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Janet P. Kennedy
Vice President, Regulatory Affairs & Gas Supply

Via E-Mail and Courier

February 28, 2018

B.C. Utilities Commission
Suite 410 - 900 Howe Street
Vancouver, BC V6Z 2N3

File No.: 4.2.7 (2018)

Attention: Patrick Wruck
Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: Pacific Northern Gas (N.E.) Ltd.
Fort St. John/Dawson Creek and Tumbler Ridge Divisions
2018-2019 Revenue Requirements Applications – Amended Applications

Accompanying, please find Pacific Northern Gas (N.E.) Ltd.'s Amended 2018-2019 Revenue Requirements Applications for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions (Amended Applications). Printed copies of the Amended Applications will be distributed by courier on Friday, March 2, 2018, including ten copies to the Commission's office and one copy to each of the parties noted below who registered as interveners into this proceeding.

These Amended Applications generally include all of the Original Applications as well as all revisions arising from the normal evidentiary update and is considered a standalone document to replace the Original Application filed with the Commission on November 30, 2017.

Please direct any questions regarding these applications to my attention.

Yours truly,

J.P. Kennedy

cc. Leigha Worth (BCPIAC) – BCOAPO
James Wightman (BCPIAC) – BCOAPO

PACIFIC NORTHERN GAS (N.E.) LTD.

(Fort St. John / Dawson Creek Division)

AMENDED Application to the

British Columbia Utilities Commission

for Approval of

2018 and 2019 Revenue Requirements

February 28, 2018

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Tab Application

1 Formal Amended Application

PACIFIC NORTHERN GAS (N.E.) LTD. (PNG(NE)) natural gas rates and operations are regulated by the British Columbia Utilities Commission (Commission).

On November 30, 2017, PNG(NE) submitted to the Commission its 2018-2019 Revenue Requirements Application (Original Application), seeking, among other things, Commission approval to amend the rate schedules for its Fort St. John / Dawson Creek Division (FSJ/DC Division) effective January 1, 2018.

On December 19, 2017, the Commission issued Order G-193-17, approving the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Original Application, on an interim basis, effective January 1, 2018, with provision for the refund/recovery of any differences between the interim and permanent rates that are determined by the Commission following final disposition of this proceeding.

Commission Order G-193-17 also established a preliminary regulatory timetable (see Section 1.6.1) for this proceeding, including the scheduling for PNG(NE) to file an updated application on February 28, 2018.

This submission represents PNG(NE)'s amended 2018-2019 Revenue Requirements Application (Amended Application). This Amended Application generally includes all of the Original Application, as well as all revisions arising from the normal evidentiary update information, such as revised demand forecasts which take into consideration the effects of 2017 actual deliveries, updated cost forecasts, as well as the impact of 2017 actual operating results on rate-base items.

Information contained in this Amended Application that PNG(NE) has assessed to be a significant change or material new information in comparison to the Original Application have been highlighted in grey-shaded text to draw the reader's attention to the information.

The following narrative provides the submissions by PNG(NE) in support of the permanent rates applied for and other approvals sought in this Amended Application. A detailed list of the approvals sought in this Amended Application is set out in Section 1.5 – Amended Approvals Sought.

