b) While the direction in Board Order 2013-03 regarding the provision of Excel spreadsheets was specifically directed to YEC, does YECL not think that Board's direction to one utility in this regard should not apply to the other?

c) Please provide Excel versions of all tables contained within YEC's application, including Tables 1 through 4, Figure 1.1-1, Table 1.1-1, Table 1.1-2, Table 1.1-3, Table 1.1-4, and Table 2-1.

d) Please provide Excel versions of all tables contained within YECL's application, including Tables 3.1 and support schedules.

ANSWER:

(a) and **(c) [the only parts pertaining to YEC].**

With regard to the direction provided in Order 2013-03, please note that the following attached electronic files, relating to the YEC filing, were provided to the Board on February 3, 2014 (the next business day immediately following the January 31, 2014 filing):

- Table 1: Revised DCF Calculation for Actual 2012 and Preliminary Actual 2013;

- Table 2: Option A: Revised ERA Calculation for Actual 2012 and Preliminary Actual 2013;

- Table 3: Option B: DDA Calculation for Actual 2012 and Preliminary Actual 2013;

- Table 1.1-3. YEC 2012/13 GRA Compliance Filing: DCF Operation Example for 5 Forecast Years; and

- Table 1.1-4. DCF Formulaic Approach Operation Example for 2012-2016 YEC Load Forecast Cases - YEC-related DCF Impacts.

As per request in (c) above YEC is also providing excel versions of Table 4, Table 1.1-1, Table 1.1-2, Table 2-1 and Figure 1.1-1. Please also note that updated Tables 1 through 3 with 2013 actuals are provided in response to YUB-YEC-1-25 Attachment 1.

REFERENCE: Board Order 2013-03, Appendix A, Paragraph 16

YEC may file a future revised DCF proposal and ERA application. The Board prefers a joint filing from YEC and YECL. However, if agreement cannot be reached, a filing in which the companies state which aspects of the revised DCF proposal and ERA amendment they agree upon, the aspects they disagree upon, and the position of each company on those aspects they disagree upon is acceptable. The filing must also address the concerns raised in Board Order 2013-01 Attachment A: Reasons for Decision. This future revised DCF proposal and ERA application will be separate from the compliance filing directed in this order."

YEC Application to Revise the DCF, Cover Letter, Page 2

"Unfortunately, despite the additional time provided, and their best efforts, the Companies have not been able to develop a joint recommendation or submission for the Board."

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) Please provide a summary table of aspects of the revised DCF proposal and ERA amendment that YEC and YECL agree upon, the aspects YEC and YECL disagree upon, and the position of both YEC and YECL on those aspects they disagree upon.

ANSWER:

(a)

Please see response to YUB-YEC-1-13(a) and (b), as well as response to YUB-YEC-1-6(c).

REFERENCE: YEC Application to Revise the DCF, Cover Letter, Attachment A
Reference: YECL Revised Proposals on the DCF and Rate Schedule 42 ERA (Page 1)

"Since the June 2013 issuance of Board Order 2013-03, Yukon Electrical has met with YEC on a number of occasions to develop a joint proposal for both the DCF and the ERA effective January 1, 2012. Unfortunately, the two utilities have been unable to agree on a proposal. YEC has been unwilling to make any substantive changes to the proposals for the DCF and ERA in its May 1, 2013 Compliance Filing, notwithstanding the significant concerns Yukon Electrical has raised with those proposals."

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) Please provide details on when the utilities met to develop a joint proposal including dates and duration of meetings, who was in attendance, copies of material reviewed and copies of minutes from these meetings.

b) Please explain why the utilities were developing a proposal effective January 1, 2012 when the YUB had already determined in its Order 2013-03 that it would not allow any changes regarding 2012 and we are now in 2014.

c) Please confirm that any charges to YECL levied under the ERA are ultimately paid by Yukon ratepayers.

d) Please explain why Yukon ratepayers should be held responsible for retroactive policy changes when they have made their electricity use choices based on the rates in place at the time the electricity was being used.

e) Please provide details of the "significant concerns" raised by YECL on YEC's

proposals and when during these meetings with YEC these concerns were raised.

ANSWER:

(a)

Attachment A to the cover letter to Yukon Energy's January 31, 2014 Filing provides a summary of the meetings and correspondence between the Companies regarding the DCF and ERA proposals. The response to YUB-YEC-1-10 and YUB-YEC-1-6 provide the available relevant materials related to these discussions. Meeting minutes were not produced following these discussions.

(b)

Please see YUB-YEC-1-19 which notes that YEC revenue requirement and final rates for the 2012 and 2013 test years were approved by Order 2013-4. Implementation of either Option A or Option B would not change YEC's approved revenue requirement or rates for those test years. This response also notes that DCF and ERA approvals were sought as part of YEC's initial GRA filings in April 2012.

With regard to the DCF and ERA payments for 2012, the record confirms the importance of the DCF and ERA approvals with regard to YEC's final financial statements for 2012 and 2013 given the rates and revenue requirement approved per Order 2013-01 and Order 2013-04. Please see the correspondence provided as Attachment 1 and Attachment 2 to this response. Specifically, on July 5, 2013 YEC sought direction from the YUB regarding DCF and ERA impacts in 2012. The Board directed in a letter dated July 16, 2013 as follows:

> "The additional earnings of $3.714 million that have been identified as a deferred payment to the DCF be transferred to the DCF on an interim basis pending final resolution of the matter. Similarly, the Board also directs the utility to record the identified ERA charge of $1.176 million on an interim basis pending the final resolution of the matter. For greater clarity, no funds identified in the July 5 letter relating to the DCF and/or ERA are to be recorded by YEC as earnings in its financial statements. All funds assigned to the DCF and/or ERA as a result of this

Board direction are on an interim basis only and will be subject to further direction by the Board once a new DCF policy is approved."

Correspondence and subsequent Board direction was provided for 2013 (see correspondence provided as Attachment 3 and Attachment 4).

(c)

Not confirmed for any ERA applied per YEC's proposed Option A; confirmed in effect for all other options being discussed, such as Option B, even though no ERA as such may be retained.

In YEC's submission, an ERA is proposed as part of Option A. As shown in Table 2 of YEC's January 31, 2014 filing, the following occur with regard to ratepayer impacts:

- 2012 - ERA charge to YECL of $439,000 (this is net of all YEC incremental revenues); however, no Deferral Account charge and no impact on ratepayers (because after accounting for all incremental YECL revenues and costs [including the ERA] from the added wholesales, YECL still retains a net revenue gain of $132,000).

- 2013 - ERA charge to YECL of $13,000; Deferral Account charge and Rider D impact on ratepayers is less (at $9,000). These numbers are not changed in the final YEC 2013 filing (see YUB-YEC-1-25).

For further background, please see Appendix 2 of Yukon Energy's January 31, 2014 Filing and the response to YUB-YEC-1-12(a), as well as YUB-YEC-1-16. Under the Option A ERA calculation proposed in the January 31, 2014 Filing (August 2013 Update to Calculation for ERA as shown in Appendix 2 Table 2-1), a Rider D charge will only result where there are ERA charges to YECL that are not offset fully by added YECL revenues from the incremental wholesale sales. Under the example in Table 2-1 for 2012, there is a $0.439 million ERA charge to YECL and no Rider D charge to customers.

In the event Option B as described in YEC's submission (or some similar mechanism) is chosen (i.e., and there is no ERA charge to YECL and a YEC Diesel Deferral Account is

created to provide for direct charges to customers), any incremental diesel costs for YEC that are not fully offset by YEC incremental revenues related to added sales by YECL (above the approved wholesale forecast for YEC), and that would therefore have been an ERA charge to YECL under Option A, will be charged directly to the new YEC Diesel Deferral Account and therefore ultimately fully charged to ratepayers.

(d)

There is no retroactive change to rates under review. Please see response to (b) above and YUB-YEC-1-19(a) and (b).

(e)

Please see YEC's summary of YECL's position provided at page 2-3 of Yukon Energy's January 31, 2014 Filing. Please see also the response to YUB-YEC-1-6(c), YUB-YEC-1-11(a) and YUB-YEC-1-13(a) and (b).

July 5, 2013

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

Dear Mr. McLennan:

Re: Yukon Energy Corporation 2012/2013 General Rate Application – 2012 DCF & ERA Impacts

Yukon Energy respectfully submits this communication in seeking direction from the Yukon Utilities Board ("YUB", the "Board") with respect to certain transactions affecting its 2012 financial results.

Background
In Board Order 2013-04, the Board accepted Yukon Energy's revised compliance filing and resulting rate increases. Further, in Order 2013-03, Yukon Energy was directed to consult with YECL and submit a joint filing on proposed changes to the DCF policy, as well as any resultant changes to Rate Schedule 42 with respect to the Energy Reconciliation Adjustment (ERA). In this regard, Yukon Energy has forwarded a package of information to YECL and arranged for a second meeting in early July. Given the nature of the topic, we are aware that the process of finalizing a joint filing and the Board's subsequent review of this filing may take several months.

Issue re: DCF
Yukon Energy has prepared its year-end financial statements reflecting the Board's direction in Orders 2013-01, 03 and 04, including accruals for expected revenues expected from the rate increases approved. Inherent in the revenue requirement approved to determine these rates is diesel fuel at 100% long term average hydro generation.

Yukon Energy's actual diesel generation in 2012 was 2,683 MW.h, well below "expected" diesel generation of 15,261 MW.h at 100% long term average hydro generation as estimated for actual 2012 grid generation requirements (i.e., YEC's actual hydro generation was correspondingly higher than long term average). Using the proposed DCF approach, YEC has accordingly deferred $3.714 million of payments to the DCF (costs to YEC, amount owing to ratepayers), as outlined in Attachment A, in order to reflect the difference in costs (at approved diesel fuel prices) between actual and expected diesel generation in 2012.

Our auditors in reviewing this transaction have concluded that, given the rejection of the proposed DCF policy, they cannot sign off on this deferral. In the absence of this deferral, it is understood that Yukon Energy will recognize additional earnings for the year equal to the amount indicated above. Yukon Energy does not believe this outcome is in the best interest of ratepayers or the utility and is not the intended outcome of the Board in the Orders referenced above.

While there is an existing approved DCF policy, application of this policy to the current system and/or the above deferral amount is problematic for reasons that YEC has outlined in past filings with the Board, including the 2012/2013 GRA. In particular, the following are noted:

1) **WAF only** – the existing policy was written to apply to the Whitehorse-Aishihik-Faro grid. As the Board is aware, since 1996/97, material changes have occurred to the system such that the "WAF" grid has been expanded to include the communities of Pelly Crossing, Stewart Crossing, Mayo and Dawson, as well as the hydro generators in Mayo. The additional generation created by this expansion was never contemplated as part of the existing model.

2) **New generation** – since the last approval, the utility has installed additional hydro generation at the Aishihik Hydroelectric generation station (i.e. AH3) as well as at Mayo (i.e., Mayo B) which further alters expected long term generation expectations.

3) **Model and load condition changes** – since 1996/97, Yukon Energy has become more sophisticated in its understanding of hydro generation capabilities on its system and overall load conditions have also radically changed, i.e., rather than a situations where the Faro mine being "on" or "off" the grid being what determines expected long term average diesel requirements (and whether the DCF is "on" or "off" under most conditions), the current loads result in a need for the DCF to be "on" at all times and to adjust as loads change. This greater understanding and radical change in load conditions have resulted in different modeling structures for predicting hydro generation on the current system, and different estimates of expected diesel generation requirements which now change as load levels and conditions change.

In summary, Yukon Energy cannot determine a DCF amount today based on the methods last approved by the Board - and, absent Board approval on some basis, Yukon Energy's auditors cannot justify a deferral account amount for the DCF in 2012.

Ideally, Yukon Energy would prefer to complete the review process to ensure certainty with respect to the outcome. Unfortunately, owing to time pressures to complete our financial statements in time to be consolidated into the public accounts of Yukon Government, we are seeking this interim direction.

Our auditors have indicated that, in the absence of a specific Board Order approving the DCF policy, they would accept a direction from the regulator approving the 2012 transfer to the DCF on an interim basis pending final resolution of this matter.

Issue re: ERA

In the event that such direction regarding the 2012 DCF is provided by the Board, a similar issue arises from Yukon Energy's proposed revised ERA wording for Rate Schedule 42.

Charges to YECL under Rate Schedule 42 related to the ERA are determined based on YEC costs incurred for incremental diesel generation that arise directly due to higher than forecast sales to YECL. Yukon Energy's actual Rate Schedule 42 wholesales sales to YECL in 2012 were 310,264 MW.h, or 14,264 MW.h higher than the Board's approved sales forecast in YEC's Compliance Filing[1]. Using the proposed DCF and related ERA approach to determine YEC's incremental diesel costs in 2012 due to higher than forecast sales to YECL, Yukon Energy has accordingly recorded $1.176 million of ERA adjustment to be paid to YEC, as outlined in Attachment B.

Given this adjustment reflects Yukon Energy's proposed wording for Rate Schedule 42 -- which wording has not yet been approved by the Board -- our auditors have concluded they are not able to sign off on this adjustment. Further, Yukon Energy cannot use the current ERA wording because that wording does not reflect the updated DCF. As a result, since Yukon Energy is not able to recognize the additional 2012 revenues arising from YECL's higher than forecast sales (and the ERA principles previously established by the Board) it cannot finalize its financial statements without further Board direction.

As with the matter of the DCF deferral amount, our auditors have indicated that, in the absence of a specific Board Order approving the amended ERA in Rate Schedule 42, they would accept a direction from the regulator approving the 2012 ERA charge on an interim basis pending final resolution of this matter.

Yours truly,



Ed Mollard, CGA
Chief Financial Officer

[1] After removing Fish Lake hydro generation variances from long-term average (which are fully addressed in the proposed DCF), these higher-than-forecast wholesales to YECL accounted for 14,427 MW.h out of the 18,984 MW.h higher than forecast YEC generation in 2012, and 5,848 MW.h of the increase in YEC's expected diesel generation.

ATTACHMENT A

Impact of the 2012 Actuals to YEC`s Income: DCF Formulaic Approach Operation Example for 2012 YEC Load

Variable cost of YEC diesel calculation

Line No				Notes
L1	Fuel Cost per kW.h	28.71	cents/kW.h	Compliance Filing Average Fuel cost

Calculation of Diesel Cost to Charge (Refund) DCF

2012 Preliminary Actuals

	Assumptions			
L2	YEC Grid load	424,538	MW.h	Preliminary actual, excluding secondary sales
L3	Fish Lake	3,388	MW.h	Fish Lake actual
L4=L2+L3	Total Grid load	427,926	MW.h	
	Assumed Actual Generation Sources			
L5	YECL Fish Lake	3,388	MW.h	Fish Lake actual
L6	YEC Hydro	421,036	MW.h	Preliminary actual, excluding secondary sales
L7	YEC Diesel, total	3,057	MW.h	
L7a	YEC Diesel charged to capital	373	MW.h	Preliminary actual charged to capital
L7b	YEC Net Diesel	2,683	MW.h	Preliminary actual (net of capital diesel)
L8	YEC Wind	445	MW.h	Preliminary actual
L9	Total Grid load	427,926	MW.h	
	Expected Generation Sources			
L10	YECL Fish Lake (expected)	4,380	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 4.35 GW.h for Unit #1.
L11	YEC Wind (expected)	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	423,307	MW.h	
L13	Expected Base Diesel Generation at 420 GW.h	14,100	MW.h	Derived from updated Table 1.1-1 of Revised DCF Proposal
L14=(L12-420 GW.h)x46%	Expected Incremental Diesel Generation at 3,319 MW.h above 420 GW.h	1,521	MW.h	46% of Grid Load between 420 GW.h and 425 GW.h is diesel - Derived from updated Table 1.1-1 of Revised DCF Proposal
L15=L13+L14	Total Expected YEC Diesel Generation	15,621	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	15,621	MW.h	100% of long-term average
L17=L7a	Actual YEC Diesel Generation	2,683	MW.h	Preliminary actual (net of capital diesel)
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 12,938	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($3,714)		

ATTACHMENT B

Proposed ERA calculation for 2012

		GRA - Compliance Filing	Preliminary Actual		Line #/Calculations	Notes
Inputs		A	B	C		
	Forecast v. Actual Variances (MW.h)					
	Retail and Industrial	77,094	79,861	2,767	1	
	Wholesale	296,000	310,264	14,264	2	
	Total Sales	373,094	390,125	17,031	3	
	Losses	32,459	34,412	1,953	4	a
	Total Generation	405,553	424,538	18,984	5	a
	Sources of Generation (MW.h)					
	Hydro	397,388	421,036		6	
	Diesel	7,926	3,057		7	
	Wind	239	445		8	
	Total Generation	405,553	424,538		9	
	Expected Diesel (MW.h)					
	Diesel Generation	7,926	3,057		10	
	less: actual diesel charged to capital projects		373		11	
	plus: Notional diesel generation transferred to DCF	0	12,938		12	
	Total in Rates (Expected Diesel)	7,926	15,621		13	
	Incremental Diesel in Base Rates (MW.h)		7,695		14=13(col B) - 13(col A)	
	Incremental Diesel in Base Rates (% of Total Gen'n Change)		41%		15=14/5(col C)	
Proposed ERA Approach						
	2013 Wholesale Rate	8.298 cents/kW.h			20	b
	Average rider revenue per kW.h	1.050 cents/kW.h			21	c
	ERA Rate Calculation:					
	Fuel Price	28.71 kW.h			22	d
	ERA rate	**28.710** cents/kW.h			23	

The **Energy Reconciliation Adjustment** is calculated as follows:
a) **sales below GRA forecast**: no adjustment for sales more than 10% below GRA forecast
b) **sales above GRA forecast:** all sales in excess of GRA forecast are subject to the adjustment

	GRA	Actual		
Incremental Wholesale Sales (MW.h)	0	14,264	24=2 (col C)	
Fish Lake impact (MW.h)		992	25	e
Incremental Wholesale Related Generation (MW.h)	0	14,427	26=(24-25)*1.087	f
Incremental Diesel Generation Subject to ERA Charge (MW.h)	0	5,848	27=26*15	g
Cost per KW.h		28.71	28=23	
Value of Incremental Diesel Generation ($000's)		$ 1,679	29=28*27/100	
Incremental Wholesale Sales Subject to ERA Credit (MW.h)	0	5,380	30=27/1.087	h
Sales value per KW.h		9.348	31=20+21	
Value of incremental Wholesale sales ($000's)		$ 503	32=28*29/100	
ERA Adjustment to be Paid (Refunded) ($000s)	**$ -**	**$ 1,176**	33=29-32	i

Notes:

a Net of secondary sales
b As approved
c 89.30% of non-industrial rider revenue of $3.51 million (See Compliance Filing:Table 1.3, Sched 9 Tab 7 [298.1 GW.h YECL retail])
d GRA Compliance Filing average for 2012
e YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 4.35 GW.h for Unit #1 less 2012 actuals.
f Incremental wholesale sales less Fish Lake impact plus losses (at 8.7%)
g Diesel generation impact from incremental wholesale sales
h Sales equivalent of diesel gen. [i.e. net of losses]
i Cost of incremental diesel subject to ERA less value of related wholesale sales.

Yukon Utilities Board

July 16, 2013

Ed Mollard
Chief Financial Officer
Yukon Energy Corporation
Box 5920
Whitehorse, Yukon Y1A 5L6

Dear Mr. Mollard:

Re YEC 2012-13 GRA – 2012 DCF and ERA impacts

The Yukon Utilities Board (Board) is in receipt of Yukon Energy Corporation's (YEC) letter of July 5, 2013, in which YEC outlined issues concerning the 2012 DCF and ERA accounts and the 2012 annual financial statements. Specifically, the letter presents the issues raised by your auditors concerning the accounting treatment of the DCF and ERA accounts. YEC is seeking direction from the Board regarding treatment of these accounts as deferral accounts.

The Board has considered YEC's request and directs that the additional earnings of $3.714 million that have been identified as a deferred payment to the DCF be transferred to the DCF on an interim basis pending final resolution of the matter. Similarly, the Board also directs the utility to record the identified ERA charge of $1.176 million on an interim basis pending the final resolution of the matter. For greater clarity, no funds identified in the July 5 letter relating to the DCF and/or ERA are to be recorded by YEC as earnings in its financial statements. All funds assigned to the DCF and/or ERA as a result of this Board direction are on an interim basis only and will be subject to further direction by the Board once a new DCF policy is approved.

The Board also directs that the revised DCF application be submitted to the Board by no later than September 30, 2013.

Sincerely,



Bruce McLennan
Chair

c. YEC 2012-13 GRA Parties

YUKON ENERGY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

April 4, 2014

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

Dear Mr. McLennan:

Re: 2013 Diesel Contingency Fund & Energy Reconciliation Adjustment Impacts

Yukon Energy Corporation ("YEC") respectfully submits this communication in seeking direction from the Yukon Utilities Board ("YUB", or "the Board") with respect to certain transactions affecting its 2013 financial results.

Consistent with last year, our auditors have indicated that, in the absence of a specific Board Order approving the DCF/ERA policy, they would accept a direction from the regulator approving the 2013 transfer to the DCF and the 2013 ERA charge on an interim basis pending final resolution of this matter.

Background
In Board Order 2013-03, Yukon Energy was directed to consult with YECL and submit a joint filing on proposed changes to the Diesel Contingency Fund ("DCF") policy, as well as any resultant changes to Rate Schedule 42 with respect to the Energy Reconciliation Adjustment ("ERA"). After numerous consultations and several deadline extensions, the utilities were unable to develop a joint recommendation on these matters. The companies filed their respective positions with the YUB on January 31, 2014.

In the interim, at the request of YEC, the YUB directed YEC to defer the preliminary balances in 2012 related to these two accounts pending a final decision (copies of YEC request and YUB response are attached as Attachment 1 and 2 respectively).

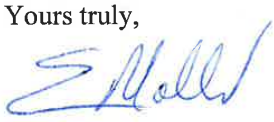
Given the extra time required for the companies to consult and file, YEC is again seeking the direction of the Board to allow the utility to close off its 2013 accounts.

Financial Statement Impact
Yukon Energy has prepared its year-end financial statements reflecting the methodology of its submission to the YUB on January 31, updated for finalization of 2013 year-end amounts.

Yukon Energy's actual diesel generation in 2013 was 1,037[1] MW.h (2012 - 2,683 MW.h), well below "expected" diesel generation of 13,291[2] MW.h (2012 – 15,622 MW.h) at 100% long term average hydro generation as estimated for actual grid generation requirements (i.e., YEC's actual hydro generation was correspondingly higher than long term average). Using the proposed DCF approach, YEC has accordingly deferred $3.518[3] million (2012 - $3.715 million) of payments to the DCF (costs to YEC, amount owing to ratepayers), as outlined in Appendix A, in order to reflect the difference in costs (at approved diesel fuel prices) between actual and expected diesel generation.

Charges to YECL under Rate Schedule 42 related to the ERA are determined based on YEC costs incurred for incremental diesel generation that arise directly due to higher than forecast sales to YECL. Yukon Energy's actual Rate Schedule 42 wholesales sales to YECL in 2013 were 307,927 MW.h (2012 - 310,264 MW.h), or 780 MW.h higher (2012 - 14,264 MW.h higher) than the Board's approved sales forecast in YEC's 2012/13 GRA Compliance Filing. Using the proposed DCF and related ERA approach to determine YEC's incremental diesel costs in 2013 due to higher than forecast sales to YECL, Yukon Energy has accordingly recorded $14,000 (2012 - $439,000) of ERA adjustment to be paid to YEC, as outlined in Appendix B. Note the 2012 calculation has been updated to reflect the approach taken by YEC in its filing with the YUB on January 31, 2014. The effect of this update reduces the ERA for 2012 from $1,176,000 estimated in YEC's July 5, 2013 letter to $439,000.

Yours truly,



Ed Mollard, CGA
Chief Financial Officer

[1] Yukon Energy's January 31, 2014 DCF/ERA filing based on preliminary actual results was 1,114 MWh.
[2] Yukon Energy's January 31, 2014 DCF/ERA filing based on preliminary actual results was 13,326 MWh
[3] Yukon Energy's January 31, 2014 DCF/ERA fling based on preliminary actual results was $3.506 million

APPENDIX A

Impact of the 2013 Actuals to YEC's Income: DCF Formulaic Approach Operation Example for 2013 Load

Variable cost of YEC diesel calculation

Line No					Notes
L1	Fuel Cost per kW.h	28.71	28.71	cents/kW.h	Compliance Filing Average Fuel cost

Calculation of Diesel Cost to Charge (Refund) DCF

2013 Preliminary actuals		**2012 actuals**	**2013 actuals**		
	Assumptions				
L2	YEC Grid load	424,541	419,173	MW.h	Preliminary Actual net of secondary sales (with losses)
L3	Fish Lake	3,388	3,687	MW.h	Fish Lake generation
L4=L2+L3	Total Grid load	427,929	422,860	MW.h	
	Assumed Actual Generation Sources				
L5	YECL Fish Lake	3,388	3,687	MW.h	Fish Lake generation
L6	YEC Hydro	421,039	416,987	MW.h	Residual as total generation less diesel and wind
L7	YEC Diesel	3,057	1,910	MW.h	Preliminary diesel
L7a	*YEC Diesel charged to capital*	*373*	*872*		Includes charged to RFID
L7b	*YEC Net Diesel*	*2,683*	*1,037*		
L8	YEC Wind	445	277	MW.h	Preliminary wind
L9	Total Grid load	427,929	422,860	MW.h	
	Expected Generation Sources				
L10	YECL Fish Lake (expected)	4,380	4,380	MW.h	Unit #2 at 4,380 GW.h - no Unit #1 generation in 2013
L11	YEC Wind (expected)	239	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	423,310	418,241	MW.h	
L13	Expected Base Diesel Generation at 420 GW.h/2012 and 415 GW.h/2013	14,100	11,800	MW.h	Derived from updated Table 4.1-1 for GRA Compliance Filing Proposal (2012 DCF) [Table 1.1-1, Revised DCF Proposal]
L14=(L12-420/415 GW.h)x46%	Expected Incremental Diesel Generation above 420/415 GW.h	1,522	1,491	MW.h	46% of Grid Load between 415 GW.h and 425 GW.h is diesel - Derived from updated Table 4.1-1 for GRA Compliance Filing Proposal [Table 1.1-1, Revised DCF Proposal]
L15=L13+L14	Total Expected YEC Diesel Generation	15,622	13,291	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	15,622	13,291	MW.h	100% of long-term average
L17=L7	FYF YEC Diesel Generation	2,683	1,037	MW.h	Net of capital diesel
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 12,939	- 12,254	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($3,715)	($3,518)		

APPENDIX B

ERA forecast for 2012 and 2013

	2012	2013		
GRA approved wholesales	296,000	307,147	MW.h	A
Actual wholesales	310,264	307,927	MW.h	B
Incremental	14,264	780	MW.h	C=B-A
Less: Fish Lake Impact	992	693	MW.h	D
Incremental net of Fish Lake	13,272	86	MW.h	E=C-D
Total YEC's actual generation net of secondary	424,541	419,173	MW.h	F
GRA approved load forecast	405,553	416,387	MW.h	G
Total YEC incremental generation relative to GRA approved	18,987	2,786	MW.h	H=F-G
Expected diesel generation at actual load	15,622	13,291	MW.h	I
Expected diesel generation at GRA load (approved)	7,926	11,006	MW.h	J
Total YEC expected incremental diesel generation	7,696	2,285	MW.h	K=I-J
Incremental Diesel in Base Rates (see Note 6)	40.5%	82.0%		L=K/H
Generation Variance Charged for Diesel Cost	5,853	77	MW.h	M=E*L*Losses
Impacts on YEC				
	ERA Based on All Incremental Wholesale (100%)			
Added Revenue	1,242	9	$000	N=E*(8.298+average rider)
Added Cost	1,680	22	$000	O=M*28.71
Net Impact on YEC	- 439	- 14	$000	P=N-O
ERA charge to YECL	439	14	$000	Q=(-P)
Impacts on YECL				
Added Revenue	1,672	11	$000	R=E/1.062*average energy rate
Added Cost	1,540	21	$000	S=E*8.298 +Q
Impact on YECL	132	- 9	$000	T=R-S
YECL Deferral Account - Rider charge (Rebate)	-	9	$000	U=If T>0 then 0; otherwise (-T)
Net Impact on YECL after Deferral Charge (Rebate)	132	-	$000	V=T+U

Notes:

1. YEC's approved wholesale and generation numbers are based on YEC's 2012/13 GRA Revised Compliance Filing (includes WHCT related sales).

2. Fish Lake impact is calculated as the difference between expected hydro generation at 4.38 GW.h (4.38 GW.h Unit #2; no Unit #1 generation) and actual generation.

3. YEC's load on Line F is net of secondary sales and related losses.

4. Added revenue for YEC is calculated at wholesale rates plus estimated rider revenues (at 1.058 cents/kW.h for 2012; at 1.69 cents/kW.h for 2013) estimated based on YEC Compliance Filing for 2012/13 GRA.

5. Added revenue for YECL is calculated based on estimated average retail energy rate (excluding block 1) of 13.38 c/kW.h per kW.h for 2012 and 13.81c/kW.h per kW.h for 2013 (and assuming a half year impact of 6.5% 2013-15 GRA interim rider) and 6.2% average YECL losses on sales.

6. Change in expected diesel generation reflects no WHCT load in 2013, and resulting need to retain updated Table 4.1-1 for GRA Compliance Filing Proposal (2012 DCF), which has higher expected diesel for load without WHCT than forecast in Table 4.1-2 (2013 GRA with WHCT load).

YUKON ENERGY
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(867) 393-5300

July 5, 2013

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

Dear Mr. McLennan:

Re: Yukon Energy Corporation 2012/2013 General Rate Application – 2012 DCF & ERA Impacts

Yukon Energy respectfully submits this communication in seeking direction from the Yukon Utilities Board ("YUB", the "Board") with respect to certain transactions affecting its 2012 financial results.

Background
In Board Order 2013-04, the Board accepted Yukon Energy's revised compliance filing and resulting rate increases. Further, in Order 2013-03, Yukon Energy was directed to consult with YECL and submit a joint filing on proposed changes to the DCF policy, as well as any resultant changes to Rate Schedule 42 with respect to the Energy Reconciliation Adjustment (ERA). In this regard, Yukon Energy has forwarded a package of information to YECL and arranged for a second meeting in early July. Given the nature of the topic, we are aware that the process of finalizing a joint filing and the Board's subsequent review of this filing may take several months.

Issue re: DCF
Yukon Energy has prepared its year-end financial statements reflecting the Board's direction in Orders 2013-01, 03 and 04, including accruals for expected revenues expected from the rate increases approved. Inherent in the revenue requirement approved to determine these rates is diesel fuel at 100% long term average hydro generation.

Yukon Energy's actual diesel generation in 2012 was 2,683 MW.h, well below "expected" diesel generation of 15,261 MW.h at 100% long term average hydro generation as estimated for actual 2012 grid generation requirements (i.e., YEC's actual hydro generation was correspondingly higher than long term average). Using the proposed DCF approach, YEC has accordingly deferred $3.714 million of payments to the DCF (costs to YEC, amount owing to ratepayers), as outlined in Attachment A, in order to reflect the difference in costs (at approved diesel fuel prices) between actual and expected diesel generation in 2012.

Our auditors in reviewing this transaction have concluded that, given the rejection of the proposed DCF policy, they cannot sign off on this deferral. In the absence of this deferral, it is understood that Yukon Energy will recognize additional earnings for the year equal to the amount indicated above. Yukon Energy does not believe this outcome is in the best interest of ratepayers or the utility and is not the intended outcome of the Board in the Orders referenced above.

While there is an existing approved DCF policy, application of this policy to the current system and/or the above deferral amount is problematic for reasons that YEC has outlined in past filings with the Board, including the 2012/2013 GRA. In particular, the following are noted:

1) **WAF only** – the existing policy was written to apply to the Whitehorse-Aishihik-Faro grid. As the Board is aware, since 1996/97, material changes have occurred to the system such that the "WAF" grid has been expanded to include the communities of Pelly Crossing, Stewart Crossing, Mayo and Dawson, as well as the hydro generators in Mayo. The additional generation created by this expansion was never contemplated as part of the existing model.

2) **New generation** – since the last approval, the utility has installed additional hydro generation at the Aishihik Hydroelectric generation station (i.e. AH3) as well as at Mayo (i.e., Mayo B) which further alters expected long term generation expectations.

3) **Model and load condition changes** – since 1996/97, Yukon Energy has become more sophisticated in its understanding of hydro generation capabilities on its system and overall load conditions have also radically changed, i.e., rather than a situations where the Faro mine being "on" or "off" the grid being what determines expected long term average diesel requirements (and whether the DCF is "on" or "off" under most conditions), the current loads result in a need for the DCF to be "on" at all times and to adjust as loads change. This greater understanding and radical change in load conditions have resulted in different modeling structures for predicting hydro generation on the current system, and different estimates of expected diesel generation requirements which now change as load levels and conditions change.

In summary, Yukon Energy cannot determine a DCF amount today based on the methods last approved by the Board - and, absent Board approval on some basis, Yukon Energy's auditors cannot justify a deferral account amount for the DCF in 2012.

Ideally, Yukon Energy would prefer to complete the review process to ensure certainty with respect to the outcome. Unfortunately, owing to time pressures to complete our financial statements in time to be consolidated into the public accounts of Yukon Government, we are seeking this interim direction.

Our auditors have indicated that, in the absence of a specific Board Order approving the DCF policy, they would accept a direction from the regulator approving the 2012 transfer to the DCF on an interim basis pending final resolution of this matter.

Issue re: ERA

In the event that such direction regarding the 2012 DCF is provided by the Board, a similar issue arises from Yukon Energy's proposed revised ERA wording for Rate Schedule 42.

Charges to YECL under Rate Schedule 42 related to the ERA are determined based on YEC costs incurred for incremental diesel generation that arise directly due to higher than forecast sales to YECL. Yukon Energy's actual Rate Schedule 42 wholesales sales to YECL in 2012 were 310,264 MW.h, or 14,264 MW.h higher than the Board's approved sales forecast in YEC's Compliance Filing[1]. Using the proposed DCF and related ERA approach to determine YEC's incremental diesel costs in 2012 due to higher than forecast sales to YECL, Yukon Energy has accordingly recorded $1.176 million of ERA adjustment to be paid to YEC, as outlined in Attachment B.

Given this adjustment reflects Yukon Energy's proposed wording for Rate Schedule 42 -- which wording has not yet been approved by the Board -- our auditors have concluded they are not able to sign off on this adjustment. Further, Yukon Energy cannot use the current ERA wording because that wording does not reflect the updated DCF. As a result, since Yukon Energy is not able to recognize the additional 2012 revenues arising from YECL's higher than forecast sales (and the ERA principles previously established by the Board) it cannot finalize its financial statements without further Board direction.

As with the matter of the DCF deferral amount, our auditors have indicated that, in the absence of a specific Board Order approving the amended ERA in Rate Schedule 42, they would accept a direction from the regulator approving the 2012 ERA charge on an interim basis pending final resolution of this matter.

Yours truly,



Ed Mollard, CGA
Chief Financial Officer

[1] After removing Fish Lake hydro generation variances from long-term average (which are fully addressed in the proposed DCF), these higher-than-forecast wholesales to YECL accounted for 14,427 MW.h out of the 18,984 MW.h higher than forecast YEC generation in 2012, and 5,848 MW.h of the increase in YEC's expected diesel generation.

ATTACHMENT A

Impact of the 2012 Actuals to YEC`s Income: DCF Formulaic Approach Operation Example for 2012 YEC Load

Variable cost of YEC diesel calculation

Line No				Notes
L1	Fuel Cost per kW.h	28.71	cents/kW.h	Compliance Filing Average Fuel cost

Calculation of Diesel Cost to Charge (Refund) DCF

2012 Preliminary Actuals

	Assumptions			
L2	YEC Grid load	424,538	MW.h	Preliminary actual, excluding secondary sales
L3	Fish Lake	3,388	MW.h	Fish Lake actual
L4=L2+L3	Total Grid load	427,926	MW.h	
	Assumed Actual Generation Sources			
L5	YECL Fish Lake	3,388	MW.h	Fish Lake actual
L6	YEC Hydro	421,036	MW.h	Preliminary actual, excluding secondary sales
L7	YEC Diesel, total	3,057	MW.h	
L7a	YEC Diesel charged to capital	373	MW.h	Preliminary actual charged to capital
L7b	YEC Net Diesel	2,683	MW.h	Preliminary actual (net of capital diesel)
L8	YEC Wind	445	MW.h	Preliminary actual
L9	Total Grid load	427,926	MW.h	
	Expected Generation Sources			
L10	YECL Fish Lake (expected)	4,380	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 4.35 GW.h for Unit #1.
L11	YEC Wind (expected)	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	423,307	MW.h	
L13	Expected Base Diesel Generation at 420 GW.h	14,100	MW.h	Derived from updated Table 1.1-1 of Revised DCF Proposal
L14=(L12-420 GW.h)x46%	Expected Incremental Diesel Generation at 3,319 MW.h above 420 GW.h	1,521	MW.h	46% of Grid Load between 420 GW.h and 425 GW.h is diesel - Derived from updated Table 1.1-1 of Revised DCF Proposal
L15=L13+L14	Total Expected YEC Diesel Generation	15,621	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	15,621	MW.h	100% of long-term average
L17=L7a	Actual YEC Diesel Generation	2,683	MW.h	Preliminary actual (net of capital diesel)
L18=L17-L16	YEC Diesel Generation to be Included in DCF	12,938	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($3,714)		

ATTACHMENT B

Proposed ERA calculation for 2012

		GRA - Compliance Filing	Preliminary Actual		Line #/Calculations	Notes
Inputs		A	B	C		
	Forecast v. Actual Variances (MW.h)					
	Retail and Industrial	77,094	79,861	2,767	1	
	Wholesale	296,000	310,264	14,264	2	
	Total Sales	373,094	390,125	17,031	3	
	Losses	32,459	34,412	1,953	4	a
	Total Generation	405,553	424,538	18,984	5	a
	Sources of Generation (MW.h)					
	Hydro	397,388	421,036		6	
	Diesel	7,926	3,057		7	
	Wind	239	445		8	
	Total Generation	405,553	424,538		9	
	Expected Diesel (MW.h)					
	Diesel Generation	7,926	3,057		10	
	less: actual diesel charged to capital projects		373		11	
	plus: Notional diesel generation transferred to DCF	0	12,938		12	
	Total in Rates (Expected Diesel)	7,926	15,621		13	
	Incremental Diesel in Base Rates (MW.h)		7,695		14=13(col B) - 13(col A)	
	Incremental Diesel in Base Rates (% of Total Gen'n Change)		41%		15=14/5(col C)	
Proposed ERA Approach						
	2013 Wholesale Rate	8.298 cents/kW.h			20	b
	Average rider revenue per kW.h	1.050 cents/kW.h			21	c
	ERA Rate Calculation:					
	Fuel Price	28.71 kW.h			22	d
	ERA rate	**28.710** cents/kW.h			23	

The **Energy Reconciliation Adjustment** is calculated as follows:
a) **sales below GRA forecast**: no adjustment for sales more than 10% below GRA forecast
b) **sales above GRA forecast:** all sales in excess of GRA forecast are subject to the adjustment

	GRA	Actual		
Incremental Wholesale Sales (MW.h)	0	14,264	24=2 (col C)	
Fish Lake impact (MW.h)		992	25	e
Incremental Wholesale Related Generation (MW.h)	0	14,427	26=(24-25)*1.087	f
Incremental Diesel Generation Subject to ERA Charge (MW.h)	0	5,848	27=26*15	g
Cost per KW.h		28.71	28=23	
Value of Incremental Diesel Generation ($000's)		$ 1,679	29=28*27/100	
Incremental Wholesale Sales Subject to ERA Credit (MW.h)	0	5,380	30=27/1.087	h
Sales value per KW.h		9.348	31=20+21	
Value of incremental Wholesale sales ($000's)		$ 503	32=28*29/100	
ERA Adjustment to be Paid (Refunded) ($000s)	$ -	$ 1,176	33=29-32	i

Notes:

a Net of secondary sales
b As approved
c 89.30% of non-industrial rider revenue of $3.51 million (See Compliance Filing:Table 1.3, Sched 9 Tab 7 [298.1 GW.h YECL retail])
d GRA Compliance Filing average for 2012
e YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 4.35 GW.h for Unit #1 less 2012 actuals.
f Incremental wholesale sales less Fish Lake impact plus losses (at 8.7%)
g Diesel generation impact from incremental wholesale sales
h Sales equivalent of diesel gen. [i.e. net of losses]
i Cost of incremental diesel subject to ERA less value of related wholesale sales.

Yukon Utilities Board

July 16, 2013

Ed Mollard
Chief Financial Officer
Yukon Energy Corporation
Box 5920
Whitehorse, Yukon Y1A 5L6

Dear Mr. Mollard:

Re YEC 2012-13 GRA – 2012 DCF and ERA impacts

The Yukon Utilities Board (Board) is in receipt of Yukon Energy Corporation's (YEC) letter of July 5, 2013, in which YEC outlined issues concerning the 2012 DCF and ERA accounts and the 2012 annual financial statements. Specifically, the letter presents the issues raised by your auditors concerning the accounting treatment of the DCF and ERA accounts. YEC is seeking direction from the Board regarding treatment of these accounts as deferral accounts.

The Board has considered YEC's request and directs that the additional earnings of $3.714 million that have been identified as a deferred payment to the DCF be transferred to the DCF on an interim basis pending final resolution of the matter. Similarly, the Board also directs the utility to record the identified ERA charge of $1.176 million on an interim basis pending the final resolution of the matter. For greater clarity, no funds identified in the July 5 letter relating to the DCF and/or ERA are to be recorded by YEC as earnings in its financial statements. All funds assigned to the DCF and/or ERA as a result of this Board direction are on an interim basis only and will be subject to further direction by the Board once a new DCF policy is approved.

The Board also directs that the revised DCF application be submitted to the Board by no later than September 30, 2013.

Sincerely,



Bruce McLennan
Chair

c. YEC 2012-13 GRA Parties

Yukon Utilities Board • Box 31728 • Whitehorse, Yukon • Y1A 6L3

Phone 867.667.5058 Fax 867.667.5059

Yukon Utilities Board

April 8, 2014

Ed Mollard
Chief Financial Officer
Yukon Energy Corporation
Box 5920
Whitehorse, Yukon Y1A 5L6

Dear Mr. Mollard:

Re 2013 DCF and ERA reconciliation adjustment impacts

The Yukon Utilities Board (Board) is in receipt of Yukon Energy Corporation's (YEC) letter of April 4, 2014, in which YEC outlined issues concerning the 2013 DCF and ERA accounts and the 2013 annual financial statements. The letter presents the issues raised by your auditors concerning the accounting treatment of the DCF and ERA accounts. YEC is seeking direction from the Board regarding treatment of these accounts as deferral accounts.

The Board has considered YEC's request and directs that the additional earnings of $3.518 million that have been identified as a deferred payment to the DCF be transferred to the DCF on an interim basis pending final resolution of the matter. Similarly, the Board also directs the utility to record the identified ERA charge of $439,000 on an interim basis pending the final resolution of the matter. For greater clarity, no funds identified in the April 4 letter relating to the DCF and/or ERA are to be recorded by YEC as earnings in its financial statements. All funds assigned to the DCF and/or ERA as a result of this Board direction are on an interim basis only and will be subject to further direction by the Board once a new DCF policy is approved.

The Board is also in receipt of the YEC-YECL filings/applications and will issue a notice and process the applications in due course.

Sincerely,



Bruce McLennan
Chair

c. Registered YEC-YECL proceeding parties

Yukon Utilities Board • Box 31728 • Whitehorse, Yukon • Y1A 6L3

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REFERENCE: YEC Application to Revise the DCF, Page 1

"Yukon Energy submitted its initial proposal to revise the DCF and ERA mechanisms as part of its 2012/13 General Rate Application ("GRA") filed April 27, 2012."

PREAMBLE:

Request to YEC:

QUESTION:

a) Please provide details of the applications that YEC has made to change either the DCF mechanism or the originally agreed upon use of DCF monies since the DCF was established.

b) Please provide a monthly continuity schedule for the DCF for each year since the DCF was created through June 2014 similar to that provided in response to UCG-YEC-2-31 (dated July 7, 1998) during the review of YECL's 1997 Final Rate Application and YEC's Revised Application.

c) Please explain how the DCF monies could be protected such that they are only used for their intended purpose and not as a funding mechanism for other initiatives.

ANSWER:

(a)

Please see response to UCG-YEC-1-2(a) and YUB-YEC-1-24(a).

(b)

Please see Attachment 1 to this response for an annual continuity schedule for the DCF for each year since the DCF was created through December 2013, similar to that provided in response to Undertaking #23 (November 19, 2012) in the YEC 2012-13 GRA

for all years to the end of 2011, and assuming adoption of the revised DCF starting January 1, 2012 as proposed in YEC's January 31, 2014 filing (DCF amounts for 2013 and 2014 are updated as per YUB-YEC-1-25 in the current proceeding). Attachment 1 also provides a monthly continuity schedule for the earlier DCF for each year from inception to the end of 2011 similar to that provided in response to UCG-YEC-2-31 (dated July 7, 1998) during the review at that time of YECL's 1997 Final Rate Application and YEC's Revised Application - this format yields useful information only for the years between 1996 and 1999 when the DCF was active, and is not relevant after 2011 with the revised DCF as now proposed. As reviewed in response to YUB-YEC-1-1(d), under the DCF as now proposed starting in 2012 monthly calculations of YEC expected hydro and diesel generation will only be a placeholder with ultimate final calculations performed only on the annual values - accordingly, monthly tables are not provided after 2011.[1]

As noted in the earlier Undertaking #23, the annual DCF continuity schedule information prior to 2012 highlights that approximately $2.8 million of withdrawals from the DCF occurred over the 1997-1999 period for non-water related purposes (i.e., general rate relief) pursuant to directions of the Board:

- Board Order 1997-7 directed a drawdown from the DCF to provide a 25% credit to the interim refundable general rider surcharge of 20% approved in Board Order 1997-6; this action was in response to an OIC direction as noted in the Board Order.

- Board Order 1998-5, which finalized YEC's 1997 rates, directed that the balance in the DCF be used to make contributions to all eligible customers to offset 100% of the net rider increases over the next 12 months.

Other YEC-related withdrawals were related to YEC hydro generation capabilities, including impacts on YEC hydraulic generation capabilities during the three last months of 1997 due to the October 1997 fire at the Whitehorse Rapids hydro facility.

[1] As noted in AEY-YEC-1-2(b), monthly DCF calculations under the current proposed approach would depend on month-by-month assessments of long-term average expected diesel generation versus actual diesel generation; aside from month-to-month expected diesel forecasts for any specific annual diesel forecast (e.g., see YUB-YEC-1-1(d)), it would also be necessary in the DCF determination to consider adjustments to the annual grid load forecast (to reflect actual loads experienced) and how this will affect the long-term average expected diesel determination.

Details on the history of the DCF (and its predecessor, the Low Water Reserve Fund set up by YEC in 1991), including Order 1999-3 approving additions and deletions to that time, were provided in the October 28, 2011 response to YUB-YEC-2-4 during the proceeding of the Board on Rider F.

(c)

Since it was created, the DCF has been subject to review by the Yukon Utilities Board. Specifically, an annual report is required to be filed with the Board detailing additions and deletions to the Fund, and the Board directs the companies on the additions and deletions to the Fund. As such, under current and proposed revised rules of operation, DCF funds cannot be used as a funding mechanism for other initiatives unless specifically directed by the YUB.

Attachment 1.1 of Yukon Energy Corporation's Revised DCF Proposal (January 31, 2014) specifically notes as follows in this regard:

- "that the DCF operates to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro and wind generation", and

- "the fund is only to be used for these purposes and is not to be accessed for other reasons without prior YUB approval, including government subsidy of rates."

For further information regarding specific cases where the YUB has directed the DCF to be used for other purposes, see response to UCG-YEC-1-2(a).

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
1996	Opening balance	500,000.00	
	YUB approved deposits	3,540,046.00	4,040,046.00
	YEC withdrawals - Fuel	(942,817.87)	
	YEC withdrawals - O&M	(189,048.95)	(1,131,866.82)
	YECL withdrawals		(325,803.92)
	Interest Income/Service Fees		188,741.49
	Ending Balance		2,771,116.75
1997	Opening balance		2,771,116.75
	YUB 1997/7 Drawdown		(346,275.62)
	YEC Whitehorse Hydro Plant Fire		516,167.23
	YEC drawdown - Fuel	(11,039.59)	
	YEC drawdown - O&M	(2,213.61)	(13,253.20)
	YECL withdrawals		(177,878.50)
	Interest Income/Service Fees		85,132.72
	Ending Balance		2,835,009.38
1998	Opening balance		2,835,009.38
	DCF Rider Drawdown		(1,283,018.76)
	YEC Forest Fire - Transfer impact to RFID		58,182.00
	YEC buildup - Fuel	399,743.47	
	YEC buildup - O&M	80,154.48	479,897.95
	YECL Net withdrawals		(12,958.18)
	Interest Income/Service Fees		158,646.58
	Ending Balance		2,235,758.97
1999	Opening balance		2,235,758.97
	DCF Rider Drawdown		(1,173,011.23)
	YEC buildup - Fuel	(943,298.36)	
	YEC buildup - O&M	(189,145.28)	(1,132,443.64)
	YECL Net withdrawals		-
	YEC Whitehorse Hydro Plant Fire		674,413.21
	Interest Income/Service Fees		43,291.97
	Ending Balance		648,009.28
2000	Opening balance		648,009.28
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		34,712.64
	Ending Balance		682,721.92

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
2001	Opening balance		682,721.92
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		32,510.57
	Ending Balance		715,232.49
2002	Opening balance		715,232.49
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		19,135.69
	Ending Balance		734,368.18
2003	Opening balance		734,368.18
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		21,056.11
	Ending Balance		755,424.29
2004	Opening balance		755,424.29
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		16,296.98
	Ending Balance		771,721.27
2005	Opening balance		771,721.27
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		19,184.49
	Ending Balance		790,905.76

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
2006	Opening balance		790,905.76
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		29,701.89
	Ending Balance		820,607.65
2007	Opening balance		820,607.65
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		35,413.19
	Ending Balance		856,020.84
2008	Opening balance		856,020.84
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		26,672.56
	Ending Balance		882,693.40
2009	Opening balance		882,693.40
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		3,967.40
	Ending Balance		886,660.80
2010	Opening balance		886,660.80
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		4,443.48
	Ending Balance		891,104.28

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
2011	Opening balance		891,104.28
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		10,752.27
	Ending Balance		901,856.55
2012	Opening balance		901,856.55
	DCF Rider Drawdown		-
	YEC buildup - Fuel	3,714,782.34	
	YEC buildup - O&M	-	3,714,782.34
	YECL Net withdrawals		-
	Interest Income/Service Fees		9,970.59
	Ending Balance		4,626,609.48
2013	Opening balance		4,626,609.48
	DCF Rider Drawdown		-
	YEC buildup - Fuel	3,517,981.67	
	YEC buildup - O&M		3,517,981.67
	YECL Net withdrawals		-
	Interest Income/Service Fees		52,410.15
	Ending Balance		8,197,001.30

1996 DCF CALCULATIONS - REVISED

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31

Continuity schedule, year ending Dec. 31, 1996 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	30,465,457	32,454,966	32,760,654	29,982,564	27,039,651	23,572,986	25,817,964	28,198,591	28,573,048	27,038,103	23,736,101	29,701,916	339,342,001
Wind	1a	Manual Input	(40)	28,080	39,790	13,110	17,210	18,730	6,960	11,380	27,270	12,000	25,560	30,120	230,170
Diesel	2	Manual Input	17,177,760	7,209,330	5,989,070	5,977,420	7,005,540	7,243,322	4,933,088	3,162,720	3,625,520	10,750,230	16,753,380	14,727,960	104,555,340
Total	3	Line 1 + Line 2	47,643,177	39,692,376	38,789,514	35,973,094	34,062,401	30,835,038	30,758,012	31,372,691	32,225,838	37,800,333	40,515,041	44,459,996	444,127,511
Forecast Generation - KWh															
Hydro	4	Manual Input	29,406,071	26,221,576	26,492,008	26,018,859	24,202,463	30,159,783	31,072,278	30,772,277	31,299,877	32,502,304	33,164,963	29,775,270	351,087,729.50
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	13,546,393	12,320,651	12,307,032	9,070,912	9,656,998	1,921,573	920,630	1,321,175	1,857,321	3,507,206	5,491,645	11,938,380	83,859,916.00
Total	6	Line 4 + Line 5	42,982,464	38,570,227	38,827,040	35,114,771	33,883,461	32,096,356	32,007,908	32,113,452	33,182,198	36,039,510	38,686,608	41,743,650	435,247,645.50
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	1,029,346	6,233,470	6,280,436	3,951,815	2,830,398	(6,583,067)	(5,262,354)	(2,582,306)	(2,724,559)	(5,482,201)	(9,433,302)	(73,234)	(11,815,558)
Diesel	8	Line 2 - Line 5	3,631,367	(5,111,321)	(6,317,962)	(3,093,492)	(2,651,458)	5,321,749	4,012,458	1,841,545	1,768,199	7,243,024	11,261,735	2,789,580	20,695,424
Total (favourable)	9	Line 3 - Line 6	4,660,713	1,122,149	(37,526)	858,323	178,940	(1,261,318)	(1,249,896)	(740,761)	(956,360)	1,760,823	1,828,433	2,716,346	8,879,866
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	1	1	1	1	1	1	1	1	1	1	1	1	1
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	13,546,393	12,320,651	12,307,032	9,070,912	9,656,998	1,921,573	920,630	1,321,175	1,857,321	3,507,206	5,491,645	11,938,380	83,859,916.00
Total variance	12	Line 9	4,660,713	1,122,149	(37,526)	858,323	178,940	(1,261,318)	(1,249,896)	(740,761)	(956,360)	1,760,823	1,828,433	2,716,346	8,879,865.50
	13	Line 11 + Line 12	18,207,106	13,442,800	12,269,506	9,929,235	9,835,938	660,255	(329,266)	580,414	900,961	5,268,029	7,320,078	14,654,726	92,739,781.50
Expected generation	14	Line 13 if Line 10=1; other=0	18,207,106	13,442,800	12,269,506	9,929,235	9,835,938	660,255	(329,266)	580,414	900,961	5,268,029	7,320,078	14,654,726	92,739,781.50
Maximum savings available	14a	Line 5	13,546,393	12,320,651	12,307,032	9,070,912	9,656,998	1,921,573	920,630	1,321,175	1,857,321	3,507,206	5,491,645	11,938,380	83,859,916.00
Actual diesel generation	15	Line 2	17,177,760	7,209,330	5,989,070	5,977,420	7,005,540	7,243,322	4,933,088	3,162,720	3,625,520	10,750,230	16,753,380	14,727,960	104,555,340.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	1,029,346	6,233,470	6,280,436	3,951,815	2,830,398	(6,583,067)	(5,262,354)	(2,582,306)	(2,724,559)	(5,482,201)	(9,433,302)	(73,234)	(11,815,558.50)
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	277,452	1,680,181	1,692,840	1,065,179	762,910	(1,774,412)	(1,418,424)	(696,039)	(734,382)	(1,477,682)	(2,542,669)	(19,740)	(3,184,786.66)
Standard price($ per litre)	19	Manual Input	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038	0.296038
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per litre)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	82,136.23	497,397.32	501,144.94	315,333.49	225,850.47	(525,293.26)	(419,907.47)	(206,054.11)	(217,405.09)	(437,450.08)	(752,726.62)	(5,843.69)	(942,817.87)
YEC Variable O&M costs	22	Line 20 x Line 16	16,469.53	99,735.52	100,486.98	63,229.03	45,286.36	(105,329.07)	(84,197.66)	(41,316.90)	(43,592.94)	(87,715.22)	(150,932.83)	(1,171.75)	(189,048.95)
YEC buildup (drawdown)	23	Line 21+22	98,605.76	597,132.84	601,631.92	378,562.52	271,136.83	(630,622.33)	(504,105.13)	(247,371.01)	(260,998.03)	(525,165.30)	(903,659.45)	(7,015.44)	(1,131,866.82)
YECL buildup (drawdown)	24	See Table 2	(27,891.62)	(29,143.33)	(18,263.55)	(25,293.64)	(14,055.96)	(17,859.11)	(39,243.08)	(40,349.39)	(13,599.28)	(31,417.17)	(33,950.46)	(34,737.33)	(325,803.92)
Total buildup (drawdown)	25	Line 23 +24	70,714.14	567,989.51	583,368.37	353,268.88	257,080.87	(648,481.44)	(543,348.21)	(287,720.40)	(274,597.31)	(556,582.47)	(937,609.91)	(41,752.77)	(1,457,670.74)
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26		0.00	4,110,760.14	4,678,749.65	5,262,118.02	5,615,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.94	2,624,128.03	
Reserve Buildup (drawdown)	27	Line 25	70,714.14	567,989.51	583,368.37	353,268.88	257,080.87	(648,481.44)	(543,348.21)	(287,720.40)	(274,597.31)	(556,582.47)	(937,609.91)	(41,752.77)	(1,457,670.74)
Transfer LWRF balance	28		500,000.00												500,000.00
YUB approved deposites	29		3,540,046.00												3,540,046.00
Ending reserve balance	30	Line 26+27+28+29	4,110,760.14	4,678,749.65	5,262,118.02	5,615,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.94	2,624,128.03	2,582,375.26	
Interest Calculation:															
Monthly interest rate	31		4.109%	4.109%	4.109%	4.109%	4.109%	4.220%	4.220%	4.220%	4.220%	4.287%	4.407%	4.407%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	14,222.49	13,875.00	17,395.00	18,445.00	20,157.00	19,390.00	17,935.00	16,478.00	15,000.00	14,260.00	11,506.00	10,078.00	188,741.49
Service fees	33		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned	34	Line 32+33	14,222.49	13,875.00	17,395.00	18,445.00	20,157.00	19,390.00	17,935.00	16,478.00	15,000.00	14,260.00	11,506.00	10,078.00	188,741.49
Cumulative net interest earned	35		14,222.49	28,097.49	45,492.49	63,937.49	84,094.49	103,484.49	121,419.49	137,897.49	152,897.49	167,157.49	178,663.49	188,741.49	
Ending reserve balance including interest	36	Line 30+35	4,124,982.63	4,706,847.14	5,307,610.51	5,679,324.39	5,956,562.26	5,327,470.82	4,802,057.61	4,530,815.21	4,271,217.90	3,728,895.43	2,802,791.52	2,771,116.75	
Interest Calculation															
Interest earned			14,222.49	28,097.49	45,492.49	63,937.49	84,094.49	103,484.49	121,419.49	137,897.49	152,897.49	167,157.49	178,663.49	188,741.49	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned			14,222.49	28,097.49	45,492.49	63,937.49	84,094.49	103,484.49	121,419.49	137,897.49	152,897.49	167,157.49	178,663.49	188,741.49	
Ending reserve balance			4,110,760.14	4,678,749.65	5,262,118.02	5,615,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.94	2,624,128.03	2,582,375.26	
Ending reserve balance			4,124,982.63	4,706,847.14	5,307,610.51	5,679,324.39	5,956,562.26	5,327,470.82	4,802,057.61	4,530,815.21	4,271,217.90	3,728,895.43	2,802,791.52	2,771,116.75	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31

Continuity schedule, year ending Dec. 31, 1996 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	565,901	546,130	602,950	555,560	651,514	651,865	425,938	454,234	723,343	519,936	465,090	478,320	6,640,781
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(291,160)	(304,226)	(190,653)	(264,039)	(146,729)	(186,431)	(409,660)	(421,207)	(141,962)	(327,963)	(354,409)	(362,624)	(3,401,063)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	(291,160.00)	(304,226.00)	(190,653.00)	(264,039.00)	(146,729.00)	(186,431.00)	(409,660.00)	(421,207.00)	(141,962.00)	(327,963.00)	(354,409.00)	(362,624.00)	(3,401,063.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	(78,480)	(82,002)	(51,389)	(71,170)	(39,550)	(50,251)	(110,420)	(113,533)	(38,265)	(88,400)	(95,528)	(97,742)	(916,728.57)
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	(23,233.06)	(24,275.71)	(15,213.10)	(21,069.02)	(11,708.30)	(14,876.21)	(32,688.52)	(33,610.08)	(11,327.89)	(26,169.76)	(28,279.92)	(28,935.35)	(271,386.92)
Variable O&M costs - $000	21	YEC Line 21 x Line 4	(4,658.56)	(4,867.62)	(3,050.45)	(4,224.62)	(2,347.66)	(2,982.90)	(6,554.56)	(6,739.31)	(2,271.39)	(5,247.41)	(5,670.54)	(5,801.98)	(54,417.00)
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	(27,891.62)	(29,143.33)	(18,263.55)	(25,293.64)	(14,055.96)	(17,859.11)	(39,243.08)	(40,349.39)	(13,599.28)	(31,417.17)	(33,950.46)	(34,737.33)	(325,803.92)
Opening reserve	23	Line 25 prior period	(325.80)	(28,217.42)	(57,360.75)	(75,624.30)	(100,917.94)	(114,973.90)	(132,833.01)	(172,076.09)	(212,425.48)	(226,024.76)	(257,441.93)	(291,392.39)	
Cumulative reserve balance - $000	25	Line 22+Line 23	(28,217.42)	(57,360.75)	(75,624.30)	(100,917.94)	(114,973.90)	(132,833.01)	(172,076.09)	(212,425.48)	(226,024.76)	(257,441.93)	(291,392.39)	(326,129.72)	

1997 DCF CALCULATIONS - REVISED

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31

Continuity schedule, year ending Dec. 31, 1997 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	35,245,105	30,041,642	27,432,167	13,176,913	16,758,996	16,155,292	16,447,882	17,856,478	20,486,451	25,580,490	27,651,195	33,706,072	280,538,683
Wind	1a	Manual Input	32,340	22,210	25,050	21,320	18,640	16,590	7,590	19,140	25,370	17,840	6,530	21,370	233,990
Diesel	2	Manual Input	9,325,290	4,277,990	9,025,200	6,861,920	1,295,370	1,260	53,010	8,610	96,630	357,870	7,140,520	6,747,710	45,191,380
Total	3	Line 1 + Line 2	44,602,735	34,341,842	36,482,417	20,060,153	18,073,006	16,173,142	16,508,482	17,884,228	20,608,451	25,956,200	34,798,245	40,475,152	325,964,053
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	4,840,822	2,314,138	437,047	(10,645,265)	(7,948,582)	(14,803,050)	(14,331,484)	(13,016,212)	(11,312,794)	(6,934,346)	(3,137,501)	3,922,304	(70,614,923)
Diesel	8	Line 2 - Line 5	(2,514,156)	(6,283,278)	(2,912,393)	(4,702,319)	(8,206,951)	(1,201,750)	(1,293,044)	(1,341,902)	(1,346,045)	(3,253,895)	(854,711)	(5,103,498)	(39,013,942)
Total (favourable)	9	Line 3 - Line 6	2,326,666	(3,969,140)	(2,475,346)	(15,347,584)	(16,155,533)	(16,004,800)	(15,624,528)	(14,358,114)	(12,658,839)	(10,188,241)	(3,992,212)	(1,181,194)	(109,628,865)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	1	1	1	-	-	-	-	-	-	-	1	1	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	2,326,666	(3,969,140)	(2,475,346)	(15,347,584)	(16,155,533)	(16,004,800)	(15,624,528)	(14,358,114)	(12,658,839)	(10,188,241)	(3,992,212)	(1,181,194)	(109,628,865.00)
	13	Line 11 + Line 12	14,166,112	6,592,128	9,462,247	(3,783,345)	(6,653,212)	(14,801,790)	(14,278,474)	(13,007,602)	(11,216,164)	(6,576,476)	4,003,019	10,670,014	(25,423,543.00)
Expected generation	14	Line 13 if Line 10=1; other=0	14,166,112	6,592,128	9,462,247	-	-	-	-	-	-	-	4,003,019	10,670,014	44,893,520.00
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	9,325,290	4,277,990	9,025,200	6,861,920	1,295,370	1,260	53,010	8,610	96,630	357,870	7,140,520	6,747,710	45,191,380.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	4,840,822	2,314,138	437,047	(6,861,920)	(1,295,370)	-	-	-	-	(357,870)	(3,137,501)	3,922,304	(138,350.00)
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	1,304,804	623,757	117,802	(1,849,574)	(349,156)	-	-	-	-	(96,461)	(845,688)	1,057,225	(37,291.10)
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per litre)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	386,271.50	184,655.74	34,873.99	(547,544.22)	(103,363.54)	-	-	-	-	(28,556.10)	(250,355.67)	312,978.71	(11,039.59)
YEC Variable O&M costs	22	Line 20 x Line 16	77,453.15	37,026.21	6,992.75	(109,790.72)	(20,725.92)	-	-	-	-	(5,725.92)	(50,200.02)	62,756.86	(2,213.61)
YEC buildup (drawdown)	23	Line 21+22	463,724.65	221,681.95	41,866.74	(657,334.94)	(124,089.46)	-	-	-	-	(34,282.02)	(300,555.69)	375,735.57	(13,253.20)
YECL buildup (drawdown)	24	See Table 2	(37,974.99)	(30,427.77)	(44,636.60)	(30,643.50)	483.36	-	-	-	-	-	(21,445.42)	(13,233.58)	(177,878.50)
Total buildup (drawdown)	25	Line 23 +24	425,749.66	191,254.18	(2,769.86)	(687,978.44)	(123,606.10)	-	-	-	-	(34,282.02)	(322,001.11)	362,501.99	(191,131.70)
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	2,771,116.75	3,196,866.41	3,388,120.59	3,385,350.73	2,697,372.29	2,573,766.19	2,573,766.19	2,467,483.00	2,224,773.39	2,227,490.57	2,227,490.57	2,274,260.39	
Reserve Buildup (drawdown)	27	Line 25	425,749.66	191,254.18	(2,769.86)	(687,978.44)	(123,606.10)	-	-	-	-	(34,282.02)	(322,001.11)	362,501.99	(191,131.70)
YUB 1997/7 Drawdown	28								(106,283.19)	(242,709.61)	2,717.18			-	(346,275.62)
YEC fire impact	29											34,282.02	368,770.93	113,114.28	516,167.23
Ending reserve balance	30	Line 26+27+28+29	3,196,866.41	3,388,120.59	3,385,350.73	2,697,372.29	2,573,766.19	2,573,766.19	2,467,483.00	2,224,773.39	2,227,490.57	2,227,490.57	2,274,260.39	2,749,876.66	
															403,052.95
Interest Calculation:															
Monthly interest rate	31		3.55%	3.34%	3.09%	3.42%	3.47%	3.46%	3.52%	3.58%	3.61%	3.93%	3.98%	2.72%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	8,984.00	8,440.00	8,900.00	8,586.00	7,811.00	7,368.00	7,594.00	7,211.00	6,688.00	7,547.00	7,486.00	5,901.00	92,516.00
Service fees	33		(1,975.54)	0.00	0.00	(1,956.56)	0.00	0.00	(1,687.44)	0.00	0.00	(1,763.74)	0.00	0.00	(7,383.28)
Net interest earned	34	Line 32+33	7,008.46	8,440.00	8,900.00	6,629.44	7,811.00	7,368.00	5,906.56	7,211.00	6,688.00	5,783.26	7,486.00	5,901.00	85,132.72
Cumulative net interest earned	35		7,008.46	15,448.46	24,348.46	30,977.90	38,788.90	46,156.90	52,063.46	59,274.46	65,962.46	71,745.72	79,231.72	85,132.72	
Ending reserve balance including interest	36	Line 30+35	3,203,874.87	3,403,569.05	3,409,699.19	2,728,350.19	2,612,555.09	2,619,923.09	2,519,546.46	2,284,047.85	2,293,453.03	2,299,236.29	2,353,492.11	2,835,009.38	
Interest Calculation															
Interest earned			8,984.00	17,424.00	26,324.00	34,910.00	42,721.00	50,089.00	57,683.00	64,894.00	71,582.00	79,129.00	86,615.00	92,516.00	
Account fees			(1,975.54)	(1,975.54)	(1,975.54)	(3,932.10)	(3,932.10)	(3,932.10)	(5,619.54)	(5,619.54)	(5,619.54)	(7,383.28)	(7,383.28)	(7,383.28)	
Net interest earned			7,008.46	15,448.46	24,348.46	30,977.90	38,788.90	46,156.90	52,063.46	59,274.46	65,962.46	71,745.72	79,231.72	85,132.72	
Ending reserve balance			3,196,866.41	3,388,120.59	3,385,350.73	2,697,372.29	2,573,766.19	2,573,766.19	2,467,483.00	2,224,773.39	2,227,490.57	2,227,490.57	2,274,260.39	2,749,876.66	
Ending reserve balance			3,203,874.87	3,403,569.05	3,409,699.19	2,728,350.19	2,612,555.09	2,619,923.09	2,519,546.46	2,284,047.85	2,293,453.03	2,299,236.29	2,353,492.11	2,835,009.38	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31

Continuity schedule, year ending Dec. 31, 1997 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	460,640	532,720	327,640	499,710	803,290	739,610	464,420	365,650	331,200	519,936	595,630	702,800	6,343,246
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(396,421)	(317,636)	(465,963)	(319,889)	5,047	(98,686)	(371,178)	(509,791)	(534,105)	(327,963)	(223,869)	(138,144)	(3,698,598)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	(396,421)	(317,636)	(465,963)	(319,889)	5,047	-	-	-	-	-	(223,869)	(138,144)	(1,856,875.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	(106,852)	(85,616)	(125,596)	(86,223)	1,360	-	-	-	-	-	(60,342)	(37,236)	(500,505.39)
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	(31,632.25)	(25,345.59)	(37,181.19)	(25,525.28)	402.61	-	-	-	-	-	(17,863.52)	(11,023.28)	(148,168.50)
Variable O&M costs - $000	21	YEC Line 21 x Line 4	(6,342.74)	(5,082.18)	(7,455.41)	(5,118.22)	80.75	-	-	-	-	-	(3,581.90)	(2,210.30)	(29,710.00)
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	(37,974.99)	(30,427.77)	(44,636.60)	(30,643.50)	483.36	-	-	-	-	-	(21,445.42)	(13,233.58)	(177,878.50)
Opening reserve	23	Line 25 prior period	-	(37,974.99)	(68,402.76)	(113,039.36)	(143,682.86)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(164,644.92)	
Cumulative reserve balance - $000	25	Line 22+Line 23	(37,974.99)	(68,402.76)	(113,039.36)	(143,682.86)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(164,644.92)	(177,878.50)	

1998 DCF CALCULATIONS

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31
Continuity schedule, year ending Dec. 31, 1998 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	36,039,040	21,433,141	22,326,425	18,580,593	18,161,991	16,545,167	16,106,899	18,101,121	18,145,949	20,640,506	22,898,681	24,840,153	253,819,666
Wind	1a	Manual Input	14,600	31,080	26,080	31,570	32,370	13,280	17,600	22,260	21,790	23,130	10,310	14,520	258,590
Diesel	2	Manual Input	6,509,130	-	19,320	-	1,680	2,478	607,362	2,940	420	4,200	34,440	17,160	7,199,130
Total	3	Line 1 + Line 2	42,562,770	21,464,221	22,371,825	18,612,163	18,196,041	16,560,925	16,731,861	18,126,321	18,168,159	20,667,836	22,943,431	24,871,833	261,277,386
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	5,617,017	(6,285,493)	(4,667,665)	(5,231,335)	(6,531,857)	(14,416,485)	(14,662,457)	(12,768,449)	(13,656,876)	(11,869,040)	(7,886,235)	(4,950,465)	(97,309,340)
Diesel	8	Line 2 - Line 5	(5,330,316)	(10,561,268)	(11,918,273)	(11,564,239)	(9,500,641)	(1,200,532)	(738,692)	(1,347,572)	(1,442,255)	(3,607,565)	(7,960,791)	(11,834,048)	(77,006,192)
Total (favourable)	9	Line 3 - Line 6	286,701	(16,846,761)	(16,585,938)	(16,795,574)	(16,032,498)	(15,617,017)	(15,401,149)	(14,116,021)	(15,099,131)	(15,476,605)	(15,847,026)	(16,784,513)	(174,315,532)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	1	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	286,701	(16,846,761)	(16,585,938)	(16,795,574)	(16,032,498)	(15,617,017)	(15,401,149)	(14,116,021)	(15,099,131)	(15,476,605)	(15,847,026)	(16,784,513)	(174,315,532.00)
	13	Line 11 + Line 12	12,126,147	(6,285,493)	(4,648,345)	(5,231,335)	(6,530,177)	(14,414,007)	(14,055,095)	(12,765,509)	(13,656,456)	(11,864,840)	(7,851,795)	(4,933,305)	(90,110,210.00)
Expected generation	14	Line 13 if Line 10=1; other=0	12,126,147	-	-	-	-	-	-	-	-	-	-	-	12,126,147.00
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	6,509,130	-	19,320	-	1,680	2,478	607,362	2,940	420	4,200	34,440	17,160	7,199,130.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	5,617,017	-	-	-	-	-	(607,362)	-	-	-	-	-	5,009,655.00
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	1,514,021	-	-	-	-	-	(163,709)	-	-	-	-	-	1,350,311.32
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per litre)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	448,207.68	-	-	-	-	-	(48,464.21)	-	-	-	-	-	399,743.47
YEC Variable O&M costs	22	Line 20 x Line 16	89,872.27	-	-	-	-	-	(9,717.79)	-	-	-	-	-	80,154.48
YEC buildup (drawdown)	23	Line 21+22	538,079.95	-	-	-	-	-	(58,182.00)	-	-	-	-	-	479,897.95
YECL buildup (drawdown)	24	See Table 2	(12,958.18)	-	-	-	-	-	-	-	-	-	-	-	(12,958.18)
Total buildup (drawdown)	25	Line 23 +24	525,121.77	-	-	-	-	-	(58,182.00)	-	-	-	-	-	466,939.77
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	2,835,009.38	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,058,128.35	2,759,812.50	2,422,325.99	
Reserve Buildup (drawdown)	27	Line 25	525,121.77	-	-	-	-	-	(58,182.00)	-	-	-	-	-	466,939.77
Rider drawdown	28										(302,002.80)	(298,315.85)	(337,486.51)	(345,213.60)	(1,283,018.76)
Forest fire impact	29								58,182.00						58,182.00
Ending reserve balance	30	Line 26+27+28+29	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,058,128.35	2,759,812.50	2,422,325.99	2,077,112.39	
Interest Calculation:															
Monthly interest rate	31		4.78%	4.92%	5.01%	5.11%	5.13%	5.13%	5.03%	4.49%	6.16%	5.83%	5.80%	5.56%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	12,586.00	12,694.00	14,342.00	14,184.00	14,738.00	14,307.00	14,509.00	12,987.00	16,506.00	14,710.00	12,676.00	10,966.00	165,205.00
Service fees	33		(1,850.89)	0.00	0.00	(1,780.51)	0.00	0.00	(1,460.05)	0.00	0.00	(1,466.97)	0.00	0.00	(6,558.42)
Net interest earned	34	Line 32+33	10,735.11	12,694.00	14,342.00	12,403.49	14,738.00	14,307.00	13,048.95	12,987.00	16,506.00	13,243.03	12,676.00	10,966.00	158,646.58
Cumulative net interest earned	35		10,735.11	23,429.11	37,771.11	50,174.60	64,912.60	79,219.60	92,268.55	105,255.55	121,761.55	135,004.58	147,680.58	158,646.58	
Ending reserve balance including interest	36	Line 30+35	3,370,866.26	3,383,560.26	3,397,902.26	3,410,305.75	3,425,043.75	3,439,350.75	3,452,399.70	3,465,386.70	3,179,889.90	2,894,817.08	2,570,006.57	2,235,758.97	
Interest Calculation															
Interest earned			12,586.00	25,280.00	39,622.00	53,806.00	68,544.00	82,851.00	97,360.00	110,347.00	126,853.00	141,563.00	154,239.00	165,205.00	
Account fees			(1,850.89)	(1,850.89)	(1,850.89)	(3,631.40)	(3,631.40)	(3,631.40)	(5,091.45)	(5,091.45)	(5,091.45)	(6,558.42)	(6,558.42)	(6,558.42)	
Net interest earned			10,735.11	23,429.11	37,771.11	50,174.60	64,912.60	79,219.60	92,268.55	105,255.55	121,761.55	135,004.58	147,680.58	158,646.58	
Ending reserve balance			3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,360,131.15	3,058,128.35	2,759,812.50	2,422,325.99	2,077,112.39	
Ending reserve balance			3,370,866.26	3,383,560.26	3,397,902.26	3,410,305.75	3,425,043.75	3,439,350.75	3,452,399.70	3,465,386.70	3,179,889.90	2,894,817.08	2,570,006.57	2,235,758.97	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31
Continuity schedule, year ending Dec. 31, 1998 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	721,790	560,440	665,200	667,690	557,790	360,150	390,080	363,280	279,960	255,230	271,820	467,800	5,561,230
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(135,271)	(289,916)	(128,403)	(151,909)	(240,453)	(478,146)	(445,518)	(512,161)	(585,345)	(592,669)	(547,679)	(373,144)	(4,480,614)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	(135,271)	-	-	-	-	-	-	-	-	-	-	-	(135,271.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	(36,461)	-	-	-	-	-	-	-	-	-	-	-	(36,461.19)
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	(10,793.84)	-	-	-	-	-	-	-	-	-	-	-	(10,793.84)
Variable O&M costs - $000	21	YEC Line 21 x Line 4	(2,164.34)	-	-	-	-	-	-	-	-	-	-	-	(2,164.34)
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	(12,958.18)	-	-	-	-	-	-	-	-	-	-	-	(12,958.18)
Opening reserve	23	Line 25 prior period	-	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	
Cumulative reserve balance - $000	25	Line 22+Line 23	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	