1.1 Background

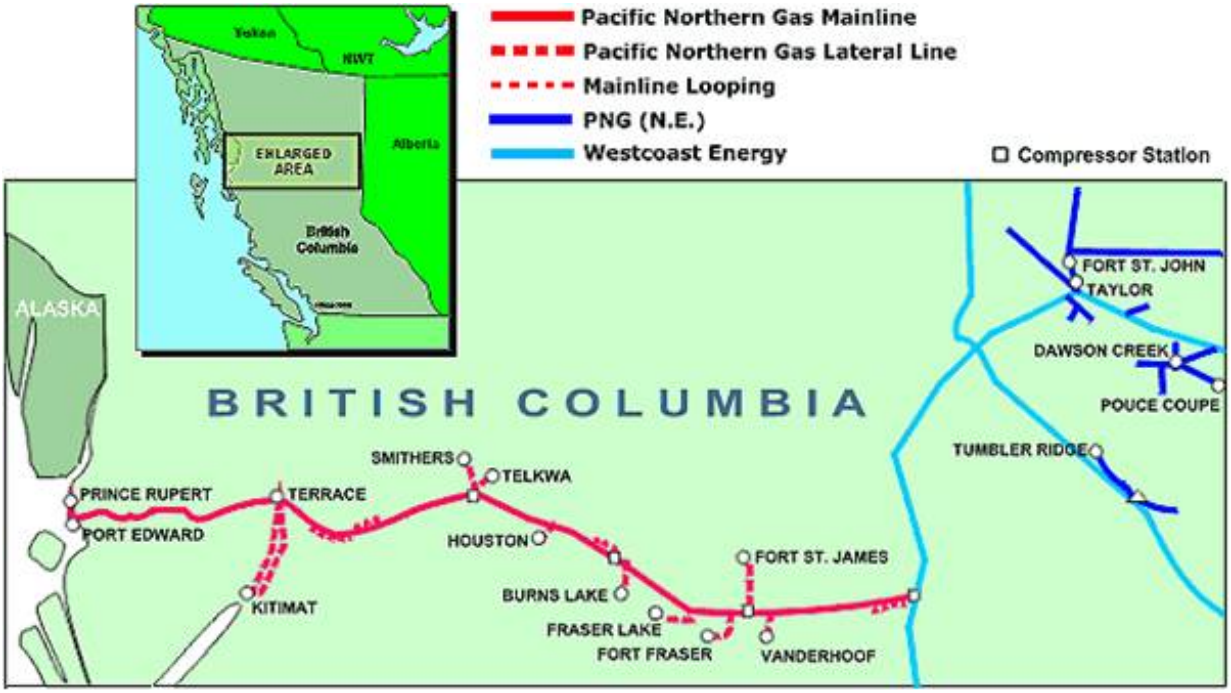
PNG(NE) is a wholly-owned subsidiary of Pacific Northern Gas Ltd. (PNG), which in turn is a wholly-owned subsidiary of AltaGas Utility Holdings (Pacific) Inc., which in turn is a wholly-owned subsidiary of AltaGas Ltd. (AltaGas).

PNG(NE) owns and operates natural gas distribution systems and a gas processing plant in northeastern British Columbia and provides service to approximately 21,400 natural gas customers in the communities of Fort St. John (FSJ), Dawson Creek (DC) and Tumbler Ridge (TR). PNG(NE) maintains separate rate schedules for both the FSJ/DC Division and the TR Division and submits standalone revenue requirements applications to the Commission for each of these divisions.

PNG also has a western division (PNG-West) that owns and operates a natural gas transmission and distribution system in west central British Columbia. The pipeline system commences at Summit Lake, just north of Prince George, and extends west to the deep water ports of Prince Rupert and Kitimat. PNG-West serves approximately 20,400 natural gas customers along this corridor. PNG-West also serves approximately 150 propane customers in the community of Granisle, B.C.

The PNG System Map, including PNG(NE) and PNG-West is illustrated in the figure below.

PNG System Map – PNG-West and PNG(NE)



1.2 Amended Application Overview

PNG(NE) has prepared this Amended Application for submission to the Commission in support of its request for approval of permanent rate changes for 2018 and 2019.

The Amended Application primarily reflects the following changes from the Original Application filed on November 30, 2017:

- The impacts of incorporating Actual 2017 figures into the financial model which will mainly result in changes to plant in service, deferred charges and demand forecasts;
- A decrease in pension and non-pension post-retirement benefits expenses primarily due to a change in the discount rate from 3.81% down to 3.6% as per a recently completed actuarial valuation; and
- The addition of capital expenditures for the replacement of the Dawson Creek Gate Station considered critical to ensure the station and related facilities are in compliance with safety and integrity related standards and regulations.

PNG(NE) is forecasting a revenue deficiency of approximately $0.816 million for Test Year 2018 compared to Decision 2017, and a revenue deficiency of approximately $0.842 million for Test Year 2019 compared to Test Year 2018. PNG(NE) is seeking approval to increase the delivery charge component of its customer rates in order to recover these amounts.

These results for Test Year 2018 and Test Year 2019 also reflect PNG(NE)'s proposal to implement a rate deferral mechanism in order to levelize the impact of the customer rate increases over the two-year period addressed in this Amended Application. Please see Section 1.3 – Proposed Rate Deferral Mechanism.

The following table summarizes the derivation of the Test Year 2018 and Test Year 2019 revenue deficiencies by comparing forecast Test Year 2018 and Test Year 2019 figures with the corresponding budgeted figures used to set delivery rates under the Commission-approved Decision 2017.