Schedule 5: REVISED 1999 DCF CALCULATIONS

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	24,703,222	19,755,439	21,697,737	17,173,732	16,385,634	16,648,649	16,902,905	17,048,595	17,532,436	19,765,543	21,390,108	24,120,830	233,124,830
Wind	1a	Manual Input	20,180	22,530	29,220	26,670	19,650	14,760	20,550	12,570	29,500	27,130	10,830	34,050	267,640
Diesel	2	Manual Input	3,952,140	3,088,060	139,860	1,942,780	2,083,550	13,370	3,150	99,330	183,540	73,080	488,770	266,280	12,333,910
Total	3	Line 1 + Line 2	28,675,542	22,866,029	21,866,817	19,143,182	18,488,834	16,676,779	16,926,605	17,160,495	17,745,476	19,865,753	21,889,708	24,421,160	245,726,380
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(5,713,221)	(7,971,745)	(5,293,213)	(6,643,096)	(8,320,934)	(14,311,523)	(13,863,501)	(13,830,665)	(14,262,679)	(12,740,003)	(9,394,288)	(5,650,258)	(117,995,126)
Diesel	8	Line 2 - Line 5	(7,887,306)	(7,473,208)	(11,797,733)	(9,621,459)	(7,418,771)	(1,189,640)	(1,342,904)	(1,251,182)	(1,259,135)	(3,538,685)	(7,506,461)	(11,584,928)	(71,871,412)
Total (favourable)	9	Line 3 - Line 6	(13,600,527)	(15,444,953)	(17,090,946)	(16,264,555)	(15,739,705)	(15,501,163)	(15,206,405)	(15,081,847)	(15,521,814)	(16,278,688)	(16,900,749)	(17,235,186)	(189,866,538)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(13,600,527)	(15,444,953)	(17,090,946)	(16,264,555)	(15,739,705)	(15,501,163)	(15,206,405)	(15,081,847)	(15,521,814)	(16,278,688)	(16,900,749)	(17,235,186)	(189,866,538.00)
	13	Line 11 + Line 12	(1,761,081)	(4,883,685)	(5,153,353)	(4,700,316)	(6,237,384)	(14,298,153)	(13,860,351)	(13,731,335)	(14,079,139)	(12,666,923)	(8,905,518)	(5,383,978)	(105,661,216.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	3,952,140	3,088,060	139,860	1,942,780	2,083,550	13,370	3,150	99,330	183,540	73,080	488,770	266,280	12,333,910.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	(3,952,140)	(3,088,060)	-	(1,942,780)	(2,083,550)	-	-	-	-	-	(488,770)	(266,280)	(11,821,580.00)
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	(1,065,267)	(832,361)	-	(523,660)	(561,604)	-	-	-	-	-	(131,744)	(71,774)	(3,186,409.70)
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	(315,359.47)	(246,410.54)	-	(155,023.37)	(166,256.06)	-	-	-	-	-	(39,001.21)	(21,247.71)	(943,298.36)
YEC Variable O&M costs	22	Line 20 x Line 16	(63,234.24)	(49,408.96)	-	(31,084.48)	(33,336.80)	-	-	-	-	-	(7,820.32)	(4,260.48)	(189,145.28)
YEC buildup (drawdown)	23	Line 21+22	(378,593.71)	(295,819.50)	-	(186,107.85)	(199,592.86)	-	-	-	-	-	(46,821.53)	(25,508.19)	(1,132,443.64)
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	(378,593.71)	(295,819.50)	-	(186,107.85)	(199,592.86)	-	-	-	-	-	(46,821.53)	(25,508.19)	(1,132,443.64)
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	2,235,758.97	1,803,928.15	1,416,812.57	1,063,222.38	877,388.24	677,511.83	677,408.68	677,400.16	677,397.99	677,307.47	677,307.47	630,338.71	
Reserve Buildup (drawdown)	27	Line 25	(378,593.71)	(295,819.50)	-	(186,107.85)	(199,592.86)	-	-	-	-	-	(46,821.53)	(25,508.19)	(1,132,443.64)
Rider drawdown	28		(431,830.82)	(387,115.58)	(353,590.19)	273.71	(283.55)	(103.15)	(8.52)	(2.17)	(90.52)	-	(147.23)	(113.21)	(1,173,011.23)
YEC Fire Impact	29		378,593.71	295,819.50					-						674,413.21
Ending reserve balance	30	Line 26+27+28+29	1,803,928.15	1,416,812.57	1,063,222.38	877,388.24	677,511.83	677,408.68	677,400.16	677,397.99	677,307.47	677,307.47	630,338.71	604,717.31	
Interest Calculation:															
Monthly interest rate	31		5.49%	5.30%	5.31%	5.22%	4.97%	4.93%	4.98%	4.90%	4.97%	5.05%	5.08%	5.22%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	9,781.00	6,581.00	5,109.00	3,963.00	3,052.00	2,659.00	2,699.00	2,660.00	2,711.00	2,761.00	2,694.00	2,638.00	47,308.00
Service fees	33		(1,389.12)	0.00	0.00	(1,062.86)	0.00	0.00	(905.02)	0.00	0.00	(659.03)	0.00	0.00	(4,016.03)
Net interest earned	34	Line 32+33	8,391.88	6,581.00	5,109.00	2,900.14	3,052.00	2,659.00	1,793.98	2,660.00	2,711.00	2,101.97	2,694.00	2,638.00	43,291.97
Cumulative net interest earned	35		8,391.88	14,972.88	20,081.88	22,982.02	26,034.02	28,693.02	30,487.00	33,147.00	35,858.00	37,959.97	40,653.97	43,291.97	
Ending reserve balance including interest	36	Line 30+35	1,812,320.03	1,431,785.45	1,083,304.26	900,370.26	703,545.85	706,101.70	707,887.16	710,544.99	713,165.47	715,267.44	670,992.68	648,009.28	
Interest Calculation															
Interest earned			9,781.00	16,362.00	21,471.00	25,434.00	28,486.00	31,145.00	33,844.00	36,504.00	39,215.00	41,976.00	44,670.00	47,308.00	
Account fees			(1,389.12)	(1,389.12)	(1,389.12)	(2,451.98)	(2,451.98)	(2,451.98)	(3,357.00)	(3,357.00)	(3,357.00)	(4,016.03)	(4,016.03)	(4,016.03)	
Net interest earned			8,391.88	14,972.88	20,081.88	22,982.02	26,034.02	28,693.02	30,487.00	33,147.00	35,858.00	37,959.97	40,653.97	43,291.97	
Ending reserve balance			1,803,928.15	1,416,812.57	1,063,222.38	877,388.24	677,511.83	677,408.68	677,400.16	677,397.99	677,307.47	677,307.47	630,338.71	604,717.31	
Ending reserve balance			1,812,320.03	1,431,785.45	1,083,304.26	900,370.26	703,545.85	706,101.70	707,887.16	710,544.99	713,165.47	715,267.44	670,992.68	648,009.28	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input													0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - $000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	
Cumulative reserve balance - $000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	

Schedule 6: REVISED 2000 DCF CALCULATIONS

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31
Continuity schedule, year ending Dec. 31, 2000 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	26,029,914	20,740,492	21,350,804	19,133,603	17,353,100	18,498,005	16,760,308	17,325,286	18,029,052	20,663,163	20,131,232	26,949,285	242,964,244
Wind	1a	Manual Input	21,080	14,940	31,070	25,830	13,070	9,950	16,400	19,690	21,160	31,890	107,725	80,739	393,544
Diesel	2	Manual Input	109,380	0	1,580	5,800	38,850	320	6,900	3,150	5,600	3,360	545,240	7,990	728,170
Total	3	Line 1 + Line 2	26,160,374	20,755,432	21,383,454	19,165,233	17,405,020	18,508,275	16,783,608	17,348,126	18,055,812	20,698,413	20,784,197	27,038,014	244,085,958
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(4,385,629)	(6,994,282)	(5,638,296)	(4,684,065)	(7,360,048)	(12,466,977)	(14,010,248)	(13,546,854)	(13,774,403)	(11,837,623)	(10,556,269)	(2,775,114)	(108,029,808)
Diesel	8	Line 2 - Line 5	(11,730,066)	(10,561,268)	(11,936,013)	(11,558,439)	(9,463,471)	(1,202,690)	(1,339,154)	(1,347,362)	(1,437,075)	(3,608,405)	(7,449,991)	(11,843,218)	(83,477,152)
Total (favourable)	9	Line 3 - Line 6	(16,115,695)	(17,555,550)	(17,574,309)	(16,242,504)	(16,823,519)	(13,669,667)	(15,349,402)	(14,894,216)	(15,211,478)	(15,446,028)	(18,006,260)	(14,618,332)	(191,506,960)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(16,115,695)	(17,555,550)	(17,574,309)	(16,242,504)	(16,823,519)	(13,669,667)	(15,349,402)	(14,894,216)	(15,211,478)	(15,446,028)	(18,006,260)	(14,618,332)	(191,506,960.00)
	13	Line 11 + Line 12	(4,276,249)	(6,994,282)	(5,636,716)	(4,678,265)	(7,321,198)	(12,466,657)	(14,003,348)	(13,543,704)	(13,768,803)	(11,834,263)	(10,011,029)	(2,767,124)	(107,301,638.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	109,380	-	1,580	5,800	38,850	320	6,900	3,150	5,600	3,360	545,240	7,990	728,170.00
											Over-ride Line 16		**- Nov Diesel Due to Frazil Ice**		
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	5.28%	5.38%	5.49%	5.57%	5.75%	5.96%	6.02%	6.02%	6.00%	6.03%	6.03%	6.03%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	3,003.00	2,686.00	2,752.00	2,801.00	2,905.00	3,020.00	3,068.00	3,083.00	3,085.00	3,115.00	3,128.00	3,141.00	35,787.00
Service fees	33		0.00	(540.99)	0.00	(530.00)	0.00	0.00	(1.70)	0.00	0.00	(1.67)	0.00	0.00	(1,074.36)
Net interest earned	34	Line 32+33	3,003.00	2,145.01	2,752.00	2,271.00	2,905.00	3,020.00	3,066.30	3,083.00	3,085.00	3,113.33	3,128.00	3,141.00	34,712.64
Cumulative net interest earned	35		3,003.00	5,148.01	7,900.01	10,171.01	13,076.01	16,096.01	19,162.31	22,245.31	25,330.31	28,443.64	31,571.64	34,712.64	
Ending reserve balance including interest	36	Line 30+35	651,012.28	653,157.29	655,909.29	658,180.29	661,085.29	664,105.29	667,171.59	670,254.59	673,339.59	676,452.92	679,580.92	682,721.92	
		TD Prime Rate for Borrowing	6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation															
Interest earned			3,003.00	5,689.00	8,441.00	11,242.00	14,147.00	17,167.00	20,235.00	23,318.00	26,403.00	29,518.00	32,646.00	35,787.00	
Account fees			0.00	(540.99)	(540.99)	(1,070.99)	(1,070.99)	(1,070.99)	(1,072.69)	(1,072.69)	(1,072.69)	(1,074.36)	(1,074.36)	(1,074.36)	
Net interest earned			3,003.00	5,148.01	7,900.01	10,171.01	13,076.01	16,096.01	19,162.31	22,245.31	25,330.31	28,443.64	31,571.64	34,712.64	
Ending reserve balance			648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	648,009.28	
Ending reserve balance			651,012.28	653,157.29	655,909.29	658,180.29	661,085.29	664,105.29	667,171.59	670,254.59	673,339.59	676,452.92	679,580.92	682,721.92	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input													0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - $000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	
Cumulative reserve balance - $000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	

2001 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2001

Continuity schedule, year ending Dec. 31, 2001 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	23,652,418	22,112,517	22,732,857	19,759,754	18,950,295	17,196,549	16,870,180	17,074,052	17,767,661	21,116,042	23,317,346	28,005,227	248,554,898
Wind	1a	Manual Input	192,757	43,581	166,748	104,171	134,867	68,644	60,814	74,786	156,429	54,297	43,477	11,940	1,112,511
Diesel	2	Manual Input	2,520	15,150	2,730	0	24,390	1,680	7,660	7,980	9,360	70,060	38,140	50,880	230,550
Total	3	Line 1 + Line 2	23,847,695	22,171,248	22,902,335	19,863,925	19,109,552	17,266,873	16,938,654	17,156,818	17,933,450	21,240,399	23,398,963	28,068,047	249,897,959
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(6,591,448)	(5,593,616)	(4,120,565)	(3,979,573)	(5,641,056)	(13,709,739)	(13,855,962)	(13,742,992)	(13,900,525)	(11,362,337)	(7,434,403)	(1,787,971)	(101,720,187)
Diesel	8	Line 2 - Line 5	(11,836,926)	(10,546,118)	(11,934,863)	(11,564,239)	(9,477,931)	(1,201,330)	(1,338,394)	(1,342,532)	(1,433,315)	(3,541,705)	(7,957,091)	(11,800,328)	(83,974,772)
Total (favourable)	9	Line 3 - Line 6	(18,428,374)	(16,139,734)	(16,055,428)	(15,543,812)	(15,118,987)	(14,911,069)	(15,194,356)	(15,085,524)	(15,333,840)	(14,904,042)	(15,391,494)	(13,588,299)	(185,694,959)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(18,428,374)	(16,139,734)	(16,055,428)	(15,543,812)	(15,118,987)	(14,911,069)	(15,194,356)	(15,085,524)	(15,333,840)	(14,904,042)	(15,391,494)	(13,588,299)	(185,694,958.58)
	13	Line 11 + Line 12	(6,588,928)	(5,578,466)	(4,117,835)	(3,979,573)	(5,616,666)	(13,708,059)	(13,848,302)	(13,735,012)	(13,891,165)	(11,292,277)	(7,396,263)	(1,737,091)	(101,489,636.58)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	2,520	15,150	2,730	-	24,390	1,680	7,660	7,980	9,360	70,060	38,140	50,880	230,550.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	5.91%	5.73%	5.54%	5.26%	4.95%	4.75%	4.57%	4.48%	4.26%	4.91%	2.85%	2.64%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	3,515.00	3,019.00	3,241.00	2,993.00	2,923.00	2,726.00	2,721.00	2,681.00	2,475.00	2,954.00	1,665.00	1,603.00	32,516.00
Service fees	33		(1.77)	0.00	0.00	(1.82)	0.00	0.00	(1.85)	0.00	0.00	0.00	0.00	0.00	(5.44)
Net interest earned	34	Line 32+33	3,513.23	3,019.00	3,241.00	2,991.18	2,923.00	2,726.00	2,719.15	2,681.00	2,475.00	2,954.00	1,665.00	1,603.00	32,510.56
Cumulative net interest earned	35		3,513.23	6,532.23	9,773.23	12,764.41	15,687.41	18,413.41	21,132.56	23,813.56	26,288.56	29,242.56	30,907.56	32,510.56	
Ending reserve balance including interest	36	Line 30+35	686,235.15	689,254.15	692,495.15	695,486.33	698,409.33	701,135.33	703,854.48	706,535.48	709,010.48	711,964.48	713,629.48	715,232.48	
		TD Prime Rate for Borrowing	6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation															
Interest earned			3,515.00	6,534.00	9,775.00	12,768.00	15,691.00	18,417.00	21,138.00	23,819.00	26,294.00	29,248.00	30,913.00	32,516.00	
Account fees			(1.77)	(1.77)	(1.77)	(3.59)	(3.59)	(3.59)	(5.44)	(5.44)	(5.44)	(5.44)	(5.44)	(5.44)	
Net interest earned			3,513.23	6,532.23	9,773.23	12,764.41	15,687.41	18,413.41	21,132.56	23,813.56	26,288.56	29,242.56	30,907.56	32,510.56	
Ending reserve balance			682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	682,721.92	
Ending reserve balance			686,235.15	689,254.15	692,495.15	695,486.33	698,409.33	701,135.33	703,854.48	706,535.48	709,010.48	711,964.48	713,629.48	715,232.48	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31

Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input													0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - $000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	
Cumulative reserve balance - $000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	

2002 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2002

Continuity schedule, year ending Dec. 31, 2002 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	26,227,887	22,698,415	24,005,137	21,001,751	19,272,298	17,679,499	16,660,103	18,834,243	19,067,528	21,750,274	21,395,011	26,736,615	255,328,761
Wind	1a	Manual Input	10,210	9,250	102,500	111,940	95,140	114,930	77,838	134,572	92,790	162,290	112,127	63,520	1,087,107
Diesel	2	Manual Input	7,300	1,050	14,880	16,410	3,360	1,260	21,420	9,870	2,100	11,480	103,900	517,960	710,990
Total	3	Line 1 + Line 2	26,245,397	22,708,715	24,122,517	21,130,101	19,370,798	17,795,689	16,759,361	18,978,685	19,162,418	21,924,044	21,611,038	27,318,095	257,126,858
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(4,198,526)	(5,042,049)	(2,912,533)	(2,729,807)	(5,358,780)	(13,180,503)	(14,049,015)	(11,923,015)	(12,664,297)	(10,620,112)	(9,288,088)	(3,005,003)	(94,971,728)
Diesel	8	Line 2 - Line 5	(11,832,146)	(10,560,218)	(11,922,713)	(11,547,829)	(9,498,961)	(1,201,750)	(1,324,634)	(1,340,642)	(1,440,575)	(3,600,285)	(7,891,331)	(11,333,248)	(83,494,332)
Total (favourable)	9	Line 3 - Line 6	(16,030,672)	(15,602,267)	(14,835,246)	(14,277,636)	(14,857,741)	(14,382,253)	(15,373,649)	(13,263,657)	(14,104,872)	(14,220,397)	(17,179,419)	(14,338,251)	(178,466,060)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(16,030,672)	(15,602,267)	(14,835,246)	(14,277,636)	(14,857,741)	(14,382,253)	(15,373,649)	(13,263,657)	(14,104,872)	(14,220,397)	(17,179,419)	(14,338,251)	(178,466,060.00)
	13	Line 11 + Line 12	(4,191,226)	(5,040,999)	(2,897,653)	(2,713,397)	(5,355,420)	(13,179,243)	(14,027,595)	(11,913,145)	(12,662,197)	(10,608,632)	(9,184,188)	(2,487,043)	(94,260,738.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	7,300	1,050	14,880	16,410	3,360	1,260	21,420	9,870	2,100	11,480	103,900	517,960	710,990.00
															Over-ride Line 16 - Dec 02 Diesel Due to Frazil Ice
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	2.39%	2.21%	2.27%	2.30%	2.50%	2.70%	3.18%	2.92%	2.99%	2.97%	2.99%	2.96%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	1,485.00	1,217.00	1,382.00	1,361.00	1,530.00	1,604.00	1,957.00	1,799.00	1,786.00	1,837.00	1,796.00	1,844.00	19,598.00
Service fees	33		(1.91)	0.00	0.00	(1.93)	0.00	0.00	(34.77)	0.00	0.00	(423.70)	0.00	0.00	(462.31)
Net interest earned	34	Line 32+33	1,483.09	1,217.00	1,382.00	1,359.07	1,530.00	1,604.00	1,922.23	1,799.00	1,786.00	1,413.30	1,796.00	1,844.00	19,135.69
Cumulative net interest earned	35		1,483.09	2,700.09	4,082.09	5,441.16	6,971.16	8,575.16	10,497.39	12,296.39	14,082.39	15,495.69	17,291.69	19,135.69	
Ending reserve balance including interest	36	Line 30+35	716,715.57	717,932.57	719,314.57	720,673.64	722,203.64	723,807.64	725,729.87	727,528.87	729,314.87	730,728.17	732,524.17	734,368.17	
		TD Prime Rate for Borrowing	6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation															
Interest earned			1,485.00	2,702.00	4,084.00	5,445.00	6,975.00	8,579.00	10,536.00	12,335.00	14,121.00	15,958.00	17,754.00	19,598.00	
Account fees			(1.91)	(1.91)	(1.91)	(3.84)	(3.84)	(3.84)	(38.61)	(38.61)	(38.61)	(462.31)	(462.31)	(462.31)	
Net interest earned			1,483.09	2,700.09	4,082.09	5,441.16	6,971.16	8,575.16	10,497.39	12,296.39	14,082.39	15,495.69	17,291.69	19,135.69	
Ending reserve balance			715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	715,232.48	
Ending reserve balance			716,715.57	717,932.57	719,314.57	720,673.64	722,203.64	723,807.64	725,729.87	727,528.87	729,314.87	730,728.17	732,524.17	734,368.17	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31

Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input													0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - $000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	
Cumulative reserve balance - $000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	

2003 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2003
Continuity schedule, year ending Dec. 31, 2003 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	26,966,635	21,837,581	25,058,959	20,286,763	18,652,163	18,243,445	18,779,057	18,146,954	22,019,946	21,249,180	28,276,925	30,193,506	269,711,114
Wind	1a	Manual Input	56,993	59,945	69,948	83,196	110,053	102,680	84,824	73,139	114,924	129,027	29,275	11,894	925,898
Diesel	2	Manual Input	7,910	6,390	1,890	2,940	18,900	36,970	2,520	6,970	23,700	32,540	13,440	97,810	251,980
Total	3	Line 1 + Line 2	27,031,538	21,903,917	25,130,797	20,372,899	18,781,116	18,383,095	18,866,401	18,227,063	22,158,570	21,410,747	28,319,640	30,303,210	270,888,992
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(3,412,995)	(5,852,188)	(1,891,263)	(3,473,539)	(5,964,002)	(12,628,807)	(11,923,075)	(12,671,737)	(9,689,745)	(11,154,469)	(2,489,026)	400,262	(80,750,584)
Diesel	8	Line 2 - Line 5	(11,831,536)	(10,554,878)	(11,935,703)	(11,561,299)	(9,483,421)	(1,166,040)	(1,343,534)	(1,343,542)	(1,418,975)	(3,579,225)	(7,981,791)	(11,753,398)	(83,953,342)
Total (favourable)	9	Line 3 - Line 6	(15,244,531)	(16,407,066)	(13,826,966)	(15,034,838)	(15,447,423)	(13,794,847)	(13,266,609)	(14,015,279)	(11,108,720)	(14,733,694)	(10,470,817)	(11,353,136)	(164,703,926)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(15,244,531)	(16,407,066)	(13,826,966)	(15,034,838)	(15,447,423)	(13,794,847)	(13,266,609)	(14,015,279)	(11,108,720)	(14,733,694)	(10,470,817)	(11,353,136)	(164,703,926.00)
	13	Line 11 + Line 12	(3,405,085)	(5,845,798)	(1,889,373)	(3,470,599)	(5,945,102)	(12,591,837)	(11,920,555)	(12,664,767)	(9,666,045)	(11,121,929)	(2,475,586)	498,072	(80,498,604.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	7,910	6,390	1,890	2,940	18,900	36,970	2,520	6,970	23,700	32,540	13,440	97,810	251,980.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	2.98%	3.01%	3.11%	3.27%	3.34%	3.40%	3.29%	3.10%	2.93%	2.84%	2.85%	2.83%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	1,884.00	1,700.00	1,951.00	1,989.00	2,103.00	2,076.00	2,079.00	1,963.00	1,801.00	1,808.00	1,764.00	1,811.00	22,929.00
Service fees	33		(438.27)	0.00	0.00	(436.73)	0.00	0.00	(494.19)	0.00	0.00	(503.70)	0.00	0.00	(1,872.89)
Net interest earned	34	Line 32+33	1,445.73	1,700.00	1,951.00	1,552.27	2,103.00	2,076.00	1,584.81	1,963.00	1,801.00	1,304.30	1,764.00	1,811.00	21,056.11
Cumulative net interest earned	35		1,445.73	3,145.73	5,096.73	6,649.00	8,752.00	10,828.00	12,412.81	14,375.81	16,176.81	17,481.11	19,245.11	21,056.11	
Ending reserve balance including interest	36	Line 30+35	735,813.90	737,513.90	739,464.90	741,017.17	743,120.17	745,196.17	746,780.99	748,743.99	750,544.99	751,849.29	753,613.29	755,424.29	
		TD Prime Rate for Borrowing	6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation															
Interest earned			1,884.00	3,584.00	5,535.00	7,524.00	9,627.00	11,703.00	13,782.00	15,745.00	17,546.00	19,354.00	21,118.00	22,929.00	
Account fees			(438.27)	(438.27)	(438.27)	(875.00)	(875.00)	(875.00)	(1,369.19)	(1,369.19)	(1,369.19)	(1,872.89)	(1,872.89)	(1,872.89)	
Net interest earned			1,445.73	3,145.73	5,096.73	6,649.00	8,752.00	10,828.00	12,412.81	14,375.81	16,176.81	17,481.11	19,245.11	21,056.11	
Ending reserve balance			734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	734,368.17	
Ending reserve balance			735,813.90	737,513.90	739,464.90	741,017.17	743,120.17	745,196.17	746,780.99	748,743.99	750,544.99	751,849.29	753,613.29	755,424.29	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input													0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - $000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	
Cumulative reserve balance - $000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	

2004 DCF Calculations														
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2004														
Continuity schedule, year ending Dec. 31, 2004 - Diesel Contingency Fund Calculations - WAF System ($000)														
	Line#		**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Actual generation - KWh															
Hydro	1	Manual Input	26,966,635	21,837,581	25,058,959	20,286,763	18,652,163	18,243,445	18,779,057	18,146,954	22,019,946	21,249,180	28,276,925	30,193,506	269,711,114
Wind	1a	Manual Input	56,993	59,945	69,948	83,196	110,053	102,680	84,824	73,139	114,924	129,027	29,275	11,894	925,898
Diesel	2	Manual Input	7,910	6,390	1,890	2,940	18,900	36,970	2,520	6,970	23,700	32,540	13,440	97,810	251,980
Total	3	Line 1 + Line 2	27,031,538	21,903,917	25,130,797	20,372,899	18,781,116	18,383,095	18,866,401	18,227,063	22,158,570	21,410,747	28,319,640	30,303,210	270,888,992
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(3,412,995)	(5,852,188)	(1,891,263)	(3,473,539)	(5,964,002)	(12,628,807)	(11,923,075)	(12,671,737)	(9,689,745)	(11,154,469)	(2,489,026)	400,262	(80,750,584)
Diesel	8	Line 2 - Line 5	(11,831,536)	(10,554,878)	(11,935,703)	(11,561,299)	(9,483,421)	(1,166,040)	(1,343,534)	(1,343,542)	(1,418,975)	(3,579,225)	(7,981,791)	(11,753,398)	(83,953,342)
Total (favourable)	9	Line 3 - Line 6	(15,244,531)	(16,407,066)	(13,826,966)	(15,034,838)	(15,447,423)	(13,794,847)	(13,266,609)	(14,015,279)	(11,108,720)	(14,733,694)	(10,470,817)	(11,353,136)	(164,703,926)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(15,244,531)	(16,407,066)	(13,826,966)	(15,034,838)	(15,447,423)	(13,794,847)	(13,266,609)	(14,015,279)	(11,108,720)	(14,733,694)	(10,470,817)	(11,353,136)	(164,703,926.00)
	13	Line 11 + Line 12	(3,405,085)	(5,845,798)	(1,889,373)	(3,470,599)	(5,945,102)	(12,591,837)	(11,920,555)	(12,664,767)	(9,666,045)	(11,121,929)	(2,475,586)	498,072	(80,498,604.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	7,910	6,390	1,890	2,940	18,900	36,970	2,520	6,970	23,700	32,540	13,440	97,810	251,980.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	2.79%	2.64%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	1,814.00	1,530.00	1,490.82	1,490.82	1,490.82	1,490.82	1,490.82	1,490.82	1,490.82	1,490.82	1,490.82	1,490.82	18,252.20
Service fees	33		(520.60)	0.00	0.00	(436.73)	0.00	0.00	(494.19)	0.00	0.00	(503.70)	0.00	0.00	(1,955.21)
Net interest earned	34	Line 32+33	1,293.40	1,530.00	1,490.82	1,054.09	1,490.82	1,490.82	996.63	1,490.82	1,490.82	987.12	1,490.82	1,490.82	16,296.99
Cumulative net interest earned	35		1,293.40	2,823.40	4,314.22	5,368.31	6,859.13	8,349.95	9,346.59	10,837.41	12,328.23	13,315.35	14,806.17	16,296.99	
Ending reserve balance including interest	36	Line 30+35	756,717.69	758,247.69	759,738.51	760,792.60	762,283.42	763,774.24	764,770.87	766,261.69	767,752.51	768,739.63	770,230.45	771,721.27	
				67,577.20											
		TD Prime Rate for Borrowing	6.50%	6.75%	7.00%	7.00%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Interest Calculation															
Interest earned			1,814.00	3,344.00	4,834.82	6,325.64	7,816.46	9,307.28	10,798.10	12,288.92	13,779.74	15,270.56	16,761.38	18,252.20	
Account fees			(520.60)	(520.60)	(520.60)	(957.33)	(957.33)	(957.33)	(1,451.51)	(1,451.51)	(1,451.51)	(1,955.21)	(1,955.21)	(1,955.21)	
Net interest earned			1,293.40	2,823.40	4,314.22	5,368.31	6,859.13	8,349.95	9,346.59	10,837.41	12,328.23	13,315.35	14,806.17	16,296.99	
Ending reserve balance			755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	755,424.29	
Ending reserve balance			756,717.69	758,247.69	759,738.51	760,792.60	762,283.42	763,774.24	764,770.87	766,261.69	767,752.51	768,739.63	770,230.45	771,721.27	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31														
Continuity schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System ($000)														
	Line #		**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Actual generation - Mwh															
Hydro	1	Manual Input													0
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	793,603	819,599	798,243	838,296	835,598	875,441	865,305	847,899	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(857,061)	(850,356)	(793,603)	(819,599)	(798,243)	(838,296)	(835,598)	(875,441)	(865,305)	(847,899)	(819,499)	(840,944)	(10,041,844)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (excess) - $000	20	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M costs - $000	21	YEC Line 21 x Line 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	-	-	-	-	-	-	-	-	-	-	-	-	-
Opening reserve	23	Line 25 prior period	-	-	-	-	-	-	-	-	-	-	-	-	
Cumulative reserve balance - $000	25	Line 22+Line 23	-	-	-	-	-	-	-	-	-	-	-	-	

2005 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2005

Continuity schedule, year ending Dec. 31, 2005 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	30,399,843	24,913,292	24,977,934	21,371,476	19,949,512	19,825,242	21,464,488	20,256,220	20,797,996	23,946,179	26,613,225	28,124,327	282,639,734
Wind	1a	Manual Input	-	138,361	113,439	59,534	74,087	58,492	45,373	100,587	121,513	104,890	-	73,552	889,828
Diesel	2	Manual Input	46,660	20,310	4,230	840	1,680	-	-	14,750	1,920	7,920	8,380	7,980	114,670
Total	3	Line 1 + Line 2	30,446,503	25,071,963	25,095,603	21,431,850	20,025,279	19,883,734	21,509,861	20,371,557	20,921,429	24,058,989	26,621,605	28,205,859	283,644,232
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	(36,780)	(2,698,061)	(1,928,797)	(2,412,488)	(4,702,619)	(11,091,198)	(9,277,095)	(10,535,023)	(10,905,106)	(8,481,607)	(4,182,001)	(1,607,259)	(67,858,034)
Diesel	8	Line 2 - Line 5	(11,792,786)	(10,540,958)	(11,933,363)	(11,563,399)	(9,500,641)	(1,203,010)	(1,346,054)	(1,335,762)	(1,440,755)	(3,603,845)	(7,986,851)	(11,843,228)	(84,090,652)
Total (favourable)	9	Line 3 - Line 6	(11,829,566)	(13,239,019)	(13,862,160)	(13,975,887)	(14,203,260)	(12,294,208)	(10,623,149)	(11,870,785)	(12,345,861)	(12,085,452)	(12,168,852)	(13,450,487)	(151,948,686)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(11,829,566)	(13,239,019)	(13,862,160)	(13,975,887)	(14,203,260)	(12,294,208)	(10,623,149)	(11,870,785)	(12,345,861)	(12,085,452)	(12,168,852)	(13,450,487)	(151,948,686.00)
	13	Line 11 + Line 12	9,880	(2,677,751)	(1,924,567)	(2,411,648)	(4,700,939)	(11,091,198)	(9,277,095)	(10,520,273)	(10,903,186)	(8,473,687)	(4,173,621)	(1,599,279)	(67,743,364.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	46,660	20,310	4,230	840	1,680	-	-	14,750	1,920	7,920	8,380	7,980	114,670.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2													-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	19,184.49
Service fees	33														0.00
Net interest earned	34	Line 32+33	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	1,598.71	19,184.49
Cumulative net interest earned	35		1,598.71	3,197.42	4,796.12	6,394.83	7,993.54	9,592.25	11,190.95	12,789.66	14,388.37	15,987.08	17,585.78	19,184.49	
Ending reserve balance including interest	36	Line 30+35	773,319.98	774,918.69	776,517.39	778,116.10	779,714.81	781,313.52	782,912.22	784,510.93	786,109.64	787,708.35	789,307.05	790,905.76	
		TD Prime Rate for Borrowing													
Interest Calculation															
Interest earned			1,598.71	3,197.42	4,796.12	6,394.83	7,993.54	9,592.25	11,190.95	12,789.66	14,388.37	15,987.08	17,585.78	19,184.49	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned			1,598.71	3,197.42	4,796.12	6,394.83	7,993.54	9,592.25	11,190.95	12,789.66	14,388.37	15,987.08	17,585.78	19,184.49	
Ending reserve balance			771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	771,721.27	
Ending reserve balance			773,319.98	774,918.69	776,517.39	778,116.10	779,714.81	781,313.52	782,912.22	784,510.93	786,109.64	787,708.35	789,307.05	790,905.76	

2006 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2006

Continuity schedule, year ending Dec. 31, 2006 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	31,038,698	25,068,429	28,640,340	22,510,457	21,967,880	19,463,367	19,950,230	20,455,159	22,496,606	22,984,228	31,753,450	31,127,170	297,456,014
Wind	1a	Manual Input	0	29,297	0	70,919	120,820	26,405	10,600	91,690	136,740	86,200	9,010	18,260	599,941
Diesel	2	Manual Input	737,000	72,970	9,720	3,990	220,780	30,700	1,230	2,268	50,151	137,536	142,064	10,786	1,419,195
Total	3	Line 1 + Line 2	31,775,698	25,170,696	28,650,060	22,585,366	22,309,480	19,520,472	19,962,060	20,549,117	22,683,497	23,207,964	31,904,524	31,156,216	299,475,150
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	602,075	(2,651,988)	1,620,170	(1,262,122)	(2,637,518)	(11,485,160)	(10,826,126)	(10,344,981)	(9,191,269)	(9,462,248)	967,234	1,340,292	(53,331,641)
Diesel	8	Line 2 - Line 5	(11,102,446)	(10,488,298)	(11,927,873)	(11,560,249)	(9,281,541)	(1,172,310)	(1,344,824)	(1,348,244)	(1,392,524)	(3,474,229)	(7,853,167)	(11,840,422)	(82,786,127)
Total (favourable)	9	Line 3 - Line 6	(10,500,371)	(13,140,286)	(10,307,703)	(12,822,371)	(11,919,059)	(12,657,470)	(12,170,950)	(11,693,225)	(10,583,793)	(12,936,477)	(6,885,933)	(10,500,130)	(136,117,768)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(10,500,371)	(13,140,286)	(10,307,703)	(12,822,371)	(11,919,059)	(12,657,470)	(12,170,950)	(11,693,225)	(10,583,793)	(12,936,477)	(6,885,933)	(10,500,130)	(136,117,767.70)
	13	Line 11 + Line 12	1,339,075	(2,579,018)	1,629,890	(1,258,132)	(2,416,738)	(11,454,460)	(10,824,896)	(10,342,713)	(9,141,118)	(9,324,712)	1,109,298	1,351,078	(51,912,445.70)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	737,000	72,970	9,720	3,990	220,780	30,700	1,230	2,268	50,151	137,536	142,064	10,786	1,419,195.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	**0.00**	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2													-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	29,701.89
Service fees	33														0.00
Net interest earned	34	Line 32+33	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	2,475.16	29,701.89
Cumulative net interest earned	35		2,475.16	4,950.32	7,425.47	9,900.63	12,375.79	14,850.95	17,326.10	19,801.26	22,276.42	24,751.58	27,226.73	29,701.89	
Ending reserve balance including interest	36	Line 30+35	793,380.92	795,856.08	798,331.23	800,806.39	803,281.55	805,756.71	808,231.86	810,707.02	813,182.18	815,657.34	818,132.49	820,607.65	
		TD Prime Rate for Borrowing													
Interest Calculation															
Interest earned			2,475.16	4,950.32	7,425.47	9,900.63	12,375.79	14,850.95	17,326.10	19,801.26	22,276.42	24,751.58	27,226.73	29,701.89	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned			2,475.16	4,950.32	7,425.47	9,900.63	12,375.79	14,850.95	17,326.10	19,801.26	22,276.42	24,751.58	27,226.73	29,701.89	
Ending reserve balance			790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	790,905.76	
Ending reserve balance			793,380.92	795,856.08	798,331.23	800,806.39	803,281.55	805,756.71	808,231.86	810,707.02	813,182.18	815,657.34	818,132.49	820,607.65	

2007 DCF Calculations														
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2007														
Continuity schedule, year ending Dec. 31, 2007 - Diesel Contingecy Fund Calculations - WAF System ($000)														
	Line#		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	31,118,560	29,508,210	29,440,856	24,946,910	22,167,550	19,697,579	21,029,184	19,912,911	22,184,575	22,982,038	28,621,981	32,920,848	304,531,202
Wind	1a	Manual Input	0	0	0	111,240	86,430	41,640	42,280	0	62,970	0	0	17,120	361,680
Diesel	2	Manual Input	78,155	82,275	7,245	11,545	54,570	2,520	80	61,007	101,930	20,626	33,038	16,273	469,264
Total	3	Line 1 + Line 2	31,196,715	29,590,485	29,448,101	25,069,695	22,308,550	19,741,739	21,071,544	19,973,918	22,349,475	23,002,664	28,655,019	32,954,241	305,362,146
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	681,937	1,758,496	2,420,686	1,214,652	(2,472,238)	(11,235,713)	(9,715,492)	(10,978,919)	(9,577,070)	(9,550,638)	(2,173,245)	3,132,830	(46,494,714)
Diesel	8	Line 2 - Line 5	(11,761,291)	(10,478,993)	(11,930,348)	(11,552,694)	(9,447,751)	(1,200,490)	(1,345,974)	(1,289,505)	(1,340,745)	(3,591,139)	(7,962,193)	(11,834,935)	(83,736,058)
Total (favourable)	9	Line 3 - Line 6	(11,079,354)	(8,720,497)	(9,509,662)	(10,338,042)	(11,919,989)	(12,436,203)	(11,061,466)	(12,268,424)	(10,917,815)	(13,141,777)	(10,135,438)	(8,702,105)	(130,230,772)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(11,079,354)	(8,720,497)	(9,509,662)	(10,338,042)	(11,919,989)	(12,436,203)	(11,061,466)	(12,268,424)	(10,917,815)	(13,141,777)	(10,135,438)	(8,702,105)	(130,230,772.00)
	13	Line 11 + Line 12	760,092	1,840,771	2,427,931	1,226,197	(2,417,668)	(11,233,193)	(9,715,412)	(10,917,912)	(9,475,140)	(9,530,012)	(2,140,207)	3,149,103	(46,025,450.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	78,155	82,275	7,245	11,545	54,570	2,520	80	61,007	101,930	20,626	33,038	16,273	469,264.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641	0.5641
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						-
Ending reserve balance	30	Line 26+27+28+29	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest	3,191.81	2,716.53	2,924.93	3,034.47	3,045.69	2,878.56	3,248.64	3,257.69	3,115.46	3,803.26	3,407.90	3,405.72	38,030.66
Service fees	33	Investment Fees	0.00	(639.24)	0.00	(645.63)	0.00	0.00	(659.26)	0.00	0.00	(673.34)	0.00	0.00	(2,617.47)
Net interest earned	34	Line 32+33	3,191.81	2,077.29	2,924.93	2,388.84	3,045.69	2,878.56	2,589.38	3,257.69	3,115.46	3,129.92	3,407.90	3,405.72	35,413.19
Cumulative net interest earned	35		3,191.81	5,269.10	8,194.03	10,582.87	13,628.56	16,507.12	19,096.50	22,354.19	25,469.65	28,599.57	32,007.47	35,413.19	
Ending reserve balance including interest	36	Line 30+35	823,799.46	825,876.75	828,801.68	831,190.52	834,236.21	837,114.77	839,704.15	842,961.84	846,077.30	849,207.22	852,615.12	856,020.84	
		TD Prime Rate for Borrowing	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%	
Interest Calculation															
Interest earned			3,191.81	5,908.34	8,833.27	11,867.74	14,913.43	17,791.99	21,040.63	24,298.32	27,413.78	31,217.04	34,624.94	38,030.66	
Account fees			0.00	(639.24)	(639.24)	(1,284.87)	(1,284.87)	(1,284.87)	(1,944.13)	(1,944.13)	(1,944.13)	(2,617.47)	(2,617.47)	(2,617.47)	
Net interest earned			3,191.81	5,269.10	8,194.03	10,582.87	13,628.56	16,507.12	19,096.50	22,354.19	25,469.65	28,599.57	32,007.47	35,413.19	
Ending reserve balance			820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	820,607.65	
Ending reserve balance			823,799.46	825,876.75	828,801.68	831,190.52	834,236.21	837,114.77	839,704.15	842,961.84	846,077.30	849,207.22	852,615.12	856,020.84	

2008 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2008

Continuity schedule, year ending Dec. 31, 2008 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	33,165,928	29,610,041	26,877,857	23,666,146	21,345,165	21,790,016	21,745,269	22,940,550	22,307,493	25,080,823	29,832,970	35,346,068	313,708,326
Wind	1a	Manual Input	0	0	25,100	0	174,790	39,760	70,500	18,900	0	0	101,390	6,450	436,890
Diesel	2	Manual Input	37,323	76,111	0	0	186,358	0	0	840	0	218,668	31,256	663,618	1,214,174
Total	3	Line 1 + Line 2	33,203,251	29,686,152	26,902,957	23,666,146	21,706,313	21,829,776	21,815,769	22,960,290	22,307,493	25,299,491	29,965,616	36,016,136	315,359,390
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	2,729,305	1,860,327	(117,213)	(177,352)	(3,206,263)	(9,145,156)	(8,971,187)	(7,932,380)	(9,517,122)	(7,451,853)	(860,866)	5,547,380	(37,242,380)
Diesel	8	Line 2 - Line 5	(11,802,123)	(10,485,157)	(11,937,593)	(11,564,239)	(9,315,963)	(1,203,010)	(1,346,054)	(1,349,672)	(1,442,675)	(3,393,097)	(7,963,975)	(11,187,590)	(82,991,148)
Total (favourable)	9	Line 3 - Line 6	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528.00)
	13	Line 11 + Line 12	2,766,628	1,936,438	(117,213)	(177,352)	(3,019,905)	(9,145,156)	(8,971,187)	(7,931,540)	(9,517,122)	(7,233,185)	(829,610)	6,210,998	(36,028,206.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	37,323	76,111	-	-	186,358	-	-	840	-	218,668	31,256	663,618	1,214,174.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	**0.00**	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						-
Ending reserve balance	30	Line 26+27+28+29	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest	3,297.73	2,870.19	2,843.68	2,521.04	2,428.57	2,383.06	2,347.38	2,172.81	2,378.75	2,339.90	1,925.31	1,881.01	29,389.43
Service fees	33	Investment Fees	(674.41)	0.00	0.00	(672.62)	0.00	0.00	(678.64)	0.00	0.00	(691.20)	0.00	0.00	(2,716.87)
Net interest earned	34	Line 32+33	2,623.32	2,870.19	2,843.68	1,848.42	2,428.57	2,383.06	1,668.74	2,172.81	2,378.75	1,648.70	1,925.31	1,881.01	26,672.56
Cumulative net interest earned	35		2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	18,838.79	21,217.54	22,866.24	24,791.55	26,672.56	
Ending reserve balance including interest	36	Line 30+35	858,644.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	878,887.08	880,812.39	882,693.40	
		TD Prime Rate for Borrowing	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%	
Interest Calculation															
Interest earned			3,297.73	6,167.92	9,011.60	11,532.64	13,961.21	16,344.27	18,691.65	20,864.46	23,243.21	25,583.11	27,508.42	29,389.43	
Account fees			(674.41)	(674.41)	(674.41)	(1,347.03)	(1,347.03)	(1,347.03)	(2,025.67)	(2,025.67)	(2,025.67)	(2,716.87)	(2,716.87)	(2,716.87)	
Net interest earned			2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	18,838.79	21,217.54	22,866.24	24,791.55	26,672.56	
Ending reserve balance			856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Ending reserve balance			858,644.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	878,887.08	880,812.39	882,693.40	

2009 DCF Calculations														
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2009														
Continuity schedule, year ending Dec. 31, 2009 - Diesel Contingecy Fund Calculations - WAF System ($000)														
	Line#		**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**TOTAL**
Actual generation - KWh															
Hydro	1	Manual Input	35,059,529	34,611,029	29,833,376	27,458,873	26,017,518	22,490,698	23,256,545	23,083,041	25,052,353	27,473,179	32,834,809	35,284,055	342,455,005
Wind	1a	Manual Input	0	0	32,860	28,520	51,680	50,250	45,763	21,200	7,950	0	0	0	238,223
Diesel	2	Manual Input	700,879	104,704	2,520	34,800	156,211	7,140	247,875	198,140	85,553	85,860	65,304	446,173	2,135,159
Total	3	Line 1 + Line 2	35,760,408	34,715,733	29,868,756	27,522,193	26,225,409	22,548,088	23,550,183	23,302,381	25,145,856	27,559,039	32,900,113	35,730,228	344,828,387
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	4,622,906	6,861,315	2,846,066	3,643,895	1,342,980	(8,433,984)	(7,484,648)	(7,787,589)	(6,764,312)	(5,059,497)	2,039,583	5,478,917	(8,694,368)
Diesel	8	Line 2 - Line 5	(11,138,567)	(10,456,564)	(11,935,073)	(11,529,439)	(9,346,110)	(1,195,870)	(1,098,179)	(1,152,372)	(1,357,122)	(3,525,905)	(7,929,927)	(11,405,035)	(82,070,163)
Total (favourable)	9	Line 3 - Line 6	(6,515,661)	(3,595,249)	(9,089,007)	(7,885,544)	(8,003,130)	(9,629,854)	(8,582,827)	(8,939,961)	(8,121,434)	(8,585,402)	(5,890,344)	(5,926,118)	(90,764,531)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(6,515,661)	(3,595,249)	(9,089,007)	(7,885,544)	(8,003,130)	(9,629,854)	(8,582,827)	(8,939,961)	(8,121,434)	(8,585,402)	(5,890,344)	(5,926,118)	(90,764,531.00)
	13	Line 11 + Line 12	5,323,785	6,966,019	2,848,586	3,678,695	1,499,191	(8,426,844)	(7,236,773)	(7,589,449)	(6,678,759)	(4,973,637)	2,104,887	5,925,090	(6,559,209.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	700,879	104,704	2,520	34,800	156,211	7,140	247,875	198,140	85,553	85,860	65,304	446,173	2,135,159.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	**0.00**	-	-	-	-	-	-	-	-	-	-	**0.00**	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						-
Ending reserve balance	30	Line 26+27+28+29	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest	1,381.22	1,043.93	876.69	608.66	458.68	419.43	332.24	305.44	260.37	369.32	369.13	369.29	6,794.40
Service fees	33	Investment Fees	(696.06)	0.00	0.00	(686.26)	0.00	0.00	(695.36)	0.00	0.00	(749.32)	0.00	0.00	(2,827.00)
Net interest earned	34	Line 32+33	685.16	1,043.93	876.69	(77.60)	458.68	419.43	(363.12)	305.44	260.37	(380.00)	369.13	369.29	3,967.40
Cumulative net interest earned	35		685.16	1,729.09	2,605.78	2,528.18	2,986.86	3,406.29	3,043.17	3,348.61	3,608.98	3,228.98	3,598.11	3,967.40	
Ending reserve balance including interest	36	Line 30+35	883,378.56	884,422.49	885,299.18	885,221.58	885,680.26	886,099.69	885,736.57	886,042.01	886,302.38	885,922.38	886,291.51	886,660.80	
		TD Prime Rate for Borrowing	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%	
Interest Calculation															
Interest earned			1,381.22	2,425.15	3,301.84	3,910.50	4,369.18	4,788.61	5,120.85	5,426.29	5,686.66	6,055.98	6,425.11	6,794.40	
Account fees			(696.06)	(696.06)	(696.06)	(1,382.32)	(1,382.32)	(1,382.32)	(2,077.68)	(2,077.68)	(2,077.68)	(2,827.00)	(2,827.00)	(2,827.00)	
Net interest earned			685.16	1,729.09	2,605.78	2,528.18	2,986.86	3,406.29	3,043.17	3,348.61	3,608.98	3,228.98	3,598.11	3,967.40	
Ending reserve balance			882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	882,693.40	
Ending reserve balance			883,378.56	884,422.49	885,299.18	885,221.58	885,680.26	886,099.69	885,736.57	886,042.01	886,302.38	885,922.38	886,291.51	886,660.80	

2010 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2010

Continuity schedule, year ending Dec. 31, 2010 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	33,496,889	32,873,530	30,347,614	27,628,959	26,849,221	23,023,763	23,925,698	25,441,685	25,150,469	26,171,764	33,310,658	37,295,582	345,515,832
Wind	1a	Manual Input	0	0	0.00	0.00	3,360.00	7,480.00	14,590.00	1,040.00	37,010.00	0.00	0.00	21,160.00	84,640.00
Diesel	2	Manual Input	145,300	38,033	10,500	7,950	18,608	23,195	276,392	235,640	33,182	169,351	72,954	1,657,978	2,689,083
Total	3	Line 1 + Line 2	33,642,189	32,911,563	30,358,114	27,636,909	26,871,189	23,054,438	24,216,680	25,678,365	25,220,661	26,341,115	33,383,612	38,974,720	348,289,555
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	3,060,266	5,123,816	3,327,444	3,785,461	2,126,363	(7,943,689)	(6,846,668)	(5,449,105)	(6,637,136)	(6,360,912)	2,515,432	7,511,604	(5,787,124)
Diesel	8	Line 2 - Line 5	(11,694,146)	(10,523,235)	(11,927,093)	(11,556,289)	(9,483,713)	(1,179,815)	(1,069,662)	(1,114,872)	(1,409,493)	(3,442,414)	(7,922,277)	(10,193,230)	(81,516,239)
Total (favourable)	9	Line 3 - Line 6	(8,633,880)	(5,399,419)	(8,599,649)	(7,770,828)	(7,357,350)	(9,123,504)	(7,916,330)	(6,563,977)	(8,046,629)	(9,803,326)	(5,406,845)	(2,681,626)	(87,303,363)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(8,633,880)	(5,399,419)	(8,599,649)	(7,770,828)	(7,357,350)	(9,123,504)	(7,916,330)	(6,563,977)	(8,046,629)	(9,803,326)	(5,406,845)	(2,681,626)	(87,303,363.00)
	13	Line 11 + Line 12	3,205,566	5,161,849	3,337,944	3,793,411	2,144,971	(7,920,494)	(6,570,276)	(5,213,465)	(6,603,954)	(6,191,561)	2,588,386	9,169,582	(3,098,041.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	145,300	38,033	10,500	7,950	18,608	23,195	276,392	235,640	33,182	169,351	72,954	1,657,978	2,689,083.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	**0.00**	-	-	-	-	-	**0.00**	-	-	-	-	**0.00**	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						-
Ending reserve balance	30	Line 26+27+28+29	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest	369.44	369.60	369.75	369.90	370.06	370.21	370.37	370.52	370.68	370.83	370.98	371.14	4,443.48
Service fees	33	Investment Fees	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned	34	Line 32+33	369.44	369.60	369.75	369.90	370.06	370.21	370.37	370.52	370.68	370.83	370.98	371.14	4,443.48
Cumulative net interest earned	35		369.44	739.04	1,108.79	1,478.69	1,848.75	2,218.96	2,589.33	2,959.85	3,330.53	3,701.36	4,072.34	4,443.48	
Ending reserve balance including interest	36	Line 30+35	887,030.24	887,399.84	887,769.59	888,139.49	888,509.55	888,879.76	889,250.13	889,620.65	889,991.33	890,362.16	890,733.14	891,104.28	
		TD Prime Rate for Borrowing	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%	6.25%	6.00%	
Interest Calculation															
Interest earned			369.44	739.04	1,108.79	1,478.69	1,848.75	2,218.96	2,589.33	2,959.85	3,330.53	3,701.36	4,072.34	4,443.48	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned			369.44	739.04	1,108.79	1,478.69	1,848.75	2,218.96	2,589.33	2,959.85	3,330.53	3,701.36	4,072.34	4,443.48	
Ending reserve balance			886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	886,660.80	
Ending reserve balance			887,030.24	887,399.84	887,769.59	888,139.49	888,509.55	888,879.76	889,250.13	889,620.65	889,991.33	890,362.16	890,733.14	891,104.28	

2011 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2011

Continuity schedule, year ending Dec. 31, 2011 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	36,438,071	32,147,410	32,867,587	26,794,885	26,547,340	24,022,422	27,642,331	27,444,233	29,055,103	29,517,879	37,529,736	33,834,311	363,841,308
Wind	1a	Manual Input	0	0	0	0	0	31,979	40,248	93,752	149,610	86,500	0	0	402,089
Diesel	2	Manual Input	1,085,689	669,811	1,815,515	120,755	186,157	877,809	141,946	244,090	297,923	2,437,457	306,219	41,940	8,225,311
Total	3	Line 1 + Line 2	37,523,760	32,817,221	34,683,102	26,915,640	26,733,497	24,932,210	27,824,525	27,782,075	29,502,636	32,041,836	37,835,955	33,876,251	372,468,708
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	6,001,448	4,397,696	5,847,417	2,951,387	1,821,122	(6,920,531)	(3,104,377)	(3,353,845)	(2,619,902)	(2,928,297)	6,734,510	4,029,173	12,855,801
Diesel	8	Line 2 - Line 5	(10,753,757)	(9,891,457)	(10,122,078)	(11,443,484)	(9,316,164)	(325,201)	(1,204,108)	(1,106,422)	(1,144,752)	(1,174,308)	(7,689,012)	(11,809,268)	(75,980,011)
Total (favourable)	9	Line 3 - Line 6	(4,752,309)	(5,493,761)	(4,274,661)	(8,492,097)	(7,495,042)	(7,245,732)	(4,308,485)	(4,460,267)	(3,764,654)	(4,102,605)	(954,502)	(7,780,095)	(63,124,210)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(4,752,309)	(5,493,761)	(4,274,661)	(8,492,097)	(7,495,042)	(7,245,732)	(4,308,485)	(4,460,267)	(3,764,654)	(4,102,605)	(954,502)	(7,780,095)	(63,124,210.00)
	13	Line 11 + Line 12	7,087,137	5,067,507	7,662,932	3,072,142	2,007,279	(6,042,722)	(2,962,431)	(3,109,755)	(2,321,979)	(490,840)	7,040,729	4,071,113	21,081,112.00
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	1,085,689	669,811	1,815,515	120,755	186,157	877,809	141,946	244,090	297,923	2,437,457	306,219	41,940	8,225,311.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	**0.00**	**0.00**	**0.00**	-	-	**0.00**	-	-	**0.00**	**0.00**	**0.00**	-	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2													-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29								-						0.00
Ending reserve balance	30	Line 26+27+28+29	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	
Monthly interest earned	32	(Beg+End)/2) * rate * (days/365)	891.10	892.00	892.89	893.78	894.67	895.57	896.46	897.36	898.26	899.16	900.06	900.96	10,752.27
Service fees	33														0.00
Net interest earned	34	Line 32+33	891.10	892.00	892.89	893.78	894.67	895.57	896.46	897.36	898.26	899.16	900.06	900.96	10,752.27
Cumulative net interest earned	35		891.10	1,783.10	2,675.99	3,569.77	4,464.44	5,360.01	6,256.47	7,153.83	8,052.09	8,951.25	9,851.31	10,752.27	
Ending reserve balance including interest	36	Line 30+35	891,995.38	892,887.38	893,780.27	894,674.05	895,568.72	896,464.29	897,360.75	898,258.11	899,156.37	900,055.53	900,955.59	901,856.55	
		TD Prime Rate for Borrowing													
Interest Calculation															
Interest earned			891.10	1,783.10	2,675.99	3,569.77	4,464.44	5,360.01	6,256.47	7,153.83	8,052.09	8,951.25	9,851.31	10,752.27	
Account fees			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net interest earned			891.10	1,783.10	2,675.99	3,569.77	4,464.44	5,360.01	6,256.47	7,153.83	8,052.09	8,951.25	9,851.31	10,752.27	
Ending reserve balance			891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	891,104.28	
Ending reserve balance			891,995.38	892,887.38	893,780.27	894,674.05	895,568.72	896,464.29	897,360.75	898,258.11	899,156.37	900,055.53	900,955.59	901,856.55	

REFERENCE: YEC Application to Revise the DCF, Page 2

"Yukon Energy's proposed DCF and ERA adjustments address changes to reflect the newly integrated grid and Board directions in Order 2013-1 (including the adoption of LTA hydro generation forecasts when setting diesel generation costs included in approved rates), while remaining consistent with long established precedents and practice in Yukon."

PREAMBLE:

Request to YEC:

QUESTION:

a) Please provide details of the "long established precedents" to which YEC is referring.

b) Please provide YEC's explanation for how a regulator like the YUB establishes precedent and where in the *Public Utilities Act* the YUB is given the powers to set precedent.

ANSWER:

(a)

Please see response to UCG-YEC-1-2(a) and YUB-YEC-1-24.

(b)

This is a legal question that can be address in argument.

REFERENCE: YEC Application to Revise the DCF, Page 7

"Analysis of Options A and B confirms that Option A has a lower cost impact on ratepayers than Option B, and protects YECL as well as YEC from incurring unrecovered costs related to changes in YEC's incremental diesel generation costs arising from changes in YECL power purchases from YEC. Option A also is consistent with past Board Orders and the directions in OIC 1995/90."

PREAMBLE:

Request to YEC:

QUESTION:

a) Please provide details of where Option A is consistent with past Board Orders and the directions in OIC 1995/90 as amended.

ANSWER:

(a)

Please see response to YUB-YEC-1-1(f) and YUB-YEC-1-2. Please see also response to YUB-YEC-1-24(a) and UCG-YEC-1-2(a) for details regarding relevant Board Orders and OIC directions.

In summary, Option A is consistent with past Board Orders and OIC Directions for the following reasons:

1. Option A includes provision for a DCF mechanism that is designed to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro and wind generation. YUB-YEC-1-1(f) reviews in detail the prior Board Orders leading to the development of the DCF that address the following key principles included in the current DCF application:

    a. The principle that risk of low water conditions would need to be borne by the customers of the utility [Order 1989-4].

b. The principle that variances in hydro from forecast based on long-term average provide for long-term rate stability and variances based on short term hydro generation forecasts will result in more rate instability [Order 1992-1 and Order 1996-7].

2. Option A includes provision for an ERA that is designed to ensure that YECL receives a pass through of the YEC incremental costs [or cost savings] of diesel generation (when diesel is on the margin) driven by increases [or decreases] in the volume of wholesale sales to YECL relative to GRA approved forecasts used to set the wholesale energy rate charged by YEC to YECL; and to ensure that Yukon Energy is able to recover its costs (as required by OIC 1995/90 section 7(b)) when diesel is on the margin.

- Provision for such an ERA mechanism was initially approved in Order 1993-7, and subsequently reviewed and confirmed in Order 1999-4 approving the Settlement between the Companies regarding Rate Schedule 42, and Order 2010-13.

- In all of these past decisions, the ERA charge adjusted accounts between YEC and YECL and had no impact on ratepayers, i.e., full consideration was given to the expectation that YECL would have offsetting changes to revenues and no expected "unrecovered costs".

- Option A as proposed by YEC recognizes and addresses fully the possibility of "unrecovered costs" for YECL under some circumstances due to the fact that current retail run out rates (unlike rates applicable at the time of the 1990 orders) do not reflect the full incremental fuel costs of thermal generation. See YUB-YEC-1-16.

REFERENCE: YECL Revised Proposals on the DCF and Rate Schedule 42 ERA (Page 4)

"YEC has relied on the historical regulatory approval of the DCF and ERA to justify its attempt to revive the mechanisms now. However, circumstances have changed. The original ERA, and YEC's proposed DCF and ERA, are no longer appropriate."

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) Why was the DCF and ERA dormant for so long? Did either of the utilities benefit as a result of this dormancy?

b) Was the DCF de-activated? If not, why was it not incurring benefits for the consumer through all the years of high water levels and little diesel usage?

c) Why was the DCF not utilized when diesel was required to facilitate/bring on line Mayo B and Aishihik 3 projects? Was not diesel on the margin for these occasions?

d) Who makes the determination that diesel is on the margin? Is this not the jurisdiction of the regulator? What are the conditions and interpretation of the definition "diesel on the margin"?

e) Please confirm that the original DCF and ERA as approved by the YUB are still enforceable today as originally approved.

ANSWER:

(a)

The DCF was dormant because diesel was not required at long-term average hydro generation water conditions for many years after the Faro mine closed in early 1998.

As reviewed in response to YUB-YEC-1-1 and YUB-YEC-1-2, the DCF was established for the WAF system when the Faro mine was operating and diesel was on the margin for that system (i.e., diesel was needed to provide firm grid energy beyond peaking periods, reserve or emergency conditions). The Faro mine closed in 1998, and resulted in a material surplus of hydro generation availability on the WAF system under long-term average hydro generation water conditions that meant diesel was not on the margin on the WAF system. The DCF was last used for payments related to water flow variations in December 1999,[1] and these payments were due to diesel generation requirements resulting from low water conditions (even though diesel was not on the margin under long-term average hydro generation water conditions).

As explained in YEC's 2012-13 GRA filing in April 2012, ongoing load growth on the grid had by that time used up the surplus hydro such that diesel was once again on the margin under long term average (LTA) hydro generation water conditions. Board Order 2013-01 confirmed this with approved material diesel generation forecast amounts in revenue requirement based on 100% of LTA hydro generation. If anything, recent above average water conditions (which, as reviewed in YUB-YEC-1-1(a), the GRA filing expected to continue in the test years) may have acted to mask the growing importance of diesel now being on the margin under LTA conditions and delay action on this matter.

The utilities did not benefit as a result of the DCF being inactive over the period following the closure of the Faro mine. The DCF was designed to ensure that the Fund (and utility ratepayers), rather than YEC earnings, pays for, or benefits from, changes to grid diesel generation due to fluctuations in grid hydro generation when diesel is on the margin. During the period after the closure of the Faro mine, there was a material hydro surplus and minimal requirements for diesel generation, even under most conditions when hydro generation was lower than long term average. As a result, except as noted in 1999, there were no changes in diesel generation during this period related to fluctuations in grid hydro generation related to water conditions.

Please see also the response to YUB-YEC-1-2(a) and YUB-YEC-1-3(a) (iv).

(b) and **(d)**

Please see response to YUB-YEC-1-2(a) and YUB-YEC-1-3(a) (iv).

[1] YEC's 2012/13 GRA, UCG-YEC-1-12 (b).

In summary, surplus hydro generation yields no benefit (or potential for DCF operation) unless it saves diesel generation otherwise expected to be required at LTA hydro generation water conditions. There were no benefits for the consumer through all the years when diesel was not on the margin.

Ultimately, the Board provides the direction and approvals for all matters affecting rates, including activation of the DCF and confirmation of the conditions and rules to determine when diesel is on the margin. These rules and conditions have been the subject of ongoing Board review each time that the DCF is under review by the Board, including the review occurring in the current proceeding. One implication of diesel being on the margin is having Board approval of revenue requirements that reflect forecast diesel generation being required under LTA hydro generation water conditions - something that the Board did not do after the Faro mine closed until the 2012-13 YEC GRA and Order 2013-01.

(c)

The purpose of the DCF is to protect ratepayers from diesel generation cost impacts caused by fluctuation of hydro generation due to water conditions, not diesel generation costs due to temporary construction works. The diesel generation that was required to facilitate/bring on line Mayo B and Aishihik Third Turbine projects was charged to the capital costs for each project as the diesel generation related only to the construction of each project. On a similar basis, diesel generation requirements that arise due to transmission line outages (such as may occur due to forest fires), are funded by RFID or insurance and are excluded from the DCF. See YUB-YEC-1-2(a).

(e)

While there is an existing approved DCF, application of the existing DCF to the current system is problematic for reasons that YEC has outlined in past filings with the Board, including the 2012/2013 GRA and YEC's letter of July 5, 2013 (see UCG-YEC-1-5(b), Attachment 1). In particular, the following are noted:

1) **WAF only** – the existing policy was written to apply to the Whitehorse-Aishihik-Faro grid. Since 1996/97, material changes have occurred to the system such that the "WAF" grid has been expanded to include the communities of Pelly Crossing, Stewart Crossing, Mayo and Dawson, as well as the hydro generators

in Mayo. The additional generation created by this expansion was never contemplated as part of the existing model.

2) **New generation** – since the last approval, the utility has installed additional hydro generation at the Aishihik Hydroelectric generation station (i.e. Aishihik Third Turbine) as well as at Mayo (i.e., Mayo B) which further alters expected long term generation expectations.

3) **Model and load condition changes** – since 1996/97, Yukon Energy has become more sophisticated in its understanding of hydro generation capabilities on its system and overall load conditions have also radically changed, i.e., rather than a situation where the Faro mine being "on" or "off" the grid determines expected long term average diesel requirements (and whether the DCF is "on" or "off" under most conditions), the current loads result in a need for the DCF to be "on" at all times and to adjust as loads change. This greater understanding and radical change in load conditions have resulted in different modeling structures for predicting hydro generation on the current system, and different estimates of expected diesel generation requirements which now change as load levels and conditions change.

In summary, a DCF amount cannot be determined based on the methods last approved by the Board in 1996/97. Prior to being activated and applied the Fund must be updated to address the material changes that have occurred since the mid-1990's.

REFERENCE: YECL Revised Proposals on the DCF and Rate Schedule 42 ERA (Page 4)

"Effective January 1, 1998, YEC moved to direct management. Since then, YEC and Yukon Electrical have prepared their own forecasts and filed separate GRAs. The ERA allowed for the sharing of forecast risk between the two companies, which was appropriate because the companies were under joint management and shared forecasts. This is no longer the case."

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) Please explain why it is not appropriate for YEC and YECL to share the risks associated with load forecasts that, regardless of who develops them, directly impact the rates charged by each of the utilities.

ANSWER:

(a)

The ERA continues to be relevant for sharing of forecast risks between the two utilities in a way that is also fair and reasonable to ratepayers. The relevance of the ERA in this regard, in YEC's view, is not affected by the factors noted by YECL in the above comment - any YEC forecast relevant to ERA application must be first approved by the Board, after full opportunity has been provided to all interested parties (including YECL) to comment and provide relevant information and/or evidence.

The proposed ERA as provided in Table 2 of YEC's January 31, 2014 Filing considers incremental revenues that utilities would have due to increased load which offsets cost and makes sure that there is a charge to ratepayers only in cases where the incremental costs of the two utilities are not recovered through the incremental revenues of the two utilities. Please see YUB-YEC-1-12 and YUB-YEC-1-16.

REFERENCE: YECL Revised Proposals on the DCF and Rate Schedule 42 ERA (Page 7)

"In consideration of Yukon Electrical's concerns with Yukon Energy's proposal above and to resolve the Board's concerns as stated in Board Order 2013-01, Yukon Electrical believes the mechanism to address diesel volume variances must adhere to the following principles:

1. *Simple, transparent, easily explainable and easily testable*
2. *Allow a utility to recover its prudently-incurred costs*
3. *Based on actual data and relates to all fuel volume variances on the interconnected system*
4. *Dispersed in a timely manner, so as to not mask market signals in times of a drought or flood and to avoid intergenerational inequity*
5. *The deferral account balance thresholds that trigger the disposal should be set at a reasonable level so as to not cause undue rate changes or rate impacts to customers."*

PREAMBLE:

Request to YEC and YECL:

QUESTION:

a) Does YECL believe that the current DCF and Rate Schedule 42 ERA are already subject to these principles? If not, why not?

b) Does YEC believe that the current DCF and Rate Schedule 42 ERA are already subject to these principles? If not, why not?

ANSWER:

(b) [only portion relevant to YEC].

The principles set out above by YECL are consistent with YECL's proposal to eliminate the DCF and ERA and re-balance risks between utilities and ratepayers (see YEC's

supplementary filing of June 30, 2014); not all of these principles are therefore consistent with the DCF or ERA as proposed by both utilities and approved by the Board in the past.

The DCF is designed to provide rate stability over time, which means that this imperative is balanced against certain of the other principles noted above. Specifically:

- In order to provide rate stability over time, the DCF, as previously approved by the Board and as now proposed by YEC, is based on diesel at long-term average hydro generation. This basic rate stability objective, which was at the heart of the YEC/YECL joint submission in the 1996/97 GRA filing (see YUB-YEC-1-2(f), including attachments), is totally ignored in YECL's above principles.

- The DCF, as previously approved by the Board and as now proposed by YEC, is to address only diesel variances related to changes in hydro generation availability due to water conditions, i.e., contrary to YECL's third principle, it does not consider all fuel volume variances on the interconnected system and does not rebalance risks as between utilities and ratepayers as now proposed by YECL.

- The purpose of the DCF, as previously approved by the Board and as now proposed by YEC, is to provide for rate stability over the long-term, and to smooth out rate impacts during times of drought or flood conditions versus high water conditions. Dispersing the fund on a frequent or "more timely" basis (as proposed by YECL's fourth and fifth principles) to avoid intergenerational inequity, or so as not to mask market signals, would not meet the basic DCF objective of providing rate stability over the long-term. Rate stability and intergenerational equity/ market signals are competing objectives that may not be accommodated in a DCF mechanism.

For additional comment on these matters, please see YEC's supplementary filing of June 30, 2014 (letter and Attachments 1 and 2) and response to YUB-YEC-1-1, YUB-YEC-1-2, YUB-YEC-1-5, YUB-YEC-1-6(c), YUB-YEC-1-7, YUB-YEC-1-8 and YUB-YEC-1-14.

REFERENCE: YEC Supplementary Filing, Cover Letter, Page 1

"In contrast, the context provided by Order 2013-1 and 2013-3 is clearly focused on making revisions to the DCF prior to its activation. The Board directives do not indicate that alternatives to the DCF should be considered (or that the relationship and allocation between utilities and customers should be reconsidered or changed)."

PREAMBLE:

Request to YEC:

QUESTION:

a) Please explain where the YUB has indicated that alternatives to the DCF cannot be considered as part of this review or that the relationship and allocation between utilities and customers should not be reconsidered or changed.

b) In YEC's view, isn't the point of this review to determine how best to address the costs associated with water level variances in a manner that is deemed fair to all parties?

ANSWER:

(a) and **(b)**

In Order 2013-1 YEC was directed to provide a revised DCF proposal that incorporated changes as directed by the Board in that order. YEC was also directed to work with YECL in order to provide a joint recommendation on how the DCF will affect the ERA in Rate Schedule 42, and any proposed wording changes to that rates schedule. The Order did not specify that alternatives to the DCF or the ERA (including discontinuing the DCF or ERA mechanisms) should be considered, particularly "alternatives" which in effect eliminated the DCF and/or ERA without providing replacement mechanisms that more effectively address the long established purposes of the DCF and ERA.

It is YEC's view that a DCF or some equivalent mechanism (e.g., the prior Low Water Reserve Fund mechanism) is necessary to manage risks and costs to ratepayers related to variances in water availability on the integrated grid. As noted in response to YUB-YEC-1-6, YECL's proposal to replace the DCF with a diesel deferral account would not provide rate stabilization for ratepayers to address material changes in water availability on the grid and would leave ratepayers without any mechanism to smooth out water-related rate impacts that will occur on Yukon's isolated grid system. YEC does not see such a proposal as being consistent with the Board's direction on this matter, or with helping parties to determine how best to address the costs associated with water level variances.

For reference, Board Order 2013-1 notes as follows (para 255):

> Given the above concerns, the Board does not approve YEC's proposed DCF but directs YEC to provide a revised DCF proposal. In the revised DCF proposal, YEC is to incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model. In addition, YEC is to incorporate the suggestions of CW and UCG as to how DCF transactions are to be reported. Further, in that submission, YEC is to provide an example of approximately five years of transactions which will show how the balance in the DCF will change and how those changes will be reported. Finally, YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of YEC and YECL as to when the revised DCF proposal is to be filed with the Board. Given the foregoing, the Board does not approve YEC's requests regarding the DCF and therefore does not approve YEC's proposed changes to Rider F. Secondary sales, as they occur, will continue to be credited to the Rider F account.

Board Order 2013-3 notes, after reiterating its direction in Order 2013-1(para 15 and 16):

> The Board notes that the revised DCF proposal was not filed jointly by YEC and YECL and that there was not a joint recommendation by the companies on how to amend the wording regarding the ERA in Rate Schedule 42. The Board considers that the revised DCF proposal has not been tested in a proceeding. Given the foregoing, the Board does not approve the revised DCF proposal filed

in YEC's 2012-13 GRA compliance filing. Consequently, the Board will not allow any changes regarding 2012 and the effects of any DCF proposal.

YEC may file a future revised DCF proposal and ERA application. The Board prefers a joint filing from YEC and YECL. However, if agreement cannot be reached, a filing in which the companies state which aspects of the revised DCF proposal and ERA amendment they agree upon, the aspects they disagree upon, and the position of each company on those aspects they disagree upon is acceptable. The filing must also address the concerns raised in Board Order 2013-01 Attachment A: Reasons for Decision. This future revised DCF proposal and ERA application will be separate from the compliance filing directed in this order.

Yukon Utilities Board (YUB)

TOPIC: **DCF ERA Activation**

REFERENCE: **YEC Diesel Contingency Fund (DCF) & Energy Reconciliation Adjustment (ERA) filing, January 31, 2014**

…This proposal arose because diesel generation on the newly integrated grid was forecast in the GRA to be on the margin under long-term average ("LTA") hydro generation water conditions…[1]

…

The Board's current and past Orders for both utilities continue to support implementation of DCF and ERA mechanisms in Yukon, and provide no basis for a proposal today to abandon either mechanism (see Appendix A); furthermore, with diesel once again on the margin on the integrated grid, both mechanisms are relevant again today and need to be reactivated as of January 1, 2012…[2]

…

Table 1 provides the DCF determinations which apply to both Options A and B, in accordance with the Revised DCF as proposed in Appendix 1(a), for actual 2012 and preliminary 2013 results.[3]

The activation of the DCF was based on a simple concept: YEC would determine whether it was actually burning diesel in a given month to determine if diesel was "on the margin" in that month. To the extent that the fund accumulated revenues in excess of the approved threshold, the surplus balance at the end of the year would be refunded or collected by way of a rider to Yukon ratepayers.[4]

[1] YEC DCF-ERA Filing, January 31, 2014, page 1.
[2] YEC DCF-ERA Filing, January 31, 2014, page 2.
[3] YEC DCF-ERA Filing, January 31, 2014, page 4.
[4] YECL DCF-ERA Filing, January 31, 2014, page 2.

PREAMBLE:

Further information is required.

QUESTION:

a) Please explain why YEC, in its 2012-13 general rate application (GRA), chose a DCF trigger that was based on a GRA forecast wherein diesel generation was forecast to be on the margin under long-term average (LTA) hydro generation water conditions, rather than choose to use a DCF trigger, which was based on actual usage, as was done previously?

b) Does YEC agree with the Yukon Electrical Company Limited (YECL) submission that in the past an actual diesel usage threshold amount in any one month would trigger the DCF for that particular month? Please explain.

c) Please explain why, as was done in the past, a threshold amount of actual diesel usage of, say 250 megawatt hours (MW.h) per month, could not be used as a threshold to determine if diesel was on the margin in any month and trigger the DCF?

d) As was done for Table 1, all else held equal, please provide DCF determinations for 2012 and 2013, using:
    a. Actual 2012 and actual 2013 results, and
    b. Diesel usage threshold amounts of 250, 300 and 350 MW.h/month to trigger the DCF.

    Please use Table 1 results as presented on page 8 of YEC's DCF ERA application as a template for illustrating the DCF determinations as requested above.

e) Going forward, if the Board were to adopt a monthly diesel usage threshold amount as a DCF trigger,
    a. what are important considerations when choosing an appropriate DCF trigger threshold?
    b. what would YEC submit as an appropriate trigger?
    c. what changes and considerations would YEC recommend, if any to its current DCF proposal — i.e. secondary sales?

d. what changes and considerations would YEC recommend, if any to its current ERA proposal?

f) If YEC's 2012-13 GRA forecast was based on forecast short-term hydro water conditions, not historic long-term average water conditions, would YEC propose a formulaic approach wherein the DCF is permanently switched on? Please explain.

ANSWER:

(a)

Contrary to YECL's assertion as quoted above, the determination of when diesel is 'on the margin' for the DCF has never in the past been decided by a trigger based on 'actual usage'.

YEC's 2012-13 GRA proposed, and Board Order 2013-01 determined, that diesel generation was forecast to be on the margin in 2012 and 2013 under long-term average (LTA) hydro generation water conditions. As reviewed below, this determination was made notwithstanding forecasts provided in the GRA that actual diesel usage in these years would be well below long-term average (due to very favourable water conditions providing hydro generation above long-term average levels).

As noted in response to (b) below, so long as diesel generation is determined to be on the margin for 2012 and 2013 there is no historic or other basis for consideration of a DCF trigger based on actual diesel usage in these years.

Additional context is provided below from the GRA as filed in April 2012 as well as the current January 2014 filing and YEC's letter to the Board dated July 5, 2013.

Overview of YEC 2012-13 GRA as Filed and Board Order 2013-01

YEC's 2012-13 GRA referenced LTA hydro generation water conditions and the expected diesel generation required at LTA of approximately 11.5 GW.h and 18.2 GW.h in 2012 and 2013 respectively (based on the original forecasts as filed with the GRA in April 2012). The GRA proposed that rates be set at approximately 66% and 59% of LTA in 2012 and 2013 respectively, noting "current favorable water supply conditions" and YEC's proposal for a "transition" to LTA diesel costs in rates, and also proposed that the DCF implementation be based on the same stipulated percentages of LTA. Table 2.2 of

the GRA provided short term hydro generation forecasts reflecting the then current favorable water conditions and indicating likely diesel generation at only 20% and 38% of LTA in 2012 and 2013 respectively.

Board Order 2013-01 (paragraph 60) did not accept the proposed transition from 2009 rates and directed YEC to base its hydro and diesel energy requirements for 2012 and 2013 on 100% of LTA hydro generation for the forecast load in its compliance filing. Consistent with this direction and with its initial GRA filing, YEC has proposed that the DCF implementation be based on the same stipulated percentage of 100% of LTA.

DCF Consistency with what Previously Approved re "Diesel on Margin" Test

The GRA as originally filed provided additional information and submissions in Appendix 3.2 and related Attachment 3.2 specifically regarding the DCF (this same information with updates is provided in Appendix 1.1 and related Attachment 1.1 of the January 31, 2014 submission), including reference to the following:

- What happened with the DCF in the past was reviewed when Faro mine connection to WAF was a key factor affecting diesel generation:
    - When diesel was "on the margin" (which the submissions defined historically as "diesel being used to meet long-term firm energy requirements on the WAF system" - in practice this meant at that time when the Faro mine was operating) the DCF stabilized diesel costs related to water flow variations; versus
    - When diesel was not on the margin (i.e., when the Faro mine was not operating) provision was still made for DCF operation in situations when baseload diesel generation arose due to low water conditions:
        - It was noted that only under this latter situation, when diesel was not on the margin, was the distinction made in the past on WAF between normal peaking operation and true baseload diesel at 250 MW.h/month for DCF calculation purposes.
        - It was also noted that even in cases in the past where diesel generation exceeded 250 MW.h when diesel was not on the margin, the DCF was not operative if the generation was determined not to be due to low water conditions.

- Under load and grid hydro supply conditions that now apply (starting at least in 2012), diesel generation is required to meet long-term firm energy requirements on the integrated grid under LTA conditions; accordingly, the DCF must now be permanently switched 'on' through the same formulaic approach used to forecast LTA hydro and diesel generation under different grid load conditions, i.e., the same approach used to establish GRA diesel generation at 100% of LTA for forecast grid firm loads - and there would no longer be a YEC "diesel on the margin test" for activating the DCF.

YEC Letter of July 5/13 (Auditor Issues)

YEC's auditors have identified issues that arose in 2012 if the DCF is not in fact operative, i.e., as set out in YEC's July 5, 2013 letter to the Board, in the absence of Board direction and/or an approved DCF, YEC would have been required to recognize additional earnings in 2012 of $3.714 million (the amount otherwise to be paid to the DCF based on actual diesel generation at 2,683 MW.h versus 15,261 MW.h of diesel generation at 100% of LTA hydro generation as estimated for actual 2012 grid generation requirements).

YEC's letter of April 4, 2014 identifies a similar issue for 2013 if the DCF is not in fact operative, i.e., in the absence of Board direction and/or an approved DCF, YEC would have been required to recognize additional earnings in 2013 of $3.518 million (the amount otherwise to be paid to the DCF based on actual diesel generation at 1,037 MW.h versus 13,291 MW.h of diesel generation at 100% of LTA hydro generation as estimated for actual 2013 grid generation requirements).

(b) and **(c)**

YEC does not agree with YECL that in the past an actual diesel usage threshold amount in any month would trigger the DCF for that month when diesel was already determined to be on the margin, i.e., when the Faro mine was operating.

As reviewed in response to (a) above, and in the YEC submissions as noted therein, a trigger based on actual usage in any month only applied when diesel was not "on the margin", i.e., the Faro mine was not operating. The purpose of the trigger was to identify when low water conditions were in any event requiring diesel generation to occur, even though diesel generation was not required under LTA water conditions.

More generally, no such monthly diesel generation use test would be relevant or appropriate in situations (such as apply in 2012 and 2013) where rates are based on LTA hydro and diesel generation is expected to be required under LTA hydro conditions. As demonstrated in Table A-2 and Figure A-2 of Exhibit B-20 filed in November 2012 during the YEC GRA proceeding (the referenced table and figure are copied in Attachment 1(a) to this response), the result of such a test under 2013 conditions would frustrate necessary contributions to the fund under multiple years with high water conditions when no diesel generation is likely to occur:

- Attachment 1 of this response shows the forecast diesel generation variability (GW.h/yr.) for different load scenarios depending on water conditions of record over the 28 water years of record used to forecast LTA hydro and diesel generation for the 2012-13 GRA.

- Based on the then GRA load forecast of 430 GW.h for 2013 (with LTA diesel generation at 18.2 GW.h), diesel generation <u>for the total year</u> is expected to be less than 1 GW.h (i.e., average per month less than 100 MW.h) for more than one-third of the 28 water years (i.e. about 10 years).[5]

- A DCF cannot function as required (to smooth out diesel generation charges to ratepayers over all water conditions) if it failed to collect contributions under 2013 loads and hydro capacity simply because there was no diesel generation occurring during the year.

- As demonstrated in Attachment 1 of this response, this situation is particularly critical under lower loads such as forecast for 2012-13, and will become less relevant when loads increase to levels where more than 1 GW.h of diesel generation is expected to occur under all water year of record conditions (e.g., 2016 Base Case with Brewery Creek load of 480 GW.h as shown in Attachment 1, as well as the 2016 Scenario A and Scenario B loads).

- Given the above issues with total annual diesel generation as a trigger for 2013 loads, there is no reasonable basis for consideration of a monthly diesel generation trigger.

[5] The 2013 GRA as approved had a forecast load of 416.4 GW.h and expected LTA diesel of 11.0 GW.h. If anything, the lower grid load forecast as approved would increase the proportion of water years with less than 1 GW.h/year diesel generation.

As noted in YEC's submissions (2012/13 GRA and January 31, 2014 DCF/ERA Filing at page A1.1-4), under the DCF as now proposed by YEC, monthly calculations of YEC expected hydro and diesel generation will only be a placeholder with ultimate final calculations performed only on the annual values. As reviewed in response to (d) and (e) below, no other approach is considered to be feasible at this time.

(d)

Under the DCF as now proposed by YEC monthly calculations of YEC expected hydro and diesel generation will only be a placeholder with ultimate final calculations performed only on the annual values. As reviewed below, meaningful DCF determinations for 2012 and 2013 cannot be provided based on monthly diesel usage thresholds as requested.

To assist in understanding implications of a month-by-month assessment, a month-by-month allocation is provided (see below) of the expected LTA diesel generation requirements noted in Table 1 of 15,622 MW.h in 2012 and 13,291 MW.h in 2013 as updated per YUB-YEC-1-25 based on actuals (the allocations are based on weekly forecasts). Actual diesel generation before excluding RFID is also shown by month.

	Monthly Expected LTA diesel (MW.h)		Actual Diesel (incl RFID) (MW.h)	
	2012	2013	2012	2013
Jan	2,210	1,752	1,049	217
Feb	2,486	2,098	31	35
Mar	4,046	3,571	53	182
Apr	3,385	2,956	31	39
May	1,209	1,036	9	23
Jun	20	13	69	102
Jul	13	11	54	747
Aug	-	-	23	37
Sep	-	-	96	37
Oct	57	26	125	58
Nov	834	532	337	61
Dec	1,363	1,296	1,181	371
Total	15,622	13,291	3,057	1,910

Actual diesel generation for 2012 and 2013 (as updated per YUB-YEC-1-25 based on actuals) as shown in Table 1 is as follows:

- **2012:** 3,057 MW.h less 373 MW.h charged to RFID (and not relevant for DCF determination), leaving net diesel of 2,683 MW.h.

- **2013:** 1,910 MW.h less 872 MW.h charged to RFID (and not relevant for DCF determination), leaving net diesel of 1,037 MW.h.

Review of actual diesel generation by month for these years indicates as follows:

- **2012:** Diesel generation exceeds 250 MW.h only in three months (prior to determination of diesel charged to RFID):
    - January at 1,049.1 MW.h.
    - November at 336.5 MW.h.
    - December at 1,179.8 MW.h.
- **2013:** Diesel generation exceeds 250 MW.h only in two months (prior to determination of diesel charged to RFID):
    - July at 747.1 MW.h (this is likely due to charges to RFID and therefore not relevant for DCF determinations).
    - December at 370.8 MW.h.

Based on the LTA monthly distribution provided above, over 99% of LTA diesel generation in 2012 and 2013 related to the DCF is expected to occur in only seven months (from November through May). Actual diesel generation in any month provides no useful indication of LTA diesel generation used by the Board to determine the approved revenue requirement for these years based on LTA hydro and diesel generation.

Accordingly, as was the case with the DCF in the past when diesel was on the margin (i.e., the Faro mine was operating), diesel usage threshold amounts by month cannot be used to trigger the DCF during 2012-2013.

To re-iterate, the procedures assumed in Table 1 of the filing are not set up to facilitate a monthly DCF determination (as all noted data would be needed for each month, including a monthly determination of expected diesel generation). Placeholder assessments of DCF amounts by month will be determined based on information that is

available during the year on a monthly basis, keeping in mind that DCF expected diesel is determined on annual basis based on actual grid loads.

(e)

For the reasons reviewed below, YEC is not able to provide any proposed trigger as requested or any other changes to the DCF or ERA along the related lines requested in this question.

Based on the issues outlined in response to (c) and (d) above, YEC is not aware of any way that a monthly diesel usage threshold amount as a DCF trigger could be feasible or appropriate under 2012-2013 GRA or currently expected future conditions. As in the past, any such monthly trigger test would only be relevant to consider for years when it is determined that no material diesel generation is forecast to be required under LTA hydro generation water conditions. No such situation applies for 2012 or 2013 based on Board Order 2013-01.

As reviewed in response to (a) and (b) above, a monthly trigger was never considered or adopted in the past for DCF implementation as approved by the Board for any year when the Faro mine was operating and diesel generation was expected to be required under LTA water conditions as approved by the Board in a GRA for rate setting purposes. YEC is not aware of any basis today for initiating or implementing such a measure.

If anything, today's conditions make consideration of a monthly or even annual diesel generation level trigger measure far more problematic than when the Faro mine connection created the simple test for "diesel on the margin" conditions and a monthly trigger was reserved as a test only when the Faro mine was not operating.

- As reviewed in response to (b) and (c) above and in Attachment 1 to (b and c) of this response, the 2012-13 load and hydro generation water conditions are such that no material diesel generation is likely to be required in over one-third of the water years of record conditions.

- Under these circumstances, failure to apply the DCF in such years (when the Board has set rates based on LTA hydro generation water conditions) would lead to YEC having to recognize additional earnings for the year in an amount equal to the gap between diesel generation as forecast at LTA and actual diesel generation, i.e., the full cost of diesel at LTA under approved diesel fuel prices.

- As noted in YEC's July 5, 2013 letter to the Board, "Yukon Energy does not believe this outcome is in the best interest of ratepayers or the utility and is not the intended result of the Board in the Orders referenced above [Orders 2013-01, 2013-03 and 2013-04]".

(f)

YEC is not able to respond to the question as asked due to uncertainty regarding what conditions would be assumed for any Board-approved GRA based on forecast short-term hydro water conditions. However, comments are provided below to assist in assessing the relevant issues.

As reviewed in response to (a) above, YEC's GRA filing did indicate short term hydro and diesel generation forecasts for 2012 and 2013 based on what was known regarding water conditions at the time of the GRA filing. As noted, these short term diesel generation forecasts were well below LTA (at only 20% and 38% of LTA in 2012 and 2013 respectively). Such short term forecasts are subject to material change as actual water conditions unfold over any given period (particularly during summer periods). Neither the GRA as filed nor the final determination of revenue requirement per Board Order 2013-01 was based on such short term hydro and diesel generation forecasts.

The following are also noted to assist in assessing the relevant issues:

- If the Board was in future to adopt a short term hydro and diesel generation forecast approach, the GRA determinations would rely upon both the forecast of actual water conditions as well as of overall grid load.

- Under such conditions, any deviation of actual water conditions from the Board-approved short-term hydro generation forecast would become a risk to be borne by the DCF, i.e., formulaic adjustments of forecast water conditions would not appear to have any relevance, and formulaic assessment of how forecast hydro generation might vary only due to load changes from forecast might also not be relevant or worthwhile under many load conditions.

- A formulaic approach might potentially still be relevant if it could be established that a major deviation from the forecast overall load would (under the short term forecast water conditions as approved by the Board) lead to a change in forecast hydro generation. This might potentially be a relevant concern if large load

changes occurred that differed materially from the approved forecast, e.g., a material mine load stopped operating and/or was added to the grid.

- Under current load conditions as well as water conditions existing at the time of the 2012-13 GRA, reliance on a short term generation forecast would have resulted in approving diesel generation well below the percentages of LTA proposed by YEC in the GRA, let alone the 100% of LTA as approved by the Board.

In general, reliance on short term generation forecasts for GRA purposes are understood to add considerable instability to rates over time in response to changing water conditions, as well as to reduce funds set aside in the DCF during high water conditions in order to help reduce rate requirements under low water conditions. Past history before the Board leading to establishment of the DCF in 1996 provides the following guidance in this regard:

- From the outset of Board review of YEC revenue requirements, it was understood that the risk of low water conditions would need to be borne by the customers of the utility. Order 1989-4 describes (page 19) the Reserve for Contingencies for YEC of $2.250 million established at the outset by the owners of YEC (who "are in the end the people") out of retained earnings in 1987, of which $2 million was established to cushion the impact of increased costs to produce electricity by diesel generation at time of low water conditions and shutdowns of hydro facilities - on the understanding that, based on NCPC experience and experiences in other jurisdictions, it would be appropriate for the consumers of the utilities to be paying for their own contingencies.

- Prior to the DCF being established, when YEC relied upon short term hydro generation forecasts and the Low Water Reserve Fund (LWRF) to address variance from such forecasts, the Board noted (Decision 1992-1, page 52) concern that use of the "level of lake [Aishihik] at the time the [hydro] forecast is prepared" as proposed then by YEC in its October 1991 update rather than using a hydro generation forecast based upon the long term average hydro generation may lead to rate instability.

- In Decision 1992-1, the Board noted its expectation that all matters relating to the LWRF would be re-examined at the next GRA and requested YEC at that time to present evidence relating to the advantages and disadvantages of using current water levels as compared to long term average hydro generation. This was in fact

addressed in the 1993/94 GRA filing in Response to Board Directives, Section 5 of the GRA (the referenced section is copied in Attachment 1 to this response). The Board addressed the LWRF in Order 1993-8 at pages 68-70, and agreed that under the then present circumstances a reasonable drawdown of the LWR could be done to reduce revenue requirement in the then current test years without causing undue risk to future customers.

- The 1996/97 GRA as filed by the two Companies (YEC and YECL) highlighted the significant variance in water flows over the three to four prior years, the significant risk that actual Aishihik water flows would continue to be below average in 1996 and 1997, and that the potentially large fluctuations in rates caused by variances in available water flows at the system hydro sites warranted a move to long term average hydro generation for the purpose of determining rates. It was proposed that the LWRF be used as a Rate Stabilization Fund to absorb the annual fluctuations in available water resources without resorting to massive rate fluctuations from year to year (the referenced section is copied in Attachment 2 to this response).

Table A-2: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2016 and 28 Water Years of Record[1]

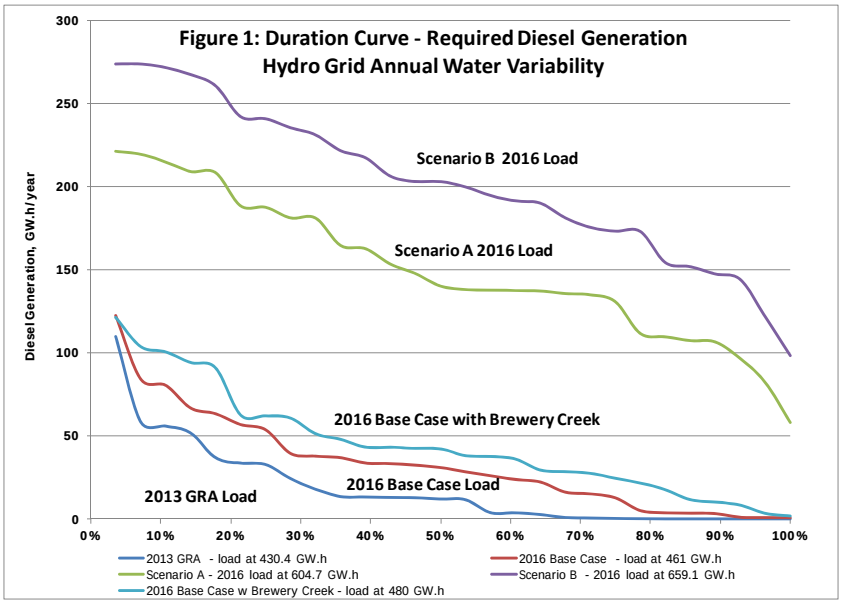
Average Annual Diesel Generation (Averaged Load Years for 28 Water Years)

Water Year	2016 Base Case - load at 461 GW.h	2016 Base Case w Brewery Creek - load at 480 GW.h	Average diesel generation required (GW.h) Scenario A - 2016 load at 604.7 GW.h	Scenario B - 2016 load at 659.1 GW.h
1981	3.9	10.3	137.8	203.1
1982	26.2	48.0	147.7	194.7
1983	28.5	38.2	135.0	191.5
1984	37.9	62.1	188.5	242.1
1985	33.5	43.3	162.7	217.4
1986	37.0	43.2	135.7	181.3
1987	12.9	24.6	137.5	199.9
1988	15.3	27.6	111.7	147.6
1989	3.6	8.4	109.7	175.5
1990	5.2	17.8	138.1	190.1
1991	3.4	11.7	107.4	144.2
1992	1.0	1.9	58.2	98.5
1993	1.2	3.6	96.6	154.4
1994	0.9	21.8	209.1	267.4
1995	56.9	94.1	219.5	273.8
1996	80.5	103.6	221.3	271.7
1997	84.3	100.5	181.1	231.2
1998	63.4	90.8	214.9	273.8
1999	122.5	121.1	208.4	260.7
2000	66.9	62.6	137.3	173.1
2001	33.8	28.6	82.3	121.8
2002	39.6	36.1	140.2	203.2
2003	31.1	51.3	187.6	240.9
2004	53.8	60.7	181.2	235.5
2005	23.9	42.2	153.4	206.3
2006	22.4	37.7	164.7	221.7
2007	32.4	42.5	130.8	173.3
2008	16.3	29.5	106.6	151.9
Average	33.5	45.1	150.2	201.7

Distribution of Annual Water Year Loads (Figure 1)

	% of Years not less than	2013 GRA - load at 430.4 GW.h	2016 Base Case - load at 461 GW.h	2016 Base Case w Brewery Creek - load at 480 GW.h	Scenario A - 2016 load at 604.7 GW.h	Scenario B - 2016 load at 659.1 GW.h
1	4%	109.9	122.5	121.1	221.3	273.8
2	7%	58.5	84.3	103.6	219.5	273.8
3	11%	55.9	80.5	100.5	214.9	271.7
4	14%	51.8	66.9	94.1	209.1	267.4
5	18%	36.8	63.4	90.8	208.4	260.7
6	21%	33.6	56.9	62.6	188.5	242.1
7	25%	32.8	53.8	62.1	187.6	240.9
8	29%	24.3	39.6	60.7	181.2	235.5
9	32%	18.0	37.9	51.3	181.1	231.2
10	36%	13.5	37.0	48.0	164.7	221.7
11	39%	13.3	33.8	43.3	162.7	217.4
12	43%	12.9	33.5	43.2	153.4	206.3
13	46%	12.8	32.4	42.5	147.7	203.2
14	50%	12.0	31.1	42.2	140.2	203.1
15	54%	11.6	28.5	38.2	138.1	199.9
16	57%	3.8	26.2	37.7	137.8	194.7
17	61%	3.7	23.9	36.1	137.5	191.5
18	64%	2.6	22.4	29.5	137.3	190.1
19	68%	0.9	16.3	28.6	135.7	181.3
20	71%	0.6	15.3	27.6	135.0	175.5
21	75%	0.3	12.9	24.6	130.8	173.3
22	79%	0.1	5.2	21.8	111.7	173.1
23	82%	0.1	3.9	17.8	109.7	154.4
24	86%	0.0	3.6	11.7	107.4	151.9
25	89%	0.0	3.4	10.3	106.6	147.6
26	93%	0.0	1.2	8.4	96.6	144.2
27	96%	0.0	1.0	3.6	82.3	121.8
28	100%	0.0	0.9	1.9	58.2	98.5
		18.2	33.5	45.1	150.2	201.7

Figure A-2: Duration Curve – Required Diesel Generation Hydro Grid Annual Water



[1] Table A-2 and Figure A-2 from Exhibit B-20 filed by YEC in November 2012 during the YEC 2012/13 GRA.

The companies have experienced difficulties in determining appropriate measures of labor productivity. Unlike most other utilities the unit cost of electricity in Yukon can increase as the sales increase, due to the fact that diesel generation has been used for the margin. Productivity measurements can also show increases when Curragh is closed and only hydro generation is used. Historical reviews can be meaningless in light of these factors.

Discussions with other power utilities indicates similar concerns about determining appropriate productivity measures of labor particularly on historical and forecast basis.

Low Water Financial Reserve

Section 7 in Decision 1992-1 requested YEC to present evidence in the next GRA relating to the advantages and disadvantages of using current water levels as compared to long term average hydro generation when calculating additions to, or deletions from, YEC's low water financial reserve.

Background on the Reserve

As reviewed in the Board's decision, the basic concept of the low water reserve as modified in the 1991/92 GRA is as follows:

(a) no direct charge for this reserve is included in forecast revenue requirement in a GRA

(b) if YEC over-earns in a year because the actual diesel generation is less than the forecast diesel generation due to higher than forecast water flows, the reserve would be increased to the extent of the difference between forecast and actual diesel generation (reflecting incremental costs saved for diesel generation) up to a maximum reserve of $4 million

(c) if YEC under-earns in a year because actual diesel generation exceeds forecast diesel generation due to lower than forecast water flows, the reserve would be decreased.

Each GRA is prepared on the basis of forecast sales, long term average water flows for the prospective test years, and the storage then available at Aishihik Lake. YEC does not, however, seek Board approval for specific levels of generation at each hydraulic plant; as events occur, YEC is required to respond to actual sales, generation needs, equipment availability, water levels and other conditions so as to minimize costs. As a general operating rule normal to similar utilities in Canada, available water is utilized (subject to water licence terms and conditions) to minimize fuel operating costs.

Diesel generation cost variance from GRA forecasts in any year will reflect many factors, including variances for overall sales, diesel fuel prices, equipment availability, and water flows. The low water financial reserve, however, is to be affected only to the extent that diesel generation variance is directly related to water flow variances that have affected hydraulic generation.

Application of Reserve: 1992 Actual Results

By way of example, in 1992 the following annual variances between actual and GRA forecast occurred in the WAF system of YEC:

- hydro generation: 3.1 GW.h
- diesel generation: (15.1) GW.h
- total generation: (12.0) GW.h

The above 1992 results indicate an overall reduction in sales (and thus total generation) of 12 GW.h relative to the GRA forecast. However, diesel generation savings were 3.1 GW.h greater than the reduction in overall generation and, after review, it was concluded that this 3.1 GW.h reflected higher than forecast water flow. The increase to the low water financial reserve for 1992 was then determined as follows:

(a) calculate WAF fuel cost saved based on GRA approved costs for 1992 (28.6¢ per litre at fuel efficiency of 3.65 kW.h/l) equals 7.83562¢ per kW.h

(b) assumed variable O&M cost saved as per 1992 GRA, at 1.5¢ per kW.h diesel generation

(c) calculated diesel generation cost saved in 1992 due to higher than forecast water flows equals $292,462 = (3,132,760) ($0.093356).

Advantages and Disadvantages of Using Current Aishihik Levels

The Board expressed concern in Decision 1992-1 that use of a hydro generation forecast which reflects the level of Aishihik Lake at the time when the forecast is prepared (rather than using long term average hydro generation) may lead to rate

instability. The Board requested YEC to present evidence on the advantages and disadvantages of these two options.

The Companies want to clarify that the initial GRA Application filed in June 1991 and the October 1991 update both used the level of Aishihik Lake at the time each of the hydro forecasts were prepared in order to forecast hydro generation for 1992. At no time have the Companies prepared a GRA which ignored the level of Aishihik Lake existing at the time when the hydro forecast is prepared. Each hydro forecast reflects the lake level then existing, assumes long term average water inflows for the future, and assumes that whatever storage may exist at Aishihik Lake will be used within the limits permitted by the water license and YEC's water management policy.

The low water reserve is intended to be calculated on the basis of deviations from the hydraulic generation forecast adopted when the Board sets rates for the test years. In 1992, the Board accepted the updated 1992 hydro generation forecast for Aishihik (which increased forecast generation for 1992 from 107 to 150 GW.h based solely on higher-than-expected water availability which occurred after filing of the initial Application in June 1991). The low water financial reserve allows both YEC and the customers to be protected against earnings and/or rate instability due to water availability variance from forecasts used in each GRA. If the Board had set 1992 rates based on long term average hydro generation at Aishihik (which was then estimated at 100 GW.h/yr), incremental costs for an extra 50 GW.h of diesel generation would have been required in the 1992 revenue requirement. Based on the WAF incremental fuel costs reflected in the Board's 1991/92 GRA decisions, such an adjustment would have had the following impacts on 1992 rates and reserve calculations:

- the 1992 revenue requirement approved by the Board would have had to be increased by about $4.7 million (this would have significantly increased 1992 rates)

- the year-end 1992 low water reserve would presumably have been calculated relative to long term average hydro generation and diesel generation; thus the apparent "saving" in diesel generation would have been 53.1 GW.h (rather than 3.1 GW.h); the low water reserve would then have been increased to its maximum of $4 million, and the balance of almost $3 million would have gone to increase YEC earnings.

In short, ignoring the level of Aishihik Lake when there is usable storage can lead to higher-than-necessary rate levels for consumers in the test years as well as the likelihood that YEC will "over-earn" on rate base (e.g., even if the Aishihik water availability in 1992 had been below the long term average, the above example would still have probably indicated an apparent saving in diesel generation relative to the forecast). These problems will not exist, of course, if no usable storage exists in the lake when the forecast is prepared; however, in this situation, long term average hydro generation would equal the most likely forecast for the test years (based on the lake level at the time when the forecast is prepared).

The above analysis demonstrates the main advantage of using forecast Aishihik hydro generation, reflecting current Aishihik Lake water levels, as compared to using long term average Aishihik hydro generation for the purpose of the low water reserve. The present approach allows the Companies to set rates based on the best available forecast of hydro generation; this in turn allows consumers to benefit during test years from reduced diesel generation forecast on the basis of current Aishihik Lake water

levels. The present approach also minimizes the year-end reserve adjustments likely to be required whenever current Aishihik Lake water levels are expected to permit Aishihik hydro generation higher than the long term average level.

The Companies also note that the main disadvantage of the present approach is that it contributes to rate instability to the extent that successive GRA's are required to adjust rates in response to current Aishihik Lake levels. Setting rates (and therefore reserve calculations) in each GRA on the basis of long term average hydro generation at Aishihik Lake would remove any instability in rates due to Aishihik Lake level fluctuation; however, it would have achieved this result in 1992 by requiring higher consumer rates and greater year-end reserve adjustments. Whenever Aishihik hydro generation is forecast to exceed the long term average (such as in 1992) due to current lake levels, the Companies see significant problems for consumer rates if the reserve is calculated using long term average hydro generation.

The present approach simply allows the Board and the utilities to set rates based on the best available forecast of hydro and diesel generation; such a forecast must reflect current Aishihik Lake levels, as well as various other factors such as forecast sales. Generation forecasts are still prepared assuming long term average water inflows for each test year to Aishihik Lake and Whitehorse Rapids; and adjustments at year-end to the low water reserve are designed solely to reflect variances in water availability relative to the GRA forecasts.

	Change since 1994 Decisions ($000s)		
	Actual	Forecast	
	1994	1996	1997
Fuel Expense	$ (203)	$ 7,627	$ 9,163
Other O&M Expense	(598)	2,348	3,128
Depreciation	96	654	1,007
Return on Rate Base	255	2,451	2,259
Income Tax Expense	11	(78)	356
Totals	$ (439)	$13,002	$15,913

Subsequent parts of this section review each of the factors which account for the above forecast changes to the revenue requirement of the combined Yukon system.

Forecast revenue requirements for 1996 and 1997 reflect sales projections prepared in the summer of 1995. Sales are expected to increase substantially due to the resumption of mining operations in Faro by Anvil Range Mining Corporation. This factor accounts for a major share of the change from the 1994 approved revenue requirement.

Based on forecast sales, total generation is also expected to increase substantially. This will have a very serious impact on the system as the high water flow years on the Aishihik system in the late 1980s and early 1990s have been replaced with drought conditions. Aishihik Lake inflows in 1994 were only 35% of long-term average which translates into a 68 GW.h loss of generation. Total water flows at Aishihik in 1995 are expected to be 52% of long-term average. As a result, the Companies will be forced to supply a significant portion of the load growth with diesel generation.

Proposed Rate Stabilization Fund

The very significant variance in water flows over the past three to four years has led the Companies to reassess their position with respect to the use of the low water reserve fund. If the Companies had been using their past practice of adjusting for actual reservoir elevations, the revenue requirement in this Application would not be materially different. There is also a significant risk that actual Aishihik water flows will continue to be below average in 1996 and 1997. We believe our suggested increases to the low water reserve fund address this risk.

The Companies believe that the potentially large fluctuations in rates which will be caused by variances in available water flows at the system hydro sites warrants a move to long-term average hydro generation for the purposes of determining rates. The low water reserve fund would then be used as a Rate Stabilization Fund to absorb the annual fluctuations in available water resources without resorting to massive rate fluctuations from year to year.

The benefits of amending the generation forecasting process and the operation of the low water reserve/rate stabilization fund would be as follows:

- low or no rate fluctuation from year to year caused by changes in water flows;
- greater certainty for customers on the future level of rates;
- simplification of the generation forecasting process; and
- the potential to extend test periods and reduce long-term regulatory costs due to a defined adjustment which will control the fluctuation in a significant cost item.

The mechanism for this new "Rate Stabilization Fund" would operate in the same manner as the currently approved low water reserve fund. The only difference would be that the "forecast" hydro generation would always be long-term average generation instead of an ever-changing forecast of hydro generation based on changes in available water from year to year.

The Companies would also like to include YECL's Fish Lake facility and YEC's wind generator in the operation of the reserve. This change fits in with the goal of providing long-term stability to rates and ensures customers receive the benefit of high flow years and the shareholder is protected from the risk of low flow years.

The Companies believe that the ceiling for this fund must be at least $5 million as this represents the impact of only one year's fluctuation in extreme conditions. The Companies wish to study the potential swings in this fund and may propose a higher ceiling at a future hearing. Our initial review of this fund is that it may be more volatile than the low water reserve due to the fact that generation forecasts will not be updated for actual water conditions at the beginning of each test period.

In Volumes I and II, the Companies have accounted for the Rate Stabilization Fund as a reduction in the rate base as directed in prior Board decisions. The Companies propose, however, that the fund be removed from rate base and that all interest income or expense on the fund be charged directly to the fund. This proposal retains the benefit of having all of the financing benefit going to the account of the customers but removes the circular calculations and volatility resulting from including the fund in rate base.

TOPIC: **DCF and related matters**

REFERENCE: **YEC DCF ERA filing, YEC 2012-2013 GRA, YEC 2008 Diesel Contingency Fund Filing**

On March 29, 2010, Yukon Energy filed its 2008 DCF filing and noted the potential need to update methods of operation of the DCF. It was noted that the DCF operating rules would require attention in the future to address a number of new circumstances, including updating long-term average hydro generation values, fund triggers, and potentially a means to address secondary sales. Today, following connection of the WAF and Mayo Dawson grids, it is also necessary to adjust the DCF to deal with more than only WAF hydro generation. [1]

The proposed updated approach would permanently switch "on" the DCF through use of a formulaic approach that would automatically adjust forecast annual long-term average hydro generation and related diesel (or other non-diesel fossil fuel) generation to reflect actual grid generation load. Based on this DCF proposal there will no longer be a "diesel on the margin" test for activating the DCF.[2]

…Diesel was not on the margin for any month of the 2008 period. During December 2008 diesel generation exceeded the on the margin threshold of 250 MW.h/month used within the Diesel Contingency Fund as a determinant to indicate that all diesel generation is presumably required only for baseload serving purposes. Upon review it is evident that the diesel generation was for unplanned maintenance or peaking purposes… [3]

[1] YEC DCF-ERA filing, Appendix 1.1, page 1.1-2.

[2] YEC 2012 GRA, Tabs 1-11, page 5.

[3] YEC 2008 Diesel Contingency Fund Filing, March 29, 2010, page 2.

PREAMBLE:

Further information is required.

QUESTION:

a) In the past, the DCF was triggered at a point where the diesel usage was "presumably required only for baseload serving purposes."[4]
   i. Does YEC's current DCF proposal go beyond accounting for baseload diesel requirements?
   ii. Please define baseload diesel requirements — i.e. is diesel generation required for short-term emergencies or peaking purposes, considered to be baseload diesel?

b) Prior to YEC's original DCF proposal which was submitted as part of its 2012-13 GRA, did YEC consult with YECL about permanently switching on the DCF through the use of a formulaic approach? If so, please provide rationale and reasoning that was proposed as well as YECL's response. Please provide all documentation.

c) With respect to the 2012 and 2013 test years, please indicate the months for each of the test years when secondary sales were not available to customers.

d) Does YEC wish to comment on YECL's statement that "…Yukon Energy believes diesel expense can be recovered from two sources: (1) ratepayers if Yukon Energy's forecast is accurate; or (2) Yukon Electrical if Yukon Energy's forecast is inaccurate. Yukon Electrical maintains that prudently-incurred costs must be recovered from ratepayers."[5]

[4] YEC 2008 Diesel Contingency Fund Filing, March 29, 2010, page 2.

[5] YECL DCF-ERA filing, January 31, 2014, Appendix A, page 6.

ANSWER:

(a)

The term "baseload diesel requirement" has been used in various past GRA and DCF submissions to highlight when diesel is "on the margin", i.e., notable diesel requirements are forecast to be required to supply a forecast load under an assumed water condition[6]. The term has not been precisely defined. It has typically indicated a situation when diesel requirements under forecast water conditions go beyond a periodic peaking requirement - however, when "baseload" requirements have been forecast, typically no attempt has been made to separate out "baseload" from "peaking" diesel requirements, and it has not been implied that diesel is necessarily "on the margin" for every hour or month. The term excludes diesel for emergencies, maintenance, and to address other similar special non-water and non-load conditions.

YEC's current DCF proposal is consistent with previously approved DCF as regards accounting for "diesel on the margin", i.e., it does not include diesel generation for emergency, maintenance or other similar special non-water and non-load conditions, and it does not attempt to separate out "peaking" from other diesel generation when diesel is on the margin.

Additional background is provided below to elaborate on these points.

YEC's current DCF proposal addresses a situation for the 2012-13 GRA test years, as well as subsequent years, when diesel is forecast to be "on the margin", i.e., diesel is forecast to be required to meet firm energy requirements (and not just periodic peaking conditions) at long-term average hydro generation water conditions.[7]

[6] A recent example is the YEC 2012-13 GRA submission filed in April 2012, Section 1.3. At page 1-7, for example, load growth is noted to be causing increased diesel generation costs and it is stated: "The Application marks a major transition in forecast annual long-term average [LTA] baseload diesel generation needed to meet grid load growth..." In the Application, LTA diesel generation provided the basis for all forecast diesel generation requirements, i.e., no attempt was made to break out "peaking" diesel generation. The LTA forecast did not consider potential emergency diesel requirements.

[7] This definition of "diesel on the margin" is what is provided in YEC's January 31, 2014 submission, Appendix 1.1, page 1.1-2.

Under such conditions as were forecast to apply for the 2012-13 GRA test years, YEC's current DCF proposal is the same as the DCF as approved in the past with regard to the following:

- There is no relevant "threshold" of actual diesel generation that is relevant to activation of the DCF in such years;

- No distinction is made between "baseload" and "peaking" diesel generation in either forecast or actual diesel generation (and no definition of such terms is relevant to implementation of the DCF); and

- Diesel generation requirements are excluded that arise due to hydro generation capital projects (i.e., when hydro generation is curtailed to carry out a capital project), or due to transmission line outages such as may occur due to forest fires, or are funded by RFID or insurance.

The referenced "YEC 2008 Diesel Contingency Fund Filing", dated March 29, 2010, including the DCF table of calculations for 2008 attached to this prior filing, is attached to this response as Attachment 1. The following elements of the prior DCF operation are demonstrated in this filing:

- The March 2010 filing stated at page 2 that "Diesel was not on the margin for any month of the 2008 period." This comment reflected the manual determination made at line 10 of the attached DCF table as to whether diesel was "on the margin" in any given month; as reviewed in past filings with the Board[8], this determination in the past was made solely based on whether the Faro mine was operating, i.e., in 2008 the Faro mine was not operating in any month, and therefore zero was shown at line 10 for each month. The definition of "diesel on the margin" at line 10 was not dependent in any way on actual diesel generation in any month.

[8] For example, YEC's filing with the Board on October 7, 1999 providing responses to specific questions asked by the Board regarding the DCF operations for 1996 through 1998. A copy of this, along with the related letter from YEC to the Board and other DCF documents from 1996 to 1999 was attached as Attachment 3 to YUB-YEC-2-4 in the 2011 proceeding re: Rider F issues - the full set of Attachments 1-4 to this earlier IR response is provided as Attachment 2 to this response.

- Reference in the March 2010 filing at page 2 to "the on the margin threshold of 250 MW.h/month" referred to a threshold that applied only to determinations made at line 16 in the attached DCF table; as provided for at line 16, this margin threshold applied only in months when it had already been determined (at line 10 of the attached DCF table) that diesel was "not on the margin". The following additional points are noted regarding the origins and purpose of this 250 MW.h/month threshold:

    - The 250 MW.h per month threshold was developed in 1997/98 when preparing DCF reports as a simple provision, when the Faro mine was shut down, for small amounts of diesel generation that may be required for purposes unrelated to variances from long-term hydro capability[9].

    - In order to address this factor when the Faro mine is closed, the DCF was not activated in any such month when actual diesel generation did not exceed 250 MW.h (as provided for at line 16 of the DCF report table for YEC).

    - Subject to further checks (see below), in such a month when actual diesel generation exceeded 250 MW.h, all of the diesel generation was included in the DCF determinations.

    - However, as noted in the 2008 filing attached as Attachment 1 for the month of December 2008, the 250 MW.h per month threshold could be set aside if it was determined separately that actual diesel generation was due to factors unrelated to below average hydro generation water conditions.[10]

    - The 250 MW.h per month threshold was developed based on WAF loads in 1997/98 when the Faro mine was not operating, and provided a useful guide for many years. However, at higher WAF loads existing by 2008 and thereafter, this number no longer provides a useful test - and as indicated in the 2012-13 GRA, and Order 2013-1, diesel generation is

[9] See Attachment 2 (page 30) to this response (October 7, 1999 filing, Attachment A page 4).
[10] See also Attachment 2 of this response, letter of October 7, 1999 to the Board and its references to treatment of 1997 and 1998 fire-related impacts.

now required to supply firm loads on the grid under long term average hydro generation water conditions.

As reviewed in Attachment 2 of this response (page 30), YEC defined "diesel on the margin" in its October 7, 1999 filing as a concept used to represent the significant impact that the operation of the Faro mine had on the Yukon electrical system. Actual hydro generation and actual diesel generation did not affect whether diesel was determined to be "on the margin" at line 10 of the DCF table. As reviewed above, in months when diesel was not "on the margin" (due to shut down of the Faro mine), no formal definition of "baseload" or "peaking" was ever defined beyond the 250 MW.h threshold per month reviewed above - and that threshold was subject to review, as noted, to exclude diesel generation required for reasons clearly not related to low water conditions.

(b)

Prior to the 2012-2013 GRA filed in April 2012, YEC had worked with YECL in developing the ERA as approved in Order 2011-06 which reflected the joint submission of both utilities and applies when "diesel generation in the Hydro zone is on the margin at long-term average water flows." YEC had also discussed with YECL issues related to YECL's wholesale purchase power deferral account as approved in Board Order 2009-02 which fully addresses any cost impacts on YECL from load forecast variance derived ERA cost charges.

YEC did not consult YECL, prior to submitting its 2012-2013 GRA in April 2012, about permanently switching on the DCF through the use of a formulaic approach. The rationale and reasoning that was proposed for this proposal was set out in detail in the 2012-2013 GRA as filed, as well as in subsequent responses to IRs.

(c)

Please see response to AEY-YEC-1-9(a). For each of the test years, secondary sales were activated during the following period:

- 2012: July 10 to October 24 [secondary sales not available from January 1 to July 9; and from October 25 to December 31].

- 2013: August 1 to October 1 [secondary sales not available from January 1 to July 31 and from October 2 to December 31].

(d)

YECL's statement, and the related Table 3.1 in its submission, do not help the Board.

The ERA as approved in the past, and as proposed by YEC today, is designed so that each utility can recover from Hydro rate zone ratepayers the diesel generation energy costs prudently incurred by YEC. The only difference today is the need to provide for a YECL deferral rate rider to recover (or rebate) any ERA amounts not covered by YECL's approved Hydro rate zone retail run-out energy rate charges - in the past this added rider was not required because Hydro zone retail run-out rate charges fully reflected the incremental diesel generation energy charges incurred by YEC.

The following additional comments are provided to assist on this matter:

1. At a most fundamental level, YECL's statement fails to recognize key features that remain unchanged in YEC's current proposals regarding the ERA from what was agreed to by both YEC and YECL in the past, and approved by the Board in past decisions, including:

    a. The ERA continues (as in the past) to address the specific issues that arise only when YEC's forecast wholesales (as approved by the Board) "is inaccurate", i.e., there are no such issues to address (and no ERA applicable) if actual wholesales from YEC to YECL (after Fish Lake adjustments) are exactly the same as the Board approved forecast, and 100% of YEC's diesel cost would under such circumstances be recovered from ratepayers.

    b. The ERA continues (as in the past) to be required and applicable only when diesel is on the margin for YEC (i.e., YEC's costs for diesel will be determined by the DCF mechanism) and actual wholesales to YECL vary

from approved forecasts (for reasons not related to Fish Lake hydro generation variances).

c. The ERA continues (as in the past) to flow through to YECL only the actual net cost (or saving) incurred by YEC with regard to diesel generation costs incurred (or saved) due to YECL's higher than forecast (or lower than forecast) wholesale purchases from YEC.[11]

d. The ERA continues (as in the past) to apply only to YECL wholesale variances from approved forecasts, i.e., it does not address the diesel cost impacts on YEC due to variances from approved forecasts for YEC retail or industrial sales.

e. The basis for the ERA being applied to YECL continues (as in the past) to reflect the following:

   i. OIC 1995/90 direction that the wholesale rate to YECL must "be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other ratepayers".

   ii. Unlike other YEC customers, YECL is a regulated utility that purchases wholesales from YEC in order to sell the power to its retail and industrial customers at rates as approved by the Board, i.e., YECL's revenues are directly impacted when changes in its retail and industrial sales lead to variances from approved forecasts in its wholesales purchases.

   iii. The wholesale rate otherwise charged by YEC to YECL (absent the ERA) is only a simple average energy rate, determined on the basis of the Board approved wholesale forecast:
      - This average energy rate wholesale charge from YEC to YECL is well below the incremental energy rates charged by YECL to its customers.

[11] Section 4.6 of YEC's 2012-13 GRA filing reviews the last Board approval of the ERA in the 2008/09 GRA per Order 2011-6.

- This average energy rate wholesale charge is also well below the incremental diesel generation energy costs incurred or saved by YEC as a result of YECL wholesale purchases varying from the approved forecast.

iv. The ERA charges or rebates continue (as in the past) to address only the gap, as applied only to the variance in actual wholesales from approved forecast, between the approved wholesale average energy rate charged to YECL and YEC's DCF-determined incremental diesel generation energy costs that impact YEC with regard to any variance in actual wholesales from approved forecast.

v. It continues to be assumed (as in the past) that YECL's incremental rate revenues related to increased wholesale requirements above approved wholesales forecasts are to be applied as "ratepayer" funding to cover ERA charges to YECL (and that the decreased rate revenues related to shortfalls in wholesale requirements below approved wholesale forecasts are also applied as "ratepayer" saving associated with ERA rebates to YECL).

2. The YECL statement also fails to recognize the one fundamental change today (from the past) in YEC's proposal related to ERA charges, i.e., all ERA charges or rebates to YECL, net of any related YECL revenue changes associated with the same purchase power variances addressed by the ERA charges or rebates, will go directly to YECL's Purchase Power Flow Through deferral account to flow through to ratepayers at such time or times as approved by the Board. This change reflects the following considerations:

a. The extent to which current run-out retail rates in the Hydro rate zone do not reflect fully YEC's incremental diesel generation energy costs with implementation of the DCF, and the need to enable YECL to recover from (or rebate to) ratepayers these prudently incurred net costs.

b. The avoidance of added impacts on ratepayers that would occur if YECL's revenue offsets are ignored as would occur under Option B in YEC's January 31, 2014 submission.[12]

[12] See pages 6 and 7 of YEC's January 31, 2014 submission - Option A (which is proposed) versus Option B saves ratepayers $531 million in deferral account amounts to be recovered through rate riders based on 2012 and 2013 examples included, with $0.443 million relating to YECL wholesales (i.e., the exclusion of offsetting YECL revenues related to wholesale variances) and the balance ($0.088 million is the corrected amount) relating to YEC industrial and retail sales impacted with Option B.

YUKON ENERGY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

Our File: 2700-05-03

March 29, 2010

Yukon Utilities Board
P.O. Box 31728
Whitehorse, YT
Y1A 6L3

Attention: Mr. Bruce McClennan, Chair

Re: 2008 Diesel Contingency Fund Filing

In accordance with the negotiated settlement resulting from the 1996/97 Revenue Requirement and Rate Design Application, Yukon Energy is to file with the Board a report on the operation of the Diesel Contingency Fund for each year.

For the 2008 year, Yukon Energy was involved in a general review of its rates, which includes activities extending well beyond the 2008 year-end (the 2008/09 General Rate Application and follow up joint YEC/YECL Phase II Rate Application). These regulatory reviews include consideration of matters related to diesel generation forecasts and the potential need to update the methods of operation of the DCF. The Phase II Rate Application document has now been finalized and submitted to the Board for review. As part of that process, the utilities have not sought any changes to the DCF at this time.

No DCF report was filed at year-end 2008 pending YEC's and the Board's review of these matters. While the DCF operating rules will require attention in future to address a number of circumstances, including updating long-term average hydro generation values, fund "triggers", and potentially a means to address secondary sales, no changes are yet being proposed to the fund.

Consequently, in order to ensure a complete record for the Board's files, please find attached the schedules and tables related to the Diesel Contingency Fund for 2008:

1. Diesel Contingency Fund Continuity Schedule for 2008,
2. Diesel Contingency Fund Calculation Tables for 2008, and
3. As required by the DCF negotiated settlement, also attached is an internal memo regarding the 2009 forecast of available water.

Following is the general information on Diesel Contingency Fund operations for 2008:

- The opening balance of the Diesel Contingency Fund as at January 1, 2008 was $856,020.84.
- The Closing Balance of the Fund as at December 31, 2008 was $882,693.40.
- The net change in the Fund of $26,672.56 is attributable to interest of $29,389.43 net of account service fees of ($2,716.87). There was no other activity impacting the fund.
- Long term average annual non-diesel generation for purposes of this report remains unchanged as follows:
  - Whitehorse Rapids Hydro – 246 GWh
  - Aishihik Hydro – 105 GWh
  - Fish Lake Hydro – 10 GWh
  - Haeckel Hill – Wind Turbine – 0.3 GWh

- Actual diesel generation for 2008 was 1,214,174 kWh. Diesel was not on the margin for any month of the 2008 period.

- During December 2008 diesel generation exceeded the on the margin threshold of 250 MW.h/month used within the Diesel Contingency Fund as a determinant to indicate that all diesel generation during a month is presumably required only for baseload serving purposes. Upon review it is evident that the diesel generation was for unplanned maintenance or peaking purposes and not due to low water flow variances. As this generation does not meet the overall intent and purpose of the Diesel Contingency Fund it has been excluded from the December 2008 calculation so that there is no impact on the Diesel Contingency Fund for this generation.

- As per the attached memorandum written by Ron Gee, Resource Management Engineer, diesel consumption for generation or capacity requirements is not expected in 2009.

If there are any questions related to the filing of this report or management of the Diesel Contingency Fund please contact the undersigned.

Sincerely,



Ed Mollard, CGA
Chief Financial Officer

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
2008	Opening balance		856,020.84
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		26,672.56
	Ending Balance		882,693.40

T:\Diesel Contingency Fund\2008\2008 DCF Schedule Summary of Continuity Schedules

2008 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2008

Continuity Schedule, Year Ending Dec. 31, 2008 - Diesel Contingecy Fund Calculations - WAF System ($000)

	Line#		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	33,165,929	29,610,041	26,877,857	23,666,146	21,345,165	21,790,016	21,745,269	22,940,550	22,307,493	25,080,823	29,832,970	35,346,068	313,708,326
Wind	1a	Manual Input	0	0	25,100	0	174,790	39,760	70,500	18,900	0	0	101,390	6,450	436,890
Diesel	2	Manual Input	37,323	76,111	0	0	186,358	0	0	840	0	218,668	31,256	663,618	1,214,174
Total	3	Line 1 + Line 2	33,203,251	29,686,152	26,902,957	23,666,146	21,706,313	21,829,776	21,815,769	22,960,290	22,307,493	25,299,491	29,965,616	36,016,136	315,359,390
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,623	27,721,714	26,992,170	23,818,498	24,702,218	30,959,932	30,771,956	30,871,830	31,799,615	32,502,676	30,765,226	29,775,138	351,087,596.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,592,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	2,729,305	1,860,327	(117,213)	(177,352)	(3,206,263)	(9,145,156)	(8,971,187)	(7,932,380)	(9,517,122)	(7,451,853)	(860,866)	5,547,380	(37,242,380)
Diesel	8	Line 2 - Line 5	(11,802,123)	(10,485,157)	(11,937,593)	(11,564,239)	(9,315,963)	(1,203,010)	(1,346,054)	(1,349,672)	(1,442,675)	(3,393,097)	(7,963,975)	(11,187,590)	(82,991,148)
Total (favourable)	9	Line 3 - Line 6	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528.00)
	13	Line 11 + Line 12	2,766,628	1,936,438	(117,213)	(177,352)	(3,019,905)	(9,145,156)	(8,971,187)	(7,931,540)	(9,517,122)	(7,233,185)	(829,610)	6,210,998	(36,028,206.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	37,323	76,111	-	-	186,358	-	-	840	-	218,668	31,256	663,618	1,214,174.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	0.00	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29														-
Ending reserve balance	30	Line 26+27+28+29	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest	3,297.73	2,870.19	2,843.68	2,521.04	2,428.57	2,383.06	2,347.38	2,172.81	2,378.75	2,339.90	1,925.31	1,881.01	29,389.43
Service fees	33	Investment Fees	(674.41)	0.00	0.00	(672.62)	0.00	0.00	(678.64)	0.00	0.00	(691.20)	0.00	0.00	(2,716.87)
Net interest earned	34	Line 32+33	2,623.32	2,870.19	2,843.68	1,848.42	2,428.57	2,383.06	1,668.74	2,172.81	2,378.75	1,648.70	1,925.31	1,881.01	26,672.56
Cumulative net interest earned	35		2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	18,838.79	21,217.54	22,866.24	24,791.55	26,672.56	
Ending reserve balance including interest	36	Line 30+35	858,644.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	878,887.08	880,812.39	882,693.40	

YUKON ENERGY

YUKON ENERGY CORPORATION
MEMORANDUM

DATE: May 5, 2008

TO: Melaine Fillion

FROM: Ronald Gee

RE: 2008 Forecast of Available Water on WAF Grid

The present sales forecast for 2008 on the Whitehorse-Aishihik-Faro (WAF) system is approximately 312.9 GWh's.

The Aishihik Lake reservoir is currently near its low for the year at an elevation of 914.27m. Inflows for 2008 are expected to be above average and therefore the forecasted peak elevation in October will reach the peak operating level of 915.1m. With the Carmacks to Stewart Crossing transmission line and Minto Mine spur expected to be in operation in 2008, the Aishihik Lake level will be brought up to near full supply level. The Aishihik system is expected to have full use of energy and capacity from the plant for the winter of 2008/09. Operationally, there is no scheduled maintenance of the Aishihik hydro units that would impact the winter generating capability of the hydro plant.

Marsh Lake reservoir is presently at 653.91m. The lake level will begin rising in the next week and is forecast to be completely full by the fall. Winter drawdown of the lake will begin in November and continue through to May 2009. Energy and capacity at Whitehorse Rapids will be constrained by the decreasing water flow in the Yukon River as the winter progresses. This decrease in generating capability is the normal operating situation for Whitehorse Rapids. Scheduled hydro maintenance is not expected to impact the winter generating capability of the Whitehorse Rapids Hydro Plant.

With the current sales forecast and the expectation of full hydro reservoirs in the fall, there is no forecast diesel generation for energy requirements expected in 2008.

Diesel generation in 2008 may occur for the following reasons: For maintenance purposes to ensure operational readiness, diesel peaking during periods of unseasonably cold temperatures and in the event of an unplanned hydro shut down. The total amount of diesel for the above purposes is not expected to exceed the thresholds specified in the calculation of the Diesel Contingency Fund. Attached is a forecast of the WAF generation levels for 2008.

\documents\memo\rg3132

Actual Data to May 3 / 08

AISH INFLOW 120 % OF LTA
2008 WAF FORECAST

WEEK ENDING	ACTUAL OR PROJ SYST GEN (GWH)	PROJ OR FORE SYST GEN AVG (MW)	**ACTUAL OR FORE WHSE GEN AVERAGE (MW)**	ACTUAL AISH INFLOW CMS.W	PROJ AISH OUTFLOW CMS	PROJECT AISH ELEV (m)	PROJ OR FORE AISH GEN AVG (MW)	**ACTUAL OR FORE DIES GEN AVG (MW)**
2008								
5-Jan	33.203251	43.886	**25.768**	3.221	8	914.824	**18.118**	**0.000**
12-Jan		44.193	**24.621**	3.169	8	914.793	**19.570**	**0.002**
19-Jan		42.098	**23.761**	4.305	8	914.767	**18.336**	**0.000**
26-Jan		43.625	**23.952**	0.761	8	914.727	**19.673**	**0.000**
2-Feb	29.686152	51.714	**25.272**	1.646	8	914.691	**25.957**	**0.485**
9-Feb		50.776	**24.248**	2.889	8	914.643	**26.367**	**0.160**
16-Feb		40.893	**23.452**	-0.850	8	914.579	**17.425**	**0.016**
23-Feb		35.832	**23.105**	0.126	8	914.539	**12.728**	**0.000**
1-Mar	26.902957	38.750	**22.153**	1.501	8	914.512	**16.597**	**0.000**
8-Mar		37.120	**21.666**	-3.643	8	914.465	**15.455**	**0.000**
15-Mar		35.866	**20.902**	2.359	8	914.443	**14.964**	**0.000**
22-Mar		35.808	**20.665**	3.517	8	914.426	**15.143**	**0.000**
29-Mar		35.109	**20.800**	0.537	8	914.397	**14.309**	**0.000**
5-Apr	25.382887	34.207	**21.273**	-4.190	8	914.349	**12.934**	**0.000**
12-Apr		33.606	**20.760**	0.608	8	914.321	**12.846**	**0.000**
19-Apr		33.277	**19.553**	4.681	8	914.310	**13.724**	**0.000**
26-Apr		31.252	**19.922**	-2.930	8	914.268	**11.330**	**0.000**
3-May	22.70213	30.351	**19.131**	9.205	8	914.276	**11.220**	**0.000**
10-May		30.514	**18.314**	13.215	6	914.306	**12.200**	**0.000**
17-May		30.514	**18.314**	14.540	6	914.341	**12.200**	**0.000**
24-May		30.514	**19.914**	16.283	5	914.387	**10.600**	**0.000**
31-May		30.514	**19.914**	21.686	5	914.455	**10.600**	**0.000**
7-Jun	20.879176	28.999	**19.299**	25.666	5	914.540	**9.700**	**0.000**
14-Jun		28.999	**19.299**	26.666	5	914.628	**9.700**	**0.000**
21-Jun		28.999	**21.049**	24.095	4	914.711	**7.950**	**0.000**
28-Jun		28.999	**21.049**	25.743	4	914.542	**7.950**	**0.000**
5-Jul	21.54486	28.970	**25.401**	24.154	4	914.625	**3.569**	**0.000**
12-Jul		28.958	**25.389**	24.837	4	914.675	**3.569**	**0.000**
19-Jul		28.958	**25.389**	27.676	4	914.730	**3.569**	**0.000**
26-Jul		28.958	**25.389**	24.308	4	914.813	**3.569**	**0.000**
2-Aug	21.435453	28.916	**28.916**	22.165	4	914.888	**0.000**	**0.000**
9-Aug		28.811	**28.811**	19.706	4	914.952	**0.000**	**0.000**
16-Aug		28.811	**28.811**	19.230	4	914.809	**0.000**	**0.000**
23-Aug		28.811	**28.811**	17.744	4	914.865	**0.000**	**0.000**
30-Aug		28.811	**28.811**	17.071	4	914.919	**0.000**	**0.000**
6-Sep	23.306207	31.861	**28.292**	16.672	4	914.971	**3.569**	**0.000**
13-Sep		32.370	**28.801**	15.053	4	915.016	**3.569**	**0.000**
20-Sep		32.370	**25.051**	12.654	6	915.043	**7.319**	**0.000**
27-Sep		32.370	**25.051**	11.586	6	915.066	**7.319**	**0.000**
4-Oct	27.945126	35.336	**25.636**	10.278	6	915.084	**9.700**	**0.000**
11-Oct		37.561	**27.861**	10.982	6	915.104	**9.700**	**0.000**
18-Oct		37.561	**27.861**	7.664	6	915.111	**9.700**	**0.000**
25-Oct		37.561	**27.861**	6.211	6	915.112	**9.700**	**0.000**
1-Nov	30.949948	38.336	**28.636**	4.585	6	915.106	**9.700**	**0.000**
8-Nov		42.986	**24.036**	4.432	12	915.075	**18.950**	**0.000**
15-Nov		42.986	**24.036**	4.579	12	915.045	**18.950**	**0.000**
22-Nov		42.986	**24.036**	5.037	12	915.016	**18.950**	**0.000**
29-Nov		42.986	**24.036**	4.890	12	914.987	**18.950**	**0.000**
6-Dec	33.357305	44.571	**23.871**	4.606	13	914.953	**20.700**	**0.000**
13-Dec		44.835	**24.133**	4.655	13	914.918	**20.702**	**0.000**
20-Dec		44.835	**24.133**	4.778	13	914.885	**20.702**	**0.000**
27-Dec		44.835	**24.133**	4.132	13	914.848	**20.702**	**0.000**

VIA FACSIMILE
03.668-3327

March 11, 1996

EXHIBIT B 16

Mr. Bill Byers
Yukon Energy Corporation
304 - 204 Lambert Street
Whitehorse, Yukon Y1A 1Z4

Dear Mr. Byers:

Re: *Proposed Settlement of Issues*
Concerning the Revenue Requirement
and Rate Design Application of YEC and YECL

The purpose of this letter is to record the settlements we have achieved with respect to specific issues in the YEC and YECL ("the Companies") Application. This letter remains confidential until it is submitted to the Yukon Utilities Board for consideration. I, therefore, ask that you provide to me a communication of endorsement for the proposal so that we may forward it to the Board and make it public by Wednesday, March 13, 1996.

I have taken the liberty of reordering issues in our proposed settlement working sheets so that they align better with the subject areas of discussion in the Application. I have also added words to the bullets that we have agreed upon to explain the settlement to those parties who were not present at negotiations.

The settlement participants agree with the content and details of the Application, save for the following adjustments and identification of specific issues to be reviewed by the Board in public hearing. It is recognized by all the parties that the agreement represents a package proposal within which there has been give and take by all parties. No issue is to be severed from the proposed settlement without allowing signatories the opportunity to address other related issues in the package.

The terms of the settlement are as follows:

1. Return on Equity ("ROE")

   It is agreed that the ROE for 1996 and 1997 is to be set at 11.25 percent and that a Diesel Contingency Fund is to be established.

2. Diesel Contingency Fund

   This fund is to replace the proposed rate stabilization fund. The fund will operate to smooth customer rate changes and offset forecast diesel costs. Rates and the fund will be determined using the long-term average water expected to be available for generation (105 + 246 GW.h). The initial funding will be determined based upon the funds available as at December 31, 1995. If additional funding becomes available due to other determinations with respect to diesel costs or other utility costs in 1995, the fund will be adjusted. The fund is only to be used for the purposes of stabilizing customer rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.

   The cap on the fund is set at the initial contribution level. If the fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider to customers over the following two years. If the fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and

negative cap levels. The fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.

The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year.

3. Capital Structure

The Companies agreed to back preferred shares out of their capital structure as soon as feasible. As the preferred shares are refunded, the Board is to consider appropriate common equity levels at future GRA hearings, having regard to the most efficient capital structure for the future.

4. Demand-Side Management ("DSM")

The DSM costs identified in the Application are accepted. A working group is to be formed, under terms of reference set by the Board, to make recommendations on energy management, conservation and efficient use programs and rates. The working group will also consider rate methods to encourage industrial self-generation when this will benefit system rates. The working group will also consider joint programs with municipalities. This working group is to be convened within one month following the Decision and a report is to be filed with the Board no later than November 1, 1996.

5. Capital Projects

The proposed capital projects schedule of the Companies is agreed to with the following changes:

- The new diesel plant at Dawson is agreed to.
- The Grum Substation is to be reassessed with ARM and it will only be added if required, and if alternative generation is not feasible. The capital cost of the substation and additional works is to be recovered from ARM so that there will be no impact on other customers.
- Any new transmission, distribution or substation capital requirement for new mines is to be paid for up front by the new mine so that other customers are not burdened with these costs.
- The proposed automatic meter reading program is removed from the 1997 budget and will be reconsidered for inclusion in 1998, or later.

6. Revenue Requirement

The revenue requirement budgets are accepted with the following conditions or changes:

- The sales forecast is to be revised based on the ARM Slurry Pipeline not proceeding.
- The Companies will revise the budgets to reflect the agreed upon long-term average water levels in the Diesel Contingency Fund.
- The Companies are undertaking a revised line loss study which is to be filed before the hearing and will be considered at the hearing.

- The program of additional maintenance for upgradings which is scheduled for completion in 1996 has been reviewed and is agreed to by the parties.
- The escalating charges from YECL's parent company, including potential future customer information system charges, are to be reviewed annually and the company is to seek out least cost alternatives.
- The Companies are to provide actual rate application costs for determination of final rates.

7. Review of Land Transactions

The proposed actions to dispose of certain housing and reconstruct new housing have been reviewed and found to be generally acceptable. The Companies detailed that any revenues from the sale of existing housing has been shown on the books such that it offsets a part of the new housing construction. UCG is to consider this issue further and report back to the Board prior to the hearing if it wishes to pursue further examination of the Companies' land transactions.

8. 1995 Interim Rates

The parties agree that the 1995 Interim Rates should be confirmed as permanent.

9. ARM Interim Rates

The interim rates outstanding for ARM since 1994 are to be confirmed as permanent.

10. Rate Design Issues

The rate design philosophy of the Companies is accepted subject to review at the hearing of Issue No. 11.

YECL and YEC are to commit to provide a preliminary cost assessment of each community in the four zones based upon the same methodology as was used in the 1992 study, updated to use 1995 data. The cost assessment is to be filed with the Board by July 1, 1996.

11. Cost of Service Allocations

The cost of service allocations are to be reviewed at the public hearing along with the appropriate revenue/cost ratios that are to be achieved by various customer classes.

12. Performance Indicators

The Companies have provided performance indicators as required by previous board decisions. Further analysis is to be undertaken to determine meaningful, measurable performance indicators to be used as a tool for management to assess performance in the areas of field generation, transmission, distribution and customer service. A report is to be filed by July 1, 1996. Based on the success of performance indicators during the current test period, the companies may suggest incentives tied to performance indicators for a future GRA.

13. Home Based Businesses

The Companies' policy with respect to home based businesses has been reviewed and found to be acceptable. It is to be filed as an Electric Service Regulation.

14. Electric Service Regulations

The proposed increase in charges for dishonoured cheques and reconnection charges are agreed to as being reasonable.

15. Retention of Monthly Time Sheets for YEC

An annual reporting by March 31 of the following year, is to be filed with the board detailing time spent on YEC versus YDC activities.

16. Filing of Monthly Fuel and Outage Reports

It is agreed that these reports should be replaced by performance indicators as they are developed. Until then quarterly reporting should be adequate for Board and customer reviews.

The companies are to provide an updated filing to the Board showing the revised revenue requirements of this proposed settlement. It may be that the reductions identified will lead to lower rates in 1996. That filing is to be made by Friday, March 15, 1996.

On another matter, the participants considered the UCG complaint with respect to water spillage in 1993 and 1994. The parties were unable to achieve a consensus view to suggest a resolution of the complaint. All intervenors present have agreed that this complaint should be heard at the upcoming public hearing.

In closing, I wish to commend the efforts of the Companies and all intervenors at the workshops and settlement discussions. The extensive efforts made by all parties to understand each issue along with the concerns and interests of other parties has allowed this settlement to come to fruition.

Yours truly,

W.J. Grant

WJG/ssc

MiscCor/YEC•YECL Specific Issues

YUKON ENERGY

JUN 11 1999

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YUKON Y1A 5L7
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EXHIBIT B/8

Our File: 2/5590-08-00
2/8005-07

June 2, 1999

FAXED 99/06/04 Om

Yukon Utilities Board
#19, 10014 1st Avenue
P.O. Box 6070
Whitehorse, Yukon
Y1A 5L7

Attention: Mr. Jim Slater, Board Secretary

Dear Sir:

Re: Diesel Contingency Fund Filings: 1996 to 1998

Please find attached the final report, which details the changes to the Diesel Contingency Fund (DCF) in 1998. Also attached are revised reports for 1996 and 1997. This filing includes a correction to remove fire-related impacts for the period October through December 1997. It also includes, for convenience, copies of relevant DCF tables for The Yukon Electrical Company Limited. We understand that both utilities have agreed on all of the DCF filings for 1996 through 1998.

The 1996/97 Settlement Agreement provided as follows:

> "*The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year.*"

Please find attached the following schedules and tables related to the Diesel Contingency Fund.

1. Summary of 1996 and 1997 DCF calculation revisions
2. DCF continuity schedule: January 1, 1996 - December 31, 1998
3. Revised 1996 and 1997 as well as final 1998 DCF schedules.

The Yukon Utilities Board is requested to approve the 1998 DCF as filed. Also, the Board has not yet approved the DCF filings for 1996 and 1997. It is requested that the Board approve the revised DCF schedules for 1996 and 1997 as final.

As requested by BCUC staff, The Yukon Electrical Company Limited and Yukon Energy Corporation discussed the DCF with BCUC staff on April 13, 1999. The current filing includes background information to explain the operation of the DCF to date (see below). Yukon

Electrical and Yukon Energy will prepare a submission to the Yukon Utilities Board regarding the operation of the DCF for 1999 and beyond.

We note that the Settlement requires that the annual DCF report include a forecast of available water for 1999. YEC will file with the Board, as soon as possible, the annual forecast in this regard for its facilities when this forecast is filed with the Yukon Territorial Water Board.

GENERAL INFORMATION ON DCF OPERATIONS

The DCF was established as at January 1, 1996 in accordance with the 1996/97 Settlement Agreement. Except for material differences specified in the 1996/97 Settlement Agreement, the DCF has been operated on the same basis as the Low Water Reserve Fund (LWRF) previously in place from 1991 through 1995.

Operation of the DCF has been described previously in letters to the Board dated May 6, 1997 and June 24, 1997. For convenience, the following points are summarized:

(a) **The opening balance of the DCF as at January 1, 1996:** The DCF opening balance was $4,040,046 as detailed in response to Question 2 in the June 24, 1997 letter (this earlier letter incorrectly references the date January 1, 1997 rather than January 1, 1996).

(b) **The positive and negative caps on the DCF:** As confirmed in the response to Questions 3 and 4 of the June 24, 1997 letter, the current "cap" on the DCF pursuant to the 1996/97 Settlement Agreement equals the initial contribution (namely, $4,040,046). Further, the current "negative cap" on the DCF pursuant to the 1996/97 Settlement Agreement is -$4,040,046, i.e., the same amount (with the reverse sign) as specified for the initial contribution and the current "cap" for contributions to the DCF. It is understood that all of the DCF terms and conditions are to be reviewed at the next GRA.

(c) **Long-term average non-diesel generation:** The DCF has operated to offset diesel generation cost changes for the WAF system that are caused solely by variances from long-term average levels of WAF system hydro and wind generation. The Negotiated Settlement Package (NSP) stipulates long-term average hydro generation of 105 GW.h (for YEC's Aishihik facility) plus 246 GW.h (for YEC's Whitehorse Rapids facility). The much smaller YEC wind generation (0.3 GW.h) and YECL Fish Lake hydro (10 GW.h), which were not included in the earlier LWRF, have also been included in the DCF operation in accordance with the 1996/97 General Rate Application. It is understood in this regard that the NSP effectively adopted the 1996/97 General Rate Application unless specific mention was made of an issue in the NSP or the Board made a specific direction to alter the NSP.

(d) **Diesel generation saving or excess for YEC:** The calculation of diesel generation saving (or excess) related to non-diesel generation for YEC is calculated to remove the effects of variances in total WAF generation for YEC (expected generation at line 14 for YEC). This reflects procedures previously approved for LWRF operation, based on Decision 1992-1 and the 1993/94 GRA response to WHSE-YEC/YECL-33(a). When the

LWRF was last calculated with diesel on the margin (1992), it was calculated on the basis of annual numbers without attempting to assess minimum diesel requirements (at line 10 in the YEC DCF) on either a monthly or annual basis.

(e) **Diesel cost savings or excess for YEC:** The YEC diesel cost savings or excess are calculated based on the approved forecasts for 1996 for YEC WAF diesel generation per kW.h costs, assuming standard efficiency at 3.71 kWh/litre of fuel and YEC average WAF diesel fuel price forecast at approximately 29.60 cents per litre. Variable O&M costs per kW.h for diesel generation are assumed at 1.6 cents per litre, as assumed for the approved 1996/97 GRA retail run-out rate calculations for WAF. These procedures in general reflect the procedures previously approved for operation of the LWRF.

(f) **DCF calculations for YECL Fish Lake:** Imputed diesel generation savings or excess related to the YECL Fish Lake hydro facility are calculated as follows:

- actual Fish Lake generation is compared with the long-term average Fish Lake generation forecast per the 1996/97 GRA filing
- imputed diesel cost savings or excess for YECL are calculated assuming the YEC WAF diesel generation standard efficiency and fuel prices are described above.

(g) **Interest calculations:** The NSP provided for interest income or expense to be calculated for the DCF based on stipulated provisions. No similar provisions existed for the LWRF.

(h) **DCF suspended when diesel is not on the margin:** The evidence provided to the Board in the NSP, and during the 1996 GRA hearing, specified that the DCF was to be only used for offsetting diesel generation, and that the DCF would only be active when diesel is on the margin. In this regard, the 1996 evidence presumed that diesel generation is not on the margin for the WAF system when the Faro mine is closed; this presumption assumed the availability of normal long-term hydro generation capability.

ADJUSTMENTS TO 1996 AND 1997 DCF FILINGS

The 1996 and 1997 DCF filings as previously provided to the Board generally reflected principles and practices as described above.

The latest filing with the Board, however, includes various adjustments to the YEC-related numbers as documented in the attached table titled "Summary of 1996 and 1997 DCF Revisions". These adjustments, in summary, increase the DCF December 31, 1997 balance as previously reported by $436,923.26. The major changes are commented on briefly below:

- **Interest calculations:** Adoption of standard monthly interest income calculation procedures, starting January 1, 1996. This includes adjustment of entries as required for the initial opening balance, and other subsequent payments, to reflect the proper timing for these transactions.

- **Line 10 correction – determination as to whether diesel is on the margin:** Correction was made to remove any "minimum required diesel generation" assumption for YEC at line 10 of the DCF table. This line is now used solely to specify whether diesel generation is on the margin for YEC in each month (assuming long-term hydro capability). This determination affects both the YEC DCF and the YECL DCF (at line 3). As noted, and as previously reported, diesel was not on the margin from June 1 to October 31, 1997. During 1998, diesel was not on the margin from February 1 to December 31, 1998.

- **Procedures to assess diesel on margin issues when Faro mine closed:** Experience since the Faro mine closure in 1998 has re-affirmed that diesel generation can in fact go back on the margin for the YEC WAF system during certain months, under specific "non-normal" conditions, even though the Faro mine is closed. The line 10 determination regarding "diesel on the margin" is made on the basis of WAF total required generation and normal long-term hydro capability. In order to provide for some minor diesel generation that may occur for voltage stability or peaking purposes, without being related to variances from long-term hydro capability, the DCF is not activated in any month when diesel is not on the margin (per line 10) and YEC diesel generation does not exceed 250,000 kW.h for the month. This adjustment at line 16 of the YEC DCF schedule then allows for the DCF to be activated for actual diesel use during months when the Faro mine is closed and diesel generation is still required in excess of 250,000 kW.h due specifically to below-normal YEC WAF hydro capability. In practice, diesel generation remained less than 250,000 kW.h in all 1997 and 1998 months when diesel was not on the margin (see the line 10 correction above), except for October 1997 and July 1998 – and these exceptions related to YEC fire impacts as described below.

- **Fire-related impacts:** The DCF has been adjusted in 1997 and 1998 to remove impacts caused by fires affecting YEC's operations. Because of the importance of these adjustments, they are explicitly reviewed below in more detail. These adjustments affect three months in 1997 (October to December inclusive).

- **Other minor adjustments:** As noted in the attached material, various other minor adjustments have been made, including corrections to reflect actual YEC generation during the final three months of 1997 and corrections regarding the YUB 1997-7 drawdown amounts.

DCF ADJUSTMENTS TO ADDRESS YEC FIRE-RELATED IMPACTS

Actual diesel generation for YEC was required during three months of 1997 (October through December) due to reduced hydro capability caused by the October 1997 fire at the Whitehorse Rapids hydro facility. These fire impacts have been estimated for each month in the attached tables (see note 5 to the first table). Under the terms of YEC's insurance policy there is a 30-day waiting period during which the cost of any fire-related diesel generation is not claimable. Accordingly, the DCF drawdown for October and November 1997 due to the fire was charged to the YEC Reserve for Injuries and Damages. The DCF drawdown for December 1997 has been charged to the fire insurance claim. (It is noted that YEC's last filing on this fire was last June 1998 in response to UCG-YEC-2-7, which included a letter to the Board dated June 26, 1998. This letter said that costs incurred for extra diesel generation in 1997 have been met in their

entirety either through use of the DCF, during the non-insured period, or thereafter through insurance coverage. It also noted that the property loss deductible was charged in 1997 through YEC's reserve for injuries and damages – but no mention was made of diesel generation being charged to this account during the non-insurance period. This change from what was previously reported on fire issues is beneficial to the DCF.)

During July 1998, YEC experienced a major forest fire that shut down the Faro transmission line for some time forcing YEC to generate diesel from the Faro plant. This diesel generation impact had nothing to do with hydro generation capability, and thus cannot be charged to the DCF. As noted in the attached table titled "DCF Continuity Schedule 1996-1998", this forest fire impact on the DCF of $58,182.00 for July 1998 has all been charged to the Reserve for Injuries and Damages.

If you have any questions, please give me a call.

Sincerely,

Rob McWilliam
President & Chief Executive Officer

/dm
Attachments

c John Carroll, General Manager, The Yukon Electrical Company Limited
Cam Osler, InterGroup Consultants Ltd.

FAXED 99/06/04 DM

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Please find attached the following draft schedules and tables related to the Diesel Contingency Fund as filed jointly by Yukon Energy Corporation and The Yukon Electrical Company Limited.

1 Summary of 1996 and 1997 DCF calculation revisions

2 DCF continuity schedule January 1, 1996 - December 31, 1998

3 Revised 1996 and 1997 as well as 1998 DCF calculation schedules

These schedules were prepared by YEC based on YEC's understanding and interpretation of relevant board orders and the intent of the DCF. YECL's understanding and interpretation of relevant board orders and the intent of the DCF may differ from YEC's. These schedules will be reviewed by Barry McKinley of BCUC with YEC and YECL during the week of April 12, 1999.

SUMMARY OF 1996 AND 1997 DCF REVISIONS

		As Filed	Revised	Change	Reference
1996	Opening balance	500,000.00	4,040,046.00	3,540,046.00	1
	Additions (Reductions)	3,540,046.00		(3,540,046.00)	1
	YEC Buildup (Drawdown)	(1,034,266.13)	(1,131,866.82)	(97,600.69)	2
	YECL Buildup (Drawdown)	(325,803.92)	(325,803.92)	-	
	Interest and service charges	148,358.17	188,741.49	40,383.32	3
	Closing balance	2,828,334.12	2,771,116.75	(57,217.37)	
1997	Opening balance	2,828,334.12	2,771,116.75	(57,217.37)	
	YUB 1997/7 Drawdown	(348,992.80)	(346,275.62)	2,717.18	4
	YEC Fire Impact Buildup	-	516,167.23	516,167.23	5
	YEC Buildup (Drawdown)	23,279.99	(13,253.20)	(36,533.19)	6
	YECL Buildup (Drawdown)	(177,878.50)	(177,878.50)	-	
	Interest and service charges	73,343.31	85,132.72	11,789.41	3
	Closing balance	2,398,086.12	2,835,009.38	436,923.26	

1 The previously filed schedule, for 1996, showed the YUB approved deposit of $3,540,046.00 as an addition in March and also included imputed interest calculated retroactively to January 1, 1996. In the revised schedule the $3,540,046.00 is included as part of the beginning balance of the DCF. Interest on this amount is calculated on a monthly basis from January 1, 1996.

2 During 1997, it was noted that the DCF was being incorrectly calculated by manually inputting at Line 10 "minimum required diesel generation" of 635,000 kW.h per month for YEC. Line 10 has been adjusted for 1996 and 1997 to deal solely with specifying whether diesel generation is on the margin for YEC each month (assuming long-term average Hydro capability). If diesel remains on the margin throughout the year, the final annual drawdown or build-up is in effect calculated on the basis of annual rather than monthly numbers. In the event that diesel is not on the margin for YEC's WAF generation during any month (assuming long-term Hydro capability), diesel savings (excess) equal zero at Line 16 for YEC (and at line 3 for YECL) in any month when diesel generation is not on the margin for YEC incremental generation. Diesel is not on the margin when so indicated at line 10 for any month (based on long-term Hydro capability), provided that YEC diesel generation does not exceed 250,000 KW.h in that month. This procedure allows for some minor diesel generation that may occur for voltage stability or peaking purposes, without being related to variances from long-term Hydro capability. The DCF was specifically approved to deal with diesel generation related solely to variances from long-term Hydro capability.

3 The change in interest is a result of calculating interest on the DCF balance on a monthly basis after the DCF schedules were adjusted for the various noted items.

4 The YUB 1997/7 Drawdown was incorrectly stated in the original 1997 filing.

5 The 1997 DCF calculations have been revised to reflect the reduced Hydro capability resulting from the loss of Hydro generating units in the fire of October, 1997. These revisions are outlined in the following Tables 1, 2 and 3.

6 This difference is mainly due to diesel generation for October being in excess of 250,000 KWh when diesel was off the margin (refer to note 2 for the rationale). The difference is also partially due to the fact that the filed 1997 DCF schedule included estimates for generation for the last three months of 1997 as a result of the fire. The revised 1997 DCF schedul has been revised using actual generation figures.

Table 1: DCF - Including Fire Related Diesel Generation:

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	25,580,480	27,661,195	33,706,072
1a	Wind	Manual Input	17,840	6,530	21,370
2	Diesel	Manual Input	357,870	7,140,520	6,747,710
3	Total	Line 1 + Line 2	25,956,200	34,788,245	40,475,152
	Forecast Generation - Mwh				
4	Hydro	Manual Input	32,502,676	30,765,226	29,775,136
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	36,144,441	38,790,457	41,656,346
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	(6,934,346)	(3,137,501)	3,922,304
8	Diesel	Line 2 - Line 5	(3,253,895)	(854,711)	(5,103,498)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,181,194)
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1 = yes, 0 = no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,194)
13		Line 11 + Line 12	(6,576,476)	4,003,019	10,670,014
14	Expected generation	Line 13 if Ln 10=1 other = 0	-	4,003,019	10,670,014
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	357,870	7,140,520	6,747,710
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 > 250,000)	(357,870)	(3,137,501)	3,922,304
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	(96,461)	(845,688)	1,057,229
19	Standard price($ per litre)	Manual Input	0.2860	0.2860	0.2860
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs($ per litre)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 16 x Line 19	(26,556.10)	(250,355.87)	312,978.71
22	YEC Variable O&M costs	Line 20 x Line 16	(5,725.92)	(50,200.02)	62,766.88
23	YEC buildup (drawdown)	Line 21+22	(34,282.02)	(300,555.68)	375,735.57
24	YECL buildup (drawdown)	See YECL Table	0	(21,445.42)	(13,233.68)
25	Total buildup (drawdown)	Line 23 +24	(34,282.02)	(322,001.11)	362,501.89

Table 2: DCF - Excluding Fire Related Diesel Generation:

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	25,840,480	31,500,795	34,888,872
1a	Wind	Manual Input	17,840	6,530	21,370
2	Diesel	Manual Input	97,870	3,290,920	5,566,910
3	Total	Line 1 + Line 2	25,956,200	34,798,245	40,476,152
	Forecast Generation - Mwh				
4	Hydro	Manual Input	32,502,876	30,765,226	29,775,138
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	36,144,441	38,790,457	41,656,346
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	(6,674,346)	712,099	5,103,104
8	Diesel	Line 2 - Line 5	(3,513,895)	(4,704,311)	(6,284,298)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,181,194)
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	*Diesel on margin (1 – yes, 0 – no)*	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,194)
13		Line 11 + Line 12	(6,576,476)	4,003,019	10,670,014
14	*Expected generation*	Line 13 if Ln 10 = 1	-	4,003,019	10,670,014
		other = 0			
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	97,870	3,290,920	5,566,910
16	Diesel savings (excess) (Mwh)	Line 14-Line 15	-	712,099	5,103,104
		(max line 14a if Ln 10 = 1; otherwise = 0, unless Ln 15 > 250,000)			
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	-	191,940	1,375,500
19	Standard price($ per litre)	Manual Input	0.2960	0.2960	0.2960
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs($ per litre)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 18 x Line 19	-	56,821.66	407,200.19
22	YEC Variable O&M costs	Line 20 x Line 16	-	11,393.58	81,649.66
23	YEC buildup (drawdown)	Line 21+22	-	68,215.24	488,849.85
24	YECL buildup (drawdown)	See YECL Table	-	(21,445.42)	(13,233.58)
25	Total buildup (drawdown)	Line 23 +24	-	46,769.82	475,616.27

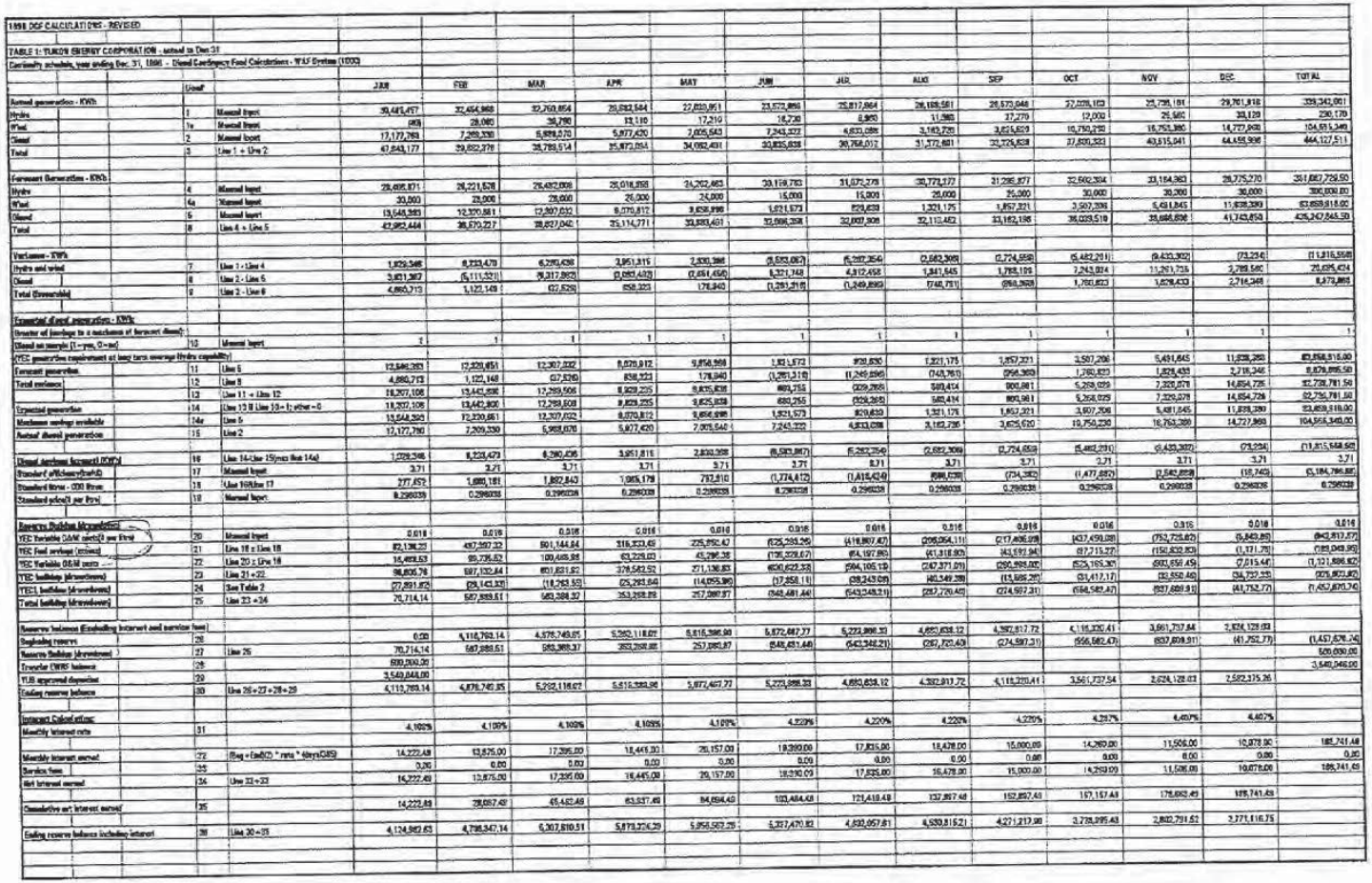
Table 3: DCF - Fire Impact

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	260,000	3,849,600	1,180,800
1a	Wind	Manual Input	0	0	0
2	Diesel	Manual Input	(260,000)	(3,849,600)	(1,180,800)
3	Total	Line 1 + Line 2	0	0	0
	Forecast Generation - Mwh				
4	Hydro	Manual Input	0	0	0
4a	Wind	Manual Input	0	0	0
5	Diesel	Manual Input	0	0	0
6	Total	Line 4 + Line 5	0	0	0
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	260,000	3,849,600	1,180,800
8	Diesel	Line 2 - Line 5	(260,000)	(3,849,600)	(1,180,800)
9	Total (favourable)	Line 3 - Line 6	0	0	0
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1 = yes, 0 = no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	0	0	0
12	Total variance	Line 8	0	0	0
13		Line 11 + Line 12	0	0	0
14	Expected generation	Line 13 if Ln 10 = 1	0	0	0
		other = 0			
14a	Maximum savings available	Line 5	0	0	0
15	**Actual diesel generation**	Line 2	(260,000)	(3,849,600)	(1,180,800)
16	**Diesel savings (excess) (Mwh)**	Line 14-Line 15	357,870	3,849,600	1,180,800
		(max line 14a if Ln 10 = 1; otherwise = 0, unless Ln 15 > 250,000)			
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	96,461	1,037,628	318,275
19	Standard price($ per litre)	Manual Input	0.2860		
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs($ per litre)	Manual Input	0.018	0.016	0.016
21	YEC Fuel savings (excess)	Line 18 x Line 19	28,556.10	307,177.33	94,221.48
22	YEC Variable O&M costs	Line 20 x Line 16	5,725.92	61,593.60	18,892.80
23	YEC buildup (drawdown)	Line 21+22	34,282.02	368,770.93	113,114.28
24	YECL buildup (drawdown)	See YECL Table	-	-	-
25	Total buildup (drawdown)	Line 23 +24	34,282.02	368,770.93	113,114.28

Under the terms of the insurance policy there is a 30 day waiting period during which the cost of any fire related diesel generation is not claimable. Accordingly the DCF drawdown for October and November was charged to the Reserve for Injuries and Damages. The DCF drawdown for December has been charged to the fire insurance claim.

DCF CONTINUITY SCHEDULE 1996 - 1998

1996	Opening balance (Old LWRF balance)	500,000.00	
	YUB approved deposites	3,540,046.00	4,040,046.00
	YEC withdrawals - Fuel	(942,817.87)	
	YEC withdrawals - O&M	(189,048.95)	(1,131,866.82)
	YECL withdrawals		(325,803.92)
	Interest Income/Service Fees		188,741.49
	Ending Balance		2,771,116.75
1997	*Opening balance*		2,771,116.75
	YUB 1997/7 Drawdown		(346,275.62)
	YEC Fire Impact - Charged to the Reserve for Injuries and Damages		403,052.95
	YEC Fire Impact - Charged to the fire insurance claim		113,114.28
	YEC drawdown - Fuel	(11,039.59)	
	YEC drawdown - O&M	(2,213.61)	(13,253.20)
	YECL withdrawals		(177,878.50)
	Interest Income/Service Fees		85,132.72
	Ending Balance		2,835,009.38
1998	*Opening balance*		2,835,009.38
	DCF Rider Drawdown		(1,283,018.76)
	Forest Fire Impact - Charged to the Reserve for Injuries and Damages		58,182.00
	YEC buildup - Fuel	399,743.47	
	YEC buildup - O&M	80,154.48	479,897.95
	YECL *Net withdrawals*		(12,958.18)
	Interest Income/Service Fees		158,646.58
	Ending Balance		2,235,758.97



1998 DCF CALCULATIONS - REVISED

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31

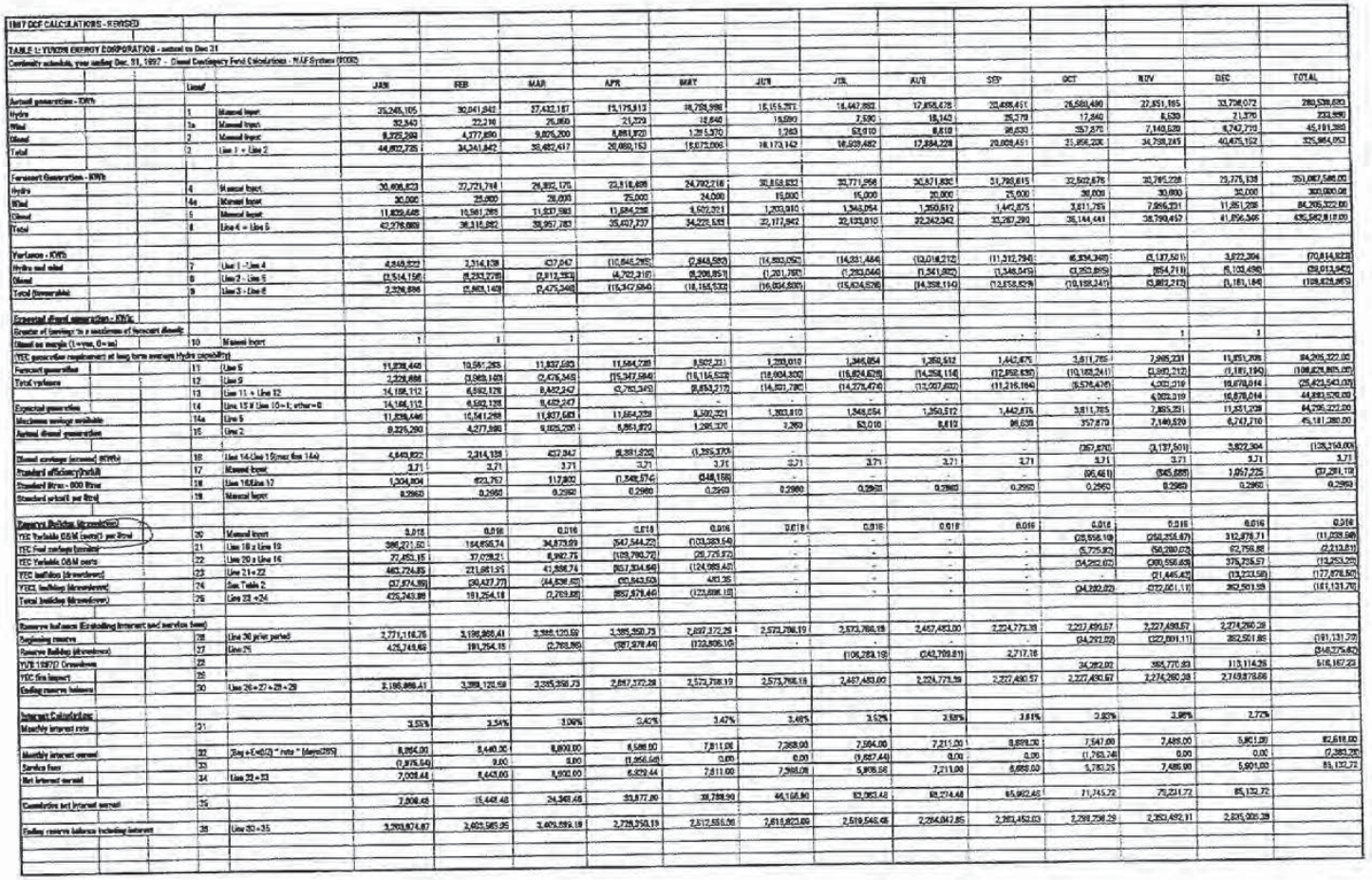
Continuity schedule, year ending Dec. 31, 1998 - Diesel Contingency Fund Calculations - YLF System (1000)

	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual input	30,445,477	32,454,968	32,760,854	29,882,544	22,830,951	23,572,866	25,817,864	26,169,581	26,573,046	27,078,103	25,796,191	29,701,918	339,342,063
Wind	1a	Manual input	969	28,080	30,790	13,116	17,219	16,720	8,950	11,965	27,279	12,000	26,560	33,129	230,179
Diesel	2	Manual input	17,177,783	7,269,330	5,899,570	5,977,420	2,005,643	7,243,322	4,833,088	3,163,735	3,625,620	10,750,236	18,763,380	14,727,993	104,551,340
Total	3	Line 1 + Line 2	47,643,177	39,822,378	38,789,514	35,873,080	24,852,431	30,832,908	30,659,902	31,377,881	30,226,945	37,840,339	40,615,041	44,455,936	444,127,511
Forecast Generation - KWh															
Hydro	4	Manual input	28,695,871	26,221,578	25,482,606	26,016,258	24,202,463	23,159,783	31,072,278	30,771,177	31,295,977	32,592,304	33,154,363	29,775,270	351,667,729.50
Wind	4a	Manual input	30,000	28,000	28,000	26,000	24,000	15,000	15,000	25,000	25,000	30,000	30,000	30,000	306,000.00
Diesel	5	Manual input	13,648,393	12,370,661	12,307,032	8,070,812	3,656,990	1,821,573	829,639	1,321,175	1,857,321	2,507,706	5,481,645	11,838,280	83,859,818.00
Total	6	Line 4 + Line 5	42,374,264	38,620,237	37,817,638	34,113,071	27,883,453	24,996,356	31,916,917	32,117,352	33,178,298	35,130,010	38,666,008	41,643,550	435,347,545.50
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	1,809,548	6,233,470	6,280,438	3,951,816	2,630,366	(5,553,087)	(5,287,364)	(2,662,369)	(2,724,658)	(5,462,201)	(9,433,302)	(73,254)	(11,816,356)
Diesel	8	Line 2 - Line 5	3,821,367	(5,111,321)	(6,317,862)	(2,093,392)	(2,651,450)	5,321,749	4,012,450	1,841,545	1,768,199	7,243,024	13,281,735	2,789,580	20,695,424
Total (Unavailable)	9	Line 2 - Line 6	4,865,713	1,122,149	(37,529)	858,223	178,840	(1,281,319)	(1,249,896)	(740,751)	956,928	1,780,823	3,848,433	2,716,346	8,879,865
Forecast diesel generation - KWh															
(number of shortage in a maximum of forecast diesel)															
Diesel as margin (1 = yes, 0 = no)	10	Manual input	1	1	1	1	1	1	1	1	1	1	1	1	1
YEC generation requirement at long term average (hydro capability)															
Forecast generation	11	Line 5	13,648,393	12,370,661	12,307,032	8,070,812	3,656,990	1,821,573	829,639	1,321,175	1,857,321	2,507,706	5,481,645	11,838,280	83,859,818.00
Total variance	12	Line 8	4,865,713	1,122,149	(37,529)	858,223	178,840	(1,281,319)	(1,249,896)	(740,751)	956,928	1,780,823	3,848,433	2,716,346	8,879,865.50
	13	Line 11 + Line 12	18,257,106	13,492,809	12,269,503	8,929,035	3,835,830	539,255	(420,258)	580,424	900,661	4,288,529	7,330,078	14,554,726	92,736,781.50
Expected generation	14	Line 13 if Line 13 > 1; other = 0	18,257,106	13,492,809	12,269,503	8,929,035	3,835,830	539,255	(420,258)	580,424	900,661	4,288,529	7,330,078	14,554,726	92,736,781.50
Maximum energy available	14a	Line 5	13,648,393	12,370,661	12,307,032	8,070,812	3,656,990	1,821,573	829,639	1,321,175	1,857,321	2,507,706	5,481,645	11,838,280	83,859,818.00
Actual diesel generation	15	Line 2	17,177,780	7,269,330	5,969,570	5,977,420	2,005,643	7,243,322	4,833,088	3,163,735	3,625,620	10,750,236	18,763,380	14,727,993	104,566,340.00
Diesel Surplus Account (DSA)	16	Line 14-Line 15(yes line 14a)	1,079,386	6,223,479	6,280,436	3,951,816	2,830,366	(5,553,087)	(5,262,354)	(2,662,369)	(2,724,659)	(5,462,201)	(9,433,302)	(73,254)	(13,815,568.50)
Standard efficiency (kwh/l)	17	Manual input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/line 17	277,652	1,680,181	1,692,843	1,065,178	762,810	(1,774,412)	(1,418,424)	(698,539)	(734,382)	(1,477,682)	(2,542,859)	(19,742)	(5,184,796.86)
Standard price/l per litre	19	Manual input	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038	0.298038
Reserve Holdback Mechanism															
YEC Variable O&M rate/kWh per litre	20	Manual input	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
YEC fuel savings (actual)	21	Line 18 x Line 19	82,736.25	497,597.32	501,144.84	316,533.45	225,952.47	(525,295.26)	(419,897.47)	(206,864.11)	(217,496.08)	(437,499.08)	(753,725.67)	(5,843.85)	(842,813.57)
YEC fuel savings (limited)	22	Line 20 x Line 18	16,469.53	99,736.52	100,465.95	63,228.03	45,296.38	(105,209.67)	(84,197.80)	(41,318.80)	(43,591.94)	(87,715.27)	(150,832.83)	(1,171.70)	(169,049.95)
YEC Variable O&M rate	23	Line 21 - Line 22	66,266.72	397,860.80	401,631.92	253,305.42	180,655.92	(420,085.59)	(335,699.67)	(165,545.31)	(173,904.14)	(349,783.81)	(602,892.84)	(4,671.75)	(673,763.40)
YEC holdback (drawdown)	24	See Table 2	(27,891.82)	(29,143.33)	(18,263.53)	(25,293.64)	(14,055.96)	(17,858.11)	(38,243.09)	(40,549.39)	(13,586.26)	(31,417.17)	(32,550.46)	(34,737.33)	(325,805.85)
YEC holdback (drawdown)	25	Line 23 +24	38,374.14	367,889.51	383,384.37	353,268.89	257,080.87	(548,481.44)	(543,248.21)	(287,720.43)	(274,597.31)	(584,585.47)	(937,689.91)	(41,752.77)	(1,457,676.24)
Reserve balance (including interest and service fees)															
Beginning reserve	26		0.00	4,116,793.14	4,575,749.65	5,282,118.67	5,816,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.54	2,624,128.03	
Reserve holdback (drawdown)	27	Line 25	38,374.14	367,889.51	383,384.37	353,268.89	257,080.87	(548,481.44)	(543,248.21)	(287,720.43)	(274,597.31)	(584,585.47)	(937,689.91)	(41,752.77)	(1,457,676.24)
Transfer CWRS balance	28		800,000.00												800,000.00
YUB approved deposits	29		3,540,044.00												3,540,044.00
Ending reserve balance	30	Line 26 + 27 + 28 + 29	4,116,793.14	4,676,745.85	5,292,118.67	5,816,386.90	5,872,467.77	5,223,986.33	4,680,638.12	4,392,917.72	4,118,320.41	3,561,737.54	2,624,128.03	2,582,375.26	
Interest Calculation:															
Monthly interest rate	31		4.100%	4.100%	4.100%	4.100%	4.100%	4.220%	4.220%	4.220%	4.220%	4.267%	4.407%	4.407%	
Monthly interest earned	32	(Beg + End)/2 * rate * days/365	14,222.48	13,875.00	17,395.00	18,445.00	20,157.00	18,360.00	17,835.00	15,478.00	15,000.00	14,260.00	11,506.00	10,878.00	186,741.48
Service fees	33		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned	34	Line 32 + 33	14,222.48	13,875.00	17,395.00	18,445.00	20,157.00	18,360.00	17,835.00	15,478.00	15,000.00	14,260.00	11,506.00	10,878.00	186,741.48
Cumulative net interest earned	35		14,222.48	28,097.48	45,492.48	63,937.48	84,094.48	102,454.48	120,289.48	135,767.48	150,767.48	165,027.48	176,533.48	186,741.48	
Ending reserve balance including interest	36	Line 30 + 35	4,124,943.63	4,788,347.14	5,307,810.51	5,873,274.29	5,956,562.26	5,337,470.82	4,800,927.61	4,530,815.21	4,271,217.90	3,739,995.48	2,800,791.51	2,771,116.75	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec.31

Continuity schedule, year ending Dec. 31, 1998 - Diesel Contingency Fund Calculations - WAF System (000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - MWh															
Hydro	1	Manual input	565,901	646,130	672,850	559,560	651,514	651,805	475,836	454,234	722,943	518,833	465,200	478,226	6,842,781
Forecast generation - MWh															
Hydro	2	Manual input	857,081	850,356	783,803	618,580	788,242	808,256	835,598	875,441	865,896	847,899	819,499	840,944	10,041,644
Variance - MWh															
Hydro	3	Line 1 - Line 2	(291,180)	(204,226)	(110,953)	(254,039)	(140,728)	(156,451)	(439,762)	(421,207)	(141,953)	(329,065)	(354,439)	(362,624)	(3,401,063)
Purchased power shortage (cost) - MWh	4	Line 3 if closed on surplus see Table 1, line 10b	(291,180.00)	(204,226.00)	(110,953.00)	(254,039.00)	(140,728.00)	(156,451.00)	(439,980.00)	(421,207.00)	(141,953.00)	(329,065.00)	(354,439.00)	(362,624.00)	(3,401,063.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	(78,480)	(62,022)	(51,359)	(71,179)	(39,659)	(52,751)	(118,427)	(113,532)	(38,263)	(88,699)	(95,539)	(97,742)	(916,726.57)
Standard price per litre	19	YEC - Line 19	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (costs) - $000	20	Line 18 x Line 19	(22,333.09)	(14,775.71)	(15,213.10)	(21,069.82)	(11,738.30)	(14,876.21)	(32,688.53)	(33,610.58)	(11,327.99)	(26,168.76)	(28,278.82)	(28,935.36)	(271,386.97)
Variable O&M costs - $000	21	YEC Line 21 x Line 4	(4,858.55)	(4,867.67)	(3,958.45)	(4,224.67)	(2,247.88)	(2,962.90)	(6,654.56)	(6,729.31)	(2,271.38)	(5,247.41)	(5,670.64)	(5,901.80)	(54,417.06)
Reserve buildup (drawdown) - $000	22	Line 20 + Line 21	(27,891.63)	(28,143.23)	(18,263.55)	(25,293.64)	(14,055.96)	(17,858.11)	(39,343.09)	(40,349.29)	(13,599.22)	(31,417.17)	(33,958.46)	(34,737.39)	(325,853.92)
Opening reserve	23	Line 25 prior period	(225.80)	(28,217.43)	(57,360.75)	(75,624.30)	(100,917.94)	(114,973.90)	(132,832.01)	(172,075.09)	(212,425.46)	(226,024.75)	(257,441.92)	(291,392.38)	
Cumulative reserve balance - $000	25	Line 22 + Line 23	(28,217.43)	(57,360.75)	(75,624.30)	(100,917.94)	(114,973.90)	(132,832.01)	(172,075.09)	(212,425.46)	(226,024.75)	(257,441.92)	(291,392.38)	(326,129.77)	



1997 DCF CALCULATIONS - REVISED															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1997 - Diesel Contingency Fund Calculations - MAF System (000S)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	35,249,105	30,041,842	27,432,187	15,175,813	16,759,988	16,155,781	16,447,882	17,856,676	20,488,451	26,589,490	27,851,165	33,736,072	280,528,693
Wind	1a	Manual Input	52,343	22,216	26,866	21,229	18,640	16,590	7,590	18,143	25,279	17,840	8,539	21,370	232,990
Diesel	2	Manual Input	8,725,280	4,277,890	9,026,200	8,881,820	1,295,370	1,263	52,010	8,810	96,630	357,870	7,149,529	6,747,710	45,181,380
Total	3	Line 1 + Line 2	44,802,735	34,341,842	36,482,417	26,080,153	18,073,998	16,173,142	16,508,482	17,884,228	20,609,451	31,956,206	34,708,245	40,475,152	325,964,063
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,823	27,721,744	26,892,175	23,818,698	24,792,218	30,858,832	32,771,958	30,871,835	31,798,815	32,502,876	30,795,238	25,775,136	351,087,546.00
Hydro	4a	Manual Input	30,000	25,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Wind	5	Manual Input	11,809,648	10,561,265	11,837,583	11,584,238	9,502,701	1,293,910	1,345,054	1,350,512	1,442,875	3,811,785	7,965,231	11,851,208	84,295,322.00
Total	6	Line 4 + Line 5	42,276,669	38,315,882	38,957,783	35,427,737	34,225,519	32,177,842	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,856,345	435,682,868.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	4,849,622	2,314,139	437,847	(10,845,295)	(2,848,590)	(14,883,052)	(14,331,484)	(13,016,212)	(11,312,794)	(6,334,349)	(5,137,501)	3,872,364	(70,814,823)
Diesel	8	Line 2 - Line 5	(3,514,156)	(6,283,278)	(2,812,783)	(4,702,317)	(8,206,851)	(1,291,780)	(1,293,046)	(1,341,832)	(1,346,045)	(3,253,915)	(854,711)	(5,103,458)	(39,013,943)
Total Generation	9	Line 3 - Line 6	2,326,886	(3,973,140)	(3,475,366)	(15,547,584)	(18,155,533)	(16,054,831)	(15,624,529)	(14,358,114)	(12,658,839)	(10,188,241)	(5,992,212)	(1,181,184)	(109,828,965)
Seasonal diesel generation - KWh															
Source of Savings: is a maximum of forecast diesel															
Diesel as margin (1=yes, 0=no)	10	Manual Input	1	1	1	-	-	-	-	-	-	-	1	1	
YEC generation requirement at long term average Hydro capability															
Forecast generation	11	Line 6	11,838,448	10,561,265	11,837,583	11,584,238	9,502,701	1,293,910	1,345,054	1,350,512	1,442,875	3,811,785	7,965,231	11,851,208	84,295,322.00
Total variance	12	Line 9	2,326,886	(3,973,140)	(3,475,366)	(15,547,584)	(18,155,533)	(16,054,831)	(15,624,529)	(14,358,114)	(12,658,839)	(10,188,241)	(5,992,212)	(1,181,184)	(109,828,965.00)
	13	Line 11 + Line 12	14,165,112	6,592,125	8,482,247	(3,763,346)	(8,652,832)	(14,761,780)	(14,279,474)	(13,007,602)	(11,216,164)	(6,376,476)	1,972,519	10,670,024	(25,533,643.00)
Expected generation	14	Line 13 if Line 10=1; other=0	14,165,112	6,592,125	8,482,247	-	-	-	-	-	-	-	1,972,519	10,670,024	41,881,926.00
Maximum savings available	14a	Line 8	11,838,448	10,561,265	11,837,583	11,584,238	9,502,701	1,293,910	1,345,054	1,350,512	1,442,875	3,811,785	7,965,231	11,851,208	84,295,322.00
Actual diesel generation	15	Line 2	8,725,280	4,277,890	9,026,200	8,881,820	1,295,370	1,263	52,010	8,810	96,630	357,870	7,149,529	6,747,710	45,181,380.00
Diesel savings (crossed) (KWh)	16	Line 14-Line 15(max line 14a)	4,849,622	2,314,139	437,847	(8,881,820)	(1,295,370)	-	-	-	-	(357,870)	(5,137,501)	3,872,364	(139,169.00)
Standard efficiency (kWh)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	1,304,804	623,757	117,802	(1,548,574)	(348,159)	-	-	-	-	(96,461)	(845,885)	1,057,225	(37,291.19)
Standard price/ litre	19	Manual Input	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Reserve Holiday (drawdown)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Variable O&M (cents) per litre	21	Line 18 x Line 19	386,271.50	184,958.74	34,873.09	(547,544.22)	(103,383.54)	-	-	-	-	(28,558.10)	(250,255.67)	312,878.71	(11,035.98)
YEC Fuel savings (costs)	22	Line 20 x Line 16	22,453.15	37,078.21	6,992.75	(109,780.72)	(26,725.92)	-	-	-	-	(5,775.92)	(50,200.02)	62,756.88	(2,213.51)
YEC Variable O&M costs	23	Line 21+22	463,724.65	221,981.95	41,865.74	(657,324.94)	(124,089.46)	-	-	-	-	(34,282.02)	(300,555.69)	375,735.57	(13,253.29)
YEC holiday (drawdown)	24	See Table 2	(37,874.89)	(30,427.27)	(44,696.82)	(30,843.53)	481.35	-	-	-	-	-	(21,445.42)	(13,223.58)	(177,976.56)
YEC holiday (drawdown)	25	Line 23 +24	425,849.88	191,554.18	(2,769.88)	(688,678.46)	(123,608.10)	-	-	-	-	(34,282.02)	(322,001.11)	362,511.99	(191,131.70)
Total holiday (drawdown)															
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 30 prior period	2,771,116.76	3,196,966.41	3,388,120.59	3,385,350.73	2,697,372.26	2,573,788.18	2,573,788.18	2,467,483.00	2,224,773.38	2,227,490.57	2,227,490.57	2,274,260.38	
Reserve Holiday (drawdown)	27	Line 25	425,849.88	191,554.18	(2,769.88)	(687,678.46)	(123,608.10)	-	-	-	-	(34,282.02)	(322,001.11)	362,511.99	(191,131.70)
	28								(106,288.18)	(242,709.62)	2,717.18				(346,280.62)
YUK 1997D Drawdown	29											34,282.02	355,770.93	113,114.28	518,167.23
YEC fin impact	30														
Ending reserve balance		Line 26+27+28+29	3,196,966.41	3,388,120.59	3,385,350.73	2,697,372.26	2,573,788.18	2,573,788.18	2,467,483.00	2,224,773.38	2,227,490.57	2,227,490.57	2,274,260.38	2,749,878.66	
Interest Calculation															
Monthly interest rate	31		3.53%	3.54%	3.00%	3.42%	3.47%	3.48%	3.52%	3.58%	3.61%	3.83%	3.98%	2.72%	
Monthly interest earned	32	[Beg + End)/2 * rate * (days/365)	8,864.00	8,440.30	8,800.00	8,588.80	7,811.06	7,368.00	7,564.00	7,211.00	8,888.20	7,547.00	7,488.00	5,901.20	92,616.00
Service fees	33		(1,975.54)	0.00	0.00	(1,956.68)	0.00	0.00	(1,687.44)	0.00	0.00	(1,783.24)	0.00	0.00	(7,383.20)
Net interest earned	34	Line 32 + 33	7,008.46	8,440.30	8,800.00	6,632.44	7,811.06	7,368.00	5,908.56	7,211.00	8,888.20	5,763.76	7,488.00	5,901.20	85,132.72
Cumulative net interest earned	35		7,008.46	15,448.46	24,248.46	30,877.90	38,688.96	46,056.96	51,965.52	59,176.52	65,952.45	71,745.72	79,233.72	85,132.72	
Ending reserve balance including interest	36	Line 30+35	3,203,974.87	3,403,569.05	3,409,599.19	2,728,250.19	2,612,556.06	2,619,823.69	2,519,548.08	2,284,047.85	2,293,452.63	2,298,736.29	2,353,492.11	2,835,009.39	

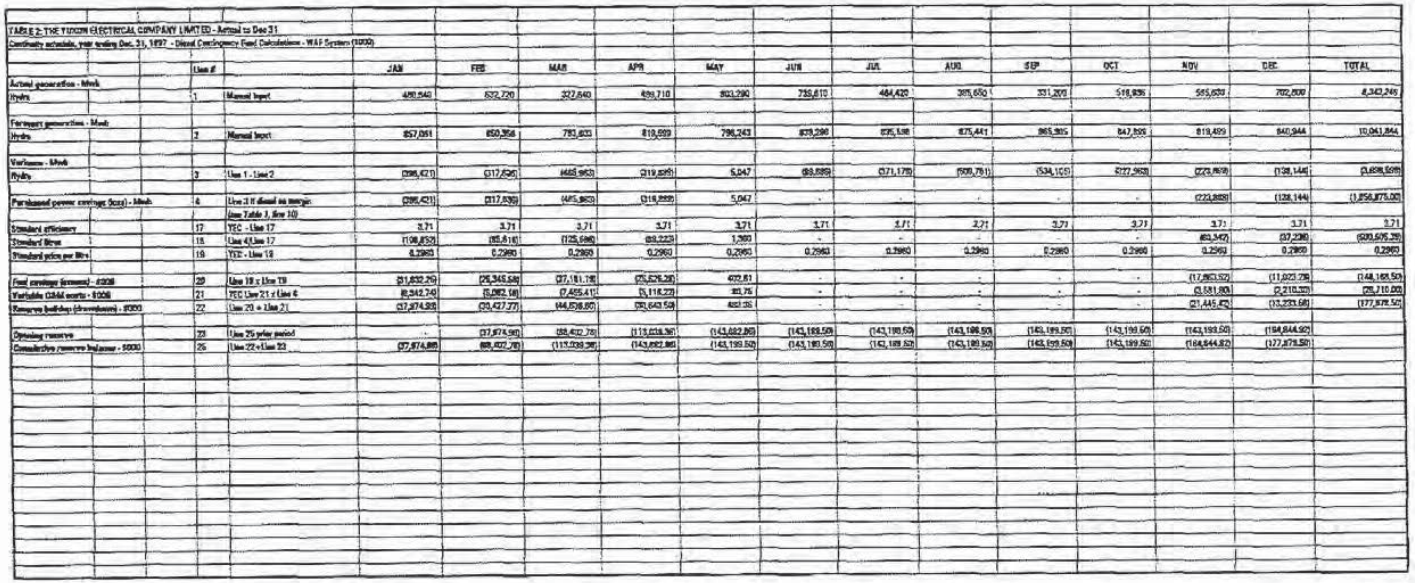
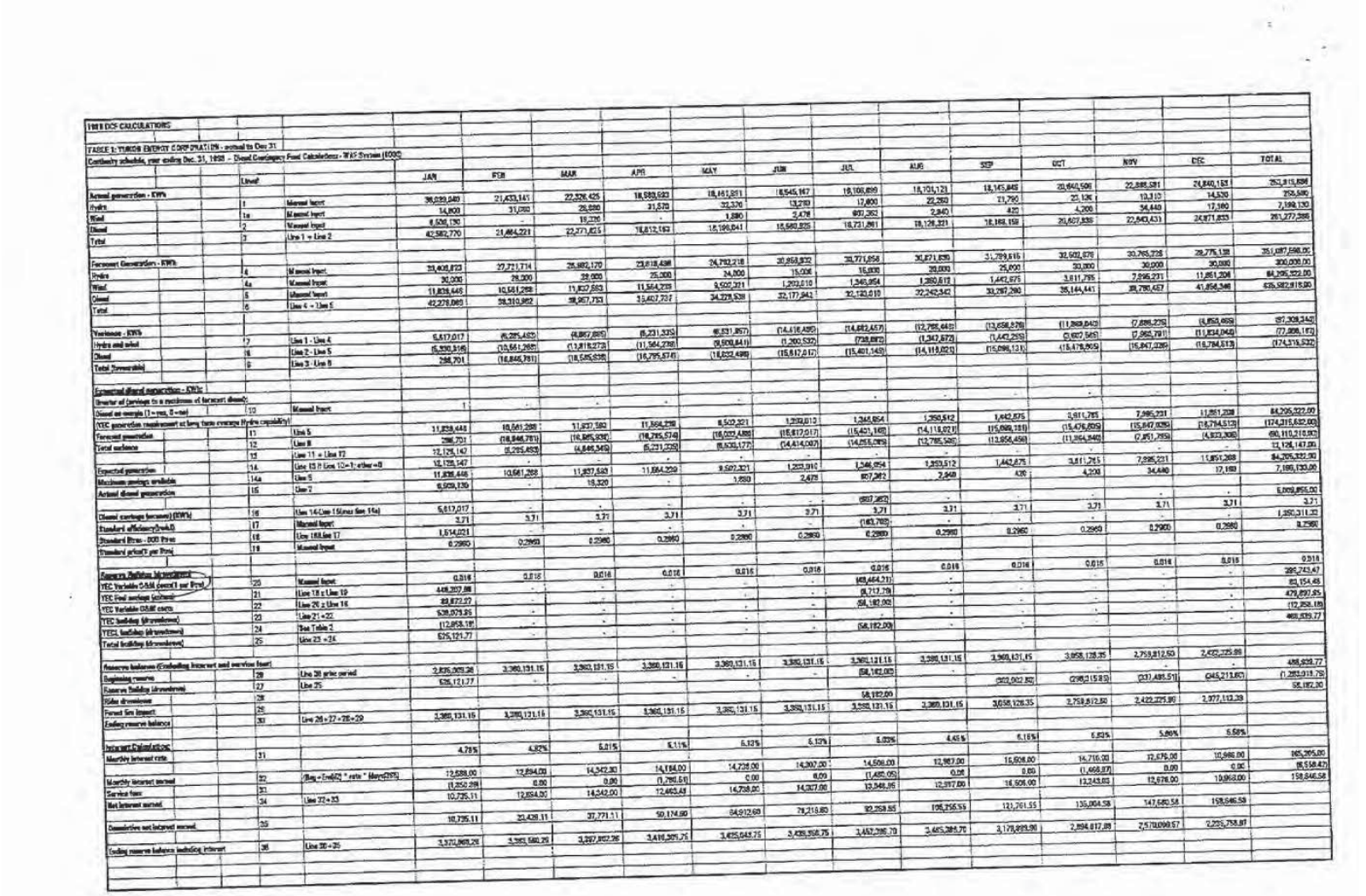


TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31
Continuity schedule, year ending Dec. 31, 1997 - Diesel Contingency Fund Calculations - WAF System (1000)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	486,540	532,720	327,640	699,710	923,290	735,610	484,420	385,650	331,200	516,836	565,630	702,000	6,343,246
Forecast generation - Mwh															
Hydro	2	Manual Input	857,091	850,364	781,633	819,699	796,243	639,290	535,188	675,441	865,395	847,809	819,499	840,944	10,041,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(396,421)	(317,636)	(465,963)	(319,699)	5,047	(63,699)	(371,179)	(509,781)	(534,195)	(277,963)	(223,869)	(138,144)	(3,698,599)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel as margin (see Table 3, line 10)	(396,421)	(317,636)	(465,963)	(319,699)	5,047	-	-	-	-	-	(223,869)	(138,144)	(1,856,875.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	106,853	85,616	125,598	86,223	1,360	-	-	-	-	-	60,347	37,236	(500,505.39)
Standard price per litre	19	YEC - Line 18	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (losses) - $000	20	Line 19 x Line 19	(31,632.29)	(25,345.64)	(37,181.78)	(25,526.26)	402.61	-	-	-	-	-	(17,863.52)	(11,023.75)	(148,169.53)
Variable O&M costs - $000	21	YEC Line 21 x Line 4	(6,342.24)	(5,062.18)	(7,455.41)	(5,118.23)	80.75	-	-	-	-	-	(3,581.80)	(2,210.33)	(29,710.00)
Reserve build-up (drawdown) - $000	22	Line 20 + Line 21	(37,974.53)	(30,427.77)	(44,636.80)	(30,643.50)	483.36	-	-	-	-	-	(21,445.42)	(13,233.68)	(177,879.53)
Opening reserve	23	Line 25 prior period	-	(37,974.90)	(68,402.76)	(113,039.36)	(143,682.86)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(164,644.92)	
Cumulative reserve balance - $000	25	Line 22+Line 23	(37,974.90)	(68,402.76)	(113,039.36)	(143,682.86)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(143,199.50)	(164,644.92)	(177,879.53)	



1988 DCF CALCULATIONS															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31															
Continuity schedule, year ending Dec. 31, 1988 - Diesel Contingency Fund Calculations - WS System (000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	36,039,940	21,433,141	22,326,425	18,589,693	18,161,851	18,545,167	18,106,899	18,704,121	18,145,845	20,640,586	22,886,581	24,840,151	253,819,599
Wind	1a	Manual Input	14,900	31,080	29,850	31,570	32,370	13,280	12,800	22,252	21,790	23,136	10,310	14,520	255,580
Diesel	2	Manual Input	6,536,130	-	19,220	-	1,880	2,478	601,362	2,940	420	4,200	34,440	17,160	7,199,130
Total	3	Line 1 + Line 2	42,582,770	21,464,221	22,373,495	18,612,163	18,196,041	18,560,925	18,721,861	18,729,321	18,168,159	20,667,930	22,843,431	24,871,833	261,277,386
Forecast Generation - KWh															
Hydro	4	Manual Input	33,405,823	27,721,714	25,982,170	23,818,498	24,732,218	20,958,872	20,771,858	30,871,830	31,789,815	32,902,876	30,765,728	28,775,138	351,697,560.00
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	16,000	20,000	25,000	30,000	30,000	30,000	300,000.00
Diesel	5	Manual Input	11,836,446	10,561,288	11,837,583	11,564,239	9,502,321	1,203,010	1,340,954	1,350,512	1,442,675	3,811,785	7,995,231	11,851,208	84,295,322.00
Total	6	Line 4 + Line 5	45,278,269	38,310,982	38,957,753	35,407,737	34,278,539	32,177,882	32,128,812	32,242,342	33,257,490	36,744,661	38,780,457	41,656,346	635,992,882.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	6,617,017	(6,285,453)	(4,867,680)	(5,231,335)	(6,331,957)	(14,418,495)	(14,682,457)	(12,765,649)	(13,658,676)	(11,869,849)	(7,886,276)	(4,850,469)	(97,309,340)
Diesel	8	Line 2 - Line 5	(5,300,316)	(10,561,288)	(11,818,363)	(11,564,239)	(9,500,441)	(1,200,532)	(1,339,954)	(1,347,872)	(1,442,255)	(3,807,565)	(7,965,791)	(11,834,048)	(77,866,187)
Total Generation	9	Line 3 - Line 6	296,701	(16,846,741)	(16,686,043)	(16,795,574)	(15,832,398)	(15,617,027)	(15,821,143)	(14,113,521)	(15,099,931)	(15,677,414)	(15,852,067)	(16,684,517)	(174,676,527)
Expected diesel generation - KWh															
Greater of (savings to a maximum of forecast diesel)	10	Manual Input	1	-	-	-	-	-	-	-	-	-	-	-	
Diesel as energy (1 = yes, 0 = no)															
YEC generation requirement at less than average Hydro capability															
Forecast generation	11	Line 5	11,836,446	10,561,288	11,837,583	11,564,239	9,502,321	1,203,010	1,340,954	1,350,512	1,442,675	3,811,785	7,995,231	11,851,208	84,295,322.00
Total variance	12	Line 8	296,701	(16,846,741)	(16,686,043)	(16,795,574)	(15,832,398)	(15,617,027)	(15,821,143)	(14,113,521)	(15,099,931)	(15,677,414)	(15,852,067)	(16,684,517)	(174,676,527)
	13	Line 11 + Line 12	12,133,147	(6,285,453)	(4,849,349)	(5,231,335)	(6,329,977)	(14,414,017)	(14,480,189)	(12,762,989)	(13,657,256)	(11,865,629)	(7,857,836)	(4,833,309)	(90,380,205.00)
Expected generation	14	Line 13 if Line 10=1; other=0	12,133,147	-	-	-	-	-	-	-	-	-	-	-	12,133,147.00
Maximum energy available	14a	Line 5	11,836,446	10,561,288	11,837,583	11,564,239	9,502,321	1,203,010	1,340,954	1,350,512	1,442,675	3,811,785	7,995,231	11,851,208	84,295,322.00
Actual diesel generation	15	Line 2	6,959,130	-	19,220	-	1,880	2,478	601,362	2,940	420	4,200	34,440	17,160	7,199,130.00
									(601,362)	-	-	-	-	-	6,059,850.00
(Diesel savings because) (KWh)	16	Line 14-Line 15 (Linear line 14a)	5,017,017	-	-	-	-	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard efficiency (Litre/kWh)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	-	-	-	-	-	-	-	1,350,311.32
Standard litres - DCF litres	18	Line 16/Line 17	1,614,021	-	-	-	-	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard price/$ per litre	19	Manual Input	0.2980	0.2980	0.2980	0.2980	0.2980	0.2980	(183,782)	-	-	-	-	-	
									0.2980	0.2980	0.2980	0.2980	0.2980	0.2980	0.2980
Reserve Holding Mechanism															
YEC Variable O&M cents/Litre Brut	20	Manual Input	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
YEC Fuel savings (cents)	21	Line 18 x Line 19	448,207.88	-	-	-	-	-	468,464.731	-	-	-	-	-	295,743.47
YEC Variable O&M costs	22	Line 20 x Line 16	89,872.27	-	-	-	-	-	(8,717.79)	-	-	-	-	-	83,154.48
YEC holding (drawdown)	23	Line 21 + 22	538,079.95	-	-	-	-	-	(64,182.00)	-	-	-	-	-	479,897.95
YEC holding (drawdown)	24	See Table 1	(12,958.18)	-	-	-	-	-	-	-	-	-	-	-	(12,958.18)
Total holding (drawdown)	25	Line 23 + 24	525,121.77	-	-	-	-	-	(64,182.00)	-	-	-	-	-	466,939.77
Reserve balance (including interest and overflow from)															
Beginning reserve	26	Line 28 prior period	2,835,000.00	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	466,939.77
Reserve holding (drawdown)	27	Line 25	525,121.77	-	-	-	-	-	58,182.00	-	-	-	-	-	58,182.00
Rider drawdown	28											(302,002.82)	(298,215.93)	(237,495.51)	(845,213.80)
Forest fire impact	29														
Ending reserve balance	30	Line 26 + 27 + 28 + 29	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,360,121.15	3,302,182.00	3,360,121.15	3,360,121.15	3,058,128.35	3,061,905.22	3,122,625.64	1,277,112.39
Interest Calculation															
Monthly interest rate	31		4.78%	4.82%	5.01%	5.11%	5.12%	5.12%	5.03%	4.45%	5.18%	5.82%	5.86%	5.68%	
Monthly interest earned	32	(Beg + End)/2 * rate * days/365	12,588.00	12,594.00	14,342.80	14,184.00	14,726.00	14,307.00	14,506.00	12,987.00	16,606.00	14,716.00	12,676.00	10,986.00	165,395.00
Service fees	33		(1,252.29)	0.00	0.00	(1,780.51)	0.00	0.00	(1,485.05)	0.05	0.00	(1,466.87)	0.00	0.00	(6,558.47)
Net interest earned	34	Line 32 + 33	10,735.11	12,594.00	14,342.00	12,403.49	14,726.00	14,307.00	13,548.95	12,987.00	16,606.00	13,243.03	12,676.00	10,986.00	158,846.58
Cumulative net interest earned	35		10,735.11	23,429.11	37,771.11	50,174.60	64,912.60	79,219.60	92,768.55	105,755.55	121,361.55	135,004.58	147,680.58	158,666.58	
Ending reserve balance including interest	36	Line 30 + 35	3,370,868.26	3,383,550.26	3,397,892.26	3,410,301.75	3,425,043.75	3,439,350.75	3,482,286.70	3,465,388.70	3,178,899.90	2,894,817.88	2,570,000.57	2,295,758.97	

TABLE 2: THE YUKON ELECTRICAL COMPANY LIMITED - Actual to Dec 31

Contingency schedule, year ending Dec. 31, 1999 - Diesel Contingency Fund Calculations - WAF System (YEC)

	Line #		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - Mwh															
Hydro	1	Manual Input	721,780	500,440	665,200	667,690	557,790	369,160	290,080	363,280	275,960	295,230	271,874	467,900	5,581,230
Forecast generation - Mwh															
Hydro	2	Manual Input	857,061	850,356	792,803	816,588	788,243	838,296	675,688	676,441	855,305	847,809	819,469	848,944	10,047,844
Variance - Mwh															
Hydro	3	Line 1 - Line 2	(135,271)	(299,916)	(128,403)	(151,909)	(240,453)	(478,148)	(445,518)	(512,161)	(585,345)	(552,659)	(547,575)	(375,144)	(4,466,814)
Purchased power savings (loss) - Mwh	4	Line 3 if diesel on margin (see Table 1, line 16)	(135,271)	-	-	-	-	-	-	-	-	-	-	-	(135,271.00)
Standard efficiency	17	YEC - Line 17	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres	18	Line 4/Line 17	(36,461)	-	-	-	-	-	-	-	-	-	-	-	(36,461.19)
Standard price per litre	19	YEC - Line 18	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960	0.2960
Fuel savings (expense) - $000	20	Line 18 x Line 19	(10,793.84)	-	-	-	-	-	-	-	-	-	-	-	(10,793.84)
Variable O&M costs - $000	21	YEC Line 21 x Line 4	(2,164.34)	-	-	-	-	-	-	-	-	-	-	-	(2,164.34)
Reserve holdback (drawdown) - $000	22	Line 20 + Line 21	(12,958.18)	-	-	-	-	-	-	-	-	-	-	-	(12,958.18)
Opening reserve	23	Line 25 prior period	-	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	
Cumulative reserve balance - $000	25	Line 22 + Line 23	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	(12,958.18)	

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Our File: 2/8005-07
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EXHIBIT B-19

October 7, 1999

BY FAX: (867) 668-6213 & (867) 667-5059

Mr. Brian Morris, Chair
Yukon Utilities Board
P.O. Box 6070
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Post-it™ Fax Note 7671E	Date 99 10 07	# of pages 14
To Intervenors	From Darlene Morgan/	
Co./Dept.	Co. Rob McWilliam-YEC	
Phone #	Phone # 393-5336	
Fax #	Fax # 393-5323	

Dear Mr. Morris:

Re: Comments on the Diesel Contingency Fund Report

This letter provides additional comments on the Diesel Contingency Fund (DCF) Report that Yukon Energy filed with the Board on June 2, 1999.

In response to your letter of August 3, 1999, we include, as set out below, comments on the July 4, 1999 submission from the Utilities Consumers' Group (UCG). We also include, as Attachment A to this letter, additional background information on questions that may assist the Board in its review of the DCF filings for 1996 to 1998. Finally, as explained below, we also provide a correction to the row label text in certain tables of the DCF Report.

Correction to row label text – no impact on numbers or conclusions

We have noted an error in the row labeling of the tables attached to the DCF Report, which is corrected in the attached set of tables. The error (Variable Diesel O&M costs were incorrectly listed at 1.6¢ per litre instead of the correct value of 1.6¢ per kWh) does not change the values, calculations, balances or conclusions of the report. The error was also present in the text of the report at page 3, bullet (e) where the variable diesel O&M should also be listed as 1.6¢/kWh instead of 1.6¢ per litre. We have provided a corrected copy of Tables 1 through 3 as provided in the earlier report, and Yukon Energy's detailed Table 1 from each of the three years reviewed.

Comments Received to date on the DCF Report

The DCF Report has been provided to the Board pursuant to the 1996/97 Settlement Agreement. The Companies have complied with the terms of the Settlement Agreement in that they previously filed the appropriate reports with the Board for 1996 and 1997. The latest report provides the same information for 1998, along with certain revisions with respect to the earlier reports.

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The Board has made provision to receive comments from any interested parties with respect to the recent DCF Report. We believe that the approach taken by the Board to date provides accountability that is consistent with the Negotiated Settlement Agreement. To date, the only written comments we have received from Intervenors are those provided by the UCG letter of July 4, 1999.

In order to assist the Board we provide the following comments on the specific concerns raised by UCG:

(a) **UCG requested further explanation and clarification of the Aishihik OIC and its effect on the DCF:** In response, additional information is provided below.

The Aishihik OIC (OIC 1997/13) affected the DCF only during the first quarter of 1997. Actual generation for the first quarter for YEC is shown in the DCF Report for 1997 after adjustments to reflect the impact of this OIC.

In total, 37,000 MWh was added to Hydro generation (actual) and 37,000 MWh was reduced from Diesel generation (actual) to reflect the impact of the OIC. In essence, the OIC compensated YEC for not using the bottom two feet of licensed water level storage at Aishihik Lake. The net effect of the above adjustments to the 1997 DCF Report ensured that the DCF was calculated on the assumption that the bottom two feet of licensed water level had been used to provide added Hydro generation during the first quarter of the year.

We note that this point was also set out in the response to UCG-YEC-1-8 in the 1998 Hearing, and was also addressed in our recent letter on fuel price variance 1997 finalization. As noted in the earlier response during the 1998 Hearing, the overall impact was to reduce YEC fuel related extra costs charged to the DCF by approximately $2.95 million and to also reduce YEC variable O&M costs charged to the DCF by approximately $0.59 million.

(b) **UCG requested further explanation and clarification of the fire-related impacts on the DCF:** Further explanation and clarification is provided below.

The DCF Report provides extensive information and comment on fire-related impacts on the DCF. These are reviewed below:

i) **1997 fire-related impacts:**
Actual diesel generation for YEC was required during three months of 1997 (October through December) due to reduced Hydro capability caused by the 1997

fire at the Whitehorse Rapids hydro facility. These fire impacts were estimated in detail for each month in the tables attached to the Report, and commented on in Note 5 to the first table.

In essence, the 1997 DCF calculations for these months were revised to reflect the reduced Hydro capability resulting from the loss of Hydro generating units due to the fire. Under the terms of YEC's insurance policy there is a 30-day waiting period during which the cost of any fire-related diesel generation is not claimable.

Accordingly, the DCF drawdown for October and November 1997 due to the fire was charged to the YEC Reserve for Injuries and Damages (as detailed in the tables to the Report, this impact equaled $403,052.95 for these two months combined). The DCF drawdown for December 1997 due to the fire has been charged to the fire insurance claim (as noted in the tables to the Report, this equaled $113,114.28). In total, fire-related impacts equal to $516,167.23 were removed from the costs charged to the DCF in 1997.

ii) **1998 fire-related impacts:**
During July 1998, YEC experienced a major forest fire that shut down the Faro transmission line for some time forcing YEC to generate diesel from the Faro plant. This diesel generation impact had nothing to do with Hydro generation capability, and thus cannot be charged to the DCF. As noted in the table attached to the Report titled "DCF Continuity Schedule 1996 - 1998", this forest fire impact on the DCF of $58,182.00 for July 1998 has all been charged to the Reserve for Injuries and Damages.

(c) **UCG requested further explanation and clarification of the Company's assumption and decision of where and when they can use forecasted versus actual numbers:**

The DCF has been operated on the same basis as the Low Water Reserve Fund (LWRF) previously in place from 1991 through 1995, except for the material differences specified in the 1996/97 Settlement Agreement. In accordance with these procedures, the DCF Report sets out both actual and forecast generation numbers for the purpose of each year's calculations. This approach has been utilized throughout the history of the LWRF, and is explained further below. Additional background information is provided in Attachment A attached to this letter.

The DCF is intended to offset diesel generation cost changes for the WAF system that are caused solely by variances from long term average levels of WAF system hydro and wind generation. The forecast generation for hydro and wind reflects the appropriate long-

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term average levels, as confirmed in the Negotiated Settlement Agreement. The forecast diesel generation for 1996 and 1997 reflects the balance of forecast generation requirement to meet the forecast load as set out in the GRA as approved by the Board.

The WAF diesel generation costs per kWh are based on the 1996 forecast as set out in the GRA (standard efficiency for diesel generation units use of fuel, YEC average WAF diesel fuel price forecasts, and the variable O&M diesel generation costs per kWh). For the 1998 DCF, the forecasts adopted for 1997 were retained. The same approach as adopted for 1998 will be used for any subsequent years until such time as the Board approves new forecasts.

The 1998 DCF Report noted that the Companies expect to prepare a submission to the YUB regarding the operation of the DCF for 1999 and beyond. When this submission is prepared, we would expect that the Board will seek comments from interested parties such as UCG and other Intervenors. This will provide additional opportunity to assess any issues related to the ongoing operation of the DCF for 1999 and subsequent years.

Based on the comments to date, we believe that the Board has the information required to approve the 1998 DCF as filed as well as the revised DCF schedules for 1996 and 1997. If you have any further questions, we would be pleased to assist you.

Yours very truly,

Rob McWilliam
President and Chief Executive Officer

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Attachments

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ATTACHMENT A
General Questions and Answers re: DCF

Why does Yukon need a Diesel Contingency Fund (DCF)?

The Diesel Contingency Fund was created as a result of the Negotiated Settlement at the 1996/97 GRA.. The DCF was to operate in the same manner as the earlier Low Water Reserve Fund (LWRF), established in the early 1990's, except for certain specified changes. The most notable adjustment was the use of long-term average water inflows, a change from the use of forecast hydro generation based on actual Aishihik water levels at the time of a rate application.

The question as to why a fund is needed at all was answered concisely in the report to the YUB in April 1997 prepared by the Accounting firm Stephen Johnson, as follows:

> *"In certain jurisdictions, electric power is generated at hydro dams or run-of-the-river hydro operations. Low Water Reserves have been established to protect customers against short-term fluctuations in the cost of electricity when more costly sources of generation, such as diesel, are substituted for hydro generation at times of low water conditions behind the dams or in the rivers. Simply, lower than average water level conditions generally result in higher diesel generation costs..."*
>
> *"Given that the reserve is a vehicle for smoothing the cost fluctuations due to water level divergence from average, it is set up so that it can be drawn down to offset the costs of diesel generation in years of low water levels."*

In addition, the DCF is set up so as to be replenished in years of high water levels. The result is better rate stability and predictability for both customers and utilities.

The 1996/97 Settlement Agreement provided for the operation of the fund as follows:

> *"The fund is to operate outside the rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund."*

How does the DCF work?

The DCF operates based on a concept of "expected diesel generation". This expected diesel generation is calculated based on long-term average hydro generation and actual electricity consumption in any given period. It is the amount of diesel that one would expect to be required based on these two values. The DCF is either drawn down or replenished when actual diesel generation varies from the "expected" level due to water flow variances.

General Points Re: Approved DCF – Expected Diesel Generation

As noted earlier, the DCF as approved in the 1996/97 Settlement Agreement is to be operated on the same basis as the earlier LWRF, except for material changes specified in the 1996/97 Settlement Agreement. The concepts and calculation methods for "expected diesel generation" were already established in the LWRF, as previously approved by the Board, for months when the Faro mine was operating and diesel generation was clearly on the margin under forecast water flow conditions.

For simplicity, the following comments ignore wind generation variances, which became incorporated in the DCF as part of the 1996/97 Settlement Agreement.

General Points Re: Approved DCF when Faro Mine Is Operating

To review the basis for "expected diesel generation" assessments when the Faro mine is operating, it is important to note that both the LWRF and the DCF address variances in the cost of diesel generation related solely to hydro generation variations from long-term averages that are due to hydro capability variances (e.g., water flows variances). The LWRF and DCF do not address other reasons for diesel generation cost variances (e.g., the DCF does not address diesel generation cost variances from forecasts due to fluctuations in sales or overall generation requirements, variances in fuel prices, or variances in diesel plant efficiencies or average O&M costs per kWh).

In order to determine how variances from long-term hydro generation capability affect diesel generation costs on a monthly basis, the LWRF specified that the following information would be used (the DCF assumes that forecast hydro generation is based on approved long-term averages):

- the forecast and actual WAF total generation requirement (WAF load)
- the forecast and actual WAF generation by source (hydro, wind, and diesel in the DCF).

The diesel generation variance from forecast can reflect a number of factors. For example, diesel generation can be affected by variances in WAF load from forecast as well as by diesel generation changes resulting from other factors not related to water flow variances.

Using an example, assume we forecast 50 GW.h of total WAF load, of which 10 GW.h is from diesel, and that actual usage is 60 GW.h of WAF load with 20 GW.h from diesel. Under these assumptions, the "expected diesel generation" methods adopted in the LWRF and retained in the DCF assume that this variance in diesel generation is not due to variance in water flows from long-term averages, despite the fact that diesel usage was 10 GW.h more than forecast. The process works likewise for a drop in system load. If we were to take the above case and argue that the diesel generation varied due to water flows it would not only be incorrect, it would elicit a payment for 10 GW.h of diesel generation costs from the fund – clearly inappropriate considering hydro and wind generation performed exactly as forecast at 40 GW.h.

Instead of using only diesel variance, the LWRF and DCF use a new figure, the "expected" diesel generation. In the above example we had forecast diesel generation at 10 GW.h plus a WAF system variance of +10 GW.h, so assuming everything else in the system operates as per forecast (including the level of water flows), the expected diesel generation would be 20 GW.h. This leaves a diesel savings/excess of 0 GW.h and no change to the fund balance.

"Expected diesel generation" is not directly affected by actual diesel generation. For example, assuming the same above forecast example (forecast 50 GW.h on the system with 10 GW.h from diesel generation) and actuals of 60 GW.h on the system with only 15 GW.h from diesel generation, the LWRF and DCF would retain the 20 GW.h expected diesel generation. In this case, however, the LWRF and DCF calculate diesel savings of 5 GW.h and the fund would thus be credited for the value of 5 GW.h of diesel generation cost savings. This is because the diesel generation variance from expected is –5 GW.h *even though the diesel generation variance from forecast is +5 GW.h.*

The LWRF and DCF also both ensure that diesel generation savings cannot exceed actual diesel generation.

It is not contemplated that "expected diesel generation" could ever be negative when the Faro mine is operating so long as YEC retains its current WAF hydro generation capability. Further, as reviewed below, the LWRF and DCF both assume that "expected generation" for diesel plant is zero when the Faro mine is not operating.

General Points Re: Approved DCF when Faro Mine Is Not Operating

Once the Faro mine is off the system, the expected WAF diesel energy generation drops to zero for the purpose of the LWRF or DCF. This is because the removal of this one load is sufficient to ensure, under current WAF load conditions and assuming long-term hydro generation capability, that WAF energy generation requirements can be met without diesel energy generation.

In actual fact, during significant periods of low water, such as the winter of 1998/99, diesel may be required for baseload WAF generation, and it is the intention of the DCF to address these variances from the "expected" level due to water flow variations. (Experience has shown that some minor level of diesel generation may also be needed, even when the Faro mine is closed, for peaking, voltage stability, or other purposes that are not affected by variances from forecast hydro generation capability. Accordingly, neither the LWRF nor the DCF consider these diesel generation requirements.)

These principles are reflected in the simple binary choice set out at line 10 of the DCF report table (YEC) for each month. When the Faro mine is operating, the "1" at line 10 indicates that diesel generation is assumed to be on the margin under long-term hydro generation conditions. When the Faro mine is not operating, the "0" indicates that diesel generation is assumed not to be on the margin under long-term hydro generation conditions.

The binary choice of "0" at line 10 dictates an "expected generation" for diesel of "0" at line 14. Under no condition can "expected generation" be set at less than "0" under the approved LWRF or DCF.

Even though the LWRF was completely suspended in 1993/94 when the Faro mine was closed, it was known that actual diesel generation may still be required under these conditions. Further, it was recognized during the 1993 GRA hearing that low water conditions could be one of the factors that necessitate such diesel generation – and that the LWRF would be expected to compensate for diesel costs incurred solely due to such low water conditions even when the Faro mine is closed. During the winter of 1998/99, with the Faro mine closed, actual low water conditions did result in baseload diesel being required, and the DCF was used in 1999 to address this variance.

The current DCF calculations recognize that small amounts of actual diesel generation may be required when the Faro mine is closed for purposes unrelated to variances from long-term hydro capability. In order to address this factor when the Faro mine is closed, the DCF is not activated in any such month when actual diesel generation does not exceed 250 MW.h (this assessment is done at line 16 of the DCF report table for YEC). Any such month with lower than 250 MW.h of diesel generation is assumed to have no diesel generation cost for the purposes of calculating the DCF.

How is 'Diesel on the Margin' Defined?

Diesel on the margin is a concept used to represent the significant impact that the operation of the Faro mine has on the Yukon electrical system. Diesel-on-the-margin is indicated in the calculations of the DCF at line 10 of the DCF report table for YEC, with a 1 indicting the Faro mine is operating and a 0 indicating the mine is shut-down. The definition of diesel on the margin at line 10 is not dependent on actual diesel generation.

Using a hypothetical example once again, assume WAF system load forecast at 50 GW.h with 10 GW.h of diesel and 40 GW.h of hydro. Assume the actual load is very low at 35 GW.h due to closure of the Faro mine (i.e., at a level where energy needs could be met solely by hydro generation at normal water flows). Finally, assume actual hydro generation is also low because of low water, at 30 GW.h. This means 5 GW.h of diesel was required. In this case, diesel is not "on the margin" at line 10 – actual load is 35 GW.h with a forecast hydro capability of 40 GW.h and there is thus no "expected" need for diesel generation. Since "expected" diesel generation is zero, the actual diesel at 5 GW.h is due to lower than average water flows, and the fund would be drawn down for the value of this generation, as would be expected based on low hydro generation.

Actual hydro generation also does not affect whether diesel is "on the margin" at line 10. It does play a significant role, however, in determining the charges or credits affecting the DCF at line 16.

Why Would the Fund Pay Out When Diesel is Less Than Forecast?

The rationale for drawing down the fund in some months when actual diesel is lower than originally forecast is the assessment that the actual diesel generation was required solely due to low water flow conditions (or other factors that similarly reduced hydro capability below long-term average capabilities).

Looking at the example used in the response to the above question, we can see that actual diesel at 5 GW.h is less than forecast diesel at 10 GW.h. However, actual hydro is also much lower than originally forecast. The variance in water flows is the cause of the 5 GW.h in diesel being needed (rather than no diesel being needed as would be "expected"). In this case the use of the DCF is called for.

There are conditions when the Faro mine is operating when the fund could also be drawn down even though actual diesel generation is less than forecast. Here again, the critical factor is "expected diesel generation" rather than only forecast diesel generation.

Conversely, there can be conditions, such as January, 1996, when diesel use is greater than forecast, but the fund is still credited due to hydro generation above what would be expected with average water flows.

Why Does the Calculation Use "Expected" Diesel Generation?

The above information outlines the calculation of the "expected" diesel generation. It is what one would expect to be required based on long-term average hydro and actual monthly system load. The principles were established earlier in the LWRF and have simply been retained in the DCF.

Attachment A – General Q & A re: DCF – Page 4

MISSING PAGE 5

The rationale for not basing this number solely on forecast or actual diesel generation has been explained above.

Expected generation is always used as the starting point for diesel savings calculations at line 16 of the DCF table for YEC – whether diesel generation is on the margin or off the margin at line 10. The line 16 calculation deducts actual diesel generation from "expected generation", subject to the constraint noted at line 14a.

By definition, diesel being off the margin at line 10 means there is zero expected diesel generation at line 14.

In contrast, if simple diesel generation variance from actual was used, it would result in the fund adjusting for the costs of all variances from forecast – including load variances – not just those relating to water flows. It would be contrary to the purpose of the DCF, the former LWRF, and the intent of the 1996/97 Negotiated Settlement.

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Table 1: DCF - Including Fire Related Diesel Generation:
(corrected September, 1999)

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	25,580,490	27,851,195	33,708,072
1a	Wind	Manual Input	17,840	6,530	21,370
2	Diesel	Manual Input	357,870	7,140,520	6,747,710
3	Total	Line 1 + Line 2	25,956,200	34,798,245	40,475,152
	Forecast Generation - Mwh				
4	Hydro	Manual Input	32,502,678	30,785,228	29,775,138
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	36,144,441	38,780,457	41,656,346
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	(6,934,348)	(3,137,501)	3,922,304
8	Diesel	Line 2 - Line 5	(3,253,895)	(854,711)	(5,103,498)
9	Total (favourable)	Line 3 - Line 8	(10,188,241)	(3,992,212)	(1,181,194)
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel);				
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,194)
13		Line 11 + Line 12	(6,576,476)	4,003,018	10,670,014
14	Expected generation	Line 13 if Ln 10=1 other = 0	-	4,003,018	10,670,014
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	357,870	7,140,520	6,747,710
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 >250,000)	(357,870)	(3,137,501)	3,922,304
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	(96,461)	(845,689)	1,057,225
19	Standard price($ per litre)	Manual Input	0.2980	0.2980	0.2980
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs($ per kW.h)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 16 x Line 19	(28,656.10)	(250,355.67)	312,976.71
22	YEC Variable O&M costs	Line 20 x Line 16	(5,725.92)	(50,200.02)	62,756.86
23	YEC buildup (drawdown)	Line 21+22	(34,282.02)	(300,555.69)	375,735.57
24	YECL buildup (drawdown)	See YECL Table	0	(21,445.42)	(13,233.58)
25	Total buildup (drawdown)	Line 23 +24	(34,282.02)	(322,001.11)	362,501.99

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Table 2: DCF - Excluding Fire Related Diesel Generation:
(corrected September, 1998)

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual Input	25,840,460	31,500,795	34,886,872
1a	Wind	Manual Input	17,840	6,530	21,370
2	Diesel	Manual Input	97,870	3,290,920	5,589,910
3	Total	Line 1 + Line 2	25,958,200	34,798,245	40,475,152
	Forecast Generation - Mwh				
4	Hydro	Manual Input	32,502,876	30,795,228	28,775,136
4a	Wind	Manual Input	30,000	30,000	30,000
5	Diesel	Manual Input	3,611,765	7,995,231	11,851,208
6	Total	Line 4 + Line 5	39,144,441	38,790,457	41,656,345
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	(6,674,346)	712,089	5,103,104
8	Diesel	Line 2 - Line 5	(3,513,895)	(4,704,311)	(6,264,298)
9	Total (favourable)	Line 3 - Line 6	(10,188,241)	(3,992,212)	(1,181,194)
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1=yes, 0=no)	Manual Input	0	1	1
	(YEC generation requirement long term avg Hydro capability)				
11	Forecast generation	Line 5	3,611,765	7,995,231	11,851,208
12	Total variance	Line 9	(10,188,241)	(3,992,212)	(1,181,194)
13		Line 11 + Line 12	(6,576,476)	4,003,019	10,670,014
14	Expected generation	Line 13 if Ln 10=1 other = 0	-	4,003,019	10,670,014
14a	Maximum savings available	Line 5	3,611,765	7,995,231	11,851,208
15	Actual diesel generation	Line 2	97,870	3,290,920	5,589,910
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 >250,000)	-	712,099	5,103,104
17	Standard efficiency(kwh/l)	Manual Input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	-	191,940	1,375,500
19	Standard price($ per litre)	Manual Input	0.2960	0.2960	0.2960
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs($ per kW.h)	Manual Input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 16 x Line 19	-	56,821.66	407,200.19
22	YEC Variable O&M costs	Line 20 x Line 16	-	11,393.58	81,649.66
23	YEC buildup (drawdown)	Line 21+22	-	68,215.24	488,849.85
24	YECL buildup (drawdown)	See YECL Table	-	(21,445.42)	(13,233.58)
25	Total buildup (drawdown)	Line 23 +24	-	46,769.82	475,616.27

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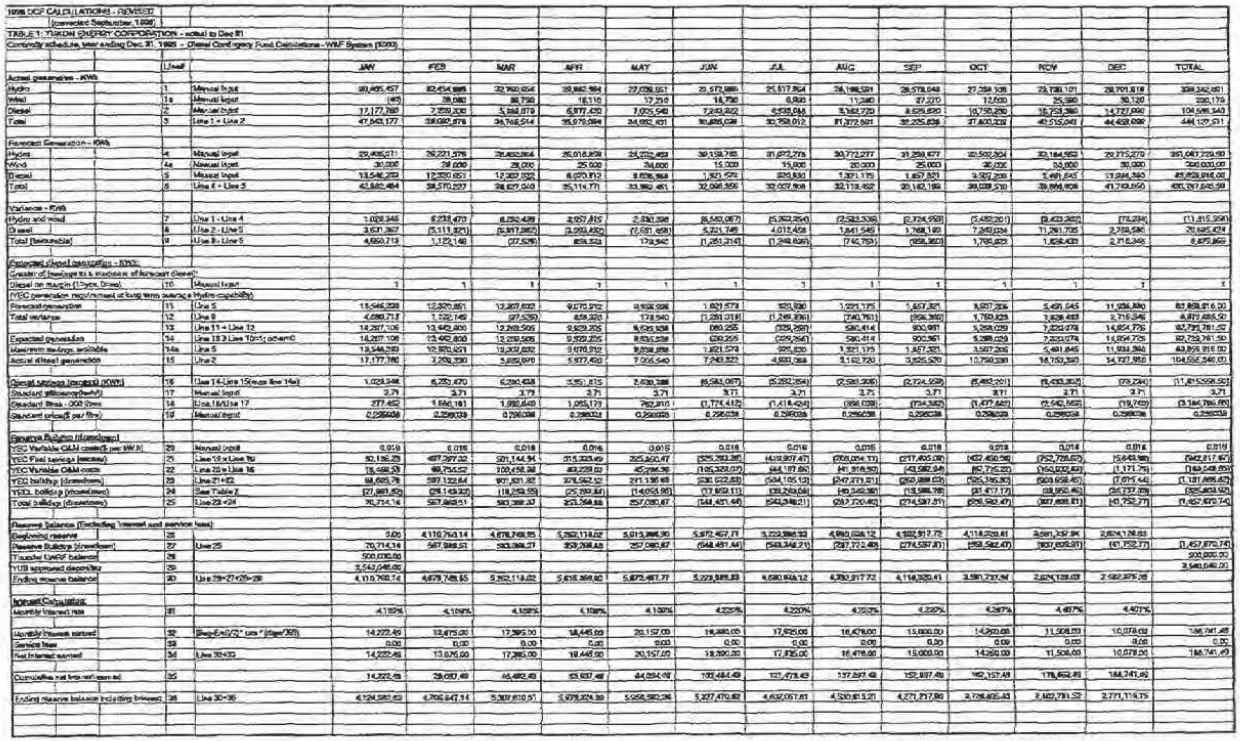
Table 3: DCF - Fire Impact
(corrected September, 1999)

Line#			OCT-1997	NOV-1997	DEC-1997
	Actual generation - Mwh				
1	Hydro	Manual input	260,000	3,849,600	1,160,600
1a	Wind	Manual input	0	0	0
2	Diesel	Manual input	(260,000)	(3,849,600)	(1,160,600)
3	Total	Line 1 + Line 2	0	0	0
	Forecast Generation - Mwh				
4	Hydro	Manual input	0	0	0
4a	Wind	Manual input	0	0	0
5	Diesel	Manual input	0	0	0
6	Total	Line 4 + Line 5	0	0	0
	Variance - Mwh				
7	Hydro and wind	Line 1 - Line 4	260,000	3,849,600	1,160,600
8	Diesel	Line 2 - Line 5	(260,000)	(3,849,600)	(1,160,600)
9	Total (favourable)	Line 3 - Line 6	0	0	0
	Expected diesel generation - Mwh:				
	Greater of (savings to a maximum of forecast diesel):				
10	Diesel on margin (1=yes, 0=no)	Manual input	0	1	1
	(YEC generation requirement *long term avg Hydro capability*)				
11	Forecast generation	Line 5	0	0	0
12	Total variance	*Line 9*	0	0	0
13		Line 11 + Line 12	0	0	0
14	Expected generation	Line 13 if Ln 10=1 other = 0	0	0	0
14a	Maximum savings available	Line 5	0	0	0
15	*Actual diesel generation*	Line 2	(260,000)	(3,849,600)	(1,160,600)
16	Diesel savings (excess) (Mwh)	Line 14-Line 15 (max line 14a if Ln 10=1; otherwise = 0, unless Ln 15 >250,000)	357,870	3,849,600	1,160,600
17	Standard efficiency(kwh/l)	Manual input	3.71	3.71	3.71
18	Standard litres - 000 litres	Line 16/Line 17	96,461	1,037,628	316,275
19	Standard price($ per litre)	*Manual input*	0.2960		
	Reserve Buildup (drawdown)				
20	YEC Variable O&M costs($ per kW.h)	Manual input	0.016	0.016	0.016
21	YEC Fuel savings (excess)	Line 18 x Line 19	28,555.10	307,177.93	94,221.48
22	YEC Variable O&M costs	Line 20 x Line 16	5,725.92	61,593.60	18,892.80
23	YEC buildup (drawdown)	Line 21+22	34,282.02	368,770.93	113,114.28
24	YECL buildup (drawdown)	See YECL Table	-	-	-
25	Total buildup (drawdown)	Line 23 +24	34,282.02	368,770.93	113,114.28

Under the terms of the insurance policy there is a 30 day waiting *period during which* the cost of any fire related diesel generation is not claimable. Accordingly the DCF drawdown for October and November was charged to the Reserve for Injuries and Damages. The DCF drawdown for December has been charged to the fire *insurance claim.*



1998 DCF CALCULATIONS - REVISED															
(corrected September, 1998)															
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31															
Currently schedule, year ending Dec. 31, 1998 - Diesel Contingency Fund Calculations - WAF System (000)															
	Line#		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	30,495,457	32,454,995	32,992,054	29,842,564	27,039,057	23,572,985	25,517,854	26,196,531	26,578,048	27,284,106	29,789,101	29,701,918	339,342,651
Wind	1a	Manual Input	(49)	39,082	86,736	18,110	17,210	14,736	8,868	11,080	27,270	12,000	35,380	36,120	330,179
Diesel	2	Manual Input	17,177,769	7,358,300	5,398,978	6,877,470	7,005,548	7,283,902	6,568,644	5,362,720	8,629,690	10,758,276	16,758,380	14,727,990	104,548,343
Total	3	Line 1 + Line 2	47,643,177	39,852,376	38,768,514	36,578,084	34,062,451	30,871,623	32,095,366	31,572,331	35,235,008	37,800,382	46,515,049	44,466,028	444,129,531
Forecast Generation - KWh															
Hydro	4	Manual Input	29,405,571	26,221,376	26,492,964	25,018,809	24,232,493	30,139,785	31,972,276	30,772,277	31,259,677	30,502,304	32,184,952	29,775,279	357,087,729.93
Wind	4a	Manual Input	30,000	28,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	330,000.00
Diesel	5	Manual Input	13,546,272	12,200,651	12,307,332	8,070,812	8,936,368	1,921,579	920,830	1,921,175	1,857,321	3,927,206	3,491,045	11,934,380	81,059,916.00
Total	6	Line 4 + Line 5	42,980,484	38,570,227	38,827,948	35,114,771	33,992,861	32,096,364	32,907,906	32,713,452	33,142,198	34,089,510	35,866,998	41,740,659	493,267,645.93
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	1,089,946	6,233,477	6,532,489	4,857,815	2,881,398	(6,540,067)	(6,362,354)	(6,563,536)	(4,724,959)	(5,485,201)	(6,423,392)	(73,234)	(11,815,399)
Diesel	8	Line 2 - Line 5	3,631,497	(5,111,921)	(6,917,967)	(1,092,452)	(1,931,020)	5,321,749	4,013,408	1,441,545	1,768,189	7,349,224	11,261,735	2,793,590	23,545,474
Total (favourable)	9	Line 6 - Line 6	4,660,719	1,121,148	(27,529)	809,533	179,942	(1,261,218)	(1,248,946)	(742,791)	(956,903)	1,765,823	4,838,433	2,710,948	6,870,865
Forecast diesel generation - KWh															
Greater of line(type in) & shortage of forecast diesel															
Diesel on margin (Hydro, Diesel)	10	Manual Input	1	1	1	1	1	1	1	1	1	1	1	1	1
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	13,546,272	12,200,651	12,307,332	8,070,812	8,936,368	1,921,579	920,830	1,921,175	1,857,321	3,927,206	3,491,045	11,934,380	81,059,916.00
Total variance	12	Line 9	4,660,719	1,121,148	(27,529)	809,533	179,942	(1,261,218)	(1,248,946)	(742,791)	(956,903)	1,765,823	4,838,433	2,710,948	6,870,865.00
	13	Line 11 + Line 12	18,207,106	13,443,800	12,279,803	8,879,265	9,116,258	660,255	(329,250)	590,414	900,961	5,693,029	7,329,478	14,654,728	87,793,781.00
Expected generation	14	Line 13 3 Line TG-10 advance	18,207,106	13,443,800	12,279,803	8,879,265	9,116,258	660,255	(329,250)	590,414	900,961	5,693,029	7,329,478	14,654,725	87,793,781.00
Maximum energy available	14a	Line 5	13,546,269	12,200,651	12,307,332	8,070,812	8,936,368	1,921,579	920,830	1,921,175	1,857,321	3,927,206	5,491,045	11,934,380	83,059,916.00
Actual diesel generation	15	Line 2	17,177,769	7,358,300	5,398,978	6,877,470	7,005,548	7,283,902	6,568,644	5,362,720	8,629,690	10,758,276	16,758,380	14,727,990	104,548,343.00
Overall savings (expense) (kWh)	16	Line 14-Line 15(+was line 14a)	1,029,346	6,233,477	6,532,489	4,857,815	2,881,398	(6,540,067)	(6,362,354)	(6,563,536)	(4,724,959)	(5,485,201)	(9,423,392)	(73,234)	(11,815,399.00)
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 (litres	18	Line 16/Line 17	277,462	1,980,181	1,992,640	1,055,179	762,910	(1,774,412)	(1,414,424)	(996,039)	(794,382)	(1,477,660)	(2,540,562)	(19,743)	(3,184,786.89)
Standard price($ per litre)	19	Manual Input	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038	0.256038
Reserve Building (drawdown)															
YEC Variable O&M costs($ per MWh)	20	Manual Input	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
YEC Fuel savings (excess)	21	Line 16 x Line 19	82,186.25	487,397.32	501,144.94	315,923.49	225,900.47	(525,393.38)	(419,807.47)	(295,254.11)	(217,405.08)	(437,450.58)	(752,728.62)	(5,843.98)	(942,817.67)
YEC Variable O&M costs	22	Line 20 x Line 16	76,488.29	98,754.52	100,458.39	83,228.63	45,296.96	(105,329.07)	(84,197.66)	(41,914.80)	(43,582.94)	(80,715.20)	(150,932.63)	(1,171.75)	(189,548.85)
YEC building (drawdown)	23	Line 21+22	68,685.76	587,152.64	601,601.32	376,362.12	271,196.68	(630,722.62)	(504,105.13)	(347,271.21)	(260,988.02)	(525,166.36)	(903,659.45)	(7,015.44)	(1,131,366.52)
YEC building (drawdown)	24	See Table 2	(27,881.83)	(28,149.20)	(18,258.39)	(25,200.84)	(14,055.95)	(17,909.11)	(26,259.08)	(40,340.38)	(13,986.78)	(31,417.17)	(38,950.40)	(36,727.39)	(320,933.02)
Total building (drawdown)	25	Line 23 +24	40,754.14	557,949.51	583,398.37	323,764.88	257,080.87	(648,481.44)	(540,348.21)	(387,720.40)	(274,587.81)	(556,583.47)	(987,609.91)	(43,752.77)	(1,457,870.74)
Reserve Balance (Including interest and service fees)															
Beginning reserve	26		3.00	4,119,740.14	4,678,748.85	5,262,118.02	5,613,996.90	5,872,457.77	5,223,996.33	4,890,038.12	4,502,917.72	4,114,203.61	3,591,737.94	2,824,128.03	2,562,375.26
Reserve Building (drawdown)	27	Line 25	70,714.14	587,949.51	583,398.37	353,298.88	257,080.87	(648,481.44)	(540,348.21)	(387,720.40)	(274,587.81)	(556,583.47)	(987,609.91)	(43,752.77)	(1,457,870.74)
Transfer DNRF balance	28		500,000.00												500,000.00
YUB approved deposits	29		3,540,046.00												3,540,046.00
Ending reserve balance	30	Line 29+27+26+28	4,110,760.14	4,679,748.65	5,262,118.02	5,616,994.90	5,872,457.77	5,223,996.33	4,890,038.12	4,502,917.72	4,114,203.61	3,591,737.94	2,824,128.03	2,562,375.26	
Interest Calculation															
Monthly interest rate	31		4.125%	4.125%	4.125%	4.125%	4.125%	4.225%	4.225%	4.225%	4.225%	4.287%	4.467%	4.467%	
Monthly interest earned	32	[Reg=E+(G*Line 7 days/365)	14,222.46	13,675.00	17,395.00	18,445.00	20,157.00	18,480.00	17,825.00	16,478.00	15,000.00	14,269.00	11,506.00	10,078.00	186,741.46
Service fee	33		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net interest earned	34	Line 32+33	14,222.46	13,675.00	17,395.00	18,445.00	20,157.00	18,480.00	17,825.00	16,478.00	15,000.00	14,269.00	11,506.00	10,078.00	186,741.46
Cumulative net long-term earned	35		14,222.46	28,097.46	45,492.46	63,937.46	84,094.46	102,484.46	120,478.46	137,897.46	152,897.46	167,157.46	178,662.46	188,741.46	
Ending reserve balance including interest	36	Line 30+35	4,124,982.60	4,708,845.14	5,307,610.51	5,679,924.39	5,956,552.26	5,327,470.82	4,932,057.61	4,520,813.21	4,271,217.86	3,758,905.43	3,002,791.52	2,771,116.75	

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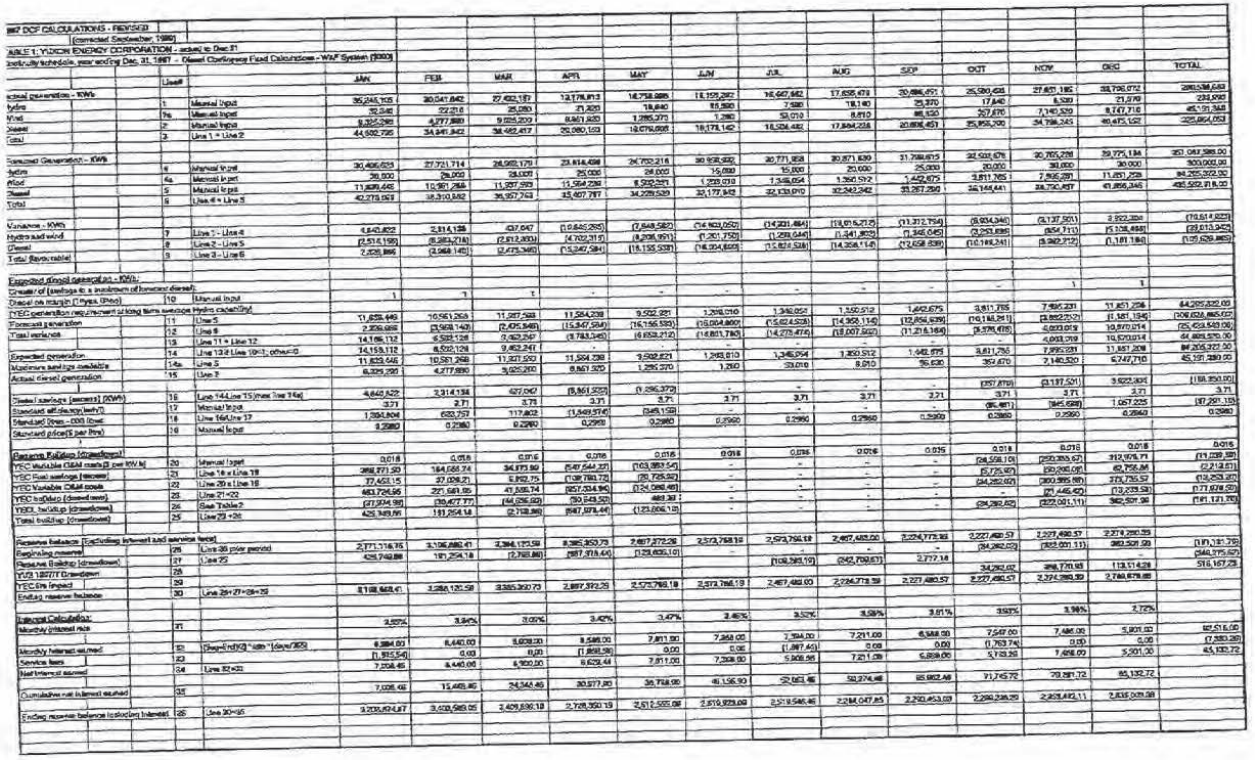

867 DCF CALCULATIONS - REVISED																
[corrected September 1998]																
TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31																
Indexity schedule, year ending Dec. 31, 1997 - Diesel Contingency Fund Calculations - WAF System ($000)																
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
actual generation - KWh		Used														
hydro		1	Manual Input	35,245,105	30,041,842	27,482,187	12,178,913	14,758,886	12,105,282	16,447,842	17,635,473	30,886,457	25,580,436	27,851,186	33,796,072	285,588,643
hydro		1a	Manual Input	32,346	22,216	25,080	21,800	19,840	16,360	7,580	78,140	25,370	17,840	8,320	21,370	293,900
Wind		2	Manual Input	9,202,290	4,277,880	9,855,200	8,861,600	1,285,370	1,280	53,010	8,810	88,630	267,870	7,145,320	8,747,710	48,175,160
Diesel		3	Line 1 + Line 2	44,600,295	34,941,942	36,462,457	20,080,103	19,679,605	18,178,142	18,524,482	17,844,226	20,858,457	25,858,200	34,736,245	40,473,127	325,864,053
total																
Expected Generation - KWh																
hydro		4	Manual Input	30,406,639	27,721,714	24,965,179	23,814,498	24,700,214	30,938,992	30,771,958	30,871,639	31,799,615	32,531,676	30,765,278	29,775,184	353,083,580.00
hydro		4a	Manual Input	29,000	26,000	28,000	25,000	28,000	16,000	15,000	20,000	25,000	20,000	30,000	30,000	302,000.00
Wind		4b	Manual Input	11,699,445	10,901,268	11,297,999	11,564,238	8,592,251	1,235,019	7,348,054	1,350,512	1,462,675	3,811,765	7,795,231	11,851,258	88,295,920.00
Diesel		5	Manual Input	42,275,963	35,310,982	36,957,743	15,407,787	34,229,529	32,177,942	32,139,910	32,343,342	35,267,390	32,144,441	28,750,457	41,856,345	426,562,218.00
Total		6	Line 4 + Line 5													
Variance - KWh		7	Line 1 - Line 4	4,840,466	2,314,128	437,047	(10,645,285)	(7,848,580)	(14,803,050)	(14,324,464)	(13,013,215)	(11,312,704)	(6,934,340)	(3,137,501)	2,922,004	(70,514,623)
Hydro and wind		8	Line 2 - Line 5	(2,514,199)	(6,283,716)	(2,812,933)	(4,702,315)	(8,206,951)	(1,201,750)	(1,259,044)	(1,041,802)	(1,348,045)	(3,293,695)	(554,711)	(5,338,468)	(39,013,345)
Diesel		9	Line 3 - Line 6	2,326,666	(2,968,140)	(2,473,346)	(15,247,584)	(15,135,939)	(14,054,600)	(13,815,528)	(14,206,114)	(12,658,936)	(10,199,241)	(5,392,212)	(1,181,186)	(105,629,865)
Total Recoverable																
Expected diesel generation - KWh																
Greater of (spillage in a month or 1/12 of forecast diesel)																
Diesel as margin (Chyrsa, Dhoo)		10	Manual Input	1	1	1	-	-	-	-	-	-	-	1	1	
YEC generation requirement (total less average Hydro capacity)																
Forecast generation		11	Line 5	11,699,445	10,901,268	11,297,999	11,564,238	9,592,251	1,235,019	7,348,054	1,350,512	1,462,675	3,811,765	7,795,231	11,851,258	88,295,920.00
Total variance		12	Line 8	2,326,666	(2,968,140)	(2,473,346)	(15,247,584)	(15,135,939)	(14,054,600)	(13,815,528)	(14,206,114)	(12,658,936)	(10,199,241)	(5,392,212)	(1,181,186)	(105,629,865.00)
		13	Line 11 + Line 12	14,186,112	8,522,128	8,824,647	(3,683,346)	(5,543,712)	(12,819,581)	(6,467,474)	(12,855,602)	(11,196,261)	(6,387,476)	(2,596,981)	10,670,072	(17,333,945.00)
Expected generation		14	Line 13 if Line 13>1; other=0	14,186,112	8,522,128	8,824,647	-	-	-	-	-	-	-	-	10,670,072	42,203,359.00
Maximum savings available		14a	Line 5	11,699,445	10,901,268	11,297,999	11,564,238	9,592,251	1,235,019	7,348,054	1,350,512	1,462,675	3,811,765	7,795,231	11,851,258	88,295,920.00
Actual diesel generation		15	Line 7	6,355,290	4,277,880	9,855,200	8,861,600	1,285,370	1,280	53,010	8,810	88,630	267,870	7,145,320	8,747,710	45,191,980.00
Diesel savings [excess] (KWh)		16	Line 14 (Line 13) max line 14a]	4,840,822	2,314,128	427,047	(5,861,325)	(1,296,372)	-	-	-	-	(357,670)	(3,137,501)	2,922,304	(159,350.00)
Standard diesel savings (each)		17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard diesel [less - ODS] (low)		18	Line 16/Line 17	1,304,804	633,757	117,802	(1,549,574)	(349,159)	-	-	-	-	(96,481)	(845,688)	1,057,225	(97,291.15)
Standard price ($ per litre)		19	Manual Input	0.2980	0.2980	0.2980	0.2900	0.2980	0.2900	0.2900	0.2900	0.2900	0.2980	0.2900	0.2900	0.2980
Reserve Kilolitre (drawdown)				0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
YEC Variable O&M costs [$ per KW h]		20	Manual Input	268,771.20	184,088.74	34,873.80	(547,544.37)	(103,383.54)	-	-	-	-	(36,538.10)	(250,350.42)	49,756.84	(1,212.61)
YEC fuel savings [excess]		21	Line 16 x Line 19	77,455.15	37,026.21	6,892.75	(138,781.72)	(20,725.82)	-	-	-	-	(5,725.97)	(50,206.08)	375,735.57	(18,253.26)
YEC Variable O&M costs		22	Line 20 x Line 18	483,726.95	221,581.95	41,535.74	(857,034.94)	(124,086.46)	-	-	-	-	(34,282.62)	(300,995.58)	(13,239.53)	(171,678.25)
YEC buildup (drawdown)		25	Line 21+22	(71,934.99)	(39,477.77)	(44,256.60)	70,548.52	482.32	-	-	-	-	-	(21,445.42)	(13,239.53)	(119,123.70)
YEC buildup (drawdown)		26	See Table 2	425,345.91	181,254.14	(2,718.86)	(847,978.44)	(123,666.13)	-	-	-	-	(34,282.62)	(322,001.11)	362,501.36	(141,121.70)
Total buildup (drawdown)		25	Line 23 + 24													
Reserve balance [excluding interest and service fees]																
Beginning reserve		26	Line 26 prior period	2,771,116.75	3,196,462.41	3,394,125.59	3,385,353.73	2,887,372.28	2,573,788.19	2,573,788.19	2,467,482.00	2,234,778.39	2,227,480.57	2,227,480.57	2,374,280.39	
Reserve (buildup) [drawdown]		27	Line 25	425,345.91	181,254.14	(2,718.86)	(847,978.44)	(123,666.13)	-	-	-	-	(34,282.62)	(322,001.11)	362,501.36	(141,121.70)
YU3 1277/T Drawdown		28								(106,583.19)	(232,703.61)	2,777.18	-	-	-	(336,775.62)
YEC 5% impact		29											34,282.62	368,770.93	119,514.28	516,167.83
Ending reserve balance		30	Line 26+27+28+29	3,196,462.41	3,376,716.55	3,391,406.73	2,537,375.29	2,763,705.91	2,573,788.19	2,467,482.00	2,234,778.39	2,227,480.57	2,227,480.57	2,374,280.39	2,494,794.67	
Interest Calculation:																
Monthly interest rate		31		3.83%	3.84%	3.83%	3.42%	3.47%	3.46%	3.52%	3.58%	3.61%	3.93%	3.96%	2.72%	
Monthly interest accrued		32	Days[Int(y)] * ann * [days/365]	9,884.93	6,440.00	8,638.20	8,585.00	7,811.00	7,358.05	7,394.00	7,211.00	6,588.50	7,549.00	7,486.00	5,901.00	87,516.68
				[1,893.54]	0.00	[0.20]	[1,868.36]	0.00	0.00	[1,887.45]	0.00	0.00	[1,763.74]	0.00	0.00	[7,383.29]
Service fees		33		7,208.45	6,440.00	6,900.00	6,629.44	7,811.00	7,358.05	5,506.55	7,211.09	6,869.00	5,713.20	7,486.00	5,901.00	65,133.72
Net interest accrued		34	Line 32+33													
				7,208.45	6,440.00	6,900.00	6,629.44	7,811.00	7,358.05	5,506.55	7,211.09	6,869.00	5,713.20	7,486.00	5,901.00	65,133.72
Cumulative net interest accrued		35		7,208.45	13,648.45	20,548.45	27,177.89	34,988.89	42,346.94	47,853.49	55,064.58	61,933.58	67,647.78	75,133.78	81,034.78	
Ending reserve balance (including interest)		36	Line 30+35	3,203,670.87	3,390,356.55	3,398,306.18	2,544,553.18	2,771,693.79	2,581,135.13	2,473,335.55	2,241,843.48	2,234,349.57	2,233,194.35	2,381,414.17	2,499,828.45	

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EXHIBIT B-17

AN ORDER IN THE MATTER OF the Public Utilities Act
Revised Statutes, 1986, c. 143, as amended

and

Yukon Energy Corporation and The Yukon Electrical Company Limited
Diesel Contingency Fund Reports

BEFORE: B. Morris, Chair)
G. Leslie, Member)
C. Metz Murray, Member)
D. Schmekel, Member)
W. Shanks, Member) October 27, 1999

ORDER 1999-3

WHEREAS:

A. The terms of the 1996/97 Negotiated Settlement approved by Board Order 1996-6 provided for the creation of a Diesel Contingency Fund ("DCF") to smooth customer rate changes and offset forecast diesel costs.

B The terms also provided that an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board is to direct the Companies on the additions and deletions to the fund.

C. On June 6, 1999 Yukon Energy Corporation filed a report, detailing the changes to the Diesel Contingency Fund in 1998, together with revised reports for 1996 and 1997. The filing also included, for convenience, copies of relevant DCF tables for The Yukon Electrical Company Limited.

D. On June 17, 1999 the Board distributed copies of the report to interested parties for comment.

E. On July 4, 1999 the Utilities Consumers' Group ("UCG") responded with some preliminary concerns and requested a full review of this report with a similar process to rate hearings; interrogatories and responses to/from the Companies to the various intervenor concerns. No other comments were received.

F. The Board forwarded the UCG concerns to the Companies but noted that the Board had the ultimate jurisdiction over the DCF.

G. On October 7, 1999 Yukon Energy Corporation provided comments on the submission from the Utilities Consumers' Group and additional information to assist the Board in its review.

H. The Board has reviewed the material and finds that approval of the report is in the public interest.

NOW THEREFORE the Board orders that:

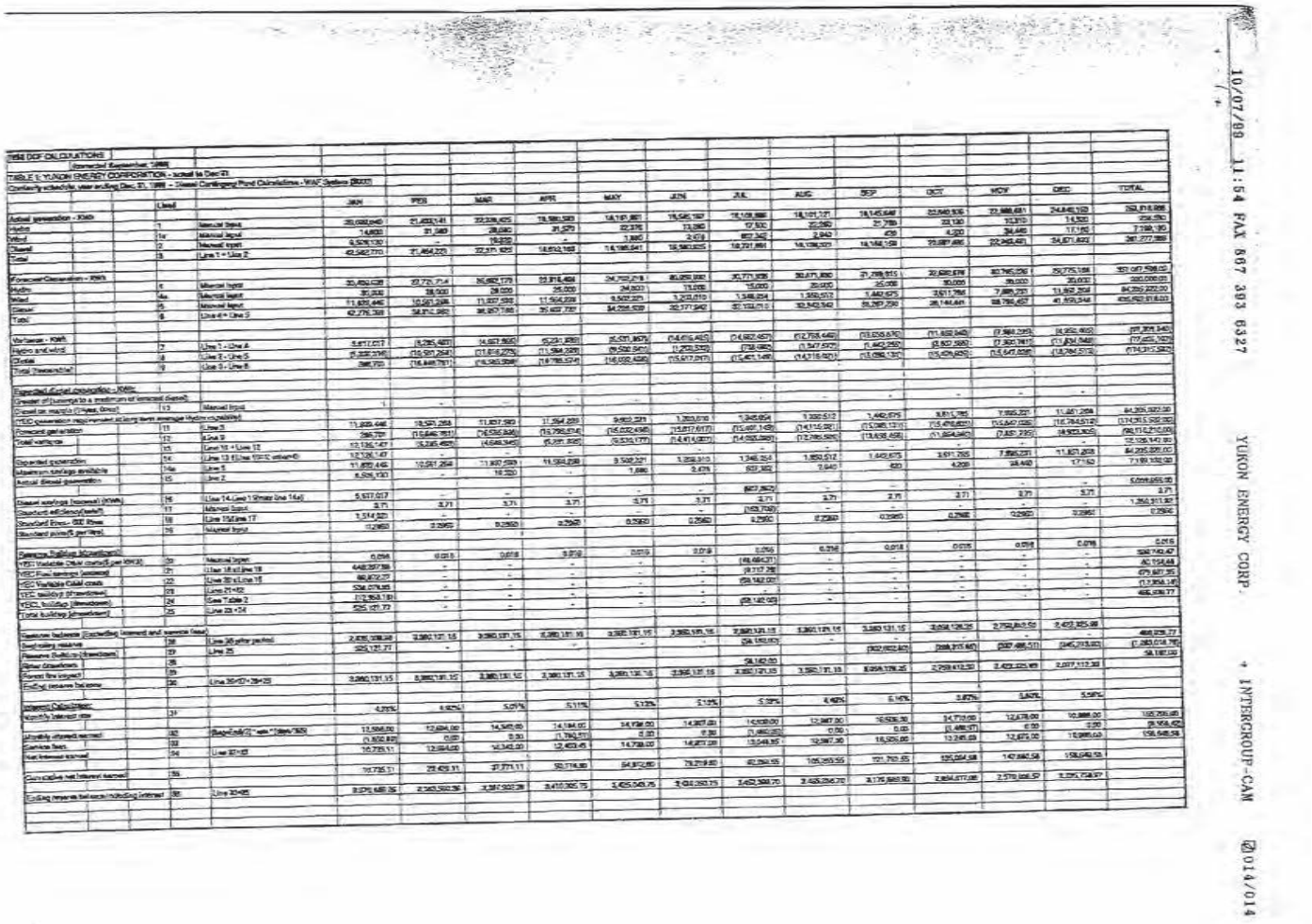
1. The Board approves the additions and deletions to the Diesel Contingency Fund for 1996 to 1998 as filed.

Dated at the City of Whitehorse, in the Yukon Territory, this 3rd day of November 1999.

BY ORDER



Brian Morris
Chair



10/07/89 11:54 FAX 867 393 6327 YUKON ENERGY CORP. → INTERGROUP-CAM 014/014

TOPIC: **YECSIM Modelling**

REFERENCE: **YEC DCF-ERA filing**

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding expected (GRA forecast) YEC Wind generation and actual less expected Fish Lake hydro generation.

2. The diesel generation and increase for the added load are based on polynomial equations derived from "YECSIM" – the simulation model developed for the Integrated Grid by KGS Group.

3. The simulation model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981- 2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.

4. The simulation model outputs for this table are based on Aishihik operation rule at 10-year rolling average spring elevation no lower than 913.7 m and current Mayo Lake operation rule (no additional storage), Mayo B and Aishihik 3rd turbine are included.

5. The simulation model outputs are based on 2012 forecast load distributions [updated based on YUB Order 2013-01], and requires modifications when new mines or industrial loads are connected to the grid.

6. This table assumes max load at 475 GW.h and minimum load at 400 GW.h. If the load exceeds these limits then the table needs to be updated.

PREAMBLE:

Further information is required.

QUESTION:

a) With regard to the YECSIM modelling tool,
   i. please explain the origin and development of the tool.
   ii. does the tool provide for Monte Carlo simulations? If so, are YEC's approved 2012- 2013 GRA forecasts, based on Monte Carlo simulations? If not, why not?
   iii. are planned and unplanned outages that effect generation facilities factored into the YECSIM output — i.e. the annual long-term average hydro generation requirements for the integrated system for the 2012-2013 test years? Please explain.
   iv. what is meant by diesel being on the margin? Please explain.
   v. can base load diesel requirements for the test years be discerned using the output from YECSIM?
   vi. based on the YECSIM model output, please explain why the DCF should be activated.
   vii. how does the model account for new hydro facilities or capabilities into hydro LTAs, considering that there may not be a long-term history to work with?
   viii. is the YECSIM model a load flow analysis tool?
   ix. with regard to ERA calculations, are the calculations and subsequent billing to YECL based on all hours, peak hours or non-peak hours of operation? Please explain.

b) When comparing actual diesel generation requirements with YECSIM output for a test year vs. a test year forecast, how is one to discern what is causing the requirement for incremental diesel generation (customer load changes, risk events that result in added diesel, vs. water availability) considering YEC's submission that "water-related considerations…form the essential foundation for

the DCF…"[1]

c) Please explain how the YECSIM model can be tested for accuracy — i.e. can backward forecasting be undertaken, for example the 2012 test year?

ANSWER:

(a)

The above quotes are footnotes to Table 1.1-1 in Attachment 1.1 (page A1.1-8) of YEC's January 31, 2014 submission. This table provides expected YEC diesel generation with LTA YEC hydro generation assuming only Minto and Alexco mine loads for 2012 as per the Compliance Filing. While reviewing the question, it was noted that footnote #2 should be corrected by adding "results" after words "derived from "YECSIM" as the equation was developed based on YECSIM model results, not in YECSIM model.

Responses to specific sub-questions under (a) are provided below.

(i)

YEC approached KGS Group in 2007 to prepare a plan for preparation of a numerical model that could be used for analysis of the operation and future expansion of the YEC electrical generating system. From 1992 up to 2006 Yukon Energy had continued to use Acres (now Hatch-Energy) MULRES model for its hydro resource planning for the purposes of assessing various supply option scenarios.[2]

The developers of the YECSIM model prepared the structure of the model to follow other well established precedents in this field. KGS Group staff has been actively involved in understanding and applying similar models that have been used for similar purposes in other hydro-thermal electric power systems. Examples are:

1. The Pacific Northwest Power Pool Model (PNPP) that represents the operation of the Columbia River hydroelectric power system.

[1] YEC DCF-ERA supplementary filing, June 30, 2014, Attachment 1, page 1-2.
[2] See response to YUB-YEC-2-17 in 2006 YEC Resource Plan hearing.

2. The PNPP was the basis also for planning and optimizing the design and operation characteristics of the Itaipu Power Development in the south-central Brazil power system. The latter was a model that simulates the operation of over 50 reservoirs in Brazil as well as the Itaipu facility, which at the time (1980's) was the largest single power plant in the world. The simulation model used by KGS staff members in engineering of that plant is similar in structure to YECSIM.

3. KGS Group staff have also been involved in peer review of the SPLASH model of Manitoba Hydro that is used for planning the expansion of the Manitoba Hydro system. The model is similar in nature to YECSIM, which adds to the confidence that the procedures being used are appropriate and state-of-the-art. In addition, KGS Group conferred with Manitoba Hydro at the outset of the YECSIM development to confirm various concepts of modelling that Manitoba Hydro had deployed.

YECSIM was custom-made by the developers to acknowledge all significant factors that affect the operation of the YEC power system. This includes the complex rules of operation and the regulatory demands on YEC. Please see response to AEY-YEC-1-5(c) and (d) for additional information.

(ii)

The YECSIM model does not apply Monte Carlo simulations. The model uses, instead, the recorded sequences of river flows (termed "water years") and superimposes it over the projected years being analyzed (termed "load years"). Each combination of a sequence of "water years" and "load years" constitutes a "cycle". The "water years" are then shifted by one year and superimposed on the "load years" again, and this process is repeated until all possible sequence combinations ("cycles") have been applied. This provides the hypothetical scenario of energy generation capability that would occur if the recorded series of "water years" would repeat itself.

In this respect, YECSIM is no different from Manitoba Hydro's SPLASH model. KGS Group consulted with Manitoba Hydro on SPLASH and how their modeling strategy could be applied to YECSIM.

In a Monte Carlo simulation, a number of synthetic series of "water years", all having the same statistical parameters of the recorded series would be generated and used as hydrologic inputs. This would allow obtaining multiple scenarios of the energy generation that would occur if the hydrologic inputs would resemble the recorded series. The more scenarios that are generated, the closer the results would be to those obtained with the historical series.

The algorithms for synthetic generation are challenging and, although applied in academic research, there is an aura of uncertainty as to whether they can provide realistic stream flows, particularly when, as in the case of YECSIM, the model includes a number of diverse watersheds. There has been hesitancy in the industry, at least in the era leading up to the development of YECSIM, to use synthetic generation of streamflows. KGS Group is not aware of other existing models that deploy Monte Carlo procedures for synthetic flow generation.

Another area where Monte Carlo procedures could be applied is in the projection of loads that are input to the model. YECSIM does not use Monte Carlo simulations in this respect. Although it would add knowledge about the uncertainty of the projections, for the purposes for which the model is used, the Monte Carlo simulations would provide the same knowledge of best estimates that are obtained with YECSIM. Typically, additional information about uncertainty is obtained with YECSIM by applying sensitivity analysis on the loads used as input.

(iii)

Yes. The input parameters allow including forced outages in the estimate of energy from each plant. The values normally used in simulations are derived from YEC's experience and can be modified by the user of the model.

(iv)

As reviewed in response to YUB-YEC-1-2(a), YEC's current DCF proposal addresses a situation for the 2012-2013 GRA test years, as well as subsequent years, when diesel is forecast to be "on the margin", i.e., diesel is forecast to be required to meet firm energy requirements (and not just periodic peaking conditions) at long-term average hydro generation water conditions.

Table 1.1-1 does not specifically reference "diesel being on the margin"; however, as explained at pages A1.1-1 though A1.1-4 of Attachment 1.1 of the submission, the table shows expected (long-term average) diesel generation requirements for various grid loads as indicated, net of expected YEC wind and expected Fish Lake generation.

Appendix 1.1 at page 1.1-2 reviews the DCF background, and indicates that diesel was defined in the past to be on the margin when it was being used to meet long-term firm energy requirements, not just periodic peaking requirements (as explained in YUB-YEC-1-2(a), in practice that meant when the Faro mine was operating).

(v)

The YECSIM model does not discern "baseload" diesel requirements from any other diesel requirements that are to be expected based on a defined grid load (net of expected wind and Fish Lake hydro), the water years of record and other parameters as noted. Similarly, the DCF as approved in the past did not discern "baseload" diesel requirements from any other diesel requirements when "diesel was on the margin", i.e., the Faro mine was operating (see YUB-YEC-1-2(a)).

(vi)

Based on the principles approved for the DCF to provide rate stability with regard to variations in water flow impacts on grid diesel generation, the DCF is to be activated when diesel is "on the margin", i.e., when diesel generation is expected to be required to meet firm energy requirements at long-term average hydro generation water conditions (see response to (iv) above for elaboration and cross references).

The YECSIM model output confirms that diesel is "on the margin" in the 2012-13 GRA test years, based on the above definition, and that the DCF should therefore be activated.

More specifically, based on the YECSIM model assessments for 2012 and 2013 grid loads, and Board Order 2013-01 wherein diesel generation costs for these test years were determined based on 100% of long-term average hydro generation as assessed by YECSIM for the approved grid load forecasts, diesel generation is forecast to be on the margin in 2012 and 2013 under long-term average (LTA) hydro generation water

conditions - and, on the basis of past principles for the DCF, these determinations mean that the DCF should be activated.

(vii)

The model is intended to be used for planning of system changes or additions.

To assist in planning, the model can incorporate new hydro facilities or capabilities, while retaining the historical record of actual water conditions that will affect operation of new capabilities.

New and existing sites are simulated based on the corresponding physical characteristics, the applicable license conditions and, if any, operational limits such as the priority sequence in the use of reservoir waters.

One motivation to develop the YECSIM model was that it would allow simulating an interconnected YEC system (i.e., connection of the WAF and Mayo Dawson grids), for which there was no historical data at the time. As a planning tool, the YECSIM model allows to test various scenarios for potential sites to assist on making design or operational decisions.

(viii)

No. YECSIM is not a load flow analysis tool. While load flow analyses are directed to study the electrical components of the system, YECSIM is more focused in the use of hydrologic inputs to supply system loads.

(ix)

ERA calculations are based on variances in YECL wholesales from Board approved forecasts for all such sales during each year, and the changes in annual diesel energy generation costs to YEC (based on expected LTA diesel requirements) that result from such variances. As noted in response to (v) above, YECSIM determinations of LTA diesel requirements do not discern baseload diesel requirements as such.

(b)

DCF determinations (i.e., more specifically for this response, the determination of the gap for DCF purposes between expected and actual diesel generation) under past and proposed implementation measures isolate the impact of water-related variances (i.e., variances from long-term average hydro generation water conditions) as these affect actual diesel generation requirements.

As reviewed in the YEC submission, YECSIM output for either a grid load forecast for a test year or an actual grid load as recorded for a test year provides "expected diesel generation" based on the defined grid load, the water years of record, and the other parameters as noted from the model.

"Expected diesel generation" as provided by YECSIM output does not reflect the impact of risk events not related to water conditions (e.g., diesel generation due to transmission outages, or diesel generation funded by RFID or insurance events) or diesel generation due to capital project restriction of hydro generation. DCF determinations under past and proposed implementation measures adjust actual diesel generation as required to remove the impact of these factors so that the DCF does not fund such risks or events.

"Expected diesel generation" as provided by YECSIM reflects the extent to which LTA diesel generation (as a <u>percent</u> of total generation) changes as grid load changes, thereby reflecting the fact that under current load conditions (unlike when the Faro mine was operating) LTA diesel generation accounts for less than 100% of any variance in grid generation requirements. Subject to this refinement, DCF determinations under past conditions (with Faro mine operation) and under current conditions with YECSIM output do not allow the DCF to fund the non-water-related diesel generation impacts of grid load variances from approved forecasts. The following demonstrates this point:

- DCF determinations with the Faro mine in operation assumed that expected diesel would account for 100% of any change in grid load, i.e., on this basis expected diesel generation increased or decreased directly (at 100% of the change) for any change in grid load from approved forecast (and the DCF, which deals only with a gap between expected and actual diesel generation, would accordingly not be charged for any portion of any such change in diesel

generation due solely to changes in actual grid load relative to approved forecasts).

- The same principles apply today with the DCF determinations using the YECSIM outputs - the only change is that YECSIM outputs determine how much of any change in load from approved forecasts can be "expected" (under LTA conditions) to be reflected by a change in hydro generation rather than by only a change in diesel generation. The overall result of YECSIM outputs in this regard is to reflect reduced expected diesel generation from what would otherwise occur if all load variances were assumed to be 100% accounted for by changes in expected diesel generation.

(c)

Being a planning model, YECSIM (as well as similar planning models such as Manitoba Hydro's SPLASH model) is not structured in a way that lends itself to retrospective verification per se. A detailed verification of a test year has not been made, for example, and such a verification or "test" would not normally be seen as a verification that is required or appropriate for this type of a planning model.

However, the model is a composite of many sub-models that combine to provide an accurate representation of the YEC power system under a variety of hydrological conditions. The accuracy of individual components of the model, such as energy generation for given flows and heads, has been verified individually. These are known to be accurate representations of the real phenomenon. Model inputs such as spillway discharge rating curves have been based on and verified with actual data.

TOPIC: **YECSIM model**

REFERENCE: **YEC DCF-ERA filing**

> …in 2012 the YECSIM forecasted 15.6 GW.h of diesel generation at actual grid load, but actual diesel generation was 2.7 GW.h. In 2013, the YECSIM forecasted 13.3 GW.h of diesel generation at actual grid load, but actual diesel generation was 1.1 GW.h.[1]

PREAMBLE:

Further information is required.

QUESTION:

a) Per the above quote taken from YECL's DCF ERA January 31, 2014 filing, please explain why there are diesel generation variations between forecast and actual diesel generation at actual 2012 and 2013 grid loads?

b) Please rerun the YECSIM model using actual grid load and actual hydro water availability and provide results for forecast diesel generation requirements.

c) For any one month — say February 2012 — assuming:
   i. that the Board adopted YEC's proposed formulaic approach, wherein the DCF is permanently switched on, and
   ii. that the historical DCF trigger approach was adopted and further assuming that diesel was on the margin for the month of February 2012, please provide and compare the respective calculations, and explain the differences between the two methodologies.

[1] YECL DCF-ERA filing, January 31, 2014, page 4.

ANSWER:

(a) and **(b)**

The diesel generation variations between YECSIM forecasts as quoted above and actual diesel generation at actual 2012 and 2013 grid loads reflect the difference between diesel generation required under long-term average (LTA) hydro generation water conditions at actual grid loads and diesel generation required under actual water conditions in these two years, i.e., the specific variance required for the purpose of DCF determinations for each year (subject to any adjustment needed of actual diesel generation to reflect impact of non-water-related factors).

The entire relevance of any DCF determination is to address the variance between actual and LTA diesel generation requirements in any year due to variances in water availability. YECSIM forecasts are used to indicate the LTA diesel generation requirement for DCF as well as system planning purposes. As reviewed in more detail below, this purpose of YECSIM, and its relevance to DCF determinations, are completely misunderstood in the YECL submission - including the quote referenced above. YECSIM has been used in YEC's submissions to indicate adjusted LTA diesel generation forecasts based on actual 2012 and 2013 grid loads - however, given its purpose, the YECSIM model cannot be rerun as requested in (b) above "using actual grid load and actual hydro water availability" in order to "provide results for forecast diesel generation requirements".

Issues related to the YECL submission assertions on this matter are reviewed in more detail below.

The above quote from YECL's DCF-ERA January 31, 2014 filing is part of a paragraph wherein YECL asserts that YECSIM is used "to forecast diesel generation", that as such YECSIM "will require careful testing", that YECSIM's forecasts of diesel generation in 2012 and 2013 differed materially from actual diesel generation, and that "Notwithstanding that apparent inaccuracy, YEC proposes to use these as the simulated diesel amounts to calculate its fuel variance, i.e., as the basis for its proposed DCF and ERA."

The YECL submission apparently does not understand that the term "expected diesel generation" as used in the past and present DCF determinations has nothing whatsoever to do with a short term forecast of diesel generation that is likely to occur in any specific year based on current water conditions as well as forecast grid loads. "Expected diesel generation" under past DCFs (with Faro mine operation) or the proposed DCF (using YECSIM outputs) is the diesel generation expected to be required at a specified grid load under LTA hydro generation water conditions. Actual diesel generation at the same grid load will, of course, be affected by actual water conditions - and the DCF's purpose is to ensure that YEC's diesel generation costs (as these affect its income statement) in any year are based on LTA rather than actual diesel generation.

The difference between LTA and short term diesel generation forecasts was fully reflected in YEC's 2012-2013 GRA. As reviewed in response to YUB-YEC-1-1(a), YEC's 2012-2013 GRA as filed in April 2012 referenced short term hydro generation forecasts reflecting the then current favorable water conditions and indicating likely diesel generation at only 20% and 38% of LTA in 2012 and 2013 respectively. The record of actual water conditions as well as actual loads in 2012 and 2013 resulted in actual diesel generation at only 17% and 8% of LTA in 2012 and 2013 respectively - which simply confirms the extent to which actual hydro generation water conditions in each test year were in fact well above LTA. In each case, the LTA determination has been adjusted (using YECSIM-based tables) to reflect LTA diesel generation at the actual grid load.

As reviewed in YEC's DCF-ERA supplementary filing of June 30, 2014 in Attachment 2, pages 2-1 and 2-2, YECL's submission also incorrectly asserts, based on the above incorrect assessments of the YECSIM "forecasts", that YEC "had substantial savings over the forecast diesel costs" in 2012. In fact, as a result of higher than forecast generation requirements (largely resulting from wholesales to YECL being higher than the approved forecast), YEC incurred actual diesel charges (under the DCF as proposed) that were materially higher than approved in the forecast used to set rates for 2012. In summary, under the DCF as applied in the past and proposed today, the "saving" between actual and expected diesel generation costs under higher-than-LTA water conditions (such as occurred in 2012 and 2013) is charged to YEC and deposited in the DCF, i.e., it is retained for the benefit of ratepayers in future years and is not taken into YEC income.

(c)

This question asks that YEC provide DCF determinations for "any one month" in 2012 (say February) under (i) the proposed "formulaic approach" and (ii) "the historical DCF trigger approach" assuming that diesel was on the margin in the selected month, and that YEC "compare the respective calculations, and explain the differences between the two methodologies."

As explained below, it is not possible to provide the requested DCF determinations or comparisons.

As reviewed in responses to YUB-YEC-1-1 and YUB-YEC-1-2, the historical and proposed DCF determinations are in principle similar for years such as 2012-2013 when "diesel is on the margin", i.e., diesel is required to supply firm load requirements under LTA hydro generation water conditions. These responses clarify that the historical DCF "trigger approach" in this regard simply addressed whether the Faro mine was operating or not in any given month - and in this regard, so long as the Faro mine was in operation, actual diesel generation in a month did not affect whether diesel was determined "to be on the margin" in that month.

Further, the ultimate determination of DCF impacts in any year generally depends on the full year assessments and not on individual month assessments. This caveat is of particular importance for the proposed formulaic approach where month-by-month assessments are placeholders and model assessments are intended to be provided on a full annual basis.

Subject to the above comments, the DCF as approved historically and as proposed today both make determinations (as to DCF charges or rebates) based on the difference between actual diesel generation and LTA diesel generation as then estimated. In this regard, as reviewed in Attachment 1.1 of YEC's January 31, 2014 submission, the only material difference between the historical and current proposed approach relates to the estimate of LTA diesel generation at the forecast grid loads. As reviewed in the submission, the proposed formulaic approach addresses necessary updates to the grid system (including interconnection of WAF and Mayo grids and new hydro generation facilities) as well as the variability of expected LTA hydro generation today at different grid load levels and conditions. YEC has no basis to provide a DCF estimate based on

the historical LTA hydro generation assumptions that would be relevant for today's conditions.

TOPIC: **DCF ERA Calculations**

REFERENCE: **YEC DCF-ERA supplementary filing**

> Historically, both the DCF and the earlier Low Water Reserve Fund (LWRF) were implemented to address variances in the cost of diesel generation related solely to hydro generation variations from GRA approved forecasts that are due to hydro capability variances (e.g., water flows variances). The LWRF and DCF did not address other reasons for diesel generation cost variances (e.g., neither the LWRF nor the previously approved DCF addressed diesel generation cost variances from forecasts due to fluctuations in sales or overall generation requirements, variances in fuel prices, or variances in diesel plant efficiencies or average O&M costs per kWh).[1]
>
> ...
>
> The LWRF and DCF included provision for "expected diesel" at varying grid loads and thereby ensured that actual diesel generation would be compared against "expected diesel" generation that would apply to actual grid loads. The proposed DCF in essence retains similar provisions to ensure that, when carrying out the DCF determinations in any year, actual diesel generation is compared with "expected diesel" applicable to the actual grid loads that occur.[2]

PREAMBLE:

Further information is required.

QUESTION:

a) Please explain clearly what YEC is alluding to when submitting that the proposed DCF in essence retains similar provisions as the previously approved DCF. Please explain what YEC is referencing when it refers to similar provisions.

[1] YEC DCF-ERA supplementary filing, June 30, 2014, page 1-6.
[2] YEC DCF-ERA supplementary filing, June 30, 2014, page 1-6, footnote 11.

b) Respecting the previously approved DCF, were the utility GRA forecasts based on long-term average hydro values?
   i. If so, are the methodologies and calculations associated with YEC's proposed DCF similar to the previously approved DCF? Please explain and provide example DCF calculations for both methods.
   ii. If not, respecting the "water-related considerations that form the essential foundation for the DCF," how does the LTA forecasting methodology, which YEC currently uses, allow for the same considerations that were given the previously approved DCF?

c) Respecting the previously approved ERA calculations, were the underlying calculations based on long-term average hydro values? Also, are the methodologies and calculations associated with YEC's proposed ERA similar to the previously approved ERA calculations? If so, please explain why the methodologies and calculations are still appropriate.

d) With regard to the ERA calculations based on the YECSIM model output, please explain how incremental diesel fluctuations can be attributed to wholesale sales to YECL, considering that the fluctuations may arise because of other increased YEC loads, for example — and not limited to — forced outages to hydro facilities or transmission lines, extended planned maintenance outages.

ANSWER:

(a)

The quoted reference to "similar provisions as the previously approved DCF" is as follows: "The proposed DCF in essence retains similar provisions ["for 'expected diesel' at varying grid loads"] to ensure that, when carrying out the DCF determinations in any year, actual diesel generation is compared with 'expected diesel' applicable to the actual grid loads that occur."

YEC is referencing the following as regards the relevance of "expected diesel" in DCF determinations when diesel is on the margin:

- The previously approved DCF and the proposed DCF as applied in any year both compare long-term average (LTA) "expected diesel generation" (at the actual grid loads that occur) to actual diesel generation (net of any diesel requirements funded by RFID or insurance, or due to transmission outages, or due to capital project restriction of hydro generation). In both cases, the following apply when diesel is on the margin:
    - YEC diesel generation costs incurred against income in any year are determined based on "expected diesel generation" at actual loads (i.e., based on LTA water and wind conditions) rather than actual diesel generation based on actual water and wind conditions.
    - DCF charges to YEC (or rebates to YEC) in any year are determined based on the difference between LTA "expected diesel generation" at actual loads and actual diesel generation (net of adjustments as noted above).
    - Costs for "expected" and actual diesel generation in each case are based on Board-approved fuel prices per kW.h, fuel efficiencies and (where applicable) non-fuel O&M costs per kW.h. [The proposed DCF only includes diesel fuel prices and unit fuel efficiency, i.e., 28.71 c/kW.h, which is the average YEC diesel fuel price in the test year based on the 2012-13 Compliance Filing].[3]

- "Expected diesel generation" in both the previously approved DCF and the proposed DCF result in diesel generation costs for GRA revenue requirement and rate determinations being based on LTA water conditions rather than the actual water conditions that affect hydro generation in any year. More specifically, the following are noted:

    - The previously approved DCF, which applied only to WAF, specified long-term average (LTA) renewable generation that applied in any year when

[3] See YEC DCF-ERA filing, January 31, 2014, page A1.1-4 and A1.1-5 for further explanation.

diesel was on the margin (i.e., the Faro mine was operating).[4] In these earlier DCF situations, LTA expected renewable generation when the Faro mine was operating was assumed not to change with different grid load levels. The last GRA approved revenue requirement and rates that assumed Faro mine operation (1996/97) included approved diesel generation costs based on 100% of LTA WAF YEC hydro generation as well as LTA expected wind and Fish Lake hydro generation.

- The proposed DCF in the current filing specifies LTA YEC hydro generation for the integrated grid (includes Mayo) using a formulaic approach (YECSIM model) which adjusts LTA hydro generation for different grid loads; LTA expected wind and Fish Lake hydro generation are also specified based on updated information as approved at the 2012-13 GRA. The 2012-13 YEC GRA, as approved in Order 2013-01, included approved diesel generation costs based on 100% of LTA YEC hydro generation as well as LTA expected wind and Fish Lake hydro generation.

(b)

As reviewed in (a) above, utility GRA forecasts with the previously approved DCF were based on long-term average hydro values.

Subject to updates to reflect current load and grid conditions, the response to (a) above confirms that the methodologies and calculations associated with YEC's proposed DCF are similar to the previously approved DCF.

"Expected diesel generation" as provided by YECSIM in the proposed DCF reflects the extent to which LTA diesel generation (as a <u>percent</u> of total generation) changes as grid load changes, thereby reflecting the fact that under current load conditions (unlike when the Faro mine was operating) LTA diesel generation accounts for less than 100% of any variance in grid generation requirements. Subject to this refinement, DCF determinations under past conditions (with Faro mine operation) and under current conditions with

[4] See YEC DCF-ERA filing, January 31, 2014, page A1.-1 which notes the following as regards the previously approved DCF: expected LTA hydro generation by YEC at Aishihik and Whitehorse combined at 351 GW.h/year plus expected LTA wind generation at 0.3 GW.h/year and expected LTA Fish Lake hydro generation at 10 GW.h/year.

YECSIM output, do not allow the DCF to fund the non-water-related diesel generation impacts of grid load variances from approved forecasts.

The following example demonstrates this point:

- DCF determinations with the Faro mine in operation assumed that expected diesel would account for 100% of any change in grid load, i.e., on this basis expected diesel generation increased or decreased directly (at 100% of the change) for any change in grid load from approved forecast (and the DCF, which deals only with a gap between expected and actual diesel generation, would accordingly not be charged for any portion of any such change in diesel generation due solely to changes in actual grid load relative to approved forecasts). The following hypothetical example is provided, assuming that expected diesel generation accounts (as per the previously approved DCF) for 100% of any change in total generation from the forecast loads:

    - Assume forecast grid generation at 50 GW.h with 10 GW.h diesel generation and 40 GWh hydro at LTA.

    - Assume actual total generation of 60 GW.h with 20 GW.h diesel.

        - With LTA hydro fixed at 40 GW.h, "expected diesel" with the actual load is 20 GW.h, and therefore equals actual diesel, i.e., no DCF impact.

    - If however actual diesel at 60 GW.h total generation had been 30 GW.h rather than 20 GW.h, actual diesel would be 10 GW.h higher than expected diesel (and this 10 GW.h balance would be funded by the DCF).

- The same principles apply today with the DCF determinations using the YECSIM outputs - the only change is that YECSIM outputs determine how much of any change in load from approved forecasts can be "expected" (under LTA conditions) to be reflected by a change in hydro generation rather than by only a change in diesel generation. The overall result of YECSIM outputs in this regard is to reflect reduced expected diesel generation from what would otherwise occur if all load variances were assumed (as in the previously approved DCF) to be

100% accounted for by changes in expected diesel generation. The above hypothetical example is repeated below, assuming that expected diesel (based on YECSIM for the relevant loads) accounts for 50% of any change in total generation from the forecast loads:

- Assume forecast grid generation at 50 GW.h with 10 GW.h diesel generation and 40 GW.h hydro at LTA.

- Assume actual total generation of 60 GW.h with 20 GW.h diesel.

  - With LTA hydro assumed to account for 50% of any change in total generation from the forecast load, LTA hydro generation now equals 40+5=45 GW.h, "expected diesel" with the actual load is 15 GW.h, and therefore actual diesel exceeds expected diesel by 5 GW.h (and this amount would be funded by the DCF).

- If however actual diesel at 60 GW.h total generation had been 30 GW.h rather than 15 GW.h, actual diesel would be 15 GW.h higher than expected diesel (and this 15 GW.h balance would be funded by the DCF).

(c) and **(d)**

The ERA as previously approved, and as now proposed, applies only to variances of actual wholesales versus approved GRA forecast wholesales when diesel is on the margin - and in each instance the ERA calculations estimate the net impact of the wholesales variance on YEC net income (after DCF impacts and revenues at the approved wholesale energy rate) based on the LTA hydro generation and actual diesel generation used for the DCF determinations.

To elaborate on the above, the following are noted regarding the previously approved ERA calculations when diesel is on the margin:[5]

- The ERA was first approved in Board Order 1993-7, using the same wording as the two utilities had proposed in Exhibit 229 filed on October 7, 1993 in the

[5] See also YEC DCF-ERA filing January 31, 2014, Appendix 2, page 2-2.

1993/94 GRA. This ERA wording remained unchanged for each Rate Schedule 42 subsequently approved by the Board during the period when the Faro mine was in operation.

- This previously approved ERA wording included provision for the following:
  - Charges to YECL will be adjusted to reconcile actual wholesale purchases to test year forecast purchases [these adjustments applied to increases or shortfalls in actual wholesale purchases relative to test year forecasts as approved by the Board].
  - The adjustment to YECL bills will be made at a rate equal to the approved run out rate for non-government residential service for the Hydro rate zone [this run out rate reflected YEC incremental diesel generation cost impacts for fuel, O&M and system losses for power delivered to the customer - it also was assumed to reflect the incremental revenue impact on YECL associated with increases or shortfalls in actual wholesale purchases].
  - Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period [this provision was intended to reflect the point at which reduced purchases would not result in savings in YEC diesel generation costs].
- The last approved ERA for Rate Schedule 42 (per Board Order 2011-6, after a joint submission by the two utilities) continued the earlier ERA provisions with the following clarifications and/or updates:[6]
  - The ERA will apply "during months when diesel generation in the Hydro zone is on the margin at long term average water flows".
  - The related adjustment to YECL bills will be made at a rate equal to the Hydro zone incremental cost of diesel of 32.74 c/kW.h as approved by the Board in Order 2010-13. [The YEC incremental cost of diesel significantly exceeds YECL's average 2012 retail energy rate (excluding block 1)

[6] See YEC DCF-ERA filing January 31, 2014, Appendix 2, page 2-3.

estimated at 13.38 c/kW.h as well as the wholesale Rate Schedule 42 energy rate otherwise applicable of 8.298 c/kW.h].

The ERA methodologies and calculations associated with YEC's proposed ERA are similar to the previously approved ERA calculations, subject to the proposed edits to clarify and update the ERA as set out in YEC's filing.[7] The proposed edits reflect, among other considerations, requirements for consistency with the proposed DCF determinations. Table 2 of YEC's filing[8] as revised and updated in response to YUB-YEC-1-25 shows the proposed ERA calculations, including:

1. Step 1: Determination of incremental wholesales (actual versus approved forecast) net of Fish Lake impacts. [Fish Lake variance from expected LTA is addressed in the proposed DCF determinations, as directed in Board Order 2013-01 – the incremental wholesale change is determined net of the Fish Lake variance from expected LTA, and equals 13,272 MW.h for 2012].

2. Step 2: Determination of the average percentage of incremental expected diesel generation in base rates, based on the changes (actual versus approved forecast) in YEC expected diesel generation and total YEC generation. [By way of example, Table 2 as revised in YUB-YEC-1-25 shows that incremental diesel accounted for 42.8% of the change in total generation (actual versus approved forecast). Note that this determination is not affected by actual diesel generation, i.e., it reflects expected diesel generation at each of the relevant grid loads].

3. Step 3: Determination of the YEC incremental expected diesel generation related to the wholesale variance from forecast. [For 2012, 42.8% of the 13,272 MW.h wholesale variance, plus YEC average losses (to reflect generation rather than sales), yielding 6,176 MW.h expected diesel generation impact for YEC as shown in YUB-YEC-1-25, Line M].

4. Step 4: Determination of ERA based on net cost impact on YEC of the wholesale variance after consideration of both revenue and diesel fuel generation cost impacts. [For 2012 as shown in YUB-YEC-1-25, the added wholesales (including added sales related to Fish Lake variance) provide added YEC revenue of

[7] See YEC DCF-ERA filing January 31, 2014, Appendix 2, page 2-8.
[8] See YEC DCF-ERA filing January 31, 2014, page 9.

$1.335 million based on average wholesale energy rate and average YEC rate rider revenue times the change in wholesales; the added wholesales also provide added diesel fuel generation cost of $1.773 million based on 6,176 MW.h expected diesel generation impact times 28.71 c/kW.h approved average fuel cost; based on these determinations, the net ERA to be recovered from YECL is calculated ($0.439 million)].

5. A final step is included in YEC's proposed ERA measures to provide for YECL recovery (through a YECL Deferral Account) of any portion of the ERA that is not estimated to be funded by YECL's incremental retail revenues related to the wholesale variance. This measure retains consistency with past practice in utilizing YECL incremental revenues to fund the ERA amounts, while also addressing the current gap between incremental YEC diesel fuel generation costs per kW.h and average YECL incremental retail revenues per kW.h. [Table 2 in YUB-YEC-1-25 shows that YECL's added revenues are estimated to exceed the added YECL costs with the ERA for 2012, but fall slightly short ($0.005 million) in 2013 which leads to this 2013 shortfall being charged to the YECL Deferral Account to be recovered in future from all ratepayers.]

As reviewed in Steps 2 and 3 above, the proposed ERA determination is not affected by actual YEC diesel generation, and therefore is not affected by forced outages or transmission lines or extended planned maintenance outages. The proposed determination of "expected diesel generation" changes for the ERA is based on an average for overall YEC generation changes in the given year, and does not attempt to attribute a specific expected diesel percentage that would apply only to YECL wholesale variances.

TOPIC: **YECL's Proposed Deferral Account Option**

REFERENCE: **YEC DCF-ERA supplementary filing**

> Yukon Electrical's January 31, 2014 Filing provides no detail or example to help explain how the deferral account would be administered, but simply notes that "The proposal above was submitted to YEC during the utilities' discussions". As no supporting detail or explanation was included in the proposal, the Board and other parties are left to interpret an approach based on the wording provided without any guidance [footnotes omitted].[1]

PREAMBLE:

Further information is required.

QUESTION:

a) Per the above quote, please provide all materials that were submitted to YEC during the utilities' discussions, as regards to YECL's proposed DCF ERA deferral account.

b) When YECL presented its proposal for a DCF ERA deferral account, were the mechanics of the proposed new deferral account or how it would operate a part of the materials that YECL provided?

c) Please explain why YEC did not accept YECL's proposals during the utilities' discussions.

ANSWER:

(a)

On July 10, 2013 YECL provided a discussion document to YEC (see Attachment 1).

[1] YEC DCF-ERA supplementary filing, June 30, 2014, Attachment 1, page 1-1.

On October 11, 2013, YECL provided Yukon Energy, on a confidential and without prejudice basis, a draft position paper on the DCF and ERA. In its January 31, 2014 filing YECL stated (page 7) that the proposal in its filing "was submitted to YEC during the utilities' discussions". YEC has subsequently confirmed with YECL that this draft position paper provided by YECL to YEC on October 11, 2013 (which is the only proposal submitted to YEC by YECL during the utilities' discussions) is no longer confidential (please see Attachment 2 to this response for a copy of the October 11, 2013 draft YECL proposal, and Attachment 3 for the related excel file).

(b)

Please see Attachments 2 (section 4.2) and the excel Schedule 1 in Attachment 3 to (a) above as regards the mechanics that YECL provided regarding its proposed new deferral account and how it would operate. In this regard, more clarity was provided in the draft proposal than in YECL's January 31, 2014 submission.

(c)

YECL in effect provided two distinct proposals during the utilities' discussions. These are each reviewed separately below along with Yukon Energy's reasons for not accepting each proposal:

1. **Replace ERA with new YEC deferral account -** This initial YECL proposal was focused only on the ERA and, consistent with YECL's final argument in the YEC 2012-13 GRA proceeding, proposed to discontinue the ERA and replace it with a new YEC diesel deferral account mechanism whereby YEC deals directly with ratepayers, YECL is no longer involved or affected, and YECL is able to retain all added revenues secured from sales in excess of approved forecasts without any offsetting charges for incremental diesel charges incurred by YEC.[2]

[2] YECL's January 31, 2014 submission at page 8 re-iterates this proposal in the event that it is determined that an ERA amount should be charged to YECL, i.e., YECL argues that the full ERA would be flowed through to all Yukon ratepayers based on the wholesale purchase power deferral flow though approved for YECL in Order 2009-02 and referenced in Order 2010-13, and that it would therefore be more efficient for YEC to administer the deferral account.

Yukon Energy addressed this YECL proposal at pages 2 to 7 of its January 31, 2014 filing, in its assessment of Option B for the ERA versus Option A that YEC has proposed.

- Option B discontinued the ERA [and YECL's Purchase Power Deferral Account] and established a new Diesel Deferral Account (DDA) administered by YEC to address YEC's net thermal generation cost changes at LTA related to variances in firm YEC sales from GRA approved forecasts for each retail and industrial customer class (after consideration of all revenue changes related to such variances in firm YEC sales).

- In contrast, Option A retained the ERA with provision to reflect net costs to YEC after all added revenues related to wholesale variances, and provision as well for YECL recovery through its deferral account (and related rate rider) of any net added cost after full consideration of added YECL revenues due to increased sales.

In summary, YEC concluded that Option A as proposed was preferable to Option B based on the following considerations:

- Option A is consistent with past Board Orders that approved an ERA and the directions in OIC 1995/90 section 7(c) regarding wholesale rates charged by YEC to YECL.

- Both options provide for the DCF as proposed by YEC and also protect both YEC and YECL from incurring unrecovered costs related to YEC's incremental diesel generation costs arising from changes in YECL power purchases from YEC.

- Option B would allow YEC to recover added incremental diesel generation costs arising from changes in YEC's industrial and retail sales (estimated added recovery in 2012-13 of $0.088 million).

- However, Option B would have materially higher cost impacts on ratepayers than Option A, e.g., in 2012-13 based on estimates in the

submission, Option A compared to Option B saves ratepayers $0.531 million in deferral account amounts to be recovered through rate riders (83% of which [$0.443 million] relates to YECL wholesales due to the exclusion under Option B of offsetting YECL revenues related to wholesale variances; the balance relates to YEC industrial and retail sales that are affected only under Option B).

- Preference for Option A is dependent on full consideration, as in the past, of YECL's added revenues associated with increases in wholesale purchases, i.e., flow through to YECL's deferral account of the full ERA, without consideration of the offsets for YECL's related revenue changes, is not consistent with Option A and would remove most of the ratepayer benefits for Option A compared with Option B. [YEC's January 31, 2014 filing at page 3 concludes that there is no relevance to an ERA including YECL if YECL's revenue changes are ignored by flow through to YECL's deferral account of the full ERA, i.e., the appropriate option would then become Option B.]

2. **Replace DCF with new YEC diesel deferral account -** This YECL proposal was provided in draft to YEC on a confidential and without prejudice basis in October 2013 (see Attachments 2 and 3 of (a) above), and is re-iterated in YECL's January 31, 2014 submission. As summarized in YEC's January 31, 2014 filing (page 3), this proposal "...would establish a simple new deferral account for YEC that would effectively remove the water-related considerations that form the essential foundation for the DCF (i.e., a fund to protect ratepayers against large variances in rates over the long-term due to fluctuations in hydro generation), and establish a new short-term deferral account mechanism to recover changes in YEC diesel generation (regardless of cause) [from] approved forecasts."

   Yukon Energy has provided, in its June 30, 2014 Supplementary Filing (letter and Attachment 1), a review of this YECL proposal to eliminate the DCF and replace it with a new diesel deferral account. In summary, major points noted by Yukon Energy for not supporting this YECL proposal include the following:

   - Overall, YEC did not view elimination of the DCF, or the re-allocation of risk between utilities and ratepayers, as proposed by YECL with this

proposal as being consistent with directions in Board Orders 2013-1 and 2013-3 to develop joint recommendations regarding the DCF and ERA.

- More specifically, YECL's proposed general purpose diesel deferral account would not provide rate stabilization for ratepayers to address material changes in water availability on the grid and would leave ratepayers without any mechanism to smooth out water-related rate impacts that will occur on Yukon's isolated grid system.

- In YEC's view, such shifting to ratepayers of the full instability of rates related to annual variations in water flows is neither reasonable nor consistent with past precedent, practice and Board decisions - and it is particularly inappropriate to implement today given the Board's decision in Order 2013-01 confirming that loads today on the Yukon grid have reached a level (notwithstanding recent material hydro capability expansion at Mayo and at Aishihik) where significant diesel generation can be reasonably expected on a long-term average basis.

- Further, YECL's proposal in principle is not limited to YEC and the hydro grid, but would in principle apply to all diesel costs in all rate zones, i.e., the general diesel deferral account concept as proposed by YECL would address all diesel variances from forecast due to any factor (e.g., customer load changes, risk events that result in added diesel, as well as water changes), and would thereby shift added risks to ratepayers that today are borne by each utility.[3]

[3] See YEC DCF-ERA supplementary filing, June 30, 2014, page 1-7 and Table 1-1.

ERA/DCF Discussion Notes

2/10/13

Background

Two mechanisms exist to deal with diesel variances: DCF and ERA.

- The DCF intends to address diesel energy volume shortfalls/surpluses due to water availability.
- The ERA intends to address diesel energy volume differences from GRA-approved wholesale sales forecast.

The Diesel Contingency Fund (DCF)

"The DCF was created (1996-97 GRA Negotiated Settlement) when the Faro mine was operating and the DCF only pertained to the WAF system. The fund was established to ensure that ratepayers, rather than YEC, covered the risk of changes in grid diesel generation due to fluctuations in hydro generation resulting from factors outside of the utility's control (such as drought conditions). The effect of the DCF is to allow rates to be based on long-term forecast hydro generation versus short-term hydro generation. The effect of the DCF is to shield rates from volatility due to hydro generation variances based on fluctuating water levels."

- Both mechanisms have been dormant since around 1999 (B.O. 2013-01, App. A).
- In YEC's most recent GRA, YEC proposed to activate the DCF and ERA because diesel is now on-the margin. In doing so, YEC proposed changes to the wording for the mechanisms and provided new calculations for how they would be implemented.
- In B.O. 2013-01 the Board:
  - "is concerned that the DCF masks market signals and that, in times of a drought, consumers will be removed from the signal to reduce consumption. The problem with smoothing rates is that it mutes market signals and hence consumer behavior."
  - "notes that the use of the fund in the past has been sporadic as evidenced by the fact that the fund has not been active since 1999. Such periods of infrequent use raise issues of intergenerational inequity in that a consumer contributing to a fund today may benefit another consumer several years later."
  - Directs "YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of YEC and YECL as to when the revised DCF proposal is to be filed with the Board."
- The Board notes in B.O. 2013-3 that the revised DCF proposal was not filed jointly by YEC and YECL and that there was not a joint recommendation by the companies on how to amend the wording regarding the ERA in Rate Schedule 42. The Board considers that the revised DCF proposal has not been tested in a proceeding. Given the foregoing, the Board does not approve the revised DCF proposal filed in YEC's 2012-13 GRA compliance filing. Consequently, the Board

ERA/DCF Discussion Notes

> will not allow any changes regarding 2012 and the effects of any DCF proposal. YEC may file a future revised DCF proposal and ERA application.
>
> The Board prefers a joint filing from YEC and YECL. However, if agreement cannot be reached, a filing in which the companies state which aspects of the revised DCF proposal and ERA amendment they agree upon, the aspects they disagree upon, and the position of each company on those aspects they disagree upon is acceptable. The filing must also address the concerns raised in Board Order 2013-01 Attachment A: Reasons for Decision. This future revised DCF proposal and ERA application will be separate from the compliance filing directed in this order.

YEC proposed increasing the DCF dispersal "trigger" from ±$4M to ±$8M in its compliance filing. According to CW-YEC-2-2, the 2013 starting balance of the DCF was a $0.946M credit to customers. YEC has indicated a possible additional credit of $3.716M (Source: ERA and DCF Actual 2012 calcs – 2013-06-20.xls).

The Energy Reconciliation Account (ERA)

The ERA was proposed in the 1993/94 GRA when YECL was managing YEC. The closure of the Faro Mine resulted in diesel not being on the margin on the WAF since that time. Rate Schedule 42, Primary Wholesale has included:

- A single energy-only rate for all primary power supplied by YEC to YECL;
- When diesel is on the margin, the ERA was established to ensure that
    - YECL receives a full pass through of YEC's incremental costs or savings due to variances in wholesale volumes driven by YECL sales;

Load growth on the WAF system has required diesel generation on the margin to meet demand. YEC has proposed that YECL should be invoiced for the ERA balance in the $1.2M range.

Principles

The mechanisms for the ERA and the DCF should have the following attributes:

- Simple
- Transparent
- Easily explainable
- Should only collect the actual cost of additional fuel from that of forecast, or conversely refund any actual fuel cost savings from or to all retail and industrial customers.
- The ERA and DCF should be netted before being passed onto customers.
- Any deferral account balances should be disposed of shortly after being incurred in a timely manner in an effort to minimize any intergenerational issues.
- The deferral account balance thresholds that trigger the disposal should be set at a reasonable level so as to not cause undue rate changes or rate impacts to customers.

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

1.0 Introduction

As part of its 2012-2013 General Rate Application ("GRA") filed in April 2013, Yukon Energy applied to update and reactivate the Diesel Contingency Fund (DCF) and the Energy Reconciliation Adjustment (ERA) provisions of Rate Schedule 42 as of January 1, 2012. Yukon Electrical was opposed to both the DCF and ERA mechanisms proposed by Yukon Energy and suggested that, as an alternative, Yukon Energy could file for a deferral account as part of its Compliance Filing to address increased or decreased diesel costs from forecast, to be administered by Yukon Energy and dispensed amongst all ratepayers by Yukon Energy.

As outlined in Yukon Electrical's Final Argument and summarized by the Yukon Utilities Board (the "Board") in Board Order 2013-01, Yukon Electrical's concerns with the proposed mechanism were as follows:

a. Yukon Electrical was not consulted regarding the proposed changes;
b. the ERA as proposed by Yukon Energy may not allow Yukon Electrical to recover its prudently incurred costs;
c. the ERA charges may have a material impact on Yukon Electrical and its customers;
d. Yukon Electrical has to carry a forecast risk based largely on a forecast prepared by Yukon Energy;
e. Yukon Electrical does not accept Yukon Energy's wholesale forecast, which could result in erroneous ERA charges;
f. the proposed ERA has no mechanism to account for system growth; and
g. the designed ERA process is administratively inefficient.

In Board Order 2013-01, the Board did not approve Yukon Energy's proposed DCF and ERA mechanisms and ordered Yukon Energy to revise the DCF with consideration of the following comments:

- "…the DCF has never been fully tested (it was the product of a negotiated settlement)" (p. 53)
- "…is concerned that the DCF masks market signals and that, in times of a drought, consumers will be removed from the signal to reduce consumption. The problem with smoothing rates is that it mutes market signals and hence consumer behavior." (p. 54)
- "….the use of the fund in the past has been sporadic as evidenced by the fact that the fund has not been active since 1999. Such periods of infrequent use raise issues of intergenerational inequity in that a consumer contributing to a fund today may benefit another consumer several years later." (p. 54)
- "…Yukon Energy is to work with Yukon Electrical, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of Yukon Energy and Yukon Electrical as to when the revised DCF proposal is to be filed with the Board." (p. 54)

As part of Yukon Energy's 2012-2013 GRA Compliance Filing filed in May 2013, Yukon Energy submitted a revised DCF proposal. Yukon Electrical continued to express its concerns in its comments to the Board dated May 10, 2013, recommending that the Board reject the DCF and ERA proposals and suggesting that the utilities develop a joint proposal. Subsequently, the Board issued Board Order 2013-03, noting that the revised DCF proposal was not filed jointly by Yukon Energy and Yukon Electrical and that there

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

was not a joint recommendation by the utilities on how to amend the wording regarding the ERA in Rate Schedule 42. Thus, the Board again did not approve the revised DCF proposal and, consequently, the Board did not allow any changes regarding 2012 and the effects of Yukon Energy's DCF proposal. In addition, the Board ordered a joint filing from Yukon Energy and Yukon Electrical. However, if agreement could not be reached, a filing in which the utilities state which aspects of the revised DCF proposal and ERA amendment they agree upon, the aspects they disagree upon, and the position of each utility on those aspects they disagree would be acceptable.

Since the Board's issuance of Board Order 2013-03, the two utilities have met to present and discuss each other's proposed approaches to handle the DCF and the ERA. Yukon Electrical does not believe the concerns it raised during Yukon Energy's GRA proceeding or the comments made by the Board in Board Order 2013-01 are being addressed by Yukon Energy. Yukon Energy continues to rely heavily on past practices and methods even when they do not make sense in today's environment. Thus, the two utilities have agreed to disagree and are correspondingly making separate filings to the Board regarding this matter.

2.0 Background

Beginning in the early to mid-1990s, there were two mechanisms in place for Yukon Energy to address the cost impact of diesel fuel volume variances:

- The Diesel Contingency Fund (DCF) was to address diesel energy volume shortfalls/surpluses due to water availability. The theory was to allow rates to be based on long-term forecast hydro generation versus short-term hydro generation, and shield rates from volatility due to hydro generation variances based on fluctuating water levels.

- The Energy Reconciliation Account (ERA) was to address diesel energy volume differences from GRA-approved wholesale sales forecast.

Even though these mechanisms originated in the early to mid-1990s, they have operated sporadically since 1997 and have been completely dormant since 1999 due to the fact that diesel generation has not been on the margin.

2.1 History of the Diesel Contingency Fund (DCF)

The Diesel Contingency Fund (DCF) was created as part of the Negotiated Settlement regarding Yukon Energy and Yukon Electrical's joint 1996-97 GRA, when the Faro mine was operating and the DCF only pertained to the Whitehorse-Aishihik-Faro (WAF) system. The fund was established to ensure that ratepayers and the utilities where kept whole from changes in grid diesel generation due to fluctuations in hydro availability from long term averages resulting from factors outside of the utility's control (e.g. drought or high water conditions outside the utilities' control)).

- Pursuant to the 1996/97 Negotiated Settlement Agreement, the cap was set to the initial contribution to the DCF of $4,040,046. The same amount was used to set the "negative cap" with the reverse sign (-$4,040,046). All DCF terms and conditions were to be reviewed at the time of the next GRA.

- Between 1996 and 1999, approximately $3.4M of net withdrawals from the DCF occurred for both non-water (such as general rate relief) and water related purposes. The DCF has had no activity since 1999 with only interest/service fee transactions occurring. (Source: YEC 2012/13 GRA, Undertaking #23)

2.2 History of the Energy Reconciliation Account (ERA)

The Energy Reconciliation Account (ERA) was originally proposed as part of Yukon Energy and Yukon Electrical's joint 1993-1994 GRA and was first approved for use in Board Order 1993-7 [Source: YEC's submission, Attachment 2.1: Background for the ERA Mechanism]. Since that point in time, the ERA has been a source of significant disagreement between Yukon Electrical and Yukon Energy in how the ERA was to be interpreted and applied.

This disagreement was evident when Yukon Energy filed its April 28, 1998 Revised Application requesting that certain amendments be approved with respect to the wholesale rate applicable during 1996 and 1997. In Board Order 1998-5, the Board agreed that the matter should be dealt with in a separate process after the public hearing. By letter on February 5, 1999, the Board agreed that the outstanding issues be resolved between the utilities utilizing the British Columbia Utilities Commission (BCUC) negotiated settlement process guidelines.

The negotiated settlement process, facilitated by the BCUC, highlighted the two utilities had very different views on the ERA and how it was to be interpreted and applied from its beginnings in 1993. Regardless of this situation, a settlement was reached between the two utilities that stated the following with respect to the ERA:

- ERA +10% issue: On an ongoing basis from January 1, 1999, and until such time as the Board approves an amended wholesale rate, Yukon Energy and Yukon Electrical agree the ERA applies without any +10% limit.

- ERA Diesel on the Margin Issue: Yukon Energy and Yukon Electrical agree the companies will not adjust payments made January 1, 1993 through to December 31, 1998 with respect to the ERA Diesel on the Margin issue under the Wholesale Rate Schedule 42. On an ongoing basis from January 1, 1999 and until such time as the Board approves an amended wholesale rate, Yukon Energy and Yukon Electrical agree that the ERA mechanism will apply only during months when diesel is on the margin for the WAF system. This treatment recognizes the fact that this principle is not explicitly set out in the currently approved wording of Rate Schedule 42.

Since the above-noted settlement, approved in Board Order 1999-4, the ERA has remained dormant and there have been no wholesale rate schedule issues between Yukon Electrical and Yukon Energy; that is until Yukon Energy's 2012-2013 GRA and the submission of its proposed changes to the ERA and DCF.

2.3 What Has Changed Since the Creation of the DCF and ERA

- The final closure of the Faro Mine in 1998 resulted in diesel no longer being 'on the margin.' The issue of if or how the ERA should operate and its interrelationship with the DCF have, therefore, not been addressed since diesel generation was not an issue. However, recently diesel has again been 'on the margin' (at least in some months) which has driven the need to update the methodology and provisions prior to the reactivation of the DCF and ERA or, conversely, create

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

another easier to understand and/or test mechanism to address the forecast risk associated with diesel generation in the Yukon.

- The DCF and ERA mechanisms were created at a time when Yukon Electrical and Yukon Energy were jointly managed by Yukon Electrical and shared GRA test periods and forecasts. Assumptions were vetted jointly by the two utilities before being presented to the Board. In 1997, the joint management of the two utilities was dissolved, allowing the utilities to operate independently. Each utility's management is now responsible for determining if and or when a GRA for their respective utility is required. This is evidenced by Yukon Energy filing a GRA for the test period 2012-2013 and Yukon Electrical filing a GRA for a test period of 2013-2015.

- Significant changes to the Yukon Interconnected System have occurred since the inception of the DCF and the ERA in the early 1990s, including the connection of the WAF and Mayo Dawson grids and the introduction of new hydro facilities (Mayo B and the Aishihik Third turbine). The system is more complex and the forecasting of diesel has become more complex it is no longer a case of diesel on or off the margin throughout the year as a result of the Faro mine being on or off the system.

- Forecasting the impact of changing loads has become more complex as there is no longer a single customer (the Faro mine) that determines whether the Yukon grid is on or off diesel on the margin. Changes in load (up or down) will be met with a mix of changes in hydro and diesel generation.

- Retail rates in the 1996 – 1997 GRA were linked to the wholesale rate structure. This is no longer the case.

2.4 Summary of Yukon Energy's Current Proposal

2.4.1 Diesel Contingency Fund

In Yukon Energy's 2012-2013 GRA, Yukon Energy sought updates or changes to the methods of operation of the DCF required to consider the effects of the connection of the WAF and Mayo Dawson grids and the introduction of new hydro facilities (Mayo B and the Aishihik Third turbine). Yukon Energy sought approval to adjust the terms of the DCF and reactivate it in consideration of Yukon Energy diesel generation costs effective January 1, 2012. Yukon Energy requested that the DCF be switched on permanently on using a "formulaic approach" rather than a "fixed value" approach; as a result, there would no longer be a diesel on the margin test for activating the DCF. The formulaic approach included a table (Table 3.2-2: Expected Diesel Generation Based on Long-term Average Hydro Generation) that would provide the expected diesel at various grid generation levels based on polynomial equations derived from the untested "YECSIM" model. The expected diesel based on actual grid generation would be used in comparison to actual diesel to determine the amount deposited or withdrawn from the DCF.

Based on information filed in Yukon Energy's 2012-2013 GRA, the balance of the DCF was $0.9M as of December 31, 2011 and, based on Yukon Energy's letter to the Board dated July 5, 2013, Yukon Energy's calculations of the DCF additions for 2012 using the applied-for methodology would grow the DCF by $3.7M, to a balance of $4.6M by December 31, 2012. It is presently unclear as to what is forecast to happen in 2013. Yukon Electrical notes, however, as part of Yukon Energy's 2012-2013 GRA

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

Compliance Filing, Yukon Energy submitted a revised DCF which also included increasing the DCF dispersal "trigger" from ±$4M to ±$8M.

2.4.2 Energy Reconciliation Adjustment

To correspond with the fact that diesel is forecast to be 'on the margin' from 2012 onward, Yukon Energy's 2012-2013 GRA included changes to the ERA provisions in Rate Schedule 42 to correspond with the changes proposed to the DCF. The ERA is proposed to be triggered based on a comparison of expected diesel and actual diesel generation related to Yukon Electrical's wholesale purchases. Yukon Energy's wholesale sales forecast for 2012 was substantially lower than the actual wholesale sales for 2012. This leads to a lower base-line starting point for the ERA mechanism.

3.0 Yukon Electrical's Position on Yukon Energy's Proposal

Yukon Energy's proposed methodology for operating the DCF and ERA has not changed substantially from that presented to the Board as part of the 2012-2013 GRA proceeding. Based on Yukon Energy's, letter to the Board dated July 5, 2013, the proposed method would result in Yukon Electrical being billed $1.176M and $3.7M of revenue collected from rate payers being allocated to the DCF. Yukon Energy has recently provided Yukon Electrical with a revised calculation of the ERA to include the effects of Yukon Energy's incremental revenue caused by actual wholesale sales being greater than forecast resulting in Yukon Electrical's invoiced ERA balance changing to $0.438M. Yukon Energy has also suggested in the latest proposal that Yukon Electrical should not be permitted to pass on the additional $0.438M in costs to customers, despite Yukon Electrical having an approved Purchase Power flow-through deferral, and instead is suggesting that Yukon Electrical should net any incremental sales it experienced in 2012 (above the sales included in its last test year of 2009) against the ERA charges.

Below is a summary of issues that Yukon Electrical has with Yukon Energy's current proposal:

- Yukon Energy;'s proposal is extremely complicated and difficult if not impossible to test.
- Yukon Energy proposes that the ERA invoiced to Yukon Electrical should be based on the variance between Yukon Energy's wholesale sales forecasts and actual wholesale sales to Yukon Electrical. Yukon Electrical was not consulted for a detailed, GRA-quality forecast for Yukon Energy's 2012-2013 GRA. As 2012 was not a test year for Yukon Electrical, it did not internally prepare a detailed, GRA-quality sales forecast.
- Yukon Energy's proposal bases the ERA on what Yukon Energy expects the amount of diesel to be utilized at certain grid loads. Forecast diesel requirements are based on Yukon Energy hydro unit efficiencies, Yukon Energy diesel unit efficiencies, and expected water supply levels at Yukon Energy facilities. The expected amounts come from the YECSIM model which has not been tested. It is unclear as to whether Yukon Electrical has the expertise to test the model and it is uncertain if it would possible to test the assumptions used by Yukon Energy to forecast the expected diesel to be used at different grid loads. A thorough testing of these numbers would require significant in-depth experience and access to all of Yukon Energy's forecast generation data and associated assumptions.
- For 2012, Yukon Energy utilized less diesel generation than was forecast and included in Yukon Energy's 2012 rates; yet, despite the fact that Yukon Energy had substantial savings over the

forecast on diesel costs, they are proposing that Yukon Electrical receive an addition charge for diesel costs. Yukon Electrical does not agree with Yukon Energy's derivation of the $0.438M ERA balance. It is based on an expected diesel of 15.6 GWh, whereas actual diesel used was only 2.683 GWh

- The current basic mechanics of the proposed ERA mechanism would allow diesel costs to be invoiced to Yukon Electrical if there was (A) system growth and (B) wholesale growth. Because Yukon Energy's proposed ERA mechanism is based on Yukon Energy's last GRA-approved forecast, this would invariably result in Yukon Electrical being invoiced diesel costs. (ie. Consider a future year, say 2017, compared with 2013 and all positive variances being invoiced at a diesel rate.)

- 2012 was a non-test year for Yukon Electrical. Yukon Energy's latest proposal, which suggests that Yukon Electrical should be required to incur an additional $0.438M in ERA costs and not have an opportunity to flow it through to customers, results in a situation where Yukon Electrical is not recovering prudently incurred costs

- Yukon Electrical has an approved deferral account for Purchase Power charges flowed through but does not have an approved mechanism (such as Rider D) to recover the cost that Yukon Energy wants to pass on to Yukon Electrical. Despite having an approved deferral, Yukon Energy has proposed that Yukon Electrical should not be permitted to collect the additional ERA charges from customers.

4.0 Yukon Electrical Proposal

Yukon Electrical continues to propose that diesel variances could be addressed through the use of a simple deferral account for Yukon Energy. As noted in Board Order 2009-2, "the typical criteria used in determining whether to approve the use of a deferral account are the level of uncertainty regarding the accuracy of the forecast and the utility's ability to control the factors influencing the forecast." It is Yukon Electrical's view that the forecasting of diesel generation by Yukon Energy has a high level of uncertainty with respect to diesel generation costs being materially higher or lower than forecast. The table below summarizes the factors that affect Yukon Energy's forecast as well as actual diesel generation requirements and identifies which utility has the ability to forecast, or not be able to forecast, these factors in Yukon Energy's GRAs:

Factors That Affect Diesel Generation Requirements	Yukon Energy	Yukon Electrical
1) Availability of water and/or wind	✓	
2) Quantum of interconnected grid sales	✓	(1)
3) Location of load (line losses)	✓	
4) Operation of the system	✓	
5) Unexpected event/loss (RID event)		

(1) Yukon Electrical has the ability to forecast its sales and associated purchase power but does not prepare a GRA -quality forecast on an annual basis for the purposes of a Yukon Energy GRA.

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

This deferral account concept is similar to that approved and used by Northland Utilities (NWT) Limited for its hydro rate zone, except that in Northland's case diesel generation is not used to supplement hydro supply but to replace it when it is not available. In the NWT hydro rate zone, most supply comes from NTPC's Taltson Dam; however, at times hydro energy is not available due to maintenance or forced outage of the hydro supply tie-line. When NTPC is unable to supply Hay River from the Taltson Dam, Northland's Hay River diesel plant is required to be run. It is very difficult for Northland to accurately forecast the availability of hydro supply as the factors that can influence the availability are not within Northland's control. As a result, the NWTPUB has approved a deferral account to allow Northland to collect the additional costs from customers or refund any savings back to customers when diesel is required or not required to replace the hydro.

4.1 The Principles

In consideration of Yukon Electrical's concerns with Yukon Energy's proposal above and to resolve the Board's concerns as stated in Board Order 2013-01, Yukon Electrical believes the mechanism to address diesel volume variances must adhere to the following principles:

1) Simple, transparent, easily explainable and easily testable
2) Allow a utility to recover its prudently-incurred costs
3) Based on actual data and relates to all fuel volume variances on the interconnected system
4) Dispersed in a timely manner, so as to not mask market signals in times of a drought or flood and to avoid intergenerational inequity
5) The deferral account balance thresholds that trigger the disposal should be set at a reasonable level so as to not cause undue rate changes or rate impacts to customers.

4.2 Mechanism

To address these principles, Yukon Electrical proposes that Yukon Energy determine fuel volume variances based on the following. Please refer to the attached Schedule 1 for a detailed calculation based on the 2012 data that Yukon Energy used in their proposal.

Step 1) Using the Actual Diesel Generation (kWh) determine the share (%) of diesel recovered through rates (Diesel Recovered) based on the ratio of forecast diesel and forecast grid sales;

Step 2) Calculate the Diesel Variance to be recovered or refunded as the difference between the Diesel Recovered through rates based on the actual grid sales less Actual Diesel;

Step 3) The Diesel Variance Cost is determined based on the GRA approved diesel fuel price (eg. $0.2871 per kWh)

Actual diesel usage for 2012 is 5,546 MWh lower than the actual diesel recovered through rates resulting in a $1.612M refund to customers, which is contrary to Yukon Energy's method that uses expected diesel values resulting in $3.7M of Yukon Energy's revenue collected from ratepayers through existing rates being allocated to the DCF and a $0.438M charge being invoiced to Yukon Electrical through the ERA.

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

5.0 Comparison of Yukon Energy and Yukon Electrical Proposals

It is Yukon Electrical's view that Yukon Energy's proposal does not meet the principles nor does it address the Board's concerns. The table below provides a side-by-side comparison on how well the respective utilities methodologies meet those principles.

Principle	Yukon Energy's Proposal		Yukon Electrical's Proposal
	DCF	**ERA**	
1) Simple, transparent, easily explainable and easily testable	No. Yukon Energy's proposed DCF mechanism is complex and heavily relies on expected diesel based on results from the YECSIM hydro/diesel generation simulation model that has not been tested. Yukon Electrical is unsure how testable this model is.	No. Expected diesel is based on results from the YECSIM hydro/diesel generation simulation model that has not been tested. Yukon Electrical is unsure how testable this model is.	Yes. The variance, in consideration of the above stated factors that affect diesel generation, is simply the difference between forecast and actual diesel cost
2) Allow a utility to recover its prudently-incurred costs	No. The $3.7M cost is derived based on the variance between expected diesel costs and actual diesel. The expected diesel cost is not what wholesale rates are collecting.	No. The $0.438M charge being proposed to Yukon Electrical is derived based on the variance between expected diesel costs and actual diesel. The expected diesel cost is not what wholesale rates are collecting.	Yes. Costs are derived based on the variance from the 'true' forecast cost of diesel and the actual cost. The 'true' forecast cost of diesel should be proportionate to the cost of diesel forecast in the GRA.
3) Based on actual data and relate to all fuel volume variances on the interconnected system	Yes. However, the variance is calculated using 'expected' diesel at actual grid load levels.	No. However, there are elements of actual wholesale sales and grid load utilized, these values are only used to derived an 'expected' variance.	Yes. Actual diesel generation is directly used in the determination of the variance.
4) Dispersed in a timely manner, so as to not mask market signals in times of a drought and to avoid intergenerational inequity	No. Yukon Energy has proposed to increase the DCF threshold caps from +/- $4M to +/-$8M	Yes. Yukon Energy's derived 2012 ERA balance of $0.438M, which is offset by the incremental sales related to the additional wholesale sales to Yukon Electrical, is being proposed to be charged to Yukon Electrical	Yes. So that proper price signals are provided to customers and the issue of intergenerational inequity is minimized, Yukon Electrical proposes that the deferral account balance be calculated and disposed of as frequently as annually.

Yukon Electrical Diesel Variance Proposal (Confidential and Without Prejudice Draft for discussion Purposes)

Principle	Yukon Energy's Proposal		Yukon Electrical's Proposal
	DCF	**ERA**	
5) The deferral account balance thresholds that trigger the disposal should be set at a reasonable level so as to not cause undue rate changes or rate impacts to customers.	Yukon Energy has proposed to increase the DCF threshold caps from +/-$4M to +/-$8M.	There is no threshold cap in place for the ERA. The ERA balance is disposed of when incurred.	So as to not cause undue rate changes or impacts to customers Yukon Electrical recommends a modest threshold cap of +/-$2M be established to trigger the disposal of funds greater than the cap.

DRAFT

Schedule 1

Yukon Electrical's Proposed Diesel Deferral Account Mechanism

			Units	Notes
	YEC's GRA Approved Forecast Fuel Price	0.2871	$/kWh	
	% Fuel Included In Rates			
[1]	Forecast Fuel	7,926	MWh	
[2]	Forecast Total Grid Sales	373,094	MWh	
[3]	% Fuel Included In Rates	2.1%		% Fuel Included in Rates = Forecast Fuel / Forecast Grid Load
	Actual Fuel Recovered from Rates			
	Actual Grid Sales			
[4]	YEC Retail Sales	80,063	MWh	Obtained from YEC Actuals
[5]	Wholesale Sales to YECL	310,264	MWh	Obtained from YEC Actuals
[6]	Total Grid Sales	390,327	MWh	Obtained from YEC Actuals
[7]	Actual Fuel Recovered from Rates	8,292	MWh	Actual Fuel Recoverd from Rates = % Fuel included in Rates * Actual Grid Sales
	Fuel Variance			
[6]	Actual Fuel	2,683	MWh	
[7]	Actual Fuel Recovered from Rates	8,292	MWh	
[8]	Fuel Variance	(5,609)	MWh	Fuel Variance = Actual Fuel - Fuel Recovered through Rates **Note: The actual fuel variance needs to be adjusted to consider forecast diesel heat rates and transmission line losses**
[9]	Cost Variance - Withdraw / (Deposit)	(1,610)	k$	Cost Variance = Volume Variance * Price

TOPIC: **DCF Diesel Usage**

REFERENCE: **YEC DCF-ERA supplementary filing**

> This reflects longstanding principles under the DCF and YEC's prior Low Water Reserve Fund, i.e., when the DCF is activated, YEC's actual costs for diesel in any year reflect GRA approved diesel generation forecasts based on specified water forecast assumptions, and not actual YEC generation.
>
> The difference in cost between forecast diesel and actual diesel generation in any year at any given level of grid generation reflects only the variance in water availability (hydro generation) relative to the forecast, and this difference is what goes into or comes out of the DCF.[1]

PREAMBLE:

Further information is required.

QUESTION:

a) Respecting the above quote, is YEC submitting that the difference in cost between forecast diesel and actual diesel generation in a test year reflects only the variance in water availability (hydro generation)? Please explain how other considerations that may lead to incremental diesel usage can be discounted.

ANSWER:

(a)

Yes, YEC is submitting that past and proposed DCF determinations in a test year when diesel is on the margin reflect only the diesel generation variance due to hydro and wind generation variance from long-term average (LTA) water and wind availability.

[1] YEC DCF-ERA supplementary filing, June 30, 2014, Attachment 1, page 1-3.

Please see response to YUB-YEC-1-3(b) for a review of how past and proposed DCF determinations isolate the impact of water-related variances as these affect actual diesel generation.

TOPIC: **Diesel Generation**

REFERENCE: **YEC DCF-ERA supplementary filing**

To understand the material changes involved in the YECL proposal relative to long standing principles associated with the DCF, it is useful to look back to when the Faro mine was operating and changes in loads had a 100% impact on diesel generation requirements under normal water conditions:

- YEC at that time under the DCF paid full diesel cost for any growth variance in load beyond forecast [DCF payment then depended on actual diesel versus what YEC had to pay], and therefore YEC's payment covered the full incremental diesel cost of load growth;
- However, under YECL's new diesel deferral proposal, YEC would have paid added diesel costs related to growth above load forecast based only on <u>average</u> diesel requirements as a percent of grid sales, and therefore at only a fraction of that load growth (about 28% based on the 1996 GRA); the net impact would mean that ratepayers, not YEC, must pay for the balance of added diesel cost at LTA through the deferral account [would mean that all ratepayers at that time would have typically faced rider charges for over 70% of added diesel costs when water flows were at or less than LTA] even though YEC would have retained 100% of revenues from the added sales that exceeded GRA forecasts.[1]

PREAMBLE:

Further information is required.

QUESTION:

a) With respect to YEC's current DCF proposal for the 2012-13 test years, do

[1] YEC DCF-ERA supplementary filing, June 30, 2014, Attachment 1, page 1-5.

changes in loads have a 100% impact on diesel generation requirements under normal water conditions?

b) Please explain what is meant by "normal water conditions".

c) At the time when the Faro mine was operating, on an annual basis, what was the percentage mix of hydro vs. diesel generation?

d) What is the percentage of hydro vs. diesel generation in the 2012 and 2013 test years?

e) Considering the answers to (c) and (d), is it appropriate that the DCF be reactivated at this time? Please explain.

f) At the time when the Faro mine was operating, can it be suggested that all of Yukon's electrical customers, be it YEC or YECL, paid for incremental diesel generation when compared to GRA forecasts? Please explain.

ANSWER:

(a) and **(b)**

With respect to YEC's current DCF proposal for the 2012-13 test years, changes in loads do not have a 100% impact on diesel generation requirements under "normal water conditions", i.e., under long-term average (LTA) hydro generation water conditions.

Table 1 of YEC's January 31, 2014 Filing indicates that 46% of grid load changes between 415 and 425 GW.h/year are accounted for by expected diesel generation under LTA hydro generation water conditions.

(c)

The 1996/97 GRA as filed by YEC/YECL assumed Faro mine operation and forecast WAF diesel generation at 100 GW.h (1996) to 115 GW.h (1997), or on average 22% to

24% of total WAF forecast generation at 461 GW.h (1996) and 477 GW.h (1997)[2]. Hydro generation at LTA levels (including Fish Lake hydro generation) was forecast to account for almost all of the balance (wind was 0.3 GW.h).

(d)

Based on Table 2 in the YEC DCF-ERA filing of January 31, 2014, expected diesel generation at LTA of 15.6 GW.h accounted for 3.7% of actual total YEC firm generation (net of secondary) of 424.5 GW.h in 2012 and 3.2% of preliminary actual total YEC firm generation of 419.2 GW.h in 2013.

(e)

Board Order 2013-01 approved diesel generation for 2012 and 2013 YEC revenue requirements based on 100% of LTA hydro generation water conditions, and these determinations confirmed that diesel was on the margin at LTA hydro generation. Accordingly, it is appropriate and necessary that the DCF be reactivated at this time.

Please also see response to YUB-YEC-1-1(a) which, among other considerations, reviews concerns raised by YEC's auditors if the DCF is not in fact operative for 2012, and the response to YUB-YEC-1-1(f) which reviews issues arising if the Board was to have approved YEC's 2012-13 GRA based on forecast short-term hydro water conditions and not on LTA water conditions.

(f)

Yes, rates approved in 1996 (Order 1996-8) when the Faro mine was operating for Hydro rate zone customers of either YEC or YECL, including the Faro mine, had run out rates that equaled or exceeded the approved YEC incremental diesel generation cost for 1996 and 1997[3].

- Run out rates were calculated per Tables 3.2 and 3.3 of the 1996/97 GRA filing based on forecast diesel fuel cost and line losses to supply customers plus a

[2] Final approved forecasts likely varied from what was filed, e.g., it appears that the final approved WAF forecast for 1997 was somewhat lower load with 87 GW.h diesel accounting for 19% of the WAF forecast generation at 448 GW.h.
[3] Run out rates for the Hydro rate zone were generally set on this same basis as of at least 1994.

non-fuel O&M cost of 1.6 c/kW.h; for the Hydro and Large Diesel (Watson Lake and Dawson City) rate zones these run out rates ranged between 10.24 to 10.38 c/kW.h for 1996 and 10.43 to10.56 c/kW.h for 1997.

- To simplify rates, an average run out rate was determined for Hydro and Large Diesel rate zones at 10.24 c/kW.h for 1996 and 10.45 c/KW.h for 1997.

- Order 1996-7, Section 4, approved the run out rate determinations as being consistent with OIC 1995/90 and reflecting short run variable costs of diesel generation.

- This average run out rate was approved (Order 1996-8) for second block rates applicable to all Residential (use greater than 1000 KW.h/month) and General Service (use greater than 2000 kW.h/month) customers [GS government customers other than Municipal had a slightly higher run out rate].

- The same average run out rate was approved (Order 1996-8) for second block energy charges for RS 39 applicable to the Faro mine, i.e., applicable starting at 90% of forecast load.

Higher run out rates, reflecting higher diesel fuel costs, were applicable to YECL customers in the Small Diesel and Old Crow rate zones where all energy was supplied using diesel generation.

TOPIC: **YECSIM Model**

REFERENCE: **YEC DCF-ERA supplementary filing**

The YECSIM model is a planning model that is designed to provide an accurate representation of the YEC power system under a variety of hydrologic conditions. It has been custom made to accommodate all significant factors that affect the operation of the YEC power system, including the complex rules of operation and the regulatory demands on YEC. It is not designed to forecast actual diesel expected to be incurred in a particular year. It is designed to provide what the diesel requirement would be under long-term average water conditions at a particular load level and under assumed licence and generation installation conditions.[1]

PREAMBLE:

Further information is required.

QUESTION:

a) Considering the above quote, please explain how the output of the YECSIM model can be verified, after the fact for a test year — say 2012.

ANSWER:

(a)

Please see response to YEC-YEC-1-3(c). Being a planning model, YECSIM (as well as similar planning models such as Manitoba Hydro's SPLASH model) is not structured in a way that lends itself to retrospective verification per se. A detailed verification of a test year has not been made, for example, and such a verification or "test" would not normally be seen as a verification that is required or appropriate for this type of a planning model.

[1] YEC DCF ERA supplemental filing, Attachment 2, page 2-3.

Typical uses of the model for system planning and/or revenue requirement assessments focus on assessing long-term average changes to hydro generation (i.e., based on an average of "water years" and "cycles" as described in response to YUB-YEC-1-3(a)(ii)) under different assumed grid load conditions. The model's assessment is on a weekly time step basis.

If the model was to be reviewed for an historic test year it would be necessary to use the actual loads and inflows as input, and consider as well any special conditions that could have occurred during the test year. These could include operation decisions, prolonged shut down periods, etc.

TOPIC: **Summary Information**

REFERENCE: **YEC January 31, 2014 Filing, Attachment A, page 3**

PREAMBLE:

QUESTION:

a) Please provide a copy of the summary memo used in the May 16, 2013 meeting that reviewed the relevant history of the ERA and the proposed wording changes to Rate Schedule 42.

b) Please provide a copy of the illustrative Excel spreadsheet showing the ERA calculations from that meeting.

c) Please provide a copy of the correspondence regarding the understanding of each company's positions and requirements for a joint filing, issued June 17, 2013.

d) Please provide a copy of YEC's May 17, 2013 response to intervener comments to the compliance filing (Attachment A) for the record of this proceeding.

ANSWER:

(a)

Please see response to YUB-YEC-1-10(c) Attachment 3.

(b)

Please see Attachment 1 to this response.

(c)

Please see Attachments 1 to 4 to this response. Please note the correspondence to YECL is dated June 24, 2014, but references the Board's Order issued June 17, 2014.

(d)

Please see Attachment 1 to this response.

Table 1.1. Impact of the 2012 Actuals to YEC`s Income: ERA calculation for 2012

	GRA - Compliance Filing	Preliminary Actual		
Inputs				
Retail and Industrial (MW.h)	77,094	79,861	1	
Wholesale (MW.h)	296,000	310,264	2	
Total Sales (MW.h)	373,094	390,125	3	
Losses (MW.h)	32,459	34,412	4	Net of secondary sales
Total Generation (MW.h)	405,553	424,538	5	Net of secondary sales
Change from GRA Forecast				
Retail and Industrial (MW.h)		2,767	6	
Wholesale (MW.h)		14,264	7=2(col E less col D)	
Total Sales (MW.h)		17,031	8	
Losses (MW.h)		1,953	9	
Total Generation (MW.h)		18,984	10	Total increased generation due to sales in excess of forecast
Hydro (MW.h)	397,388	421,036	11	
Diesel (MW.h)	7,926	3,057	12	
Wind (MW.h)	239	445	13	
Total Generation (MW.h)	405,553	424,538	14	
Diesel MW.h	7,926	3,057	15	
less: diesel to capital		373	15a	
less: DCF	0	(12,943)	16	
Total in Rates (Expected Diesel)	7,926	15,627	17	
Incremental Diesel in Base Rates (MW.h)		7,701	18=17(col E) - 17(col D)	
Incremental Diesel in Base Rates (% of Total Gen'n Change)		41%	19=18/10	

Proposed ERA Approach

Proposed 2013 Wholesale Rate	8.298	cents/kW.h	20	current wholesale rate
Average proposed rider revenue per kW.h	1.050	cents/kW.h	21	89.30% of non-industrial rider revenue of $3.51 million (CF:Table 1.3, Sched 9 Tab 7 [298.1 GW.h YECL retail])
ERA Rate Calculation:				
Fuel Price	28.71	kW.h	22	GRA Compliance Filing average for 2012
ERA rate	**28.710**	cents/kW.h	23	

The **Energy Reconciliation Adjustment** is calculated as follows:

a) **sales below GRA forecast**: no adjustment for sales more than 10% below GRA forecast

b) **sales above GRA forecast:** all sales in excess of GRA forecast are subject to the adjustment

	GRA	Actual		
Incremental Wholesale Sales (MW.h)	0	14,264	24=7	
Fish Lake impact (MW.h)		(980)	25	
Incremental Wholesale Related Generation (MW.h)	0	14,440	26	at 8.7% losses
Incremental Diesel Generation Subject to ERA Charge (MW.h)	0	5,857	27=26*19	Diesel generation impact from incremental wholesale sales
Incremental Wholesale Sales Subject to ERA Credit (MW.h)	0	5,388	28=27/1.087	sales equivalent of diesel gen. [i.e. net of losses]
Amount paid under normal ongoing billing ($000s)	$ 24,562	$ 25,746	29	
ERA Adjustment to be Paid (Refunded) ($000s)	$ -	$ 1,178	30=(27*23-28(20+21))	Cost of incremental diesel subject to ERA less value of wholesale sales.
Total Amount Paid after ERA	$ 24,562	$ 26,924	31	

Note:

Calculations are to be done on a monthly basis, however in practice the adjustment and calculations would be addressed periodically (and made final based on a year-end reconciliation processes).

Table 1.2. Impact of the 2012 Actuals to YEC`s Income: DCF Formulaic Approach Operation Example for 2012 YEC Load

Variable cost of YEC diesel calculation

Line No				Notes
L1	Fuel Cost per kW.h	28.71	cents/kW.h	Compliance Filing Average Fuel cost

Calculation of Diesel Cost to Charge (Refund) DCF

2012 Preliminary Actuals

	Assumptions			
L2	YEC Grid load	424,538	MW.h	Preliminary actual, excluding secondary sales
L3	Fish Lake	3,400	MW.h	Fish Lake actual
L4=L2+L3	Total Grid load	427,938	MW.h	
	Assumed Actual Generation Sources			
L5	YECL Fish Lake	3,400	MW.h	Fish Lake actual
L6	YEC Hydro	421,036	MW.h	Preliminary actual, excluding secondary sales
L7	YEC Diesel, total	3,057	MW.h	
L7a	YEC Diesel charged to capital	373	MW.h	Preliminary actual charged to capital
L7b	YEC Net Diesel	2,683	MW.h	Preliminary actual (net of capital diesel)
L8	YEC Wind	445	MW.h	Preliminary actual
L9	Total Grid load	427,938	MW.h	
	Expected Generation Sources			
L10	YECL Fish Lake (expected)	4,380	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 4.35 GW.h for Unit #1.
L11	YEC Wind (expected)	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	423,319	MW.h	
L13	Expected Base Diesel Generation at 420 GW.h	14,100	MW.h	Derived from updated Table 1.1-1 of Revised DCF Proposal
L14=(L12-425 GW.h)x50%	Expected Incremental Diesel Generation at 3,319 MW.h above 420 GW.h	1,527	MW.h	46% of Grid Load between 420 GW.h and 425 GW.h is diesel - Derived from updated Table 1.1-1 of Revised DCF Proposal
L15=L13+L14	Total Expected YEC Diesel Generation	15,627	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	15,627	MW.h	100% of long-term average
L17=L7a	Actual YEC Diesel Generation	2,683	MW.h	Preliminary actual (net of capital diesel)
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 12,943	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($3,716)		

June 24, 2013

Yukon Electrical Company Limited
100 – 1100 1st Avenue
Whitehorse, YT Y1A 3T4

Attn: Dwight Redden
General Manager

Dear Sir:

Re: YEC General Rate Application 2012-13
Diesel Contingency Fund/Energy Reconciliation Account

On June 17, the Yukon Utilities Board (YUB) issued Order 2013-03 wherein they did not approve YEC's revised DCF as included in the YEC Compliance Filing dated May 1, 2013. In their Reasons for Decision, the YUB stated that it prefers a joint filing from YEC and YECL regarding a revised DCF proposal and ERA application. The Board also stated as follows:

> "…if agreement cannot be reached, a filing in which the companies state which aspects they agree upon, and the position of each company on those aspects they disagree upon is acceptable."

In order to expedite the requested joint filing, we are forwarding the following:

1. **YEC's Revised DCF Proposal -** This is basically the revised DCF proposal that YEC filed on May 1, 2013 as Section 4 of its Compliance Filing and that YECL had the opportunity to review at that time. Aside from format changes and edits to accommodate a standalone proposal, the only notable change is to remove any reference to secondary sales given Order 2013-03.
2. **Backgrounder on ERA** - This is the May 13, 2013 memo that we prepared and forwarded to you May 15, 2013 prior to our meeting the next day. Aside from review of relevant history, this memo reviews YEC's proposed wording changes to Rate Schedule 42 and a list of the YECL issues and Board directions re: DCF and ERA outlined in Board Order 2013-01.
3. **Excel Spreadsheet analysis of 2012 Actuals to DCF for YEC and Related ERA Charge to YECL** - This updates what was provided at our meeting on May 16, 2013 to reflect YEC's Revised Compliance Filing filed June 20, 2013 as well as updated actuals for 2012.

Unless otherwise indicated above, the information provided is consistent with our recent filings to the YUB on these matters or as otherwise previously shared with you.

For each of the DCF and ERA, we expect the joint filing to first describe the policy and administration of each account and second review the calculations that support the forecast amounts.

From our last meeting as well as YECL's final argument in the recent YEC GRA proceeding, YEC is aware of YECL's proposal that the ERA be removed from Rate Schedule 42 and, instead, the YEC diesel costs related to YECL wholesale variances from YEC's GRA forecasts as approved be recovered from ratepayers through a new YEC deferral account to be administered by YEC and dispersed by YEC. As you know, Yukon Energy does not support this proposal - our specific comments in this regard were set out at Attachment A in YEC's May 17, 2013 Response to Intervener Comments on the Compliance Filing. However, YEC's understanding is that it would be helpful to the Board if YEC and YECL could at least agree on the mechanics of the calculation regarding the needed adjustment addressed in the current ERA - Order 2013-03, as quoted above, would allow our joint submission to set out the position of each company on those aspects that we disagree upon.

With respect to the DCF, we are not aware of specific concerns you may have with our proposed updated policy and approach. We look forward to any comments in this regard.

YEC is interested to resolve these matters as expeditiously as possible. Please advise your earliest possible date for a meeting to discuss these matters.

Yours truly,



Ed Mollard, CGA
Chief Financial Officer

YUKON ENERGY CORPORATION
REVISED DIESEL
CONTINGENCY FUND (DCF)
PROPOSAL

REVISED DIESEL CONTINGENCY FUND (DCF) PROPOSAL

Yukon Energy has prepared the following revised DCF proposal in response to Order 2013-01.

Order 2013-1 (paragraph 255) directs YEC to provide a revised Diesel Contingency Fund (DCF) proposal which provides for the following specific revisions to the DCF updates filed in the Application, Attachment 3.2 ("DCF Term Sheet: Updates for YEC Grid"):

1. Incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model.

2. Incorporate suggestions of CW and UCG as to how DCF transactions are to be reported.
    a. CW requested YEC be directed to report on the DCF on a quarterly basis and the report contain a narrative indicating what action will be required for the DCF (replenish or refund).
    b. UCG supported the CW view that the DCF filings should include a narrative section and added that the annual DCF filing should include working spreadsheets detailing the calculations and that parties be offered the opportunity to comment on the annual filings.
3. Provide an example of approximately five years of transactions which will show how the balance in the DCF will change and how those changes will be reported.

Each of the above changes has been incorporated into the revised DCF.

BACKGROUND

In Appendix 3.2 of the Application (Attachment 3.2), YEC proposed a formulaic approach to determine expected YEC diesel generation for the YEC grid based on long-term average water-based YEC hydro generation forecast using a formulaic relationship to the integrated YEC grid generation load in each year (including non-test years) rather than a fixed value as historically done.

The following specific measures were proposed in this regard in Attachment 3.2 of the Application:

- Yukon Energy proposed that Table 3.2-1 in Attachment 3.2 be adopted to determine annual expected YEC diesel generation in the test years prior to any new mine or industrial load connections based on long term average hydro generation at YEC grid loads (net of wind and Fish Lake generation) ranging from 400 to 500 GW.h/year.
- Yukon Energy also proposed that Table 3.2-2 in Attachment 3.2 be adopted to determine annual expected YEC diesel generation in 2013 after such time as the WHCT industrial load is connected, based on long term average hydro generation at YEC grid loads (net of wind and Fish Lake generation) ranging from 400 to 500 GW.h/year and the annual load shape forecast with this new industrial customer.

- Yukon Energy also committed to provide the Board with an update to Table 3.2-2 when required in future to address material changes in long-term average hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

An updated DCF applicable to YEC activities is an integral element of the YEC revenue requirement approved by Board Order 2013-1, including direction to include YEC diesel generation in this revenue requirement and rates based on 100% long-term average YEC hydro generation.

- The updated DCF as previously filed fully reflects impacts on YEC diesel generation arising from actual variances from long-term average YEC wind and hydro generation that arise due to variances in actual wind or water conditions.
- The revised DCF proposal fully reflects impacts on YEC expected diesel generation arising from actual variances from long-term average YECL Fish Lake hydro generation that arise due to variances in actual water conditions at this YECL facility. The Fish Lake elements of the DCF in the revised proposal modify DCF-related transactions by YEC without involving YECL (other than to provide reporting on actual Fish Lake generation) and these DCF-related changes will not be affected by any future determinations regarding the ERA as provided for in Rate Schedule 42[1].

Attachment 1.1 to Appendix 1.1 sets out the revised DCF proposal, amending the DCF Term Sheet initially provided as Attachment 3.2 to the Application to address Board directions provided in paragraph 255 of the Order, and including an example of five years of transactions as required in Board Order 2013-1. Attachment 1.1 also includes revised tables[2] to determine annual expected diesel generation in 2012 and 2013, reflecting changes in the YEC load and generation forecasts for wholesales and industrial loads as included in YEC's Compliance Filing. Appendix 1.1 provides additional background and updated analysis to reflect the revised scope for the DCF Term Sheet.

A summary of the changes to the proposed DCF in response to each Board directive is outlined below.

1.1 DIRECTION TO INCORPORATE NON-DIESEL GENERATION FACILITIES (WIND, FISH LAKE HYDRO) FORECASTS

Long term average YEC hydro generation under any set of assumed YEC grid generation load and grid generation capacity and licence conditions is determined based on power benefit model calculations based on 28 years of water record for the interconnected grid. As load grows a portion of the load growth is currently served (on average) by increased YEC hydro output and the remainder by increased diesel generation.

[1] The revised DCF will allow Rate Schedule 42 provisions for the ERA, which YEC and YECL are to jointly review and make joint recommendations to the Board, to exclude wholesale changes that are related only to Fish Lake water-related generation variations from long-term averages as approved by the Board.

[2] Tables 1.1-1 and 1.1-2 will replace Tables 3.2-1 and 3.2-2 in the Application.

Yukon Energy has reviewed direction provided in paragraph 255 of the Order and provides the following information summary of the revised DCF proposal included as Attachment 1.1:

1. **Wind and Fish Lake, as non-dispatchable generation, affect the quantity of expected diesel generation in a similar manner** - Yukon Energy originally proposed to operate the DCF based off of the total YEC generation, and the expected diesel that would be required given that total generation. Based on the Board Order, YEC has revised the DCF proposal to calculate off of total grid-wide generation (YEC generation plus Fish Lake).
    a. The basic premise for the DCF calculations is that at a given load level, there is a known quantity of diesel generation that should be expected. If diesel generation varies from this expected level due to water or wind variations, the DCF should be used (credit or debit).
    b. In the revised DCF proposal, the total grid-wide load (YEC generation + actual Fish Lake generation) is the total load to be analyzed. From this total load, the long-term average or "expected" non-dispatchable generation is subtracted (wind and Fish Lake at long-term average) to yield the total expected YEC baseload grid generation.
    c. The total expected YEC baseload grid generation is then calculated into expected YEC baseload hydro and expected YEC diesel using the values from Table 1.1-1 and 1.1-2 of Appendix 1.1 (the output of the power benefits model).
    d. All other mechanics of the DCF remain the same as proposed by YEC in the Application. That is, the expected YEC diesel is compared to actual YEC diesel to determine the annual transfer from/to the DCF.
2. **Incorporation of Wind Forecasts into the DCF analysis that supports the determination of annual expected diesel generation** – Wind variation that affects diesel generation is already implicitly accounted for in the updated DCF as provided in the Application, and does not require any changes to the power benefits model:
    a. Tab 3, Appendix 3.2, Attachment 3.2 of the Application notes the last approved long-term average wind on the YEC WAF grid for the DCF was established in the 1996/97 GRA at 0.3 GWh/year.
    b. YEC proposed to update the DCF based on changes to the grid system, including using wind generation as forecast in the last approved GRA. Forecast wind for the test years reflects assumed long-term average capability (0.239 GW.h in 2012 and 0.238 GW.h in 2013). This is not sensitive to grid load, hydro generation or any other factor relevant to the power benefits model. By deducting <u>expected</u> wind generation from any specific grid load, the updated DCF enables the power benefits model to determine expected diesel generation under long-term average wind and hydro conditions.
    c. YUB-YEC-1-30(b) and YECL-YEC-2-1 provided a series of hypothetical scenarios that showed related impacts on the DCF and the ERA. These scenarios provided cases with wind generation at forecast and below forecast levels. In effect, the examples confirmed that the updated approach would fully reflect the impact on YEC diesel

generation due to wind variances from long-term average wind generation from existing facilities[3].

3. **Incorporation of Fish Lake Hydro generation impacts into the power benefits modelling that supports the determination of annual expected diesel generation –** Appendix 3.2 (page 3.2-2 and 3.2-3) of the Application notes imputed diesel generation savings or excess related to the YECL Fish Lake hydro facility were calculated in the past when the DCF was operating[4]. Order 2009-2 following the 2008/2009 GRA determined 8.73 GWh to be a reasonable long term average hydro generation number for Fish Lake. However, subsequent to Order 2009-2 Unit#1 at Fish Lake was shut down and is now not expected to be operating until December 2, 2013. The original DCF proposal noted that changes in Fish Lake average hydro were beyond Yukon Energy's scope and consequently updates to DCF rules related to YECL's Fish Lake plant were not addressed by Yukon Energy in the Application.

   As Yukon Energy has been directed to include Fish Lake in its revised DCF proposal, the revised DCF Term Sheet in Attachment 1.1 includes this Fish Lake hydro component, reflecting the last approved long term average generation of 8.73 GWh/year for Fish Lake[5], excluding long-term average generation for Unit #1 until such time as the unit is back in service[6].

   The updated DCF procedures take into account the fact that Fish Lake hydro generation variances from long-term average due to water conditions only affect the expected YEC diesel generation (not YECL diesel generation). For this reason, Fish Lake variances are included in the revised DCF for their impact on YEC diesel.

   While Fish Lake variances can also affect YECL wholesale purchases, the underlying diesel-related impact on costs for the utilities and ratepayers is to YEC diesel. The DCF is not

[3] The updated DCF determines YEC expected hydro and YEC expected diesel generation for any specific actual YEC grid load after deduction of expected YEC wind generation, i.e., expected YEC diesel reflects the diesel required with expected wind generation, and any variance of wind from long-term average will therefore be assumed to directly affect actual diesel generation to the extent that can occur at any give grid load and set of hydro conditions.

[4] Actual Fish Lake generation was compared with the long term average Fish Lake generation forecast per the 1996/97 GRA filing (10 GWh/year) and imputed diesel cost savings or excess for YECL were calculated assuming the YEC WAF diesel generation standard efficiency and fuel prices.

[5] Order 2009-2 notes "In making a determination on this issue, the Board considered YECL's submission in argument that it is in a new water-licence period and is subject to certain restrictions. Further, the Board accepts YEC's suggestion that the available generation at the Fish Lake hydro plant should be based on all years of available data. Accordingly, the Board finds 8.73 GW.h is reasonable as the base generation for the Fish Lake hydro facility, prior to considering the impact of any downtime due to the Fish Lake hydro rebuilds. Therefore, the Board directs YECL in its refilling to reflect base hydro generation of 8.73 GW.h".

[6] In principle, as reviewed in Revised DCF proposal, the DCF is not intended to address changes in hydro generation due to unit failures, fires, replacement or licence issues.

intended, and has not been used for more than a decade to result in transactions for YECL to recover or refund simple variations in YECL wholesale purchases. For this reason, YEC does not propose any DCF related transactions involving YECL's costs or revenues.

1.2 DIRECTION REGARDING CONTENT OF ANNUAL FILINGS

The revised DCF Term Sheet in Attachment 1.1 provides for the quarterly and annual reporting as directed in Order 2013-1, as well as other related matters. In addition, the following are noted:

- The DCF account will be managed on a monthly basis to permit financial reporting through use of a simple pre-determined monthly percentage distribution. However, due to imprecision in forecast long-term average hydro monthly distributions it is possible that inappropriate values may arise during monthly estimating but these will not be part of final annual DCF calculations. Monthly calculations will be a placeholder with ultimate final calculations performed only on the annual calendar year values[7].

- The response to CW-YEC-1-24(a) provided a sample pro-forma DCF monthly report with a hypothetical snapshot of the DCF status as of October 2013. A similar analysis would be re-run each month, to update the projected annual transfer and how it has changed based on each new month of data. A final true up will be done at the end of the calendar year and included in the annual report.

- The quarterly and annual report will include a narrative indicating any action that will be required for the DCF (replenish or refund). The annual DCF filing will also include (among other information) working spreadsheets detailing the DCF calculations, and it is proposed that parties be offered the opportunity to comment on the annual filings.

1.3 DIRECTION TO PROVIDE FIVE YEARS OF TRANSACTIONS THAT INDICATE HOW THE BALANCE IN THE DCF WILL CHANGE AND HOW THOSE CHANGES WILL BE REPORTED

The revised DCF Term Sheet in Attachment 1.1 provides an example for five years of transactions that indicates how the balance in the DCF will change and how those changes will be reported.

[7] There are limits to the ability to permit each month to have its own formula or polynomial, and differing monthly distributions may permit occasional odd values that resolve themselves in annual calculations. This same factor applied in the DCF calculations in the past.

Appendix 1.1

APPENDIX 1.1: REVISED DIESEL CONTINGENCY FUND ("DCF") PROPOSAL

INTRODUCTION

Board Order 2011-15 included the following directive at page 9:

- The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA. Also, the Board requires that YEC provide a specific definition of the term "diesel on the margin". The Board directs that YEC complete its review and bring the necessary changes before the Board at the earliest of its next GRA or July 1, 2012.

Appendix 3.2 to YEC's 2012-2013 Application responded in full to this Board directive. Attachment 3.2 ("DCF Term Sheet: Updates for YEC Grid") provided a summary of components of the current Diesel Contingency Fund (DCF or Fund) as per the Negotiated Settlement approved in Order 1996-7; June 2, 1999 letter to the YUB regarding Diesel Contingency Fund Filings - 1996 to 1998; and October 7, 1999 letter to the Yukon Utilities Board regarding Comments on the Diesel Contingency Fund report.

Board Order 2013-1 (paragraph 255) directed YEC to file a revised DCF proposal with the following specific revisions to the DCF updates filed in the Application:

1. Incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model.
2. Incorporate suggestions of CW and UCG as to how DCF transactions are to be reported.
    a. CW requested YEC be directed to report on the DCF on a quarterly basis and the report contain a narrative indicating what action will be required for the DCF (replenish or refund).
    b. UCG supported the CW view that the DCF filings should include a narrative section and added that the annual DCF filing should include working spreadsheets detailing the calculations and that parties be offered the opportunity to comment on the annual filings.
3. Provide an example of approximately five years of transactions which will show how the balance in the DCF will change and how those changes will be reported.

Background

Based on past practice and current rules, the DCF applied only to the Whitehorse-Aishihik-Faro (WAF) grid. As reviewed in the October 28, 2011 response to YUB-YEC/YECL-2-4 during the proceeding of the Board on Rider F, the DCF was established as a result of the Negotiated Settlement at the 1996/97 GRA,

and was to operate in the same manner as YEC's earlier Low Water Reserve Fund (LWRF), established by YEC in 1991, except for certain specified changes[1].

When operative in the past, the DCF account for WAF could be either credited or debited each month for one of two reasons with regard to WAF operations:

- **When diesel is "on the margin[2]"** (defined as diesel being used to meet long-term firm energy requirements of the WAF system, not just periodic peaking requirements), the account stabilizes the diesel costs related to water flow variations. In these situations (i.e., with diesel on the margin), when hydro varies positive or negative from the long-term average forecast, that variance is met effectively one for one with changes in diesel generation compared to what would have occurred had the hydro variance not occurred. This happened, for example, in the periods of 1996-1998 when the Faro mine was operating, and was last triggered for January 1998.
- **When diesel in not on the margin,** the account can in certain circumstances be used to pay for the costs of baseload generation using diesel when such baseload generation arises due to low water conditions. This happened, for example, in a number of months of 1999, when diesel was not considered to be on the margin (due to low grid load levels hydro should have been able to supply all baseload requirements) but extremely low water led to the need for baseload diesel generation. In practice, the distinction between normal peaking operation and true baseload diesel has been set in the past on WAF at 250 MW.h/month for calculation purposes[3].

Prior to the Yukon Energy 2012-2013 GRA, diesel has not been on the margin since the Faro mine closed in 1998. Diesel was not forecast to be on the margin, for example, in YEC's 2009 GRA. No DCF determinations have been made subsequent to the 2009 GRA.

The Fund was established for the WAF system when the Faro mine was operating and diesel was on the margin for that system, (i.e., diesel was needed to provide baseload grid energy beyond peaking periods, reserve or emergency conditions). The DCF has been generally inactive since the Faro mine closed. More specifically, the Fund has been inactive when hydro generation surplus conditions exist and diesel is not on the margin.

[1] As noted in Attachment A to YEC's October 7, 1999 to the letter to the Board (attached to YUB-YEC/YECL-2-4 2011 response noted), the most notable adjustment for the DCF relative to the LWRF was the use of long-term average water inflows versus forecast hydro generation based on actual Aishihik water levels at the time of a rate application. The same Attachment A quoted from an April 1997 report to the YUB prepared by the accounting firm Stephen Johnson explained why such a fund is needed on the Yukon grid. YECL Fish Lake generation was not included in the LWRF.

[2] In the Yukon Energy 2008/2009 GRA filing it was noted that the DCF would not be advanced in the "diesel on the margin" mode until such time as the system has firm loads that exceed the long-term average capability of the hydro system over the course of a long period (many months to years). Yukon Energy did not anticipate a requirement for such a Fund to be in operation during 2008 and 2009. Until "diesel is on the margin" the Fund cannot be triggered and amounts cannot be debited or credited to the Fund.

[3] Even in cases where diesel generation exceeded 250 MW.h but the generation was for peaking requirement, the DCF has not been charged – for example, December 2008.

The Fund is to operate outside of rate base but an annual report detailing additions and deletions to the Fund is to be filed with the Board so that the Board may oversee the Fund's activities. The Board will direct the Companies on the additions and deletions to the Fund. The annual report to the Board will also include a forecast of available water for the year.

On March 29, 2010, Yukon Energy filed its 2008 Diesel Contingency Fund Filing and noted the potential need to update methods of operation of the DCF. It was noted that the DCF operating rules would require attention in the future to address a number of new circumstances, including updating long-term average hydro generation values, fund triggers, and potentially a means to address secondary sales. Today, following connection of the WAF and Mayo Dawson grids, it is also necessary to adjust the DCF to deal with more than only WAF hydro generation. Until the necessary changes in operating rules are addressed and reviewed and approved by the YUB, Yukon Energy stated that it did not anticipate that it would trigger operation of the DCF fund.

Separate from the YEC WAF grid DCF applications and accounting, starting in 1996 imputed diesel generation savings or excess related to the YECL Fish Lake hydro facility were calculated and accounted for when the DCF was operating[4]. In effect, the DCF paid YECL (at YEC's then approved incremental cost of diesel fuel plus diesel O&M) for shortfall variances in Fish Lake hydro generation from the approved long-term average, and YECL paid the DCF on the same basis for surplus variance in Fish Lake hydro generation. None of these YECL-related DCF transactions affected YEC's income or costs; however, the net effect on YECL of these YECL-related DCF transactions would offset Rate Schedule 42 Energy Reconciliation Adjustment (ERA) impacts on YECL to the extent that YECL wholesale purchases from YEC were fluctuating due to Fish Lake hydro generation variances from long-term average as approved by the Board. The DCF and ERA did not apply to YECL operations when the Faro mine was not operating.

During the 2013 hearing for the YEC 2012-2013 GRA, the response to Undertaking #23 provided a continuity table for the Fund as managed by Yukon Energy. Highlights from this response include:

- The Fund had an opening balance of approximately $4.04 million in January 1996 (including $0.5 million balance from the LWRF), a balance of approximately $0.65 million as at the end of 1999, and a balance of $901,856.65 at the end of 2011. The only changes to occur in the Fund after 1999 were annual interest fees paid into the Fund.

- During the period to the end of 1999, approximately $2.8 million of withdrawals from the DCF occurred for non-water related purposes (i.e., general rate relief) pursuant to directions of the Board[5].

[4] Actual Fish Lake generation was compared with the long-term average Fish Lake generation forecast per the 1996/97 GRA filing (10 GW.h/year); and imputed diesel cost savings or excess were calculated assuming the YEC WAF diesel generation standard efficiency and fuel prices.

[5] Board Order 1997-7 directed a drawdown from the DCF to provide a 25% credit to the interim refundable general rider surcharge of 20% approved in Board Order 1997-6 (this action was in response to an OIC direction noted in the Order). Board Order 1998-5, which finalized YEC's 1997 rates, directed that the balance in the DCF be used to make contributions to all eligible customers to offset 100% of the net rider increase over the next 12 months.

- YEC and YECL related impacts on the Fund are separately accounted for (reflecting separate tables).
    - Prior to the end of 1999, YEC water availability impacts on hydraulic generation capabilities included approximately $1.1 million of withdrawals during 1996 and 1997, and approximately $0.5 million of additions in 1998. Impacts related to the fire in 1997 at the facility were charged either to the fire insurance claim or the RFID.
    - Prior to the end of 1999, YECL withdrawals of approximately $0.5 million from the Fund related to water availability impacts at the Fish Lake hydraulic generation facilities.

Updated Long-Term Average YEC Hydro and Wind Generation

The updated DCF as proposed in YEC's 2012/13 GRA addressed the need to provide adjusted long-term average estimates for YEC hydro generation that reflect current Integrated System grid YEC loads, facilities, licences and water records, including the reality that baseload diesel generation was once again being impacted by grid loads. Board Order 2013-1 subsequently directed that YEC base its hydro and diesel energy requirements on 100% long-term average hydro generation for the forecast 2012 and 2013 load in its Compliance Filing (paragraph 60 of Order 2013-1).

Board Order 2013-1 accepted YEC's expected wind generation for the test years at 239 MW.h in 2012 and 238 MW.h in 2013[6]. Expected wind generation is not affected by changes in YEC's grid loads.

In contrast, the Compliance Filing regarding Board Order 2013-1 was required to determine long-term average YEC hydro generation in light of the adjusted sales forecasts approved for the test years, i.e., a key consideration in regard to determination of expected long-term average YEC hydro is that long-term average YEC hydro generation today varies as YEC grid loads vary. The Compliance Filing related to Board Order 2013-1 includes long-term expected YEC hydro generation as follows:

- **2012:** Long-term expected YEC hydro generation at 397.39 GW.h (grid load generation forecast, excluding expected wind generation, of 405.32 GW.h); expected diesel generation is 7.93 GW.h.
- **2013:** Long-term expected YEC hydro generation at 405.14 GW.h (grid load generation forecast, excluding expected wind generation, of 416.15 GW.h); expected diesel generation is 11.01 GW.h.

In order to demonstrate the variance in expected long-term YEC hydro generation at different grid load levels, Figure 1.1-1 provides estimated long-term average YEC hydro generation capability over a range from 400 to 475 GW.h/year of Integrated System grid loads (net of expected YEC wind generation[7]), based on current installed hydro generation and licences/permits and the 2012 GRA load mix with the Minto and Alexco mine loads (as adjusted in the YEC Compliance Filing related to Board Order 2013-1)[8].

[6] Expected wind generation is set out in Table 2 of this Order. At paragraph 92 of Board Order 2013-1, the Board did not accept intervenor recommendations for YEC to budget added funds to improve production at Haeckel Hill to 0.8 GW.h/year in 2013.

[7] Excluding expected wind generation in effect assumes that expected wind generation occurs, i.e., any variance in wind generation due to wind fluctuation from the expected level will thereby be treated by the DCF in the same way as any variance in hydro generation due to water availability fluctuation from the expected level.

[8] Also reflects added wholesales due to continued closure of Fish Lake Unit #1 during 2012.

Figure 1.1-1: YEC Hydro Generation at Different 2012 Load Scenarios

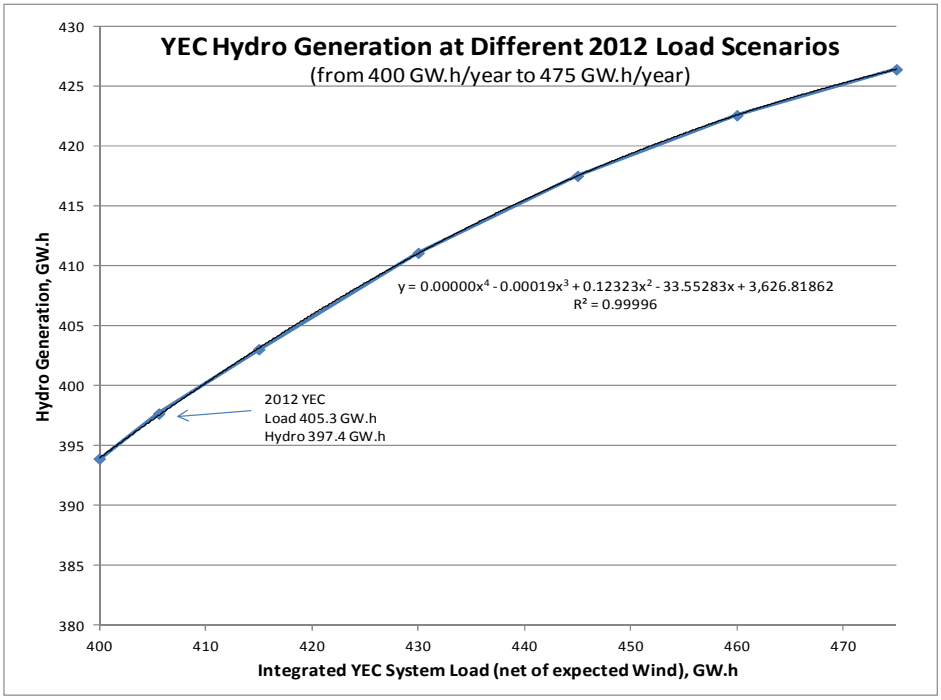


Table 1.1-1 (Attachment 1.1) shows the resulting estimates of 2012 hydro and diesel generation at 5 GW.h/year grid load increments as shown in Figure 1.1-1. Extensions of this model can be provided for higher grid loads and different load mixes - but such extensions would require modified formula to address both the higher load range and any expected shift in annual load shape at such higher grid loads.

Long-term average YEC hydro generation at any specific grid load will vary slightly when new mines are added that modify the annual load shape. Accordingly, adjustments are needed to Table 1.1-1 to reflect material changes in load mix or shape.

By way of example, Table 1.1-2 (Attachment 1.1) shows the slightly modified estimates of long-term average hydro and diesel generation at 5.0 GW.h/year grid load increments with YEC loads as provided in the Compliance Filing for Board Order 2013-1, based on current installed hydro generation and licences/permits and the 2013 GRA loads in the Compliance Filing with the addition of the Whitehorse Copper Tailings (WHCT) mine load (also reflects added wholesales due to continued closure of Fish Lake unit #1 until December 2013). Table 1.1-2 only becomes applicable for 2013 (i.e., replaces Table 4.12-1) if WHCT is connected as assumed in mid 2013.

Hydro generation in any one year can vary a great deal from the long-term average estimated in the above figure. By way of example, Appendix 3.2 of the Application noted that at grid loads as initially

forecast for 2013 of 430.4 GW.h/year and based on water year records currently included in the relevant water models:

- Long-term average hydro generation (net of expected wind at 0.2 GW.h) capability approximates 412.0 GW.h, with expected diesel generation (long-term average) approximating 18.2 GW.h.

- In extreme high water years increased hydro generation capability could lead to almost no baseload diesel generation; and

- In extreme low water years reduced hydro generation capability could require diesel generation exceeding 100.0 GW.h/year.

Updated Long-Term Average Fish Lake Generation & Related DCF Update

In contrast to YEC hydro generation, YECL's Fish Lake hydro generation is not affected in any material way by YECL's wholesales load levels or YEC's overall grid loads. Accordingly, updating the DCF for Fish Lake hydro simply involves updating the long-term average Fish Lake hydro generation based on current information, and including variances in actual Fish Lake generation versus the long-term average when assessing YEC diesel generation impacts on the DCF.

In Order 2009-2 following the 2008/2009 YECL GRA, the Board determined 8.73 GW.h to be a reasonable long-term average hydro generation number for Fish Lake; however, subsequent to Order 2009-2, Unit #1 at Fish Lake has been shut down during 2012 and is not currently expected to be replaced until December 2013.

Subsequent to the Compliance Filing for Board Order 2013-1, YEC has consulted with YECL and confirmed that 8.73 GW.h is currently the appropriate long-term average hydro generation for Fish Lake when both units are in operation, and that this long-term average for 2013 is reduced by 3.85 GW.h to reflect shut down of Unit #1 until December. YEC assumes that the Board will review long-term average Fish Lake generation estimates in the forthcoming YECL GRA proceeding and that any adjustments required for 2013 or subsequent years will be identified in the Board's resulting decisions.

In the updated DCF as it relates to Fish Lake hydro, the impacts on YEC diesel generation from variances in Fish Lake hydro generation from long-term average must be determined taking into account the extent to which YEC long-term hydro varies as YEC grid load varies. This assessment is done for any given year based on the impact on expected YEC diesel generation at actual YEC grid generation loads for that year, i.e., any Fish Lake generation variance from long-term average would have reduced or increased YEC's expected generation relative to what was determined based on actual YEC grid loads (including YECL wholesales that had been affected by the Fish Lake generation variance). This impact is determined by adjusting the YEC grid load used to determine expected YEC diesel (i.e., the grid load used for Tables 1.1-1 and 1.1-2) for the difference between actual Fish Lake generation and long-term average expected Fish Lake generation (after adjustments as needed for any unit shutdowns). In this way, changes to YEC diesel generation costs impacts (positive and negative) related to Fish Lake water variances are directly tracked and YEC's DCF transactions modified as required to comply with Order 2013-1.

DCF Term Sheet re: Recommended DCF Updates for YEC Grid & YECL Fish Lake

Attachment 1.1 to this proposal includes a DCF Term Sheet that sets out the current provisions of the DCF and recommended adjustments to update the DCF for the YEC grid and YECL Fish Lake generation, based on current circumstances on the Integrated Grid and the Board's directions in Order 2013-1. Tracked changes show changes from the DCF Term Sheet included at Attachment 3.2 to the Application.

With regard to Board Order 2013-1, in summary the following are addressed:

- Incorporation of non-diesel generation forecasts into DCF determinations:
  - Confirm that YEC wind generation differences from LTA will impact the DCF; and
  - Procedures and assumptions to incorporate Fish Lake generation into DCF determinations.
- Quarterly and annual reporting is provided that incorporates suggestions of CW and UCG.
- An example over five years shows how the DCF balance changes and will be reported.

Attachment 1.1-1 to this proposal is provided to show as tracked changes the revisions made to the DCF Term Sheet from the DCF Term Sheet provided in the Application as Attachment 3.2.

Attachment 1.1

ATTACHMENT 1.1: DCF TERM SHEET: YEC GRID & YECL FISH LAKE

PURPOSE & FUNCTION: The DCF operates to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro and wind generation. The Fund is only to be used for these purposes and is not to be accessed for other reasons without prior YUB approval, including government subsidy of rates. Historically, the DCF has operated to offset diesel generation cost changes only for the WAF system[1] caused solely by variances from long-term average levels of WAF system hydro and wind generation.

UPDATE: *For the purposes of updating the Fund to address circumstances in 2012, the following additional adjustments are required: (1) the Fund needs to be amended to address the new interconnected system (i.e., not reference only "WAF" system generation and instead reference all interconnected grid hydro operated by YEC); (2) the Fund needs to be amended to address incremental costs for any fossil fuel used to displace diesel fuel (e.g., natural gas as may be supplied by LNG, as well as incremental costs for diesel fuel).*

LONG-TERM AVERAGE: The Fund currently assumes that the quantum of YEC diesel generation costs in rates is determined using the long-term average water expected to be available for YEC hydro generation and for YECL's Fish Lake hydro generation.

The last approved long-term average hydro and wind on the YEC WAF grid for the DCF as established in the 1996/97 GRA is set out below[2]:

1. Aishihik Facility - 105 GWh/yr;
2. Whitehorse Rapids - 246 GWh/yr;
3. YEC wind generation - 0.3 GWh/yr; and
4. YECL Fish Lake hydro -10 GW.h/yr.

UPDATE: *The above long-term average generation for YEC wind and Fish Lake hydro generation can be updated as required based on latest GRA approvals by the Board, e.g., as at April 2013, expected YEC wind generation is 0.24 GW.h/yr and long-term average Fish Lake hydro generation is 8.73 GW.h less any loss of this generation due to shut down of a unit (in 2013, the long-term average is reduced by 3.85 GW.h due to shut down of Unit #1 until December; in 2012, the*

[1] After UKHM closed prior to 1990, surplus hydro conditions existed in Mayo system.

[2] The 2008/2009 GRA noted Yukon Energy's long-term average hydro generation capability from its Whitehorse and Aishihik plants on the WAF system, as estimated in the 1996/1997 General Rate Application when the Faro mine was assumed to be fully operational and all available hydro generation was expected to be fully utilized, approximated 351 GW.h per year.

long-term average is reduced by 4.35 GW.h due to shut down of Unit #1 all year).

However, the previous approach of setting a single value for the long-term average YEC hydro is not suited to today's system. At the range of grid loads relevant today and current hydro capabilities, it is necessary to recognize that long-term average YEC hydro capability varies with variations in annual grid loads. Additional variation can occur regarding month-by-month estimates of long-term average hydro and wind generation in years when, for at least some months, diesel is not on the margin.

The following changes are required as regards the determination of expected YEC hydro generation:

1. Updates based on changes to YEC grid system

a. Mayo facility long-term average hydro updated to include existing conditions and licences with regards to Mayo A and Mayo B.

b. Aishihik facility long-term average hydro based on existing conditions and licences, including Aishihik Third Turbine.

c. Long-term average wind generation as forecast in the last approved GRA. As noted below, this expected wind generation is deducted from actual YEC generation (net of any secondary sales related generation) when determining expected YEC hydro and diesel generation.

2. Update to include YECL Fish Lake hydro impacts on Expected YEC Generation – *Long-term average Fish Lake generation forecasts, as described above, are required by Board Order 2013-1 to be incorporated into YEC's model for determining expected YEC hydro and diesel generation.*

As is the case with wind generation, expected generation from Fish Lake hydro is not affected by overall YEC grid loads and therefore the effects of this generation can best be assessed prior to the determination of expected YEC hydro generation.

Accordingly, as is done with wind generation, YECL Fish Lake generation will be incorporated at the outset into the calculation of grid generation loads used to determine expected YEC hydro and diesel generation, i.e., actual YECL Fish Lake generation will be added to actual YEC grid generation (net of secondary sales impacts on YEC generation), and expected (i.e., long-term average) Fish Lake generation will then be deducted. In this manner, grid loads will be determined excluding expected wind and expected Fish Lake hydro.

3. Formulaic approach *– determine expected YEC diesel generation based on long-term average water-based YEC hydro generation that is forecast using a formulaic relationship to load in each year (including non-test years) rather than a fixed value as historically done*[3]*:*

a. Table 1.1-1 is adopted at this time to determine annual expected YEC diesel generation prior to any new mine or industrial load connections based on long-term average YEC hydro generation at YEC grid loads (net of expected wind and expected Fish Lake generation) ranging from 400 to 475 GW.h/year.

b. The summary below (Example 4.1-1) provides an example of the determination of expected YEC diesel generation at a grid load of 417 GW.h (net of expected wind and expected Fish Lake generation).

Example 1.1-1: Expected YEC Diesel Generation Example for the YEC Load at 417 GW.h (net of expected YEC Wind and expected Fish Lake)

Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 4).

Step 2. Find the diesel generation from Column C = 11.8 GW.h (Line 4).

Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 5, 46%) to the difference from Step 3 (2 GW.h) = 0.92 GW.h

Step 5. Add numbers from Step 2 (11.8 GW.h) and Step 4 (0.92 GW.h) = 12.72 GW.h

The expected diesel generation at 417 GW.h load is 12.72 GW.h.

Notes:
The load assumed the maximum load at 475 GW.h and the minimum load at 400 GW.h.

c. Table 1.1-2 is adopted at this time to determine annual expected YEC diesel generation in 2013 after such time as the Whitehorse Copper Tailings industrial load is connected to YECL, based on long-term average hydro generation at grid loads (net of expected YEC wind and expected Fish Lake generation) ranging from 400 to 500 GW.h/year and the annual load shape forecast with this new industrial load.

[3] Long-term average hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined based on power benefit model calculations based on 28 years of water record for the interconnected grid. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average diesel. This same analysis would apply to LNG if it replaces diesel on the grid.

d. *Yukon Energy will provide an update to Table 1.1-2 when required in future to address material changes in long-term average YEC hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.*

4. ***Monthly and Annual reporting of YEC Hydro Long-Term Average Hydro and Expected YEC Diesel Generation –*** *ensure the account can be managed on a monthly basis to permit financial reporting through use of a simple pre-determined monthly percentage distribution. Due to imprecision in forecast long-term average YEC hydro monthly distributions it is possible that inappropriate values may arise during monthly estimating but these will not be part of final annual DCF calculations. Monthly calculations of YEC expected hydro and diesel generation will therefore be a placeholder with ultimate final calculations performed only on the annual values*[4]*.*

DCF DIESEL SAVINGS (COSTS):

YEC diesel generation savings (excess) for the DCF related to changes in non-diesel generation for YEC or YECL is calculated to remove the effects of YEC hydro-wind or YECL Fish Lake hydro generation variances. Diesel cost savings (excess) are calculated based on the approved forecasts for YEC WAF diesel generation costs per kWh based on GRA approved fuel prices, average diesel unit fuel efficiency, and average diesel unit incremental O&M costs per kWh[5].

UPDATE: *The relevant diesel fuel prices, unit fuel efficiency and incremental O&M costs are updated in each YEC GRA. In principle, the same approach would also apply regarding any other fossil fuel, i.e., these cost parameters are not limited only to diesel. To become operational for a fossil fuel other than diesel, this would require a GRA to approve related non-diesel fuel costs and engine efficiencies.*

At this time, with 100 % LTA diesel generation being re-applied, the updated DCF will only include diesel fuel prices and unit fuel efficiency, i.e., 28.71 c/kW.h (the average YEC diesel fuel cost in the current test years based on the Compliance Filing). Although an incremental O&M cost of 3 c/kW.h was adopted for some purposes in the 2009 Phase II filings, this number was not based on short term incremental costs applicable to YEC and no such updated cost

[4] There are limits to the ability to permit each month to have its own formula or polynomial, and differing monthly distributions may permit occasional odd values that resolve themselves in annual calculations. This same factor applied in the DCF calculations in the past.

[5] Forecast from 1996/97 GRA were as follows: standard efficiency at 3.71 kWh/litre of fuel and YEC average WAF diesel fuel price forecast at approximately 29.60 cents/litre. Variable O&M costs per kWh of diesel fuel were assumed at 1.6 cents per litre, as assumed for the approved 1996/97 GRA retail runoff rates calculations for WAF.

information has been developed or reviewed at this time[6]. In order to ensure that the DCF in fact tracks incremental short term costs for YEC as these change within a given year, it is important that non-fuel O&M reflect costs that do in fact change in the year due to changes in actual diesel generation - and at this time, YEC has not recently assessed these costs. YEC will review and report on this at its next GRA.

DIESEL ON THE MARGIN: Historically, the DCF was to be used only for offsetting baseload diesel generation changes due to the hydro/wind variances from long-term forecasts reflected in rates set in a GRA, and the DCF was only active when YEC diesel was on the margin. The 1996 evidence presumed YEC diesel generation was not on the margin for the WAF system when the Faro mine was closed.

UPDATE: *Under the proposed updated approach, the Fund would be permanently switched "on" through a formulaic approach that, subject to YUB review at each YEC GRA, automatically adjusts forecast long-term YEC hydro generation and related diesel (or other non-diesel fossil fuel) YEC generation to reflect actual YEC grid generation load. Accordingly, there would no longer be a YEC diesel on the margin test for activating the DCF.*

With the YEC diesel on the margin test discontinued for the DCF, there is need to consider other related items that would be affected (i.e., RS 42 with the related ERA requires that diesel on the margin be defined).

- *Effective the same date that the updated DCF approach becomes effective (i.e., January 1, 2012, as that is the date when YEC diesel generation is to be included in rates at 100% of LTA), for the purpose of RS 42 it is necessary to recognize that diesel is on the margin, and that any required ERA determinations be made based on YEC costs incurred for actual diesel generation and/or DCF-related payments, i.e., based on the DCF as updated, YEC costs related to YEC grid loads (and grid load changes) would be determined as provided for in the updated DCF.[7] As in the past DCF operation, ERA determinations do not affect any of the DCF determinations.*

[6] For example, see evidence of Mr. Bowman, Vol. 18 of the transcript regarding the Phase II hearing, at page 174 and an explanation as to why the change in O&M from 1.6 cents per kW.h (in YEC's Phase 1 GRA) to 3 cents per kW.h (in the Part II application).

[7] Board Order 2013 directed YEC to re-file a Rate Schedule 42 in cooperation with YECL, and to work with YECL to provide a joint recommendation on how the DCF will affect the ERA in Rate Schedule 42 and any proposed wording changes to that rate schedule with regard to the ERA (paragraph 281 and paragraph 255). As reviewed in Section 1 of YEC's Compliance filing relating to Order 2013-1, Yukon Energy is meeting with YECL to develop a joint recommendation on how the DCF will affect the ERA in Rate Schedule 42 and any proposed wording changes to that rate schedule, and will report to the Board as soon as possible on this matter.

QUANTUM & CAP:

The initial Fund was determined based on funds available as at December 31, 1995[8]. The cap on the Fund is currently set at the initial contribution level ($4,040,046). The "negative cap" is currently ($-4,040,046). If the Fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider rebate to customers over the following two years. If the Fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and negative cap levels.

UPDATE: *When YEC diesel remains the marginal source of supply, major adjustments to the cap will need to be considered to adequately address the material potential swings related to diesel generation (e.g., potential for greater than +/- $20 million swings)[9]. However, it is not apparent that an excessively high cap would either (a) be able to be fully financed by YEC in the event it was a negative DCF balance; or (b) would yield the best outcome in terms of rate stability. In this respect, when diesel remains the marginal source of supply, one possibility is that the Fund have a very high cap for positive funding (perhaps up to $20 to 30 million reflecting the degree of possible drought today; funds which would be externally invested, or available to be "borrowed" by YEC as short term capital) but a much lower cap in terms of negative balances that must be financed by YEC.*

Given Board Order 2013-1 set rates at 100% of LTA and fuel costs at this time still require high cost diesel, YEC recommends that the current threshold be doubled to +/- $8 million. Given that the Fund is ultimately in place to provide rate stability for ratepayers and protect for potential drought conditions as were experienced in the late 1990s, Yukon Energy believes that the recommended threshold is appropriate at this time, but will require ongoing review at each GRA. For example, in the event of a shift to LNG with incremental fuel costs much lower than diesel costs, a lower threshold such as the current +/- $4 million may be feasible.

INTEREST:

The Fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the Fund and any negative balances would only attract interest at the lowest short term borrowing rate available to the Companies through a line of credit.

UPDATE: *No change is recommended to the current mechanism for interest.*

[8] The opening balance as at January 1, 1996 was $4,040,046.

[9] As noted at page 3.2-4 of the YEC 2012/13 GRA, under the then forecast potential loads in 2013 potential annual diesel generation due to hydro fluctuations could exceed 100 GW,h/year, or over 80 GW.h higher than the applicable annual long-term average, reflecting a potential swing in annual diesel generation costs exceeding $20 million in extreme conditions.

Quarterly & Annual Reporting	An annual report is required to be filed with the Board detailing additions and deletions to the Fund, and the Board directs the Companies (YEC and YECL) on the additions and deletions to the Fund. The annual report to the Board is also to include a forecast of available water for the year. **Update:** *Yukon Energy, with the assistance of YECL as regards actual Fish Lake hydro generation, will provide a quarterly report detailing additions and deletions to the Fund as then recorded (which are subject to adjustment as noted earlier at calendar year end), and providing a narrative indicating what, if any, actions are required to replenish or refund monies with regard to the Fund (due to the Fund being expected to approach its positive or negative cap as then defined by the Board). The annual report filed with the Board by YEC will include any updated Table 1.1-1 or Table 1.1-2 that is adopted for determining YEC expected hydro and diesel generation for the year (reflecting actual grid load and other relevant factors as required and feasible) as well working spreadsheets detailing the DCF calculations, and it is proposed that the Board offer parties the opportunity to comment on the annual filing.*
5-Year Example	*Tables 1.1-3, 1.1-4 and 1.1-5 an example of five years of transactions which will show how the balance in the DCF will change going forward from today and how those changes will be reported.*

Table 1.1-1: Expected YEC Diesel Generation with LTA YEC Hydro Generation (Assumes Only Minto & Alexco Mine Loads for 2012 (Compliance Filing))

Line Number	YEC Grid Load (GWh)	YEC Hydro Generation (GWh)	YEC Diesel Generation (GWh)	Increase in Load (GWh)	Increase in Diesel Generation (GWh)	Diesel as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	400	394.0	6.0			
2	405	397.2	7.8	5.0	1.8	36%
3	410	400.2	9.8	5.0	2.0	40%
4	415	403.2	11.8	5.0	2.0	40%
5	420	405.9	14.1	5.0	2.3	46%
6	425	408.6	16.4	5.0	2.3	46%
7	430	411.1	18.9	5.0	2.5	50%
8	435	413.4	21.6	5.0	2.7	54%
9	440	415.5	24.5	5.0	2.9	58%
10	445	417.5	27.5	5.0	3.0	60%
11	450	419.4	30.6	5.0	3.1	62%
12	455	421.1	33.9	5.0	3.3	66%
13	460	422.6	37.4	5.0	3.5	70%
14	465	424.0	41.0	5.0	3.6	72%
15	470	425.3	44.7	5.0	3.7	74%
16	475	426.4	48.6	5.0	3.9	78%

Notes:
1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding expected (GRA forecast) YEC Wind generation and actual less expected Fish Lake hydro generation.
2. The diesel generation and increase for the added load are based on polynomial equations derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The simulation model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model outputs for this table are based on Aishihik operation rule at 10-year rolling average spring elevation no lower than 913.7 m and current Mayo Lake operation rule (no additional storage), Mayo B and Aishihik 3rd turbine are included.
5. The simulation model outputs are based on 2012 forecast load distributions [updated based on YUB Order 2013-01], and requires modifications when new mines or industrial loads are connected to the grid.
6. This table assumes max load at 475 GW.h and minimum load at 400 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

Example

Expected YEC Diesel Generation for the YEC generation at 417 GW.h (net of expected (GRA) Wind)

Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 4).

Step 2. Find the diesel generation from Column C = 11.8 GW.h (Line 4).

Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 5, 46%) to the difference from Step 3 (2 GW.h) = 0.92 GW.h

Step 5. Add numbers from Step 2 (11.8 GW.h) and Step 4 (0.92 GW.h) = 12.72 GW.h

The expected diesel generation at 417 GW.h load is 12.72 GW.h.

Notes:
The load assumed the maximum load at 475 GW.h and the minimum load at 400 GW.h.

1 **Table 1.1-2: Expected YEC Diesel Generation with LTA YEC Hydro Generation**

2 **(Assumes WHCT & Other Industrial Loads for 2013 (Compliance Filing))**

Line Number	YEC Grid Load (GWh)	YEC Hydro Generation (GWh)	YEC Diesel Generation (GWh)	Increase in Load (GWh)	Increase in Diesel Generation (GWh)	Diesel as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	400	394.9	5.1			
2	405	398.3	6.7	5.0	1.6	32%
3	410	401.5	8.5	5.0	1.8	36%
4	415	404.5	10.5	5.0	2.0	40%
5	420	407.3	12.7	5.0	2.2	44%
6	425	409.9	15.1	5.0	2.4	48%
7	430	412.3	17.7	5.0	2.6	52%
8	435	414.6	20.4	5.0	2.7	54%
9	440	416.7	23.3	5.0	2.9	58%
10	445	418.7	26.3	5.0	3.0	60%
11	450	420.5	29.5	5.0	3.2	64%
12	455	422.2	32.8	5.0	3.3	66%
13	460	423.9	36.1	5.0	3.3	66%
14	465	425.4	39.6	5.0	3.5	70%
15	470	426.8	43.2	5.0	3.6	72%
16	475	428.1	46.9	5.0	3.7	74%
17	480	429.4	50.6	5.0	3.7	74%
18	485	430.6	54.4	5.0	3.8	76%
19	490	431.8	58.2	5.0	3.8	76%
20	495	432.9	62.1	5.0	3.9	78%
21	500	434.0	66.0	5.0	3.9	78%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding expected (GRA forecast) YEC Wind generation and actual less expected Fish Lake hydro generation.

2. The diesel generation and increase for the added load are based on polynomial equations derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.

3. The simulation model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.

4. The simulation model outputs for this table are based on Aishihik operation rule at 10-year rolling average spring elevation no lower than 913.7 m and current Mayo Lake operation rule (no additional storage), Mayo B and Aishihik 3rd turbine are included.

5. The simulation model outputs are based on 2013 forecast load distributions [updated based on YUB Order 2013-01], and requires modifications when new mines or industrial loads are connected to the grid.

6. This table assumes max load at 500 GW.h and minimum load at 400 GW.h. If the load exceeds these limits then the table needs to be updated.

7. Numbers are subject to rounding.

Example

Expected YEC Diesel Generation for the YEC generation at 447 GW.h (net of expected (GRA) Wind)

Step 1. Find the closest load from Column A that is less than 447 GW.h = 445 GW.h (Line 10).

Step 2. Find the diesel generation from Column C = 26.3 GW.h (Line 10).

Step 3. Find the difference between the given load (447 GW.h) and load from Step 1 (445 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 11, 64%) to the difference from Step 3 (2 GW.h) = 1.28 GW.h

Step 5. Add numbers from Step 2 (26.3 GW.h) and Step 4 (1.28 GW.h) = 27.58 GW.h

The expected diesel generation at 447 GW.h load is 27.58 GW.h.

Notes:

3 The load assumed the maximum load at 500 GW.h and the minimum load at 400 GW.h.

Yukon Energy Corporation
Diesel Contingency Fund June 21, 2013

1 **Table 1.1-3: YEC 2012/13 GRA Compliance Filing: DCF Operation Example for 5 Years**

Line	Activity	Year 1	Year 2	Year 3	Year 4	Year 5
A	**DCF Opening Balance[1] ($000s)**	**$902**	**$1,731**	**$2,300**	**$3,285**	**$1,100**
B	**Yukon Grid Generation[2]**	409,653	420,987	445,500	455,600	470,200
C	**YECL Fish Lake[2]**	4,100	4,600	8,900	7,000	9,200
	YEC Grid Generation[2]					
D	Assumed actual YEC Hydro (MW.h)	400,108	407,149	418,362	413,400	425,762
E	Assumed actual YEC Diesel (MW.h)	5,000	9,000	18,000	35,000	35,000
F	Assumed actual actual Wind (MW.h)	445	238	238	200	238
G=D+E+F	Total YEC Generation (MW.h)	405,553	416,387	436,600	448,600	461,000
H	Expected YEC Diesel Generation in Rates[3] (MW.h)	7,814	10,882	21,289	27,344	36,962
I=E-H	YEC Diesel Generation to be Included in DCF (MW.h)	-2,814	-1,882	-3,289	7,656	-1,962
J	YEC Adjustments[4] (MW.h)	0	0	0	0	0
K=H-J	YEC Diesel Generation Included in DCF after Adjustments (MW.h)	-2,814	-1,882	-3,289	7,656	-1,962
L=K*$0.3168	Incremental Diesel Generation Cost to Charge[5] (Refund) DCF ($000s)	($808)	($540)	($944)	$2,198	($563)
M=L	Total DCF operation for YEC					
	YEC pays to DCF Fund	$808	$540	$944		$563
	YEC withdraws from DCF Fund				($2,198)	
N=A+M	**DCF Ending Balance ($000s)**	**$1,710**	**$2,272**	**$3,244**	**$1,087**	**$1,664**
O	**Interest on DCF Balance[6] ($000s)**	**$21**	**$28**	**$41**	**$14**	**$21**
P=N+O	**DCF Ending Balance[7] after Interest charge ($000s)**	**$1,731**	**$2,300**	**$3,285**	**$1,100**	**$1,685**

Notes:
1. DCF opening balance for Year 1 is 2011 actual ending balance of DCF account.
2. Assumed actual generation. Please see detailed calculations in Table 1.1-4.

3. Expected YEC diesel generation is calculated based on Table 1.1-1 and Table 1.1-2. Please see detailed calculations in Table 1.1-4.
4. Adjustments for YEC would include diesel generation not related to load or water variance, e.g., maintenance, fires, construction, etc.
5. Diesel generation cost assumed at 28.71 cents/kW.h (based on 2012/13 GRA Compliance Filing average fuel cost).

6. Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit. For this example used 1.25% based on Government of Canada Bond Yields for 3-year and 5-year issues.

2 7. Positive balances represent amounts to the benefit of ratepayers; negative balances are amounts owing to the Companies.

Table 1.1-4: DCF Example for 2012-2016 YEC Load Cases

Line No				Notes
L1	Fuel Cost per kW.h	28.71	cents/kW.h	Compliance Filing Average Fuel cost
	Calculation of Diesel Cost to Charge (Refund) DCF - YEC portion of DCF			
	Year 1 - 2012 GRA compliance filing load forecast; Actual Wind at Forecast; Actual Diesel Generation Below Expected			
	Assumptions			
L2	YEC Grid load	405,553	MW.h	assumed actual
L3	Fish Lake	4,100	MW.h	assumed actual
L4=L2+L3	Total Grid load	409,653	MW.h	
	Assumed Actual Generation Sources			
L5	YECL Fish Lake	4,100	MW.h	assumed actual
L6	YEC Hydro	400,108	MW.h	assumed actual
L7	YEC Diesel	5,000	MW.h	assumed actual
L8	YEC Wind	445	MW.h	assumed actual
L9	Total Grid load	409,653	MW.h	
	Expected Generation Sources			
L10	YECL Fish Lake (expected)	4,380	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 4.35 GW.h for Unit #1.
L11	YEC Wind (expected)	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	405,034	MW.h	
L13	Expected Base Diesel Generation at 405 GW.h	7,800	MW.h	Derived from Table 1.1-1
L14=(L12-405 GW.h)x40%	Expected Incremental Diesel Generation at 34 MW.h above 405 GW.h	14	MW.h	40% of Grid Load between 405 GW.h and 410 GW.h is diesel - Derived from updated Table 1.1-1 for GRA Compliance Filing
L15=L13+L14	Total Expected YEC Diesel Generation	7,814	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	7,814	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation	5,000	MW.h	assumed actual
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 2,814	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($808)		

Table 1.1-4 (cont): DCF Example for 2012-2016 YEC Load Cases

Year 2 - 2013 GRA compliance filing load forecast; Actual Wind at Forecast; Actual Diesel Generation Below Expected

	Assumptions				
L2	YEC Grid load		416,387	MW.h	assumed actual
L3	Fish Lake		4,600	MW.h	assumed actual
L4=L2+L3	Total Grid load		420,987	MW.h	
	Assumed Actual Generation Sources				
L5	YECL Fish Lake		4,600	MW.h	assumed actual
L6	YEC Hydro		407,149	MW.h	assumed actual
L7	YEC Diesel		9,000	MW.h	assumed actual
L8	YEC Wind		238	MW.h	assumed actual
L9	Total Grid load		420,987	MW.h	
	Expected Generation Sources				
L10	YECL Fish Lake (expected)		4,880	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA at 8.73 GW.h less 3.85 GW.h for Unit #1 for Jan-Dec 2013.
L11	YEC Wind (expected)		238	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind		415,869	MW.h	
L13	Expected Base Diesel Generation at 415 GW.h		10,500	MW.h	Derived from updated Table 1.1-2
L14=(L12-415 GW.h)x44%	Expected Incremental Diesel Generation at 969 MW.h above 415 GW.h		382	MW.h	44% of Grid Load between 415 GW.h and 420 GW.h is diesel - Derived from updated Table 1.1-2
L15=L13+L14	Total Expected YEC Diesel Generation		10,882	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates		10,882	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation		9,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	-	1,882	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)		($540)		

1 **Table 1.1-4 (cont): DCF Example for 2012-2016 YEC Load Cases**

Year 3 - 2014 load forecast [please see Exhibit 20, page A-3, Base Case load for 2014; Wind at Forecast; Actual Diesel Generation Below Expected]

	Assumptions				
L2	YEC Grid load		436,600	MW.h	
L3	Fish Lake		8,900	MW.h	
L4=L2+L3	Total Grid load		445,500	MW.h	
	Assumed Actual Generation Sources				
L5	YECL Fish Lake		8,900	MW.h	
L6	YEC Hydro		418,362	MW.h	
L7	YEC Diesel		18,000	MW.h	
L8	YEC Wind		238	MW.h	
L9	Total Grid load		445,500	MW.h	
L10	YECL Fish Lake (expected)		8,730	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA.
L11	YEC Wind (expected)		238	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind		436,532	MW.h	
L13	Expected Base Diesel Generation at 435 GW.h		20,400	MW.h	Derived from updated Table 1.1-2
L14=(L12-435 GW.h)x58%	Expected Incremental Diesel Generation at 1,532 MW.h above 435 GW.h		889	MW.h	58% of Load between 435 GW.h and 440 GW.h is diesel
L15=L13+L14	Total Expected YEC Diesel Generation		21,289	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates		21,289	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation		18,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	-	3,289	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)		($944)		

2

3

1 **Table 1.1-4 (cont): DCF Example for 2012-2016 YEC Load Cases**

Year 4 - 2015 load forecast [please see Exhibit 20, page A-3, Base Case load for 2015; Actual Wind below Forecast; Actual Diesel Generation Above Expected]

	Assumptions			
L2	YEC Grid load	448,600	MW.h	
L3	Fish Lake	7,000	MW.h	
L4=L2+L3	Total Grid load	455,600	MW.h	
	Assumed Actual Generation Sources			
L5	YECL Fish Lake	7,000	MW.h	
L6	YEC Hydro	413,400	MW.h	
L7	YEC Diesel	35,000	MW.h	
L8	YEC Wind	200	MW.h	
L9	Total Grid load	455,600	MW.h	
	Expected Generation Sources			
L10	YECL Fish Lake (expected)	8,730	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA.
L11	YEC Wind (expected)	238	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	446,632	MW.h	
L13	Expected Base Diesel Generation at 445 GW.h	26,300	MW.h	Derived from updated Table 1.1-2
L14=(L12-445 GW.h)x64%	Expected Incremental Diesel Generation at 1,632 MW.h above 445 GW.h	1,044	MW.h	64% of Load between 445 GW.h and 450 GW.h is diesel
L15=L13+L14	Total Expected YEC Diesel Generation	27,344	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	27,344	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation	35,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	7,656	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	$2,198		

2

1

Table .1-4 (cont): DCF Example for 2012-2016 YEC Load Cases

Year 5 - 2016 load forecast [please see Exhibit 20, page A-3, Base Case load for 2016; Wind at Forecast; Actual Diesel Generation Below Expected]

	Assumptions				
L2	YEC Grid load		461,000	MW.h	
L3	Fish Lake		9,200	MW.h	
L4=L2+L3	Total Grid load		470,200	MW.h	
	Assumed Actual Generation Sources				
L5	YECL Fish Lake		9,200	MW.h	
L6	YEC Hydro		425,762	MW.h	
L7	YEC Diesel		35,000	MW.h	
L8	YEC Wind		238	MW.h	
L9	Total Grid load		470,200	MW.h	
	Expected Generation Sources				
L10	YECL Fish Lake (expected)		8,730	MW.h	YECL Fish Lake long term average hydro generation based on YUB Order 2009-2 (page 11) on YECL's 2008/09 GRA.
L11	YEC Wind (expected)		238	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind		461,232	MW.h	
L13	Expected Base Diesel Generation at 460 GW.h		36,100	MW.h	Derived from updated Table 1.1-2
L14=(L12-460 GW.h)x70%	Expected Incremental Diesel Generation at 762 MW.h above 460 GW.h		862	MW.h	70% of Load between 460 GW.h and 465 GW.h is diesel
L15=L13+L14	Total Expected YEC Diesel Generation		36,962	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates		36,962	MW.h	100% of long-term average
L17=L7	Actual YEC Diesel Generation		35,000	MW.h	Assumed
L18=L17-L16	YEC Diesel Generation to be Included in DCF	-	1,962	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)		($563)		

2

Attachment 1.1-1

Attachment 1.1-1: DCF TERM SHEET: ~~UPDATES FOR~~ YEC GRID & YECL FISH LAKE

PURPOSE & FUNCTION:

The DCF operates to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro and wind generation. The Fund is only to be used for these purposes and is not to be accessed for other reasons without prior YUB approval, including government subsidy of rates. Historically, the DCF has operated to offset diesel generation cost changes only for the WAF system[1] caused solely by variances from long-term average levels of WAF system hydro and wind generation.

UPDATE: *For the purposes of updating the Fund to address circumstances in 2012, the following additional adjustments are required: (1) the Fund needs to be amended to address the new interconnected system (i.e., not reference only "WAF" system generation and instead reference all interconnected grid hydro operated by YEC); (2) the Fund needs to be amended to address incremental costs for any fossil fuel used to displace diesel fuel (e.g., ~~liquefied~~ natural gas as may be supplied by~~or~~ LNG, as well as incremental costs for diesel fuel).*

LONG-TERM AVERAGE:

The Fund currently assumes that the quantum of YEC diesel generation costs in rates is determined using the long-term average water expected to be available for YEC hydro generation and for YECL's Fish Lake hydro generation.

The last approved long-term average hydro and wind on the YEC WAF grid for the DCF as established in the 1996/97 GRA is set out below[2]:

1. Aishihik Facility - 105 GWh/yr;
2. Whitehorse Rapids - 246 GWh/yr;
3. YEC wind generation - 0.3 GWh/yr; and
4. ~~3.~~ YECL Fish Lake hydro -10 GW.h/yr.

UPDATE: *The above long-term average generation for YEC wind and Fish Lake hydro generation can be updated as required based on latest GRA approvals by the Board, e.g., as at April 2013, expected YEC wind generation is 0.24 GW.h/yr and long-term average Fish Lake hydro generation is 8.73*

[1] After UKHM closed prior to 1990, surplus hydro conditions existed in Mayo system.
[2] The 2008/2009 GRA noted Yukon Energy's long-term average hydro generation capability from its Whitehorse and Aishihik plants on the WAF system, as estimated in the 1996/1997 General Rate Application when the Faro mine was assumed to be fully operational and all available hydro generation was expected to be fully utilized, approximated 351 GW.h per year.

GW.h less any loss of this generation due to shut down of a unit (in 2013, the long-term average is reduced by 3.85 GW.h due to shut down of Unit #1 until December; in 2012, the long-term average is reduced by 4.35 GW.h due to shut down of Unit #1 all year).

However, t~~T~~he previous approach of setting a single value for the long-term average YEC hydro is not suited to today's system. At the range of grid loads relevant today and current hydro capabilities, it is necessary to recognize that long-term average YEC hydro capability varies with variations in annual grid loads. Additional variation can occur regarding month-by-month estimates of long-term average hydro and wind generation in years when, for at least some months, diesel is not on the margin.

The following changes are required as regards the determination of expected YEC hydro generation:

1. Updates based on changes to YEC grid system

a. *Mayo facility long-term average hydro updated to include existing conditions and licences with regards to Mayo A and Mayo B.*

b. *Aishihik facility long-term average hydro based on existing conditions and licences, including Aishihik Third Turbine.*

c. *Long-term average w~~W~~ind generation as forecast in the last approved GRA. As noted below, this expected wind generation is deducted from actual YEC generation (net of any secondary sales related generation) when determining expected YEC hydro and diesel generation.*

2. Update to include YECL Fish Lake hydro impacts on Expected YEC Generation – *Long-term average Fish Lake generation forecasts, as described above, are required by Board Order 2013-1 to be incorporated into YEC's model for determining expected YEC hydro and diesel generation.*

As is the case with wind generation, expected generation from Fish Lake hydro is not affected by overall YEC grid loads and therefore the effects of this generation can best be assessed prior to the determination of expected YEC hydro generation.

Accordingly, as is done with wind generation, YECL Fish Lake generation will be incorporated at the outset into the calculation of grid generation loads used to determine expected YEC hydro and diesel generation, i.e., actual YECL Fish Lake generation will be added to actual YEC grid

generation (net of secondary sales impacts on YEC generation), and expected (i.e., long-term average) Fish Lake generation will then be deducted. In this manner, grid loads will be determined excluding expected wind and expected Fish Lake hydro.

3. ***Formulaic approach*** *– determine expected YEC diesel generation based on long-term average water-based YEC hydro generation that is forecast using a formulaic relationship to load in each year (including non-test years) rather than a fixed value as historically done[3]:*

   a. *Table 413.12-1 is adopted at this time to determine annual expected YEC diesel generation prior to any new mine or industrial load connections based on long-term average YEC hydro generation at YEC grid loads (net of expected wind and expected Fish Lake generation) ranging from 400 to 475500 GW.h/year.*

   b. *The summary below (Example 41.1-13.2-1) provides an example of the determination of expected YEC diesel generation at a grid load of 4147 GW.h (net of expected wind and expected Fish Lake generation).*

Example 41.13.2-1: Expected YEC Diesel Generation Example for the YEC Load at 41747 GW.h
(net of expected YEC Wind and expected Fish Lake)

Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 4).

Step 2. Find the diesel generation from Column C = 11.8 GW.h (Line 4).

Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 5, 46%) to the difference from Step 3 (2 GW.h) = 0.92 GW.h

Step 5. Add numbers from Step 2 (11.8 GW.h) and Step 4 (0.92 GW.h) = 12.72 GW.h

The expected diesel generation at 417 GW.h load is 12.72 GW.h.

Notes:
The load assumed the maximum load at 475 GW.h and the minimum load at 400 GW.h.

   c. *Table 41.1-3.2-2 is adopted at this time to determine annual expected YEC diesel generation in 2013 after such time as the Whitehorse Copper Tailings industrialmine load is connected to YECL, based on long-term average hydro generation at grid loads (net of expected YEC wind and expected Fish Lake generation)*

[3] Long term average hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined based on power benefit model calculations based on 28 years of water record for the interconnected grid. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average diesel. This same analysis would apply to LNG if it replaces diesel on the grid.

ranging from 400 to 500 GW.h/year and the annual load shape forecast with this new industrial load~~mine~~.

d. Yukon Energy will provide an update to Table ~~4~~1.1 ~~3.2~~ 2 when required in future to address material changes in long-term average YEC hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

4. Monthly and Annual reporting of YEC Hydro Long-Term Average Hydro and Expected YEC Diesel Generation – *ensure the account can be managed on a monthly basis to permit financial reporting through use of a simple pre-determined monthly percentage distribution. Due to imprecision in forecast long-term average YEC hydro monthly distributions it is possible that inappropriate values may arise during monthly estimating but these will not be part of final annual DCF calculations. Monthly calculations of YEC expected hydro and diesel generation will therefore be a placeholder with ultimate final calculations performed only on the annual values[4].*

DCF DIESEL SAVINGS (COSTS):

YEC d~~D~~iesel generation savings (excess) for the DCF related to changes in non-diesel generation for YEC or YECL is calculated to remove the effects of~~for~~ YEC hydro-wind or YECL Fish Lake hydro generation variances~~ in total WAF generation for YEC~~. Diesel cost savings (excess) are calculated based on the approved forecasts for YEC WAF diesel generation costs per kWh based on GRA approved fuel prices, average diesel unit fuel efficiency, and average diesel unit incremental O&M costs per kWh[5].

UPDATE: *The relevant diesel fuel prices, unit fuel efficiency and incremental O&M costs are updated in each YEC GRA. In principle, the same approach would also apply regarding any other fossil fuel, i.e., these cost parameters are not limited only to diesel. To become operational for a fossil fuel other than diesel, this would require a GRA to approve related non-diesel fuel costs and engine efficiencies.*

At this time, with 100 % LTA diesel generation being re-applied, the updated DCF will only include diesel fuel prices and unit fuel efficiency, i.e., 28.71

[4] There are limits to the ability to permit each month to have its own formula or polynomial, and differing monthly distributions may permit occasional odd values that resolve themselves in annual calculations. This same factor applied in the DCF calculations in the past.

[5] Forecast from 1996/97 GRA were as follows: standard efficiency at 3.71 kWh/litre of fuel and YEC average WAF diesel fuel price forecast at approximately 29.60 cents/litre. Variable O&M costs per kWh of diesel fuel were assumed at 1.6 cents per litre, as assumed for the approved 1996/97 GRA retail runoff rates calculations for WAF.

c/kW.h (the average YEC diesel fuel cost in the current test years based on the Compliance Filing). Although an incremental O&M cost of 3 c/kW.h was adopted for some purposes in the 2009 Phase II filings, this number was not based on short term incremental costs applicable to YEC and no such updated cost information has been developed or reviewed at this time[6]. In order to ensure that the DCF in fact tracks incremental short term costs for YEC as these change within a given year, it is important that non-fuel O&M reflect costs that do in fact change in the year due to changes in actual diesel generation - and at this time, YEC has not recently assessed these costs. YEC will review and report on this at its next GRA.

DIESEL ON THE MARGIN:

Historically, the DCF was to be used only for offsetting baseload diesel generation changes due to the hydro/wind variances from long-term forecasts reflected in rates set in a GRA, and the DCF was only active when YEC diesel was on the margin. The 1996 evidence presumed YEC diesel generation was not on the margin for the WAF system when the Faro mine was closed.

UPDATE: *Under the proposed updated approach, the Fund would be permanently switched "on" through a formulaic approach that, subject to YUB review at each YEC GRA, automatically adjusts forecast long-term YEC hydro generation and related diesel (or other non-diesel fossil fuel) YEC generation to reflect actual YEC grid generation load. Accordingly, there would no longer be a YEC diesel on the margin test for activating the DCF.*

With the YEC diesel on the margin test discontinued for the DCF, there is need to consider other related items that would be affected (i.e., RS 42 with the related ERA requires that diesel on the margin be defined).

- *Effective the same date that the updated DCF approach becomes effective (i.e., ~~recommended~~ January 1, 2012, as that is the date when YEC diesel generation is to be included in rates at 100% of LTA), for the purpose of RS 42 it is necessary to recognize that diesel is on the margin, and that any required ERA determinations be made based on YEC costs incurred for actual diesel generation and/or DCF-related payments, i.e., based on the DCF as updated, YEC costs related to YEC grid loads (and grid load changes) would be determined as provided for in the updated DCF.[7] As in the past DCF operation, ERA determinations do not affect any of the DCF determinations.*

[6] For example, see evidence of Mr. Bowman, Vol. 18 of the transcript regarding the Phase II hearing, at page 174 and an explanation as to why the change in O&M from 1.6 cents per kW.h (in YEC's Phase 1 GRA) to 3 cents per kW.h (in the Part II application).

[7] Board Order 2013 directed YEC to re-file a Rate Schedule 42 in cooperation with YECL, and to work with YECL to provide a joint recommendation on how the DCF will affect the ERA in Rate Schedule 42 and any proposed wording changes to that rate

QUANTUM & CAP:

The initial Fund was determined based on funds available as at December 31, 1995[8]. The cap on the Fund is currently set at the initial contribution level ($4,040,046). The "negative cap" is currently ($-4,040,046). If the Fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider rebate to customers over the following two years. If the Fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and negative cap levels.

UPDATE: *When YEC diesel remains the marginal source of supply, major adjustments to the cap will need to be considered to adequately address the material potential swings related to diesel generation (e.g., potential for greater than +/- $20 million swings)[9]. However, it is not apparent that an excessively high cap would either (a) be able to be fully financed by YEC in the event it was a negative DCF balance; or (b) would yield the best outcome in terms of rate stability. In this respect, when diesel remains the marginal source of supply, one possibility is that the Fund have a very high cap for positive funding (perhaps up to $20 to 30 million reflecting the degree of possible drought today; funds which would be externally invested, or available to be "borrowed" by YEC as short term capital) but a much lower cap in terms of negative balances that must be financed by YEC ~~(including potentially no larger than the $4 million presently approved)~~.*

Given Board Order 2013-1 set rates at 100% of LTA and fuel costs at this time still require high cost diesel, YEC recommends that the current threshold be doubled to +/- $8 million. Given that the Fund is ultimately in place to provide rate stability for ratepayers and protect for potential drought conditions as were experienced in the late 1990s, Yukon Energy believes that the recommended threshold is appropriate at this time, but will require ongoing review at each GRA. For example, in the event of a shift to LNG with incremental fuel costs much lower than diesel costs, a lower threshold such as the current +/- $4 million may be feasible.

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schedule with regard to the ERA (paragraph 281 and paragraph 255). As reviewed in Section 1 of YEC's Compliance filing relating to Order 2013-1, Yukon Energy is meeting with YECL to develop a joint recommendation on how the DCF will affect the ERA in Rate Schedule 42 and any proposed wording changes to that rate schedule, and will report to the Board as soon as possible on this matter.

[8] The opening balance as at January 1, 1996 was $4,040,046.

[9] As noted at page 3.2-4 of the YEC 2012/13 GRA, under the then forecast potential loads in 2013 potential annual diesel generation due to hydro fluctuations could exceed 100 GW,h/year, or over 80 GW.h higher than the applicable annual long-term average, reflecting a potential swing in annual diesel generation costs exceeding $20 million in extreme conditions.

~~*With potential shift to LNG with incremental fuel costs that are much lower than diesel costs, the current +/- $4 million threshold may continue to be relevant and feasible as a +/- cap.*~~

~~*Given that the Fund is ultimately in place to provide rate stability for ratepayers, Yukon Energy has not developed a specific recommendation at this time to modify the current quantum and cap for the Fund.*~~

~~**SECONDARY SALES:**~~ ~~The Fund does not currently deal with secondary sales conditions or revenues, since the Fund only is active when diesel is on the margin (i.e., when secondary sales are not allowed).~~

~~Secondary sales revenues for YEC (retail and wholesale) are currently included in YEC income in the same manner as firm sales, subject only to having the Secondary sales rate fixed at a forecast rate as approved in the last GRA (with variances in the actual rate from this forecast each quarter, due to rate changes implemented each quarter per procedures approved by the Board, being included in the Rider F account).~~

~~**UPDATE:** *Secondary revenues remain highly variable component of YEC's income structure. Assuming that YEC diesel generation costs are included in rates based on 100% of long term average YEC hydro generation (as Board Order 2013-1 has so directed), YEC's concurrent long-term forecast is zero secondary sales. However, although YEC cannot forecast such sales at the time of a GRA filing, actual secondary sales will be and fundamentally are made feasible from time to time based on actual water flows and conditions, e.g., in 2012 and early 2013 YEC had actual secondary sales. For this reason YEC noted the following in its 2012 2013 GRA:*~~

- ~~*Absent any changes, YEC revenues will fluctuate based on actual water conditions affecting secondary sales.*~~
- ~~*Aa logical connection exists for secondary sales, when the occur due to favourable water conditions, to the updated DCF and the overall objective of facilitating rate stability, i.e., such opportunistic revenues tied to favourable water conditions can logically be used to help fund higher diesel costs when hydro generation is below long term average generation.*~~
- ~~*In. In order to have stability in GRA rate revenues, YEC it is proposed that itYEC will forecast 0 GWh of secondary sales in any GRA for the purposes of setting rates whenever annual long-term average hydro forecasts indicate the need for forecast baseload diesel/gas generation costs to be included in rates.*~~

~~*In the event secondary sales arise secondary revenues YEC proposed that such revenues will then be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), thereby helping to Ffund the long term risks related to hydro generation water condition fluctuation.*~~

~~*Board Order 2013-1 directed (paragraph 260) that, as a result of the Board's determination regarding the DCF, YEC's proposed changes for secondary sales is moot and YEC is directed to continue applying any secondary sales to the Rider F account.*~~

~~*At such time as the Board approves the revised DCF as herein filed (with any further modifications as directed by the Board), YEC seeks direction of the Board as to the treatment of secondary sales revenues. In the event that the Board directs that all YEC secondary sales revenue be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), the secondary sales wording as provided above would be included in the DCF Term Sheet and thereby allow this to occur. In the event that the Board directs YEC to continue applying any secondary sales to income (with adjustments to the Rider F account as currently occurs for variances in the rate from the GRA forecast), the above wording on secondary sales would be deleted from the DCF Term Sheet.*~~

INTEREST: The Fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the Fund and any negative balances would only attract interest at the lowest short term borrowing rate available to the Companies through a line of credit.

UPDATE: *No change is recommended to the current mechanism for interest.*

Quarterly & Annual Reporting An annual report is required to be filed with the Board detailing additions and deletions to the Fund, and the Board directs the Companies (YEC and YECL) on the additions and deletions to the Fund. The annual report to the Board is also to include a forecast of available water for the year.

Update: *Yukon Energy, with the assistance of YECL as regards actual Fish Lake hydro generation, will provide a quarterly report detailing additions and deletions to the Fund as then recorded (which are subject to adjustment as noted earlier at calendar year end), and providing a narrative indicating what, if any, actions are required to replenish or refund monies with regard to the Fund (due to the Fund being expected to approach its positive or negative cap as then defined by the Board). The annual report filed with the Board by YEC will include any updated Table 4.1-1 or Table 4.1-2 that is adopted for determining YEC expected hydro and diesel generation for the year (reflecting*

		actual grid load and other relevant factors as required and feasible) as well working spreadsheets detailing the DCF calculations, and it is proposed that the Board offer parties the opportunity to comment on the annual filing.
	5-Year Example	*Tables 41.1-3, 41.1-4 and 41.1-5 an example of five years of transactions which will show how the balance in the DCF will change going forward from today and how those changes will be report.*

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Memorandum

DATE:	**MAY 13, 2013**	**PROJECT:**	P306.6.1
TO:	File	**FILE:**	P:\P306\2.0\2013\Issues\ERA\Memo re ERA.doc
CC:			
FROM:	Mona Pollitt-Smith		
SUBJECT:	**Wholesale Rate Schedule 42 and Energy Reconciliation Adjustment (ERA)**		

Background - Long Standing ERA Mechanism

Rate Schedule 42 establishes one rate applicable to all YECL wholesale power purchases from YEC throughout Yukon. Wholesale service is provided by YEC to YECL in the Hydro rate zone.

The wholesale rate to Yukon Electrical has been designed to comply with Section 7(a) of OIC 1995/90, which specifies that YEC's rates for electricity sales to YECL "must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers."

Since the 1993/94 GRA, Schedule 42 Primary Wholesale has included two elements: first, a single energy-only rate for all primary power supplied by YEC to YECL; and second, when diesel is on the margin, an additional provision, the Energy Reconciliation Adjustment (ERA), which was established to ensure the following:

1. That YECL receives a full pass through of YEC's incremental costs or savings of diesel generation that result from changes in the volume of YECL wholesale purchases compared to the forecast approved by the YUB to establish the then current single energy-only wholesale rate; and
2. That YEC is able to recover its costs from YECL (as required by OIC 1995/90, Section 7(b)) when diesel generation is on the margin in the Hydro zone.

The ERA mechanism was proposed in the 1993/94 GRA, when YECL was managing YEC, to provide a more stable balance of costs and revenues between the two Companies, and was first approved in Order 1993-7. The ERA was subsequently addressed in Order 1996-7 and in Order 1999-4. Thereafter, closure of the Faro mine resulted in diesel not being on the margin on WAF and, accordingly, suspension of any application of the ERA until such time as diesel was once again on the margin in the Hydro zone.

As established in 1993, the ERA in effect ensured that YECL's retail Hydro zone loads would be served by YECL under the same risk profile as all other YECL loads in Yukon. When YECL's loads vary, and this variation in load drives changes in the quantities of diesel generation required, YECL would carry the cost

(or capture the saving) that results from these diesel generation changes. The ERA included from the outset a provision where adjustment for shortfalls in actual wholesale purchase would be limited to minus 10% of the forecast wholesale purchases in any period - the 10% limitation on shortfalls reflected the assumption that once the actual wholesale purchases were less than 90% of forecast there would be no diesel generation saving for YEC at normal water flows.

From the outset, the ERA mechanism addressed only changes in YEC diesel costs based on YUB approved hydro generation forecasts and YUB approved diesel fuel prices. If the diesel cost change is driven by low water at Fish Lake hydro or at YEC hydro facilities, ratepayers bear the risk directly through the Diesel Contingency Fund (DCF) mechanism. Similarly, ratepayers bear the risk of diesel fuel price changes directly through the Rider F mechanism.

Current ERA approved by the YUB

The ERA currently included in Rate Schedule 42 was approved by Board Order 2011-6 after a joint submission by the Companies and provides as follows[1]:

> Charges to YECL will be adjusted on a monthly basis to reconcile actual wholesale purchases to test year forecast purchase during months when diesel generation in the Hydro zone is on the margin at long term average water flows. To the extent that actual wholesale purchases fall short or exceed forecast wholesale purchases, an adjustment to the YECL bills will be made at a rate equal to the Hydro zone incremental cost of diesel of 32.74 cents per kW.h as approved by the Board in Order 2010-13. Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

In summary, when diesel is on the margin in the Hydro zone at long term average water flows, Board Order 2011-6 currently provides that the ERA automatically adjusts YECL's Rate Schedule 42 bills (to the extent that actual wholesale purchases vary from forecast wholesale purchases) at a rate equal to 32.74 cents/kWh (subject to the 10% limit noted for shortfalls). For the purpose of this ERA adjustment, the relevant "forecast" wholesale purchases are forecasts as last approved by the YUB for a YEC GRA.

During review of YECL's last GRA, the Board also approved new mechanisms relating to the impact of ERA charges on YECL. Board Order 2009-2 relating to YECL's last GRA approved a wholesale purchase power deferral account which fully addresses any cost impacts on YECL from load forecast variance derived ERA cost changes. Board Order 2010-13 (paragraph 181) confirmed that implicit in its approval of this YECL deferral account is approval of a future rate rider to dispense the accumulated balances in the deferral account. In this regard, YECL proposed a specific Rider D mechanism that would dispense such accumulated balances to all retail and industrial ratepayers of YEC and YECL throughout Yukon.

ERA Updates Proposed in YEC 2012/13 GRA

The updates to the ERA proposed in the YEC 2012/2013 GRA sought to provide clarifications and updates as required to define the wholesale forecasts and diesel generation costs that will apply when

[1] See Order 2011-6

determining the ERA approved by the Board in Order 2011-6. These changes did not prejudice YECL or Yukon ratepayers relative to what the Board had already approved in Order 2011-6 based on the joint submission of YEC and YECL.

In summary, the ERA edits in the Application sought to clarify and/or update the following:

1. Charges to YECL under the ERA will apply only to the extent that diesel generation costs incurred by YEC are varied as a direct result of actual wholesale purchases falling short or exceeding YEC's most recent test year forecast wholesale purchases (as approved by the Board).

2. In this regard, the amended wording deleted the specific rate of 32.74 cents per kW.h as currently approved, and directed that YECL's ERA bill adjustment "will be made based on the variance in diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale purchases falling short or exceeding forecast wholesale purchases."

3. The amended wording specified that reference to forecast wholesale purchases is addressing "Yukon Energy's most recent test year forecast wholesale purchases". This clarification reflects what YEC understands to what has always applied for the ERA - and, if it assists, the wording could also make clear that such forecast is "as approved by the Board."

4. The amended wording deleted the currently approved reference to the ERA applying when "diesel generation in the Hydro zone is on the margin at long term average water flows". This change reflected YEC's updated DCF proposal whereby the DCF would be permanently switched "on" as of January 1, 2012 through use of a formulaic approach, i.e., subject to Yukon Utilities Board review at each GRA, the proposed approach would automatically adjust forecast long-term hydro generation and related diesel (or other non-diesel fossil fuel) generation to reflect actual grid generation load.

During the GRA proceeding, YEC provided further clarifications through IR responses. In particular, the response to YECL-YEC-2-1 outlined and demonstrated the following methods to determine incremental diesel generation (MW.h) subject to the ERA charge:

- An ERA charge to YECL would only occur in a year when there is YEC grid system load growth (above YEC GRA forecast), and that load growth is caused in whole or in part by YECL wholesale sales exceed YEC GRA forecast.
- An ERA credit to YECL would only occur in a year when there is YEC grid system load decline (below YEC GRA forecast), and that load reduction is caused in whole or in part by YECL wholesale sales being less than YEC GRA forecast.
- The examples provided in the ERA indicated that the calculation to determine the appropriate YECL share (of the growth or decline) would be based on the average percentage change in overall YEC expected diesel generation due to the overall change in YEC generation from the approved GRA forecast. All determinations would be finalized based on annual calendar year numbers.

- Where the YECL load changes are driven by underlying changes in YEC delivery areas (e.g., if the reason YECL's load grows is because of growth in YECL's sales to YEC at a downstream delivery location, such as Johnson's Crossing, where YEC repurchases back from YECL power than was originally generated by YEC), then this will not be considered to be YECL load growth or load reductions for the purpose of ERA determinations.

Board Order 2013-1 and YEC's Compliance Filing

Board Order 2013-1 (paragraph 60) directed YEC to reflect 100% long term average (LTA) hydro generation in calculating test year diesel generation requirements. Accordingly, YEC understands that it will now incur diesel generation costs in any given year (starting in the 2012 test year) at 100% LTA based on actual generation in that year - and that, as a result, YEC will incur diesel generation fuel costs at 100% LTA related to any incremental load growth above GRA approved generation forecasts.

YEC provided a Compliance Filing on May 1, 2013 in accordance with the directions of Order 2013-1, including a revised DCF proposal that incorporates the three specific changes set out in paragraph 255 of the Order. Based on the revised DCF, YEC noted that it can proceed to address accounting for 2012, and going forward, with respect to ongoing diesel fuel expenses in compliance with Order 2013-1. YEC also noted that approval is sought for a revised DCF on the understanding that an ERA and any required changes in Rate Schedule 42 will be approved and implemented and applicable for the 2012 test year (as well as going forward) in order to ensure that YEC is held whole.

The following elements of the revised DCF proposal will affect the ERA determinations:

1. **Fish Lake hydro:** The revised DCF includes YECL Fish Lake hydro impacts on expected YEC generation, as directed by the Board. Actual YECL Fish Lake generation will be added to actual YEC grid generation (net of secondary sales impacts on YEC generation), and expected (i.e., long term average generation as last approved by the Board[2]) Fish Lake generation will then be deducted. YEC payments to the DCF and or credits from the DCF will therefore reflect the impact on YEC diesel generation due to Fish Lake generation varying from long term average. ERA determinations will exclude Fish Lake variance impacts on YEC wholesales sales to YECL.

2. **Incremental cost of diesel generation**: The revised DCF at this time only includes diesel fuel prices and unit fuel efficiency, i.e., 28.71 cents/kW.h (the average YEC diesel fuel cost in the 2013 test year based on the Compliance Filing).

[2] The revised DCF noted that, as of April 2013, long term average Fish Lake hydro generation is 8.73 GW.h/year less any loss of this generation due to shut down of a unit (in 2013, the long term average is expected to be reduced by 3.85 GW.h due to shut down of Unit #1 until December; in 2012, the long term average is reduced by 4.35 GW.h due to shut down of Unit #1 all year).

Attachment A – Issues Raised & Board Directions re: DCF and ERA

Paragraph 277 of Order 2013-1 outlines concerns regarding the implementation of the ERA raised by YECL in argument, noting as follows:

- YECL was not consulted regarding the proposed changes
- the ERA as proposed by YEC may not allow YECL to recover its prudently incurred costs
- the ERA charges may have a material impact on YECL and its customers
- YECL has to carry a forecast risk based largely on a forecast prepared by YEC erroneous ERA charges
- the proposed ERA has no mechanism to account for system growth
- the designed ERA process is administratively inefficient

The Order notes YECL opposed the ERA mechanism proposed by YEC and asked the Board to direct YEC to prepare and file a deferral account to address increased diesel costs[3]. (paragraph 278)

Paragraph 279 of Order 2013-1 also summarizes YEC's Reply Argument and notes based on past decisions of the Board, there is no basis to delay the ERA amendments as proposed and that YECL's Rider D protects YECL from cost impacts from load forecast variance derived from ERA cost charges.

The following specific Board Directions were provided in Order 2013-1

- The Board does not approve YEC's proposed DCF but directs YEC to provide a revised DCF proposal. In the revised DCF proposal, YEC is to incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model. In addition, YEC is to incorporate the suggestions of CW and UCG as to how DCF transactions are to be reported. Further, in that submission, YEC is to provide an example of approximately five years of transactions that will show how the balance in the DCF will change and how those changes will be reported. Finally, YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of YEC and YECL as to when the revised DCF proposal is to be filed with the Board. Given the foregoing, the Board does not approve YEC's requests regarding the DCF and therefore does not approve YEC's proposed changes to Rider F. Secondary sales, as they occur, will continue to be credited to the Rider F account [Paragraph 255].
- As the Board has requested YEC to file a revised DCF, and to address the concerns raised by the Board in that filing, the Board directs YEC to refile a Rate Schedule 42 in cooperation with YECL as directed in Section 3.6.2 of this decision [Paragraph 281].

[3] The Order notes YECL's position that the deferral account is to be administered by YEC and dispensed by YEC and should form part of YEC's compliance filing.

Attachment B – Proposed Revisions to ERA in 2012/2013 GRA

RATE SCHEDULE - 42

WHOLESALE PRIMARY (YEC)

AVAILABLE: To The Yukon Electrical Company Limited.

APPLICABLE: For wholesale primary supply to The Yukon Electrical Company Limited.

RATE:

Energy Charge

All Energy consumed at 8.298¢ per kW.h

Energy Reconciliation Adjustment

Charges to YECL will be adjusted on a monthly basis to reconcile actual wholesale purchases to Yukon Energy's most recent test year forecast purchases during the months when Yukon Energy diesel generation is modified by such variances in wholesale purchases. ~~diesel generation in the Hydro zone is on the margin at long term average water flows.~~ To the extent that actual wholesale purchases fall short or exceed Yukon Energy's most recent test year forecast wholesale purchases, an adjustment to the YECL bills will be made based on the variance in diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale purchases falling short or exceeding forecast wholesale purchases. ~~at a rate equal to the Hydro zone incremental cost of diesel of 32.74 cents per kW.h as approved by the Board in Order 2010-13.~~ Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

TERMS AND CONDITIONS OF SERVICE: The Company's Terms and Conditions of Service approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

YUKON ENERGY
CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

May 17, 2013

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

Dear Mr. McLennan:

Re: Yukon Energy Corporation 2012/2013 General Rate Application – YEC Response to Intervenor Comments on Compliance Filing

On May 2, 2013, Yukon Energy provided for approval of the Board a Compliance Filing in accordance with directions set out in the Reasons for Decision (Appendix A to Order 2013-1). The Board established a process for intervenors to provide comments on Yukon Energy's Compliance Filing on May 10, and for Yukon Energy to provide a response to intervenor comments on the Compliance Filing by May 17, 2013.

Yukon Electrical Company Limited (YECL) provided comments on May 10, 2013 and Utilities Consumer's Group (UCG) provided comments on May 11, 2013. Leading Edge, the City of Whitehorse and Yukon Conservation Society did not provide comments on the Compliance Filing.

Yukon Energy's response to each of intervenor comments is provided below.

YECL COMMENTS

The following two issues are raised by YECL in its comments:

1. **Revised DCF Proposal** - YECL's position is that the DCF and the ERA are highly integrated, and for this reason YECL requests that the Board reject YEC's revised DCF proposal or any related matters associated with the Energy Reconciliation Account in Rate Schedule 42 until such time as a joint proposal is filed by the Companies. Alternatively, should the Board choose to consider these matters as part of YEC's May 1 Compliance Filing, YECL requests that a formal process be established by the Board to allow for testing of YEC's revised DCF proposal. YECL quotes paragraph 255 of Board Order 2013-1, noting the direction that "...YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule." YECL also quotes paragraph 281 of Board Order 2013-1, noting the direction for YEC to "refile a Rate Schedule 42 in cooperation with YECL as directed in Section 3.6.2 of this decision".

Yukon Energy responds that the revised DCF included in the Compliance Filing carries out the directions at paragraph 255 of Board Order 2013-1 relating to three specific adjustments to the DCF as proposed in the Application which were reviewed at length during the proceeding. It also addresses the implications for the DCF arising from other Board directions.

On the matter of interrelationship between the DCF and the ERA, the DCF determines costs incurred by YEC for diesel generation - and therefore determines YEC's incremental diesel generation costs that flow through to YECL via the approved ERA when wholesales vary from GRA forecasts approved by the Board. Therefore clarity is needed on what DCF has been approved by the Board in order to address how the DCF will affect the ERA - but the ERA does not in any way affect the DCF.

On the matter of the ERA, YEC has met with YECL as directed by the Board. Please see Attachment A for review of the ERA discussion with YECL .

YEC re-iterates that approval of an updated DCF is integral to YEC being able to determine how its actual diesel generation costs are to be accounted for in 2012 (and going forward) now that the Board has directed that rates be set based on diesel generation at 100% of long-term average (LTA) hydro generation. It also needs clarity to ensure that YEC is held whole.

It is also important to emphasize that Yukon Energy will be unable to close its 2012 year-end financial statements until its auditors are able to understand the impact of the Board's directions on LTA and the DCF.

2. **Reimbursing YECL (paragraph 316 of Order) -** YECL notes that YEC states at page 5-5 of the Compliance Filing that the direction at paragraph 316 of Board Order 2013-1 will be implemented for future capital projects, and that no changes are reflected in the Compliance Filing. YECL requests further comment from the Board addressing YEC's commitment towards reimbursing YECL, and including in revenue requirement, YECL's invoices associated with the Haines Junction bypass and the CSTP projects.

   Yukon Energy responds that the Compliance Filing fully responds to the Board's direction at paragraph 316 of Board Order 2013-1.

   In summary, this decision did not direct YEC to amend its revenue requirement to include YECL's invoices associated with the Haines Junction bypass and the CSTP projects. Yukon Energy has committed to implement the direction at paragraph 316 of Board Order 2013-1 for future capital projects.

UCG COMMENTS

UCG notes that its submission highlights areas that appear inconsistent with the intent of the Board's directions in Order 2013-1, and indicates "displeasure" that YEC's compliance filing did not include EXCEL versions of the tales and calculations provided.

Yukon Energy fundamentally disagrees with the various allegations made by UCG in its Compliance Filing comments.

1. UCG at times goes beyond commenting on whether the Compliance Filing reflects the directions provided in Order 2013-1 and instead ventures into further argument on areas where the Board has provided direction, specifically
    a. With regard to secondary sales, UCG asserts that if secondary sales occur in 2013 and subsequent years, then all net revenues should be held in a deferral account and passed through to all Yukon ratepayers at the time of the next rate adjustment.
    b. Similarly, with regard to potential added industrial load connected to the grid in mid-2013 UCG asserts that "if an additional load magically appears on the system during 2013, then all net revenues should be held in a deferral account and passed through to all Yukon ratepayers at the time of the next rate adjustment."

    In both of the above cases UCG is simply re-opening argument after the proceeding has already concluded and in both cases the assertions and recommendations from UCG are inappropriate and should be ignored.

2. UCG makes assertions that YEC has not implemented the Board Directions correctly and consequently the Compliance Filing is incomplete:
    a. **Wholesale Sales Forecast** - UCG asserts that the wholesale sales forecast included in the Compliance Filing is incomplete for the following reasons: (1) YEC has updated the wholesale sales for 2013 but has not made any adjustments for 2012; (2) YEC has not provided correspondence from YECL that confirms the specific changes that have been made with respect to the unavailability of Fish Lake Hydro during 2012 and 2013 (as directed in Order 2013-1) and the addition of Whitehorse Copper Tailings as a YECL customer; and (3) YEC has not provided any detail regarding the information received from YECL regarding Fish Lake Hydro or assumptions regarding Whitehorse Copper Tailings load and associated YECL line losses.

        Yukon Energy disagrees with these assertions and notes as follows:
        i. Board Order 2013-1 found "YEC's wholesale forecast reasonable" (paragraph 34) and the Board did not direct any specific adjustments to the 2012 wholesale forecast related to Fish lake or to WHCT[1].

[1] Board Order 2013-1 the Board "finds YEC's wholesale forecast reasonable" (paragraph 34), but noted the view that "YECL may have more up to date information regarding the unavailability of Fish Lake during the 2012-13 test period" and directed YEC to consult with YECL regarding the unavailability of Fish Lake during the test period and adjust the forecast if necessary in the compliance filing (paragraph 35). Unavailability of Fish Lake Unit #1 was already considered as part of the GRA forecasts and was not an issue.

ii. The issue of concern regarding the unavailability of Fish Lake[2], and the impact on the wholesale sales forecast (as raised by YECL at the oral hearing[3]) was focused on the continued unavailability of Fish Lake in 2013.
iii. Order 2013-1 did not require YEC to file correspondence from YECL and did not direct YEC to consult with YECL (or provide documentation) regarding assumptions underlying the WHCT load forecast or associated line losses. The Compliance Filing page 1-3, footnote 3 explains the adjustment to the Wholesale forecast related to WHCT and the assumed losses.
iv. The only direction related to Whitehorse Copper Tailings provided in Order 2013-1 was to remove Whitehorse Copper Tailings volumes from the industrial sales forecast and include these volumes in the wholesale sales forecast for the test years and adjust the revenue requirement accordingly. This change was included in the Compliance Filing (see Table 1-3, Table 1-1 and Table 2-2).

b. **Industrial Sales Forecast** - UCG assert that the industrial sales forecast included in the Compliance Filing should be updated for the more accurate Alexco sales forecast identified in Argument at the hearing noting "if more accurate information is identified during the hearing, it should be incorporated into the compliance filing," and "while YEC felt free to adjust the industrial revenues for more accurate information related to Alexco, it did not do the same for sales".

Yukon Energy disagrees with the assertions made by UCG regarding the implementation of directions related to the industrial sales forecast and notes as follows:

i. Paragraph 39 of Order 2013-1 (which is quoted by UCG in its comments) clearly directs YEC to update the major industrial sales forecast in the Compliance Filing to account specifically for change to the 2012 and 2013 Minto sales forecasts referred to in the hearing and does not direct YEC to make similar adjustments to the Alexco sales forecast.
ii. YEC did not adjust industrial revenues "for more accurate information" as asserted by UCG, but made corrections to address clear errors that were identified in the GRA as filed (the Alexco peak demand correction noted at page 1-3 of the Compliance Filing was identified in response to UCG-YEC-1-20(b) and YEC committed to make this correction in argument; the demand revenue forecast correction also noted at page 1-3 of the Compliance Filing was identified subsequent to the hearing).

c. **Power Generation** - UCG asserts that YEC was directed to take into consideration in its Compliance Filing any adjustments needed to reflect the effect of the Mayo A runner improvements and that as YEC "simply confirmed that they were considered in the

[2] Tab 2 Page 2-4 of the GRA notes, "YECL wholesale sales were adjusted to reflect expected in-service of a new Fish Lake hydro unit #1 in 2013." Footnote 7 at page 2-4 indicates further that, "Unit #1 failed in March 2010. Per discussions with Yukon Electrical management in fall 2011, this unit is currently expected to be back in service in January 2013. YECL provided an update at the oral hearing (November 12-14, 2012) that Fish Lake Unit #1 would not be available January 1, 2013 as forecast.
[3] See November 12, 2012 Transcript page 131 where counsel for YECL indicates expectation that Fish Lake Unit#1 would not be in service until Q3 of 2013.

modeling", UCG "submits that there is not enough information provided in the compliance filing to confirm what the impact is nor how the impact was reflected in the final numbers."

Yukon Energy disagrees with the above assertions made by UCG and note as follows:

i. Order 2013-1, paragraph 60 directs YEC to confirm whether the effect of Mayo A runner improvements have been included in the forecast and if not to update its generation forecast accordingly.

ii. YEC in the Compliance Filing at page 1-5 confirmed that the effects on generation related to the Mayo A runner improvements were considered in the modeling that informed the GRA. As it is confirmed that Mayo A runner improvements are already considered in the generation forecast there is no need to update the forecast in the Compliance Filing. Order 2013-1 did not provide any further direction in this regard.

3. UCG several times throughout its comments asserts that the filing is incomplete and calculations cannot be confirmed due to information not being provided or due to lack of EXCEL spreadsheets being available.

Yukon Energy disagrees with the assertion that information is not available to determine that the Board directed adjustments have been made. The following are specifically noted:

a. **Fuel Cost -** With regard to fuel cost UCG asserts that it cannot agree with the amount of the adjustment as the filing does not include explanations regarding how the impacts of changes to the load forecast and generation mix have been calculated so there is no way to confirm YEC's adjustments to the 2012 and 2013 revenue requirements. This assertion fails to recognize that the Compliance Filing includes sufficient information and explanations to confirm the impact of changes in load forecast and generation mix on fuel cost. The following are specifically noted:

i. Page 1-4 of the Compliance Filing provides a narrative explanation regarding the changes in load forecast and related impacts on generation and diesel requirements and fuel costs. When dealing with changes to expected diesel generation at 100% LTA, YEC has noted its reliance on the relevant power benefit model (which has at no time been provided in the form of an EXCEL file);

ii. Appendix 1.1-1, Table 1-1 provides a summary of changes in LTA hydro and diesel generation in the Compliance Filing compared to the 2012/2013 GRA.

iii. Appendix 4.1, Attachment 4.1 provides revised Tables 4.1-1 and 4.1-2 from Appendix 3.2 of the 2012/2013 GRA. These tables may be used to calculate expected YEC diesel generation with LTA YEC Hydro generation for each test year and can be used to confirm the 7.9 GWh diesel generation forecast at 100% LTA hydro generation in 2012 and 11 GWh of diesel generation forecast at 100% LTA hydro generation in 2013.

b. **Cost of Debt -** UCG asserts that it is unable to determine whether the directions to adjust the forecast cost for new debt in 2012 and 2013 have been implemented as directed given only a PDF version of Schedule 11 was provided. Again, this can be readily determined from the material as provided.

i. Section 1, page 1-5 explains the decrease in interest cost from 5% assumed in the Application to 3.97% in 2012 and 3.58% in 2013 and notes that the 2011 long term debt interest was also updated to reflect actual 3.69% interest rate rather than 5% in order to be consistent (as this expense would carry forward to each test year)[4]. This is also noted in Section 2, Table 2.1 and 2.2

ii. Section 3 of the Compliance Filing includes a Tab 7 with adjustments as directed by Board Order 2013-1 (see Schedule 11 at page 14).

iii. Appendix 3.1 and Appendix 3.2 provide annotated versions of Tab 7 for each test year, which provide an explanation for adjustments in each test year (see page 13 of each appendix).

c. **Western Copper Aerial Mapping -** UCG notes the Compliance Filing identifies a $6000 reduction to depreciation in each test year regarding Western Copper, but UCG states that it does not see any changes to the rate base proposed in 2012 and 2013.

Yukon Energy disagrees with the assertions made by UCG regarding this item and notes the following information provided in the Compliance Filing:

i. Section 1, page 1-7 notes deferred costs for this item remain in WIP for future recovery from that customer, reducing mid-year net rate base by $0.027 million in 2012 and by $0.021 million in 2013 (paragraph 301).

ii. Page 1-6 notes that Tables 1.1-2 and 1.1-3 in Appendix 1.1 provide a detailed assessment of impacts on rate base and revenue requirement resulting from Order 2013-1 directions related to capital and deferred cost projects.

iii. Appendix 1.1, Table 1.1-3 specifically notes under items between $0.100 million and $1 million reduction in amortization of $6,047 and reduction in ratebase impact in 2012 of $27,210 and in 2013 of $21,163.

d. **Deferred Projects -** UCG notes it sees reductions to rate base of $219,000 in 2012 and $478,000 in 2013 related to Marsh Lake and Gladstone and does not see enough detail in the compliance filing to confirm that YEC has followed the Board's direction.

Yukon Energy disagrees with the above assertions and notes as follows:

i. Section 1, Page 1-6 notes keeping Marsh Lake and Gladstone in WIP will reduce mid-year rate base by $3.962 million in 2012 and $8.178 million in 2013.

ii. Appendix 1.1, Table 1.1-2 provides adjustments to rate base, return on rate base and amortization expense and specifically notes the adjustments due to directions related to Marsh Lake and Gladstone: $3.962 million of total $5.750 million reduction in mid year net rate base before rate case in 2012 and $8.178 million of total $13.311 million reduction in mid year net rate base before rate case in 2013.

iii. Appendix 1.1, Table 1.1-2 provides the specific reduction in amortization expense for each project and the reduction in rate base.

4. UCG asserts that "YEC has taken it upon themselves to submit a revised DCF proposal for approval by the Board as part of this Compliance Filing" and submits that "it is completely absurd

[4] With respect to the 2011 long term debt of $19.148 million, the following clarification is noted: $17.095 million is amortized over 25 years at an annual interest rate of 3.69%, and the balance of $2.053 million is an unsecured advance (due one year after demand, with no principal repayment schedule) at an annual interest rate of 3.97%.

to submit a revised policy proposal such as this as part of a compliance filing and not give stakeholders an opportunity to thoroughly review the proposal and underlying assumptions, submit information requests pertaining to the revised proposal/ assumptions and then allow for time to test alternative approaches." UCG notes it "disagrees with YEC's statement that the impact to Rate Schedule 42 is not related to the revised DCF policy" and asserts that "submitting a revised DCF proposal and underlying assumptions as part of the compliance filing was not the intent of the board's direction especially when there are outstanding components of that direction that YEC has not yet undertaken." UCG asserts it is "premature for the Board to approve the revised DCF proposal and underlying assumptions until stakeholders have an opportunity to better test the proposal."

Yukon Energy disagrees with the above assertions. In summary as noted in YEC's response to similar issues raised by YECL :

a. The revised DCF included in the Compliance Filing carried out the directions at paragraph 255 of Board Order 2013-1 for three specific straight forward adjustments to the updated DCF that was proposed in the Application and reviewed at length during the proceeding. Further, it addressed the implications for the DCF of other Board directions. Finally, recent meetings with YECL have confirmed that, while the DCF is crucial to informing the ERA calculation, the same is not true for the converse i.e. resolution today on the ERA is not required for the Board to approve the DCF as proposed in the Compliance Filing.
b. Approval of an updated DCF is integral to YEC being able to have clarity as to how its actual diesel generation costs are to be accounted for in 2012 (and going forward) given that the Board has directed that rates be set based on diesel generation at 100% of long-term average (LTA) hydro generation.
c. Clarity on the DCF is also required in order to assess how the DCF will affect the ERA, and how the Board's directions relating to LTA and DCF impact YEC's 2012 financial statements.

5. Finally, UCG notes section 26(2) of the PUA states that "as public utility shall not change its accounting practices under subsection (1) except with the prior approval of the Board", and UCG submits that YEC should be applying for accounting orders from the Board to allow YEC to establish the deferral accounts directed to be established by the Board in Order 2013-1 and to continue operation of existing deferral accounts in 2013 and beyond.

   In response to this comment, it is noted that the Compliance Filing implemented the Board's directions as set out in Order 2013-1. If the Board determines YEC requires accounting orders to allow YEC to establish the accounts established by Board direction in Order 2013-1 it is expected that the Board will provide such direction in its Order on the Compliance Filing.

Please direct any questions on this communication to the undersigned.

Yours truly,



Ed Mollard
Chief Financial Officer

ATTACHMENT A: ERA

YEC met with YECL as directed by the Board. The issues raised by YECL relate primarily to the ERA. The concern raised was focused on whether regulatory efficiency would be best attained through YECL or YEC administering an ERA deferral account.

In this meeting, YECL re-iterated its proposal, as set out in its Reply Argument, that the ERA be removed from Rate Schedule 42 and, instead, the YEC diesel costs related to YECL wholesale variances from Yukon Energy's GRA forecasts as approved be recovered from ratepayers through a new YEC deferral account to be administered by YEC and dispersed by YEC.

Yukon Energy notes that Board Order 2009-2 approved a wholesale purchase power deferral account for YECL to accommodate any cost impacts on YECL from ERA charges, and Board Order 2010-13 (paragraph 181) confirmed that implicit in its approval of this YECL deferral account is approval of a future rate rider to dispense the accumulated balances in this deferral account. Accordingly, in response to YECL's request, YEC is agreeable to seeking confirmation from the Board that, based on the Board's previous directions, ERA amounts will flow through to ratepayers through a new rider, and that any amounts not so approved by the Board would result in adjustments to the ERA amounts paid to (or recovered from) YEC.

Yukon Energy, however, understands that Board Order 2013-1 directed the Companies jointly to propose wording changes to the ERA in the existing Rate Schedule 42, and did not direct consideration of any new YEC deferral account. Yukon Energy notes that the ERA is long-established as an integral part of this wholesale rate, being first approved in Order 1993-7, and being most recently approved in Board Order 2011-6 based on joint recommendation of the Companies. YEC also notes that the ERA mechanism as part of Rate Schedule 42 complies with Section 7 of OIC 1995/90.

Yukon Energy re-iterates that it is critical for the ERA and Rate Schedule 42 matters to be addressed expeditiously at this time in order for YEC to be able to close its 2012 year-end financial statements, and to ensure that YEC is held whole.

In order for the ERA to be finalized, direction is sought from the Board as regards the option that the Companies are to pursue.

TOPIC: **Joint Agreement**

REFERENCE: **YEC/YECL DCF-ERA Filings of January 31, 2014**

PREAMBLE:

QUESTION:

a) With respect to the DCF and ERA materials, please confirm that the Companies (YEC and YECL) were not able to agree on any single item. If not confirmed, please explain.

b) Please provide YEC's opinion on what purpose the DCF and ERA mechanisms should serve. Please also indicate whether that purpose has been adequately served in the past.

ANSWER:

(a)

The discussion process between YEC and YECL to date has not taken place in a context where agreement on any single issue has been possible.

The discussions and document exchange between the two companies are outlined in Appendix A of the cover letter to YEC's January 31, 2014 Filing. The materials referenced in Appendix A of the cover letter that were prepared and distributed by YEC as part of this discussion process are provided in response to YUB-YEC-1-10.

- Yukon Energy's position throughout the discussions has been that the DCF and the ERA should continue (with adjustment to reflect changing conditions on the existing grid system and directions in Board Order 2013-01) as they are both necessary, reflect past precedents and practices and are in the interest of ratepayers.

- Yukon Energy summarized its initial understanding of YECL's issues and concerns in Appendix A to the May 17, 2013 response to intervenor comments

> on the Compliance Filing. At that time, based on discussions that had occurred, Yukon Energy understood that YECL's concerns related primarily to the ERA. YEC was not aware of any material concerns with the DCF, until YECL provided its proposal in October 2013.

In summary, these discussions focused primarily on the ERA. Despite attempts to document YEC's position and relevant historical background relating to this position, plus effort to understand YECL's concerns and some actual changes and refinements made to YEC's proposal for the ERA as a result of these discussions, it is fair to observe that the overall discussion ultimately did not move beyond the two very different positions set out in the record from argument in the YEC 2012-13 GRA, i.e., YECL wanted YEC to discontinue the ERA and institute a YEC deferral account, and YEC did not see any basis whereby it could support this proposal. In the end, YEC's January 31, 2014 filing attempted (as directed by the Board) to document with Options A and B the two positions on this matter and the basis for YEC proposing Option A.

With regards to the DCF, when YEC became aware in October 2013 of YECL's proposal to abandon the DCF, YEC could not see any basis for further discussion on this matter. YEC's ability to reference YECL's proposal in its subsequent January 31, 2014 filing was also very restricted, given that it had been provided only as confidential and without prejudice basis. YEC's concerns regarding this proposal have subsequently been set out in the June 30, 2014 supplementary filing.

(b)

With regard to the purpose of the DCF as established in 1996, please see Attachment 1.1 of Appendix 1.1 of YEC's January 31, 2014 Filing which notes at page A1.1-1 with regard to the purpose and function of the DCF.[1]

> "The DCF operates to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro and wind generation. The fund is only to be used for these purposes and is not to be accessed for other reasons without prior YUB approval, including government subsidy of rates. Historically, the DCF has operated to offset diesel generation cost changes only for the WAF

[1] The referenced comments reflect the original purpose per the 1996 Settlement Agreement (see Attachment 2 to YUB-YEC-1-2(a). Updates provided to the original DCF scope are noted as well at page A1.1-1 of the January 31, 2014 filing.

system caused solely by variances from long-term average levels of WAF system hydro and wind generation."

The DCF is required to account for variance in actual diesel generation due to variance from long-term average levels of hydro and wind generation. In the past, the DCF (and LWRF before it) adequately served this primary purpose; however, as documented in response to UCG-YEC-1-6 (b and c), the DCF was also on occasion used for other purposes.

The purpose of the ERA is summarized in Appendix 2 of YEC's January 31, 2014 Filing (see page 2-2). Specifically, the ERA was established to ensure:

1. That YECL receives a full pass through of YEC's incremental costs or savings of diesel generation that result from changes in the volume of YECL wholesale purchases compared to the forecast approved by the YUB to establish the then current single energy-only wholesale rate; and

2. That YEC is able to recover its costs from YECL (as required by OIC 1995/90, Section 7(b)) when diesel generation is on the margin in the Hydro zone.

As established in 1993, the ERA in effect ensured that YECL's retail Hydro zone loads would be served by YECL under the same risk profile as all other YECL loads in Yukon. When YECL's loads vary and this variation in load drives changes in the quantities of diesel generation required, YECL would carry the cost (or capture the saving) that results from these diesel generation changes.

TOPIC: **Netting of all Related Revenues for both YEC and YECL**

REFERENCE: **Draft September 7, 2013**

PREAMBLE:

QUESTION:

a) Please describe the netting of all related revenues for both YEC and YECL and explain what impact this provides. If it does not provide any impact, why is it done?

ANSWER:

(a)

The "netting of all related revenues for both YEC and YECL" is described in detail in Appendix 2 of Yukon Energy's January 31, 2014 Filing [see pages 2-6 to 2-9 and example provided in Table 2-1 at page 2-9]. As reviewed below, this netting of all related revenues acts to reduce the current ERA that YEC charges to YECL, and to reduce its ultimate impact on all retail and industrial ratepayers.

In summary, as part of the consultation process with YECL in 2013, YEC reviewed the approach to calculating the ERA (as proposed in the 2012/2013 GRA). Yukon Energy noted that the approach to the ERA calculation reviewed in July 2013 (and earlier) did not consider the revenue YEC or YECL would receive from 100% of the added wholesales over and above the YUB approved forecast. The Revised ERA calculations proposed by YEC in its January 31, 2014 Filing (and as revised in YUB-YEC-1-25 to include Fish Lake variance impacts) take all related YEC and YECL incremental revenues into account. This results in a reduced ERA and no requirement for YECL to charge Rider D to ratepayers for 2012.

All related revenue impacts were implicitly considered for YECL, and directly addressed for YEC, when the ERA was established for the 1993/94 GRA to apply when diesel was on the margin on the WAF grid (see page 2-7 of YEC's January 31, 2014 filing). The material change in rate-related conditions today is that retail and industrial run out rates

in the Hydro rate zone are well below current incremental costs of YEC diesel generation – a situation which creates a need to consider an appropriate new YECL Purchase Power Flow Through deferral account to allow YECL to recover any ERA costs not recovered by YECL through its run out rate incremental revenues.

YEC provided an updated calculation to YECL in September 2013 [see Table 2-1 at page 2-9 of the January 31, 2014 Filing] that took all related incremental revenues into account. Table 2-1 compares 2012 results for the ERA calculation used in the 2012/2013 GRA (July 2013 version) and the results using the approach that nets 100% of added revenue for YEC and YECL (August 2013 version). Differences between the two approaches to the ERA calculation are detailed below.[1]

Earlier ERA calculation reviewed in July 2013 (and earlier) without netting all revenues.

- **The YEC ERA charge to YECL -** considers only the portion (i.e., 40.5%) of the added 2012 wholesale sales that attracts DCF added costs (and deducts from added cost the added revenue YEC gets from this sale). The result is an ERA charge to YECL of $1.176 million:

    - On incremental wholesales of 13,272 MW.h (net of Fish Lake), the added diesel cost to YEC (applicable to 40.5% of these sales, after adding in YEC losses) is $1.679 million.

    - The added YEC revenue on the same 40.5% of the added wholesales is $0.503 million (reflects wholesale rate of 8.298 c/kW.h plus 1.05 c/kW.h other added revenue from riders).

    - The $1.176 million ERA charge reflects the added diesel cost less the added revenue related only to 40.5% of the added wholesales.

[1] The example reviewed is as per the filing, Table 2-1 and does not reflect subsequent changes after this example was provided to YECL based on the August 2013 update. Subsequent revisions are all reflected in YUB-YEC-1-25 which includes Fish Lake variance impacts on YEC wholesale revenues. These Fish Lake variances do not affect (or in any way reflect) incremental changes to YECL retail revenues.

- **YECL Rider D charge to Ratepayers** - It is understood that based on Board Order 2009-02, YECL expects to place all of any future ERA charges in a deferred cost account; accordingly, it was assumed that YECL will ultimately charge ratepayers the full $1.176 million ERA for 2012 through a new Rider D. The net impact on YECL of the added wholesales has been estimated in Table 2-1 at $0.231 million positive net revenue after the Rider D recovery of the full ERA – this reflects the net benefit to YECL of the added wholesales prior to any ERA charge:

    - YECL's average incremental revenue (ignore first block rates) on retail sales is estimated at 13.38 c/kW.h).

    - YECL's added 2012 revenue has been estimated at $0.678 million on the same 40.5% of the incremental wholesales after all rider flow through charges related to these incremental wholesales (calculated at the average incremental rate of 13.38 c/kW.h after reducing the sales for YECL losses assumed at 6.2%].

    - Offsetting this added revenue is the normal wholesale charges at 8.298 c/kW.h (equals about $0.446 million for 2012) plus the ERA charge of $1.176 million (total cost impact of $1.622 million).

    - On this basis, the net YECL cost prior to Rider D is $0.945 million; however, after the Rider D recovery of the full ERA charge, the net YECL 2012 revenue from the added wholesales is $0.231 million.

Revised ERA Calculation Included in the January 31, 2014 Filing with netting of all revenues.[2]

- **YEC ERA charge to YECL** - Includes 100% of the added 2012 YEC wholesale sales revenues that attract DCF added costs (and deducting this from the added cost) – the result is an ERA charge to YECL of $0.439 million (rather than $1.176 million as previously determined):

[2] The ERA for 2012 has been revised subsequently per YUB-YEC-1-25 (the overall ERA remained unchanged despite changes in revenues and costs).

- On incremental wholesales of 13,272 MW.h, the added diesel cost to YEC (applicable to 40.5% of these sales, after adding in YEC losses) remains $1.680 million.

- The added YEC revenue on 100% of the added wholesales is $1.242 million (reflects wholesale rate of 8.298 c/kW.h plus 1.058 c/kW.h other added revenue from riders).

- The $0.439 million ERA charge reflects the added diesel cost after netting all YEC revenues resulting from the added wholesales.

- **YECL Rider D charge to Ratepayers** - Under this approach, YECL would place in a deferred cost account and ultimately charge ratepayers an ERA through Rider D only for the net adverse impact on its income from 100% of the increased 2012 wholesales – in this specific example, no Rider D charge would be required in 2012.

  - Under this approach, full consideration would be given to YECL's added net revenue of approximately $0.571 million after all rider flow through charges related to these incremental wholesales (calculated at average incremental rate of 13.38 c/kW.h), or $1.672 million on 100% of the incremental wholesales [after reducing the sales for YECL losses assumed at 6.2%] less normal wholesale charges at 8.298 c/kW.h (equals about $1.101 million for 2012).

  - In summary, the YEC ERA charge of $0.439 million would be less than YECL's related incremental net revenues of $0.571 million prior to the ERA charge.

  - On this basis, there would be no ERA charge required to ratepayers for 2012, and YECL would retain a net revenue benefit from the added 2012 wholesales of $0.132 million.

As indicated above, there is a material impact and materially different outcomes where the ERA is based on all incremental YEC and YECL wholesale revenues as opposed to only the diesel portion of incremental wholesale revenues.

The proposed revised ERA calculation included in YEC's January 31, 2014 Filing assumes 100% of added revenue for both YEC and YECL from added wholesales. In Yukon Energy's view this updated approach better reflects the transitional period currently occurring with long term average diesel requirements showing an increasing share of new grid generation growth requirements.

Please also see response to YUB-YEC-1-16 and YUB-YEC-1-25.

TOPIC: **Response to Previous Board Directions**

REFERENCE: **YEC January 31, 2014 Application**

PREAMBLE:

QUESTION:

a) How does the filed application conform with the direction from Board Order 2013-01, to provide a revised DCF proposal that incorporates specific changes noted in that Order and to work with YECL to provide a joint recommendation regarding how the DCF will affect the ERA in Rate Schedule 42, or Board Order 2013-03 that YEC and YECL provide a joint filing regarding the revised DCF proposal, and the ERA, stating if agreement cannot be reached, a filing in which the Companies state which aspects they agree upon, the aspects they disagree upon and the position of each company on those aspects they disagree upon.

b) Please summarize in YEC's view, any aspects the Companies agree upon, the points the Companies disagree upon, why there is disagreement and what would be necessary to bridge those areas of disagreement.

c) If the Companies cannot agree on changes to the DCF and ERA, should the DCF and ERA be discontinued? Please explain.

d) Is there a legislative requirement to continue with the DCF? Please explain.

e) Is there a legislative requirement to continue with the ERA? Please explain.

f) Would any DCF or ERA calculations be valid for any years that are not a GRA test year? Please explain.

ANSWER:

(a) and **(b)**

Please see YEC's January 31, 2014 Filing, Appendix 1, pages 1-1 to 1-5 which outlines changes to the revised DCF in response to the Board directive outlined in paragraph 255 of Order 2013-1. Specifically, the proposed DCF has been revised to consider the following:

- Include diesel generation costs at 100% of LTA hydro generation;
- Remove secondary sales;
- Incorporate non-diesel generation facilities (wind, Fish Lake hydro) forecasts;
- Incorporate suggestions of CW and UCG as to how DCF transactions are to be reported in annual filings; and
- Provide five years of transactions that indicate how the balance in the DCF will change and how those changes will be reported.

With regard to the direction that the utilities should provide a joint filing regarding the revised DCF proposal and the ERA, and "if agreement cannot be reached, a filing in which the companies state which aspects they agree upon, and the position of each Company on those aspects they disagree upon", Yukon Energy notes as follows:

- Response to YUB-YEC-1-6(c) outlines the fundamental differences that the Companies have regarding the DCF and the ERA;[1]
- Response to YUB-YEC-1-11 outlines the process undertaken by the Companies to resolve issues, and notes that the context of the discussions i.e., the fundamental differences outlined in response to YUB-YEC-1-6(c), was such that agreement on any one item was not realistic or achievable. This response also notes how YEC's January 31, 2014 filing attempted to set out (through Options A

[1] As regards documents exchanged between YEC and YECL and outline of discussions, please see YUB-YEC-1-6(a) and (b) and YUB-YEC-1-10.

and B) as clearly as possible the disagreement regarding the ERA - and how YEC was constrained at that time as to what it could say with regard to YECL's October 2013 DCF proposal.

The response to YUB-YEC-1-11(a) outlines how the discussion process between YEC and YECL to date has not taken place in a context where agreement on any single issue has been possible. YUB-YEC-1-6(c) outlines the two core matters of disagreement and the extent to which each ultimately relates to how ratepayer interests and impacts are to be addressed. Overall, the fundamental nature of the disagreement would appear to require the Board to determine what course of action is in the best interests of ratepayers in the context of the legislative requirements.

(c)

Whether or not the DCF and ERA continue is at the discretion of the Yukon Utilities Board, and is not conditional upon the Companies agreeing on the changes to the DCF and/or ERA mechanisms. The near and long term implications of not continuing the DCF and ERA are reviewed in YUB-YEC-1-14. YEC sees no basis for discontinuing the DCF or the ERA unless similar mechanisms are adopted that can as effectively address what the DCF and ERA are designed to address.

The DCF solely addresses ratepayer interest with regard to thermal generation cost-induced rate fluctuations and instability due to water variability. This mechanism was established for the benefit of ratepayers (and funded by ratepayers), as it has been long established that thermal generation cost impact risks related to impacts of water variability are borne by ratepayers and not the utilities. Discontinuance of the DCF without establishing a similar replacement mechanism will in effect remove a long established mechanism (pre-dating the DCF) that has been in place to cushion ratepayers from the material swings in diesel costs (and rates) that may occur due to changes in water availability.

Yukon Energy has understood that the core consistent disagreement between the Companies relates to the continuance of the ERA charges by YEC to YECL - even though this mechanism was jointly established by the Companies in 1993 to address issues that continue to be relevant today. In order to address concerns raised by YECL Yukon Energy specifically included two Options in its January 31, 2014 Filing; Option B

removes the ERA mechanism and allows YECL to protect its incremental revenues related to wholesales in excess of YEC forecasts - aside from this difference, the parties ultimately impacted by the selection of Option B versus Option A are retail and industrial ratepayers (who would face higher costs under Option B versus Option A). Option A is proposed by YEC in consideration of these ratepayer savings as well as consistency with past practice when diesel was last on the margin for the hydro grid.

(d)

There is no specific legislative requirement in the *Public Utilities Act* or via OIC regulation to continue with the DCF per se. However, Section 3 of OIC 1995/90 directs that the Board review and approve rates in accordance with principles established in Canada for utilities, including principles established by regulatory authorities regulating hydro and non-hydro electric utilities normal principles - and on this basis it would be relevant to review how rate stability is addressed by other hydro-based jurisdictions as regards water availability fluctuation impacts on hydro and thermal generation.

In addition, as reviewed in response to YUB-YEC-1-14, there is a clear need to address issues raised by YEC's auditors with regard to at least 2012 and 2013 financial records in the event that the DCF is not approved as required to address these issues.

(e)

The structure of the wholesale rate to Yukon Electrical must meet the criteria of OIC 1995/90. Specifically, the OIC sets out two key requirements:

1. The wholesale rate must "be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers"; and

2. The wholesale rate "shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein."

Since Order 1993-7 this has been achieved through the ERA charge included in Rate Schedule 42.

Absent an ERA charge being included in Rate Schedule 42, there is still a legislative requirement for the wholesale rate to be sufficient to enable YEC to recover its costs that are not recovered from other customers.

In summary, if YEC does not recover incremental diesel generation costs arising from changes in YECL power purchases from YEC through some form of a Diesel Deferral Account mechanism charged to industrial and retail non-industrial customers (as outlined in Option B in YEC's submission), such costs must be charged to YECL through Rate Schedule 42.

(f)

Please see response to YUB-YEC-1-20(c). The DCF/ERA calculations would be valid for test years and non-test years.

TOPIC: **DCF/ERA**

REFERENCE: **YEC DCF-ERA filing, page 2**

PREAMBLE:

The Board's current and past Orders for both utilities continue to support implementation of DCF and ERA mechanisms in Yukon.

QUESTION:

a) What is the impact if the Board determines that the continuance of the DCF and ERA is no longer required?

ANSWER:

(a)

The response below addresses the DCF and ERA separately.

Impact of Discontinuing the DCF

As reviewed in response to YUB-YEC-1-1(a), YEC's auditors have identified immediate issues that arise for YEC's 2012 and 2013 financial statements if it is determined that the DCF no longer applies.

- As set out in YEC's July 5, 2013 letter to the Board, in the absence of Board direction and/or an approved DCF, YEC would have been required to recognize additional earnings in 2012 of $3.714 million (the amount otherwise to be paid to the DCF based on actual diesel generation at 2,683 MW.h versus 15,261 MW.h of diesel generation at 100% of LTA hydro generation as estimated for actual 2012 grid generation requirements).

- As set out in YEC's April 4, 2014 letter to the Board, a similar problem would arise for 2013 in the amount of $3.518 million in the absence of Board direction and/or an approved DCF.

On a go-forward basis, the impact of not continuing a DCF would be to increase rate instability for ratepayers, mask rather than display the expected long-term cost of power, and frustrate rather than facilitate intergenerational equity and fair treatment related to the benefits provided by hydro generation over its long-term economic life. These points are elaborated on below.

In the event that the DCF is not operative it would appear necessary, in order to minimize in future years the financial reporting issues identified by YEC's auditors, for the Board to abandon setting YEC rates based on 100% of long term average (LTA) hydro generation as per Order 2013-01 and instead revert to setting rates based on forecast short term hydro water conditions. However, as reviewed in response to YUB-YEC-1-1(f), it is difficult to see how even on this basis the Board could avoid the necessity of making operative some form of DCF mechanism:

- As demonstrated in the 2012-13 GRA filings and in Attachment 1 to YUB-YEC-1-1(b and c), the fundamental reality that drives the need for a DCF mechanism remains, i.e., material YEC diesel generation is expected to occur at current and future forecast loads on the integrated grid at LTA hydro generation water conditions, and much higher than LTA diesel generation will be required in years when hydro generation water conditions are less than the LTA.

    - Attachment 1 to YUB-YEC-1-1(b and c) highlights the expected variability in diesel generation as assessed in a November 2012 filing based on variation in water conditions and different potential future grid load conditions.

    - At a grid load of 461 GW.h as then forecast under the Base Case for 2016, with LTA diesel generation at 33.5 GW.h, a repeat of water conditions experienced from 1995 to 2000 (six years) would require diesel generation each year ranging from 56.9 GW.h to 122.5 GW.h.

    - At the same grid load, diesel generation in excess of LTA would be required in five additional years out of the 28 water years then included in the YECSIM analysis.

- Attachment 1 to YUB-YEC-1-1(b and c) also shows that the frequency of material diesel generation requirements will increase as grid loads increase.

- As demonstrated in the 1990s prior to approval of the DCF in 1996 and the adoption of LTA hydro generation forecasts for rate setting, a Low Water Reserve Fund was still required for YEC even with rates based on forecast short term hydro water conditions in order to address the fact that any deviation of actual water conditions from the Board-approved short-term hydro generation forecast would remain a risk to be borne by ratepayers.

- Under current and expected future grid load conditions, reliance on a short-term forecast of hydro water conditions would add considerable instability to rates over time simply in response to changing water conditions, and reduce funds set aside in the DCF (or other deferral account mechanism) during high water conditions in order to help reduce rate requirements under low water conditions. (YUB-YEC-1-1(f) reviews relevant past history of the Board in this regard leading to the establishment of the DCF).

The magnitude of rate instability impacts due to discontinuation of the DCF will depend on what other mechanisms are established to replace the DCF, the actual load conditions which occur, and the actual water conditions which occur. Even with the DCF, actual water conditions and loads may still give rise to some rate instability - and the degree of such instability can also be affected by the upper and lower cap limits adopted for the DCF from time to time, i.e., narrow or low limits will increase rate instability with regard to water condition variability.

With regard to DCF discontinuance impacts on price signals, intergenerational equity and long-term planning, please see response to AEY-YEC-1-10(a) and (b).

Impact of Discontinuing the ERA

As reviewed in response to YUB-YEC-1-5 (c) and (d) and in YEC's January 31, 2014 filing (Attachment 2), the ERA mechanism originated prior to the DCF to address issues arising with the Low Water Reserve Fund and the impact on YECL (when loads were less than forecast) of diesel cost-based run out rates. Accordingly, discontinuance of the

ERA gives rise to issues that differ from discontinuance of the DCF - and these issues relate primarily to cost allocations or sharing between YEC and YECL, rather than rate impacts for retail and industrial ratepayers.

As directed by Section 7(a) of OIC 1995/90, some similar form of wholesale rate mechanism is also needed in this regard to keep YEC whole whenever incremental diesel generation costs are incurred in future by YEC as a result of wholesales to YECL being higher than the approved GRA forecast.

Accordingly, if the Board determines that the "ERA" is no longer required, it will be necessary to ensure that the issues addressed by the ERA are in fact addressed adequately by an alternative rate-related mechanism.

With regard to ERA discontinuance impacts on price signals, intergenerational equity and long-term planning, please see response to AEY-YEC-1-10(a) and (b).

TOPIC: **ERA**

REFERENCE: **YEC DCF-ERA filing, page 2**

PREAMBLE:

… (b) to provide for YECL recovery through a Rate Rider of any net added YECL cost not otherwise recovered from ratepayers after full consideration of YECL revenue changes related to the wholesale variance.

QUESTION:

a) Please provide an illustrative example.

ANSWER:

(a)

Please see response to YUB-YEC-1-17.

TOPIC: **Unrecovered Costs**

REFERENCE: **YEC DCF-ERA filing, page 3**

PREAMBLE:

Both options also protect YECL from incurring unrecovered costs related to changes in YEC's incremental diesel generation costs arising from changes in YECL power purchases from YEC.

QUESTION:

a) Please provide examples of these unrecovered costs.

b) What is the root cause for these costs to be incurred at a rate which exceeds the incremental revenues?

c) Please describe the risks associated with this process.

ANSWER:

(a)

The "unrecovered costs" referenced at page 3 of YEC's filing are short-term incremental costs incurred by YECL with regard to additional wholesales that are not recovered from (funded by) YECL's incremental sales revenues related to the incremental wholesales. This assessment is made prior to any consideration of a YECL deferral account related to ERA charges.

Table 2 of the YEC filing (page 10) provides examples for 2012 and 2013 - looking at 2013 Preliminary, the following example can be described:

- Actual wholesale purchases by YECL were 780 MW.h higher than the approved forecast; however, the net increase after considering Fish Lake is only 86 MW.h.[1]

[1] Fish Lake impacts reflect impacts on wholesales due only to the variance between LTA generation as approved, and actual generation, at Fish Lake. The Fish Lake variance is directly addressed in the DCF (see Table 1 at page 8); wholesale changes due to the Fish Lake variance affect the ERA (including revisions in YUB-YEC-1-25) through impacts

- Based on Option A, an ERA of $13k is charged to YECL by YEC - this charge relates to the added wholesales of 86 MW.h and is to cover incremental costs otherwise unrecovered by YEC, i.e., YEC incurs $22k added diesel cost (DCF charge) due to the added wholesales and only recovers $9k through related incremental wholesale energy charges to YECL.

- YECL's overall incremental costs due to the added wholesales are $20k, reflecting the ERA charge ($13k) plus normal wholesale rate energy charges ($7k) at 8.298 c/kW.h.

- YECL's overall incremental revenues due to the added wholesales are $11k, reflecting YECL's estimated average retail energy rate (excluding block 1) for incremental retail sales (at 13.81 c/kW.h for 2013) and YECL line losses averaging 6.2%.

- In this example, YECL's "unrecovered costs" related to the incremental wholesales for 2013 equal $9k, i.e., the $20k incremental costs less the $11k recovery of these costs through added retail revenues[2].

Table 2 as filed January 31, 2014 provides the same calculations for 2012 actual results with YECL incremental wholesales of 14,264 MW.h above the approved forecast, and 13,272 MW.h after consideration of Fish Lake impacts - however, in this instance YECL's related incremental costs of $1,540k are more than fully recovered through YECL's incremental retail revenues of $1,672k, i.e., YECL retains a net incremental income gain of $132k.[3]

In principle, the same determinations would apply if YECL wholesales were less than the approved forecast. In such cases, YEC would be expected to provide an ERA rebate and YECL would have incremental cost savings (due to the ERA rebate and reduced wholesale energy charges). However, YECL would also have incremental retail revenue reductions related to the reduced wholesales. To the extent that YECL cost savings exceeded its revenue reductions, YECL would have cost savings not covered by

on YEC incremental revenues and incremental costs; related impacts on YECL affect YECL costs for wholesales but do not affect YECL incremental retail revenues.

[2] As revised in YUB-YEC-1-25 for actual results, the YECL "unrecovered costs" related to the incremental wholesales for 2013 equals $5k ($16k incremental costs less $11k recovery of these costs through added retail revenues).

[3] As revised for 2012 in YUB-YEC-1-25, the YECL incremental cost of $1,622k are more than fully recovered through YECL's incremental retail revenues of $1,672k, and YECL retains a net incremental income of $50k.

revenue reductions, i.e., the negative equivalent of "unrecovered costs" that arise when wholesales exceed the approved forecast.

See AEY-YEC-1-4 for a range of additional examples for various scenarios for 2012 (in none of these 2012 examples does YECL incremental costs exceed its incremental revenues due to the wholesale variances assumed).

(b)

The root cause for YECL to incur "unrecovered costs" at a rate which exceeds incremental retail revenues is that relevant incremental retail rate revenue received by YECL relating to added wholesales (estimated [after considering YECL line losses] to average 12.60 c/kW.h of added wholesales in 2012 and 13.00 c/kW.h in 2013) is below incremental fuel costs for additional diesel generation at LTA hydro generation (as applies for rates in 2012-13).

- Incremental fuel costs for additional diesel generation will exceed incremental retail rate revenues when diesel generation at LTA accounts for a sufficient share of the incremental total generation required to supply incremental wholesales.[4]

- Table 2 demonstrates that in 2012 incremental diesel at 40.5% of incremental generation was not high enough to result in "unrecovered costs" for YECL, i.e., incremental diesel would need to equal or exceed about 44% of incremental generation in 2012 to result in "unrecovered costs" for YECL under Option A as defined in YEC's submission.

- Aside from the impact of incremental thermal generation costs at LTA increasing as grid load increases, "unrecovered costs" for YECL will also be impacted by the gap between approved retail rates (excluding block 1) affecting incremental sales and the incremental cost of thermal generation per kW.h of such generation.

"Unrecovered costs" for YECL did not occur in the past due to ERA charges when the Faro mine was operating and diesel generation accounted for 100% of any incremental YEC generation requirements. As reviewed in response to YUB-YEC-1-8(f), retail run out

[4] Incremental fuel cost for diesel generation by YEC is currently approved at 28.71 c/kW.h of diesel generation required at LTA hydro generation water conditions. The DCF determinations assess the extent to which "expected diesel generation" as shown in Table 2 changes with changes to overall grid loads.

rates then applicable to incremental retail or industrial sales were at least equal to approved YEC incremental diesel generation costs. Please also see the response to YUB-YEC-1-5 (c and d) for elaboration regarding the previously approved ERA calculations when diesel was on the margin with the Faro mine in operation.

(c)

It is not clear what is meant by "risks associated with this process". The estimates provided in Table 2 and the above examples indicate a relatively high degree of clarity, consistent with past ERA implementation, as to YECL incremental wholesales and related YECL incremental revenues and costs. Under Option A, any "unrecovered costs" of YECL would be fully addressed by the YECL Deferral Account and thereby remove any risks for YECL related to these costs. In this regard, uncertainties or risks related to YEC's incremental diesel generation costs do not affect YECL, i.e., any resulting ERA impacts on YECL are clear and the process for addressing them is clear so as to protect YECL from incurring unrecovered costs related to changes in YEC's incremental diesel generation costs arising from changes in YECL power purchases from YEC.

TOPIC: **Option A**

REFERENCE: **YEC DCF-ERA filing, page 3**

PREAMBLE:

… to reflect net cost to YEC after all added revenues related to wholesale variances, and provides as well for YECL recovery through its deferral account (and related rate rider) of any net added cost after full consideration of added revenues due to increased sales.

QUESTION:

a) Please provide an illustrative example of the above.

ANSWER:

(a)

Table 2 of YEC's January 31, 2014 DCF-ERA filing provides example calculations for Actual 2012 and Preliminary Actual 2013 information, addressing impacts separately for both YEC and YECL.

For example, in 2012 the incremental wholesale sales net of Fish Lake of 13,272 MW.h are shown in Table 2 to have the following impacts on YEC and YECL:

- **YEC:**
  - Added revenues to YEC of $1.242 million, based on all of the incremental wholesales and rate revenue at 9.356 c/kW.h (wholesale energy rate of 8.298 c/kW.h and provision for added rider rate revenues of 1.058 c/kW.h for 2012).

  - This added revenue is included as an offset to the added cost of diesel of $1.680 million (reflects 40.5% of the generation variance related to the incremental wholesales [wholesales variance plus YEC losses at about 8.7%] and diesel cost at 28.71c/kW.h of diesel generation).

- The net result decreases the ERA charge to YECL from $1.680 million to $0.439 million.

- The ERA as so determined under Option A in effect reflects the net cost to YEC after all added revenues related to the wholesale variance.

- **YECL:**
  - Added revenues for YECL of $1.672 million, based on all of the incremental wholesales [reduced to account for average YECL line losses of 6.2%] and rate revenue at 13.38 c/kW.h (estimated average retail energy rate for YECL in 2012 excluding block 1 sales).

  - This added YECL revenue is included as an offset to the added cost of YECL wholesale purchases of $1.540 million (reflects energy charge at 8.298 c/kW.h for incremental wholesales plus the ERA charge of $0.438 million).

  - The net result is that YECL's incremental revenues of $1.672 million fully offset YECL's incremental costs of $1.540 million, leaving a net income gain to YECL of $0.132 million.

  - The ERA impacts as so determined under Option A provides for YECL recovery through its deferral account (and related rate rider) of any net added cost after full consideration of added revenues due to increased sales:

    - Table 2 shows that YECL in 2012 has no net added cost, and thus no basis for any recovery through its deferral account.

    - In contrast, Table 2 shows that YECL in 2013 has a net added cost of $0.009 million after full consideration of added revenues due to increased sales, and that this net added cost would be recovered by YECL through its deferral account. [See response to YUB-YEC-1-16(a) for elaboration on the 2013 example from Table 2].

YUB-YEC-1-12 provides a review with examples of the netting of all related revenues for both YEC and YECL and how the current Option A differs from what was originally proposed in the 2012-13 GRA filing.

TOPIC: **YECL Concerns**

REFERENCE: **YEC DCF-ERA filing, page 3**

PREAMBLE:

YEC understands that these ERA issues for YECL are magnified by the need today for a "formulaic approach" to estimate expected diesel under different load conditions and the difficulties inherent in allocating to YECL a share of YEC's overall incremental thermal generation cost changes arising from load variances relative to approved GRA forecasts.

QUESTION:

a) Why is a formulaic approach required? Please explain.

ANSWER:

(a)

A formulaic approach is required today because the previous approach used in the 1990s when the Faro mine was operating of setting a single value for the long-term average hydro for DCF and GRA purposes is not suited to today's system. The past approach was understood to be a simplification, i.e., some variation of long-term average hydro generation would occur on the grid at different loads, but such variances were not considered to be material with Faro mine loads and then current hydro capabilities.

At the range of grid loads relevant today and current hydro capabilities,[1] it is necessary to recognize that long-term average hydro capability varies materially with variations in annual grid loads. Table 1.1-1 of YEC's January 31, 2014 filing shows how the long-term average hydro generation increases as load grows, e.g., at 415 GW.h load level, net of wind and Fish Lake, the long-term average hydro generation is about 403.2 GW.h, increasing to 408.6 GW.h when load level increases to 425 GW.h. A formulaic approach is required to address such variations in hydro generation related to load changes.

[1] Including interconnection of Mayo-Dawson (MD) and Whitehorse-Aishihik-Faro (WAF) grids, addition of Mayo B and Aishihik 3rd turbine.

Ultimately, a formulaic approach is required to provide GRA and DCF assessments that adjust as reasonably needed for changes in grid load conditions today so as to avoid major inaccuracies as to LTA diesel generation requirements and costs. The issue here is not one of seeking high level refinement - it is more to avoid material misrepresentation.

Board Order 2013-01 has determined that 100% LTA hydro generation is now being used for approved YEC revenue requirements and rates based on test year forecasts. In this context, failure to reflect 100% LTA hydro generation for actual loads as needed for DCF purposes would mask the extent to which LTA diesel generation costs are changing as actual grid loads change. Adjustments to reflect actual grid loads are also relevant for DCF determinations in future non test years in order to enable YEC to track the impact on LTA diesel generation as loads change.

The available information confirms that diesel generation at LTA hydro generation will account today for a notable portion of any change in total YEC generation from test year forecasts - but that this portion is well below 100% at this time.

Table 1.1-1 in YEC's January 31, 2014 filing shows that LTA diesel generation as a percent of increased load is also today subject to material change as current grid loads change (thus supporting a need for a formulaic approach to allow for changes in the assumed diesel share of load change rather than merely assuming any one specific percentage for all load changes). For example, Table 1.1-1 shows that diesel at LTA hydro generation without new mine loads accounts for:

- 36% of grid load increases from 400 to 405 GW.h/year;
- 46% of grid load increases from 415 to 420 GW.h/year;
- 50% of grid load increases from 425 to 430 GW.h/year,
- 58% of grid load increases from 435 to 440 GW.h/year; and
- Increasing to 78% of grid load increases when grid loads grow from 470 to 475 GW.h/year.

Table 2 in YEC's January 31, 2014 filing shows the relevance of the formulaic assessments in addressing the material variance in that test year between GRA approved forecast grid load and actual loads:

- **Forecast 2012 grid load** was 405,553 MW.h for YEC generation (405,314 net of expected wind and assuming no impacts from Fish Lake variance from LTA):
    - Expected hydro generation at LTA was 397,388 MW.h;
    - Expected diesel at LTA hydro was 7,926 MW.h; and
    - Diesel generation fuel cost for GRA at $2.276 million.
- **Actual 2012 grid load** was 424,541 MW.h for YEC generation (423,310 net of expected wind and actual net impacts from Fish Lake variance from LTA):
    - Expected hydro generation at LTA was 407,688 MW.h;
    - Expected diesel at LTA hydro was 15,622 MW.h; and
    - Diesel generation fuel cost for GRA at $4.485 million.
- **Impact of formulaic approach:**
    - Change in grid load (net of wind and Fish Lake) = 17,996 MW.h increase;
    - Change in LTA hydro generation = 10,300 MW.h (57.23% of total change rather than 0% as in 1990s with Faro mine in operation or 100% of total change when diesel not on the margin); and
    - Change in expected diesel generation = 7,696 MW.h (42.76% of total change).

Differences between Table 1.1-1 and Table 1.1-2 indicate the relevance today of also allowing for revisions in LTA hydro generation contributions to reflect material changes in the seasonal shape of grid loads (in this case to reflect the impact of adding the assumed

WHCT industrial load with its focus on non-winter peak periods when hydro generation is relatively more available). In summary, Table 1.1-2 compared to Table 1.1-1 shows lower expected diesel at each grid load level (e.g., at 415 GW.h load, expected diesel drops from 11.8 GW.h in Table 1.1-1 to 10.5 GW.h in Table 1.1-2) even though there is only minimal change in the percentage of load growth accounted for by diesel generation as load levels change. Tables 1 and 2 in the filing demonstrates the importance of this difference when addressing the DCF at LTA for 2013 when the WHCT load that had been forecast for this test year did not in fact materialize, i.e., accepting the actual grid load that occurred, retaining LTA estimates based on Table 1.1-1 versus shifting to Table 1.1-2 resulted in expected diesel generation estimates of 13,326 MW.h (per Table 1.1-1) rather than 11,959 MW.h (per Table 1.1-2).

TOPIC: **Option A and Option B, Required Approvals**

REFERENCE: **YEC DCF-ERA filing, page 4**

PREAMBLE:

QUESTION:

a) Given that approvals are requested effective January 1, 2012 for Option A, how is this not considered retroactive rate-making?

b) Given that approvals are requested effective January 1, 2012 for Option B, how is this not considered retroactive rate-making?

ANSWER:

(a) and **(b)**

The rule against retroactive ratemaking prevents a utility from seeking past costs in a future period.[1] Deferral accounts with accumulating balances are an accepted practice with no element of retroactive ratemaking. As such, implementation of either Option A or Option B would not be considered retroactive ratemaking.

Specifically, the GRA for YEC revenue requirement and final rates for the 2012 and 2013 test years was filed in April 2012 (i.e., well before the end of 2012) and the relevant revenue requirements and rates were approved by Order 2013-4. Implementation of either Option A or Option B would not change YEC's approved revenue requirement or rates for those test years.

DCF and ERA approvals were sought as part of YEC's initial GRA filings in April 2012, and continued referencing of these to become effective January 1, 2012 simply ensures a reasonable date for start of the relevant determinations that is consistent with the approved and related test year revenue requirements.

[1] See discussion in Order 1997-4 where the Board addressed issues related to retroactivity.

Implementation of Option A or Option B only affects whether the annual diesel cost variances due solely to variances from YUB approved GRA wholesale forecasts are collected (net of related incremental YEC revenues) through either:

1. An ERA charged to YECL under Option A (to the extent that this ERA cannot be funded by YECL's net incremental revenues from the wholesale variance, it is ultimately deferred to YECL's approved Purchase Power Flow Through Account to be collected from ratepayers via a Rider D mechanism); or

2. A Diesel Deferral Account charge under Option B from YEC to retail and industrial customers.

In each case the incremental costs are incurred after the 2012/2013 General Rate Application, and are not considered retroactive.

In the case of ERA charges to YECL it is also noted that an ERA mechanism has been in place since Order 1993-7 and there is established Yukon precedent for ERA charges from YEC to YECL [i.e., such past charges were not considered retroactive ratemaking]. Further, Board Order 2009-8 (following YECL's 2008/2009 GRA) approved a wholesale purchase power deferral account to fully address any cost impacts to YECL from load forecast variance derived ERA cost changes, and Order 2010-13 (paragraph 181) confirmed that implicit in its approval of this YECL deferral account is approval of a future rate rider to dispense the accumulated balances in the deferral account.

TOPIC: **Net Revenue Cost**

REFERENCE: **YEC DCF-ERA filing, page 5**

PREAMBLE:

After the ERA, YECL would retain a net revenue cost impact of $0.009 million as a result of the wholesales variance …

QUESTION:

a) Does this example mean that in certain situations, the revenues from the incremental sales over the forecast amount are less than the wholesale costs of the energy associated with those incremental sales?

b) In YEC's view, is this a forecast risk that should be borne by the utility? Please explain.

c) How would YEC handle this during non-test years?

ANSWER:

(a)

Yes, in certain situations the revenues from the incremental sales over the forecast amount are less than the wholesale costs of the energy associated with those incremental sales. Please see YUB-YEC-1-16(a) and (b) for a review of such "unrecovered costs" as demonstrated by the Table 2 review of 2013 Preliminary Actual costs and a discussion of the root causes for such outcomes.

(b)

In YEC's view the utility in Yukon normally bears the risks related to impacts of sales and generation variances not related to water variability or fuel price variability.

In this instance, however, "unrecovered costs" arise for YECL as a result of incremental wholesale purchases that exceed GRA approved forecasts in situations when YECL's and YEC's combined rate revenues related to such incremental wholesales are not sufficient to recover related incremental short term costs for thermal energy generation at long-term average hydro generation water conditions. More specifically, the ERA charged to YECL is net of all related YEC incremental revenues - and YECL only incurs "unrecovered costs" when, and to the extent that, its incremental wholesale costs exceed its related incremental retail revenues. Under these circumstances the unrecovered costs are prudently incurred by YECL and therefore, in YEC's view, are reasonably charged to a deferral account. Please see YUB-YEC-1-16 for more detailed review of "unrecovered YECL costs" in this specific context; YUB-YEC-1-17 also reviews the assessment of any net added cost for YECL after full consideration of added revenues due to increased sales.

Option A as recommended in YEC's submission proposes that in this situation the unrecovered YECL costs [but only the unrecovered portion of the YECL costs] be recovered from ratepayers through a YECL deferral account. This proposal differs from any option where the full ERA amount as such, without consideration of related incremental retail revenues of YECL, would be recovered from ratepayers through a YECL wholesale purchase power deferral account.

(c)

Option A as proposed in YEC's submission, including both the proposed DCF and the proposed ERA, would be applied the same way in non-test years as well as in test years.

As in the past when diesel was on the margin with the Faro mine operating, it is essential that the DCF and related ERA mechanisms be operative for both test and non-test years. Approved rates remain as set based on test year forecasts - the DCF and ERA are designed to address variances from the relevant forecast in a test year or a subsequent non-test year (2013 forecasts will apply for any post-2013 non test year) as regards actual YEC generation, actual YEC and YECL hydro generation water conditions, and (in the case of the ERA) actual wholesales. The proposed DCF includes provision to adjust Table 1.1-1 and/or Table 1.1-2 as required to reflect changed conditions (see response to YUB-YEC-1-26 and YUB-YEC-1-27); provisions are also provided to adjust the DCF for LNG (see YUB-YEC-1-29).

TOPIC: **Rate Rider**

REFERENCE: **YEC DCF-ERA filing, page 6**

PREAMBLE:

Industrial and retail firm sales would be required to pay a rate rider for recovery of the above DDA amounts for 2012 and 2013 (total $0.540 million).

QUESTION:

a) Please explain how this would work. Would YECL collect these amounts on behalf of YEC?

ANSWER:

(a)

It is anticipated that DDA amounts would be collected in a manner similar to past Yukon Energy Rate Riders (e.g., YEC Rider R and Rider J collected in relation to the 2012/2013 General Rate Application). A rider would be applicable to all YEC and YECL firm retail rates (all YECL recoveries from this rider would flow through to YEC) and industrial rates.

TOPIC: **Charges to YECL**

REFERENCE: **YEC DCF-ERA filing, page 6**

PREAMBLE:

There would be no new charges to YECL under this option related to any of the wholesales variances from approved GRA forecasts (i.e., the ERA would be discontinued, and YECL net revenue gains from added wholesales of $0.571 million in 2012 and $0.004 million in 2013 would be retained) (footnote omitted).

QUESTION:

a) In YEC's view does this shift forecast risk from YECL to the customer?

ANSWER:

(a)

Yes, Option B in this regard shifts forecast risk impact (equal to YECL's incremental revenues from increased wholesales) from YECL to all Yukon retail and industrial customers, and YECL is able to retain all incremental revenues from added wholesales. In addition, as reviewed below, some forecast risk is shifted from YEC to all Yukon retail and industrial customers.

Under either Option A or Option B there are provisions whereby wholesale forecast risk is borne by a utility rather than the customers.

- Under Option A:
  - YECL would be held whole through its approved Purchase Power Flow Through Account, and any YECL unrecovered wholesale purchase charges from YEC would be passed through to all Yukon retail and industrial customers through a Rider D charge. In this instance, however, the cost risk to customers is reduced by estimated YECL incremental retail and industrial revenues related to the incremental wholesales (this is

consistent with how the ERA was applied when the Faro mine was operating).

- YEC would forego all incremental revenue from incremental wholesales to YECL, and through the ERA will in the end also have no wholesale cost risk (this is consistent with how the ERA was applied and YEC wholesale risks were addressed when the Faro mine was operating).

- YEC will continue to bear all cost risks related to changes from approved forecast in YEC sales to retail and industrial customers (when the Faro mine was operating run out rates to these customers fully reflected YEC's incremental diesel generation costs – in contrast, today YEC is exposed to potential unrecovered costs from incremental sales above forecast to these customers).

- Under Option B:

  - YECL would have no cost risk related to added wholesales, and (unlike Option A) would retain all YECL revenue gains from added wholesales.

  - YEC would charge all Yukon industrial and retail firm customers a diesel deferral account rider for recovery of YEC unrecovered costs due to increased sales above forecast for each retail and industrial customer class.

The key difference between Option A and Option B is that under Option B, ratepayer cost impacts exclude YECL revenues related to wholesale variances from forecast and include YEC unrecovered costs from YEC's industrial and retail sales variances from forecast. As indicated in Table 2 of Yukon Energy's January 31, 2014 filing, Option A would therefore have a lower cost impact on ratepayers than Option B, i.e., Option B relative to Option A shifts forecast risk impacts from the utilities (mostly from YECL) to all Yukon retail and industrial customers.

TOPIC: **YECL Deferral Account**

REFERENCE: **YEC DCF-ERA filing, page 6**

PREAMBLE:

Under Option A, added YECL revenues from increased retail sales variances either equal or exceed any net ERA cost to YECL (due to ability to flow through any net costs to the YECL deferral account).

QUESTION:

a) In YEC's view, does the deferral account only apply to the change in rates for wholesale purchases from YEC or does it consider changes in volume too?

ANSWER:

(a)

Under Option A, the YECL deferral account applies to YECL's unrecovered costs from a variance in actual wholesales from forecast wholesales, i.e., it applies to changes in volume, but is restricted only to the amount by which incremental YECL costs exceed incremental YECL revenues from the change in volume.

The issues related to YECL wholesales only arise with regard to changes in wholesale volumes relative to the approved wholesale forecast (see response to AEY-YEC-1-1(a) which confirms that no ERA charge occurs if actual wholesales [after Fish Lake variances] equal forecast wholesales; without an ERA charge, there is no basis for consideration of any deferral account use).

TOPIC: **Prior Direction**

REFERENCE: **YEC DCF-ERA filing, page 7**

PREAMBLE:

Option A also is consistent with past Board Orders and the directions in OIC 1995/90.

QUESTION:

a) Please provide the specific prior Board directions and the specific part of OIC 1995/90 that YEC is referring to.

ANSWER:

(a)

Please see also response to UCG-YEC-1-2(a) Attachment 1 and Attachment 2 which details relevant prior Board directions and OIC directives related to the DCF and the ERA.

Relevant Sections of OIC 1995/90:

- Section 3 - Normal principles to apply.
- Section 7 – Wholesale Rates.

Relevant Board Directions regarding the DCF (or the earlier Low Water Reserve Fund):

- Order 1989-4 (Establishment of Reserve for Contingencies as part of the 1989/90 General Rate Application).
- Order 1992-1 (Approving implementation of a low water financial reserve as part of the 1991/92 General Rate Application).
- Order 1996-7 (1996/97 GRA Negotiated Settlement).

- Order 1999-3 (Diesel Contingency Fund Reports).

- Order 2011-15 (Rider F Policy) - [Appendix A, page 9].

- Order 2013-1 (YEC 2012/13 GRA Compliance Filing) – [Appendix A, paragraph 255].

- Order 2013-3 (YEC 2012/13 GRA Revised Compliance Filing) – [Appendix A, paragraph 15 and 16].

Relevant Board Directions regarding the ERA:

- Order 1993-7 – Order following the 1993/94 GRA approving the ERA mechanism.

- Order 1998-5 – Agreement by Board that dispute between YEC and YECL regarding amounts paid pursuant to Rate Schedule 42 should be addressed in a separate process after the public hearing related to the 1998 Revised Application.

- Order 1999-4 – Order approving the energy charge rate and the terms of settlement agreement between YEC and YECL regarding the ERA (provided as Attachment to the Order).

- Order 2009-2 – Order approving YECL's wholesale Purchase Power Flow Through Account.

- Order 2010-13 – Order did not approve the Rider D mechanism as applied for but noted that "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."

TOPIC: **2013 Preliminary Actuals**

REFERENCE: **YEC DCF-ERA filing, Tables 1-3 (pages 8-10 inclusive)**

PREAMBLE:

QUESTION:

a) Please provide the final DCF and ERA tables, results and calculations for 2013.

ANSWER:

(a)

Please see YUB-YEC-1-25 Attachment 1 for updated Tables 1, 2 and 3 with 2012 and 2013 actuals.

Please note based on review of the proposed approach for ERA determination in light of various scenarios, the calculation as filed in the January 31, 2014 filing was modified to better reflect Fish Lake impacts as well as the determination of expected diesel in Table 1 for actual grid loads (i.e., for the DCF). The refinements include:

- Lines N and S, where the incremental calculations are linked to the incremental wholesale sales before Fish Lake impact, i.e. to line C instead of line E;
- Lines F and G, which are now net of expected wind and expected Fish Lake generation (as per Table 1 for expected diesel regarding actual grid load); and
- Line U, the test in the formula has been refined to deal with rebates as well as charges.

The overall impact of these changes is as follows:

- **No impact case:** "no change in wholesales" now is determined net of Fish Lake impacts (to reflect the GRA assumptions that forecast wholesales assume expected Fish Lake generation).

- **ERA:** impacted by YEC revenue impacts being based on all wholesales (including sales related to Fish Lake) and refined incremental diesel in base rates - no change in 2012; in 2013, revised ERA from $0.013 million charge to $0.048 million rebate (reflects impact of including revenues on wholesales related to Fish Lake impacts plus very small net change in other wholesales).

- **YECL Deferral Account - Rider charge (Rebate):** impacts relate to modified ERA plus consideration of cost impacts re Fish Lake changes - no deferral account impact in 2012 in all assessments; deferral account rebate in 2013 (changes reduce this from $0.009 million to $0.005 million).

Tables 1, 2 and 3 attached address annual DCF and ERA or Deferral Account determinations for 2012 and 2013 based on actual loads and generation. The following are noted on the separate matter of the DCF cap:

- The YEC submission recommends a DCF cap today, subject to ongoing review, of +/- $8 million, notwithstanding that low water impacts could result in impacts well in excess of this dollar amount (see for example AEY-YEC-1-10(a)); the YEC submission proposes that if the cap is exceeded at the end of a fiscal year, YEC will apply to the Board for a rate rider charge or rebate as required to deal with such excess or deficit (including a proposal as to the term for such rider).[1] Any such rider would be applied to all retail and industrial rates for both utilities (in the same way as other YEC rate riders).

- The DCF cap is addressed through separate DCF continuity schedules; see UCG-YEC-1-6(b) for the annual continuity schedule to the end of 2013, which shows a DCF balance as at December 31, 2013 of approximately $8.197 million or slightly more than the proposed $8.0 million cap.

- The status of the DCF balance relative to any cap determines only one matter, i.e., whether approval should be sought from the Board for a rider rebate or charge.

[1] YEC January 31, 2014 DCF-ERA Filing, Appendix 1, Attachment 1.1, pages 1.1-5 and 6

- The status of the DCF balance at any time (e.g., including a time when a rebate rider is operative) does not impact the determination of 100% LTA hydro generation or related expected diesel for GRA purposes. Regardless of the status of the DCF balance relative to any cap, so long as diesel continues to be on the margin for a test year (similar to the case for 2012 and 2013 test years) YEC revenue requirements and firm rates are assumed to continue being set in any GRA based on 100% LTA expected diesel generation reflecting 100% LTA hydro generation conditions; as a result, any variance between actual diesel and expected diesel will also continue to be determined in the same way as set out in Table 1; and the ERA will continue to be determined in the same way as set out in Table 2.

- Although the cap was exceeded at the end of 2013, due to the very small amount of this excess YEC proposes to defer any action related to the cap until after the 2014 year end accounts are available at which time the balance will be notably higher unless 2014 water conditions are such that actual diesel exceeds "expected diesel" based on long-term average (LTA) hydro generation water conditions.

Table 1: Revised DCF Calculation for Actual 2012 and Actual 2013

Variable cost of YEC diesel calculation

Line No					Notes
L1	Fuel Cost per kW.h	28.71	28.71	cents/kW.h	Compliance Filing Average Fuel cost

Calculation of Diesel Cost to Charge (Refund) DCF

2013 Preliminary actuals		2012 actuals	2013 actuals		
	Assumptions				
L2	YEC Grid load	424,541	419,173	MW.h	Actual net of secondary sales (with losses)
L3	Fish Lake	3,388	3,687	MW.h	Fish Lake generation
L4=L2+L3	Total Grid load	427,929	422,860	MW.h	
	Assumed Actual Generation Sources				
L5	YECL Fish Lake	3,388	3,687	MW.h	Fish Lake generation
L6	YEC Hydro	421,039	416,987	MW.h	Residual as total generation less diesel and wind
L7	YEC Diesel	3,057	1,910	MW.h	Diesel
L7a	*YEC Diesel charged to capital*	*373*	*872*		Includes charged to RFID
L7b	*YEC Net Diesel*	*2,683*	*1,037*		
L8	YEC Wind	445	277	MW.h	Wind generation
L9	Total Grid load	427,929	422,860	MW.h	
	Expected Generation Sources				
L10	YECL Fish Lake (expected)	4,380	4,380	MW.h	Unit #2 at 4.380 GW.h - no Unit #1 generation in 2013.
L11	YEC Wind (expected)	239	239	MW.h	
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	423,310	418,241	MW.h	
L13	Expected Base Diesel Generation at 420 GW.h/2012 and 415 GW.h/2013	14,100	11,800	MW.h	Derived from updated Table 4.1-1 for GRA Compliance Filing Proposal (2012 DCF) [Table 1.1-1, Revised DCF Proposal]
L14=(L12-420/415 GW.h)x46%	Expected Incremental Diesel Generation above 420/415 GW.h	1,522	1,491	MW.h	46% of Grid Load between 415 GW.h and 425 GW.h is diesel - Derived from updated Table 4.1-1 for GRA Compliance Filing Proposal [Table 1.1-1, Revised DCF Proposal]
L15=L13+L14	Total Expected YEC Diesel Generation	15,622	13,291	MW.h	
L16=L15	Expected YEC Diesel Generation in Rates	15,622	13,291	MW.h	100% of long-term average
L17=L7	FYF YEC Diesel Generation	2,683	1,037	MW.h	Net of capital diesel
L18=L17-L16	YEC Diesel Generation to be Included in DCF	- 12,939	- 12,254	MW.h	
L19=L1xL18	Incremental YEC Diesel Generation Cost to Charge (Refund) DCF ($000s)	($3,715)	($3,518)		

Table 2: Option A: Revised ERA Calculation for Actual 2012 and Actual 2013

ERA forecast for 2012 and 2013

	2012	2013		
GRA approved wholesales	296,000	307,147	MW.h	A
Actual wholesales	310,264	307,927	MW.h	B
Incremental	14,264	780	MW.h	C=B-A
Less: Fish Lake Impact	992	693	MW.h	D
Incremental net of Fish Lake	13,272	86	MW.h	E=C-D
Total YEC's actual generation net of secondary, LTA wind &FL	423,310	418,241	MW.h	F - per Table 1 (DCF), L12
GRA approved load forecast, net of expected wind	405,314	416,148	MW.h	G
Total YEC incremental generation relative to GRA approved	17,995	2,093	MW.h	H=F-G
Expected diesel generation at actual load	15,622	13,291	MW.h	I - per Table 1 (DCF), L15
Expected diesel generation at GRA load (approved)	7,926	11,006	MW.h	
Total YEC expected incremental diesel generation	7,696	2,285	MW.h	K=I-J
Incremental Diesel in Base Rates (see Note 6)	42.8%	109.2%		L=K/H
Generation Variance Charged for Diesel Cost	6,176	103	MW.h	M=E*L*Losses
Impacts on YEC				
	ERA Based on All Incremental Wholesale (100%)			
Added Revenue	1,335	78	$000	N=C*(8.298+average rider)
Added Cost	1,773	29	$000	O=M*28.71
Net Impact on YEC	- 439	48	$000	P=N-O
ERA charge to YECL	439	- 48	$000	Q=(-P)
Impacts on YECL				
Added Revenue	1,672	11	$000	R=E/1.062*average energy rate
Added Cost	1,622	16	$000	S=C*8.298 +Q
Impact on YECL	50	- 5	$000	T=R-S
				U=If S>0 then 0 if T>0; otherwise (-T)
YECL Deferral Account - Rider charge (Rebate)	-	5	$000	U=If S<0 then 0 if T<0: otherwise (-T)
Net Impact on YECL after Deferral Charge (Rebate)	**50**	**-**	$000	V=T+U

Notes:

1. YEC's approved wholesale and generation numbers are based on YEC's 2012/13 GRA Revised Compliance Filing (includes WHCT related sales).

2. Fish Lake impact is calculated as the difference between expected hydro generation at 4.38 GW.h (4.38 GW.h Unit #2; no Unit #1 generation) and actual generation.

3. YEC's load on Line F is net of secondary sales and related losses, and net of expected wind and expected Fish Lake generation.

4. Added revenue for YEC is calculated at wholesale rates plus estimated rider revenues (at 1.058 cents/kW.h for 2012; at 1.69 cents/kW.h for 2013) estimated based on YEC Compliance Filing for 2012/13 GRA.

5. Added revenue for YECL is calculated based on estimated average retail energy rate (excluding block 1) of 13.38 c/kW.h per kW.h for 2012 and 13.81c/kW.h per kW.h for 2013 (and assuming a half year impact of 6.5% 2013-15 GRA interim rider) and 6.2% average YECL losses on sales.

6. Change in expected diesel generation reflects no WHCT load in 2013, and resulting need to retain updated Table 4.1-1 for GRA Compliance Filing Proposal (2012 DCF), which has higher expected diesel for load without WHCT than forecast in Table 4.1-2 (2013 GRA with WHCT load).

Table 3: Option B: DDA Calculation for Actual 2012 and Actual 2013

Diesel Deferral Account for 2012 and 2013

	2012	2013		
GRA approved firm sales	373,094	383,061	MW.h	A
wholesales	*296,000*	*307,147*		*A1*
industrial	*42,783*	*40,592*		*A2*
YEC retail	*34,312*	*35,321*		*A3*
Actual firm sales	390,125	384,518	MW.h	B
wholesales	*310,264*	*307,927*		*B1*
industrial	*44,030*	*40,513*		*B2*
YEC retail	*35,831*	*36,078*		*B3*
Less: Fish Lake Impact (affects wholesales)	992	693	MW.h	C
Incremental	16,039	764	MW.h	D=B-A*C
wholesales	*13,272*	*86*		*D1=B1-A1-C*
industrial	*1,247*	*-79*		*D2=B2-A2*
YEC retail	*1,520*	*757*		*D3=B3-A3*
Total YEC's actual generation net of secondary, LTA wind &FL	423,310	418,241	MW.h	E - per Table 1 (DCF), L12
GRA approved load forecast, net of expected wind	405,314	416,148	MW.h	F
Total YEC incremental generation relative to GRA approved	17,995	2,093	MW.h	G=E+F
Expected diesel generation at actual load	15,622	13,291	MW.h	H
Expected diesel generation at GRA load (approved)	7,926	11,006	MW.h	I
Total YEC expected incremental diesel generation	7,696	2,285	MW.h	J=H+I
Incremental Diesel in Base Rates (see Note 6)	42.8%	109.2%		K=J/G
Generation Variance Charged for Diesel Cost	7,443	908	MW.h	L=D*K*Losses [E/B]
Impacts on YEC				
Revenue Impacts	1,568	116	$000	M
wholesales	*1,242*	*9*		M1=D1*(8.298c+average rider)
industrial	*106*	*7*		M2=D2*8.08c + average rider
YEC retail	*221*	*115*		M3=D3 * average rate+average rider
Cost Impacts	2,137	261	$000	N=L*28.71
wholesales	*1,768*	*29*		
industrial	*166*	*27*		
YEC retail	*203*	*258*		
Net Impact on YEC (before deferral charge)	-569	-144	$000	O=M-N
wholesales	*-527*	*-21*		
industrial	*-61*	*-20*		
YEC retail	*18*	*-143*		
YEC Diesel deferral charge-Rider (Rebate)	569	144	$000	P=(-O)
Net Impact on YEC after Deferral Charge (Rebate)	-	-		

Notes:

1. YEC's approved sales and generation numbers are based on YEC's 2012/13 GRA Revised Compliance Filing (includes WHCT related sales).

2. Actual sales and generation exclude secondary sales and related generation.

3. Added revenue for YEC is calculated: (i) wholesale rates plus estimated rider revenues (at 1.058 cents/kW.h for 2012; at 1.69 cents/kW.h for 2013); (ii) industrial energy rate at 8.08 plus estimated rider revenues (at 0.39 cents/kW.h for 2012; at 0.92 cents/kW.h for 2013); (iii) average retail energy rate (excluding block 1) at 13.43 cents/kW.h plus estimated rider revenues (at 1.09 cents/kW.h for 2012; at 1.76 cents/kW.h for 2013). All rider revenues estimated based on YEC Compliance Filing for 2012/13 GRA.

4. Change in expected diesel generation reflects no WHCT load in 2013, and resulting need to retain updated Table 4.1-1 for GRA Compliance Filing Proposal (2012 DCF), which has higher expected diesel for load without WHCT than forecast in Table 4.1-2 (2013 GRA with WHCT load). [These tables are provided in Appendix 1 of this filing, Tables 1.1-1 and 1.1-2.]

TOPIC: **Tables**

REFERENCE: **YEC DCF-ERA filing, Appendix 1, page 1-2**

PREAMBLE:

Yukon Energy also committed to provide the Board with an update to Table 3.2-2 when required in future to address material changes in long-term average hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

QUESTION:

a) Has Table 3.2-2 been updated to reflect Mayo B, the Aishihik third turbine and the upgrade to Fish Lake hydro?

b) How are load changes reflected? What does YEC consider to be a threshold for a material load change?

c) What does YEC consider to be a material change in terms of capacity?

d) How will the ERA be adjusted for LNG generation? How will LNG generation be distinguished from diesel generation?

e) How will the DCF be adjusted for LNG generation? How will LNG generation be distinguished from diesel generation?

ANSWER:

(a)

Table 3.2-2, Expected Diesel Generation Based on Long-Term Average Hydro Generation, was included in YEC's 2012/13 GRA.

The table was updated based on GRA Compliance Filing load forecast assumptions and included in YEC's Revised DCF Proposal from January 31, 2014 (Table 1.1-1 for 2012 and Table 1.1-2 for 2013). As noted in the notes to the tables, the expected diesel

generation numbers include Mayo B and Aishihik 3rd Turbine (note 4) and exclude expected Fish Lake hydro generation (note 1). Fish Lake variances from expected generation are addressed separately (see Table 1 in filing).

(b)

Load changes were reflected in the GRA and in the January 31, 2014 filing by providing two separate tables, e.g., Table 1.1-1 and Table 1.1-2 in the latest filing; as explained at page A1.1-3, Table 1.1-2 applies only after such time as the WHCT industrial load is connected to the grid. DCF determinations for 2013 (see Table 2) accordingly are based on Table 1.1-1 since WHCT was not connected to the grid in 2013.

As highlighted in note 5 to Table 1.1-1 and Table 1.1-2, modifications are expected to be required when there is a material change in load shape over the year due to a new mine being connected to the grid which tends to have a flatter load shape compared to non-industrial load (or, as in the case of WHCT, has a load actually focused on the non-winter season). However, beyond this provision, YEC has not proposed a specific load change threshold for a material load change.

(c)

A material change in capacity as regards Tables 1.1-1 or 1.1-2 would typically include changes and/or additions (regardless of scale) to YEC hydro energy generating capability connected to the grid. For example, approval of the Mayo Lake Hydro Enhancement Project[1] with additional drawdown capability increases long-term average hydro generation and will therefore impact the thermal generation requirements.

(d) and **(e)**

Once in-service, LNG generation capability to supply thermal generation requirements at long term average (LTA) hydro generation will be assessed in accordance with YEC's Part 3 Application and its review by the Board, and LNG-supplied generation will be assumed to be the first source used to meet LTA thermal generation requirements as otherwise determined for actual grid loads.

[1] This project involves a change to the licensing parameters. Other hydro enhancement projects such as Marsh Lake will also have similar affect.

Except as adjustments are required to reflect lower costs per KW.h for expected LNG-supplied generation versus expected diesel-supplied generation, all DCF and ERA determination procedures will remain unchanged.

Expected thermal generation requirements at LTA hydro generation as required for DCF determinations for actual grid loads will be allocated accordingly between LNG and diesel generation. An average fuel cost per kW.h of expected thermal generation will be determined based on the expected share of expected thermal generation supplied by LNG versus diesel generation, and based on approved forecast diesel and LNG fuel costs per kW.h (the LNG costs per kW.h to be determined and provided for Board approval).

Cost per kW.h of expected thermal generation as required for ERA determinations regarding any time period will be based on the average fuel cost per kW.h as determined for the DCF amounts for the same time period.

TOPIC: **Tables**

REFERENCE: **YEC DCF-ERA filing, Appendix 1, page 1-2**

PREAMBLE:

Attachment 1.1 also includes revised tables to determine annual expected diesel generation in 2012 and 2013, reflecting changes in the YEC load and generation forecasts for wholesales and industrial loads as included in YEC's Compliance filing.

QUESTION:

a) What process does YEC envision for updating testing and getting approval for the updated tables?

ANSWER:

(a)

The revised tables provided in Attachment 1.1 (Tables 1.1-1 and 1.1-2) reflect the forecast 2012 and 2013 loads as approved by the Board in the Compliance Filing (Order 2013-4), and based on current installed hydro generation and licenses/ permits.

Please see YUB-YEC-1-26(b) and (c) for a review of the expected basis for adjusting these tables in response to material changes in load conditions (shape) and/or renewable hydro supply capability – including not applying Table 1.1-2 so long as the WHCT load as assumed for the 2013 approved forecast is not connected to the grid. Such changes are prepared by adjusting YECSIM model parameters and/or assumed weekly loads as required, i.e., no "testing" step would normally be required.

In the event such adjustments are required in the future to conclude an annual DCF determination prior to another GRA, Yukon Energy would file an updated Table 1.1-1 with the YUB for review and approval. YEC would expect to provide updated tables as required as part of any future GRA.

TOPIC: **Fish Lake Hydro**

REFERENCE: **YEC DCF-ERA filing, Appendix 1.1, page 1.1-6**

PREAMBLE:

In contrast to YEC hydro generation, YECL's Fish Lake hydro generation is not affected in any material way by YECL's wholesales load levels or YEC's overall grid loads.

QUESTION:

a) What is the impact ($) to YECL if Fish Lake hydro generation is above long-term average?

b) What is the impact ($) to YECL if Fish Lake hydro generation is below long-term average?

ANSWER:

(a) and **(b)**

The referenced text in the preamble notes that Fish Lake hydro generation is not affected in any material way by YECL's wholesales load levels or YEC's overall grid loads.

However, Fish Lake generation will have impact to YECL's wholesales load levels and YEC's overall grid loads.

- If the Fish Lake hydro generation is higher by 1 kW.h, YECL's power purchases and YEC generation decrease by the same amount (plus associated YEC losses as regard the YEC generation impact).

- In a case with higher Fish Lake generation, YECL would see lower purchased power cost at 8.298 cents/kW.h offset by any additional cost that YECL may occur due to increased generation in Fish Lake (this is understood to be negligible).

- In contrast, if the Fish Lake hydro generation is lower by 1 kW.h, YECL's power purchases and YEC generation increases by the same amount (plus associated YEC losses as regard the YEC generation impact). In this case YECL would see higher purchased power cost at 8.298 cents/kW.h offset by any decreased cost that YECL may incur due to decreased generation in Fish Lake (this is understood to be negligible).

In both cases the impact of Fish Lake generation increases or decreases relative to approved long term average generation is reflected in DCF/ERA calculations such that there is no ERA impact on YECL. For example, in 2012 the following are reflected in Tables 1 and 2 of YEC's January 31, 2014 filing:

- In Table 1, it is noted that actual Fish Lake generation in 2012 was at 3,388 MW.h compared to 4,380 MW.h expected based on long-term average (Unit #1 was out of service), i.e., the actuals were 992 MW.h lower than long-term average.

- As provided in Table 1, YEC grid load used to determine expected diesel at LTA was adjusted to reflect expected rather than actual Fish Lake generation.

- As provided in Table 2 of YEC's filing, the 992 MW.h shortfall in Fish Lake generation from LTA levels was removed from ERA calculations related to YECL wholesales change from approved forecast.

The subsequent revisions to ERA determinations set out in YUB-YEC-1-25 do not change any of the above observations. However, Fish Lake variations from expected generation are now recognized in the following two determinations (see Table 2, YUB-YEC-1-25):

- Fish Lake changes are reflected in changes to YEC revenues (Line N at Table 2) included as an offset to cost changes (when determining the ERA amount).

- Fish Lake changes are reflected in changes to YECL costs (Line S at Table 2) when determining the net impact on YECL of the ERA and whether a YECL Deferral Account Rider Charge (Rebate) is required due to YECL incurring unrecovered added costs (Lines T and U at Table 2).

TOPIC: **LNG**

REFERENCE: **YEC DCF-ERA filing, Attachment 1.1, page A1.1-4**

PREAMBLE:

UPDATE: The relevant diesel fuel prices, unit fuel efficiency and incremental O&M costs are updated in each YEC GRA.

QUESTION:

a) How will LNG costs be incorporated if the units are in service before a GRA test year?

ANSWER:

(a)

Please see response to YUB-YEC-1-26 (d) and (e). When the gas-fired generation units come into service, YEC will proceed to file for Board approval a forecast LNG fuel cost for use with the forecast diesel fuel cost, as well as the assumed LNG generation capability to displace LTA diesel generation. Quarterly and annual reporting to the Board as outlined at page A1.1-7 of YEC's January 31, 2014 filing will include any LNG related assumptions and/or determinations.

TOPIC: **ERA Calculations**

REFERENCE: **YEC DCF-ERA filing, Appendix 2, page 2-6**

PREAMBLE:

Yukon Energy would also now propose that the ERA calculations apply in all years, including years when wholesale changes do not move in the same direction as overall grid load changes.

QUESTION:

a) Please fully explain why this change is necessary.

ANSWER:

(a)

This change was made (along with other changes noted at page 2-6) in order to be consistent with past practice and in order to fully capture the impacts of any variances in wholesale sales.

The ERA determinations in the past reflected impacts of wholesale changes relative to approved forecasts when diesel was on the margin (i.e., when the Faro mine was operating), regardless of any other changes affecting YEC retail or industrial loads. When diesel was on the margin, this approach preserved the relationship between the wholesale rate (with ERA) and retail rates, providing consistent treatment to both utilities based on actual wholesales relative to the approved YEC forecast for wholesales. In this context, there is no basis (as originally proposed) now to link the ERA for charges to YECL only to situations where YEC load has also increased above forecast, or to limit ERA rebates to YECL only to situations where YEC load has also decreased below forecast.

The procedure for assessing impacts on expected diesel generation of wholesale load changes from forecast is set out in Table 2 of the January 31, 2014 YEC filing.

TOPIC: **DCF**

REFERENCE: **YECL DCF-ERA filing, page 2**

PREAMBLE:

The DCF was designed to apply narrowly based on the specific circumstances of the time.

QUESTION:

a) Do the circumstances as known then for the DCF exist today? Please explain.

b) Please provide YEC's interpretation/definition of a drought condition.

ANSWER:

(a)

The DCF was designed and approved in 1996 to provide for rate stability and smooth out material swings in rate impacts that may result from material changes in water availability on the WAF grid. It was designed to apply during periods when diesel was "on the margin" (defined as diesel being used to meet long-term firm energy requirements of the WAF system, not just periodic peaking requirements, assuming long term average hydro generation water conditions). In practice, in 1996 diesel was defined to be on the margin for the DCF when the Faro mine was operating (see response to YUB-YEC-1-1(a)).

Circumstances that lead to the need for a DCF historically once again exist today. In summary:

- As in the past, the Yukon has a predominantly hydro-based and isolated grid system; the only material changes since the mid-1990's is that the WAF system has been expanded by an interconnection with the Mayo Dawson System, and hydro capability has been expanded at Aishihik and at Mayo.

- As in the past, material changes in hydro availability on the grid due to water availability lead today to material changes in diesel generation requirements with material rate impacts for ratepayers (see response to YUB-YEC-1-14).

- As in the past, when grid hydro generation is not available to meet incremental load growth, additional load is met using more costly thermal generation (from the 1990's to date this would be met using diesel, after 2014 this is expected to be met on the Integrated Grid using LNG).

- In the mid-1990's, diesel was generally considered to be on the margin when the Faro mine was operating due to the material impact that this single load had on the system and on the requirement for firm diesel generation. There is no similar single magnitude load on the system today; however, ongoing non-industrial and industrial load growth (e.g., Minto mine) since 1998 has depleted the surplus hydro available after the closure of the Faro mine such that the Board has determined in Order 2013-01 that material diesel generation is required and included in rates for forecast 2012 and 2013 grid loads with 100% long-term average hydro generation (i.e., diesel is once again on the margin at long term average hydro generation).

Please also see response to AEY-YEC-1-10(a).

(b)

A drought condition is not a defined term for the purpose of the DCF. However, it is reasonable to consider that a drought condition would occur when there are low water inflows over a period of time that notably reduce the amount of available hydro generation. For example, the most extreme drought recorded at Aishihik was for 1998, when inflows were 36% of long-term average inflows for a 12 month period.

Looking at current grid loads and conditions, diesel generation higher than LTA will be required in years when hydro generation water conditions are less than the LTA.

- Attachment 1 to YUB-YEC-1-1(b and c) highlights the expected variability in diesel generation as assessed in a November 2012 filing based on variation in water conditions and different potential future grid load conditions.

- At a grid load of 461 GW.h as then forecast under the Base Case for 2016, with LTA diesel generation at 33.5 GW.h, a repeat of water conditions experienced from 1995 to 2000 (six years) would require diesel generation each year ranging from 56.9 GW.h to 122.5 GW.h.

- At the same grid load, diesel generation in excess of LTA (33.5 GW.h) would be required in five additional years out of the 28 water years then included in the YECSIM analysis.

Please also see response to AEY-YEC-1-10(a).