Table 1: Amended Summary of Revenue Deficiencies

Cost of Service Items ($000's)	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017
		$000's	%		$000's	%	
Operating, maintenance, administrative and general expenses	9,423	166	1.8%	9,257	342	3.7%	8,914
Transfers to capital operating, administrative and general	(690)	(186)	27.0%	(504)	168	(33.3)%	(672)
Other cost of service Items including property taxes, depreciation and amortization	3,358	231	6.9%	3,127	(223)	(7.1)%	3,351
Return components including return on equity, income taxes and debt costs.	5,329	444	8.3%	4,885	440	9.0%	4,444
Cost of Service Excluding Company Use Gas	17,419	655	3.9%	16,765	728	4.5%	16,037
Operating Margin Using Existing Year Rates	16,914	(149)		15,784	253		16,037
Test Year Revenue Deficiency (Sufficiency) Before Proposed Rate Deferral	505	505		981	981		
Impact of Proposed Rate Deferral	337	337		(165)	(165)		
Test Year Revenue Deficiency	842	842		816	816		

The forecast revenue deficiency for Test Year 2018 from Decision 2017 can be attributed mainly to the following factors:

An overall increase in operating and maintenance and administrative and general costs of $0.3 million, a 3.7% increase over Decision 2017, primarily due to inflationary increases as well as additional resources required for field operations to address engineering work, records management, digital mapping and a new geographical information system;

Lower transfers to capital of $0.2 million due to less capital projects forecast in PNG(NE) compared to PNG-West for 2018 thereby resulting in a lower allocation of overheads capitalized;

A margin decrease of $0.3 million mostly due to the continuing decreasing trend in use per account, particularly for residential customers;

Higher return on common equity component of $0.1 million due to the higher mid-year rate base due to increasing capital investments; and

Higher interest expense of $0.4 million reflecting the higher mid-year rate base as well the higher average effective interest rate primarily due to market conditions as reflected in the recent refinancing plan.

The adverse impacts of the above factors have been partially offset by:

Lower depreciation expense of $0.2 million due to the extension of the useful life of a number of utility assets as per the results of the recently completed depreciation study; and

A decrease of $0.2 million to reflect PNG(NE)'s proposal to create a new rate deferral account to levelize the impact of the combined forecast increases for Test Year 2018 and Test Year 2019 on customer rates over these two years.

The forecast revenue deficiency for Test Year 2019 from Test Year 2018 can be attributed mainly to the following factors:

Net higher operating and maintenance and administrative and general costs of $0.2 million, a 1.8% increase over Test Year 2019, primarily due to inflationary increases;

Higher depreciation expense of $0.2 million, higher return on equity of $0.2 million and higher interest expense of $0.2 million, all due to increasing capital investments in PNG(NE); and

$0.3 million related to PNG(NE)'s proposal to create a new rate deferral account to levelize the impact of the combined forecast increases for Test Year 2018 and Test Year 2019 on customer rates over these two years.

The adverse impacts of the above factors have been partially offset by:

Higher transfers to capital as a result of more capital projects in PNG(NE) compared to PNG-West forecast in 2019 thereby resulting in a higher allocation of corporate overheads capitalized; and

Higher margins of $0.1 million mainly due to a full year of deliveries to a new small industrial customer in Dawson Creek.

1.3 Proposed Rate Deferral Mechanism

For this two-year Amended Application, PNG(NE) is proposing that the full impact of the combined rate changes anticipated for Test Year 2018 and Test Year 2019 be levelized over the two-year period. This would be achieved by recording $165,000 of the Test Year 2018 anticipated revenue deficiency in Test Year 2019 in an interest bearing deferral account. As noted in this Amended Application, the calculated revenue deficiency would be $0.816 million for Test Year 2018 and $0.842 million for Test Year 2019, which would result in a residential rate increase of approximately 6.3% and 6.1%, respectively, on the delivery rate component of customer rates.

Without the proposed rate deferral mechanism, PNG(NE)'s calculations indicate a revenue deficiency of $0.515 million for Test Year 2018 and a revenue deficiency of $0.970 million for Test Year 2019, with a cumulative total revenue deficiency of $1.485 million for the two-year period. These results would necessitate a a residential delivery rate increase of approximately 7.5% in 2018 and a subsequent increase of approximately 3.7% in 2019. The primary reason for the large revenue deficiency in Test Year 2018 is mainly due to the continuing decline in the use per account, in particular for residential customers, and the impact of continued capital investment in the northeast region.

PNG(NE) is proposing this rate deferral mechanism in view of other factors that are also impacting customer rates effective January 1, 2018, including a reduction in the RSAM rate rider and a decrease in commodity rates. PNG(NE) acknowledges that changes in gas commodity rates and GCVA rate riders are addressed through a separate process, the Commission's quarterly review of gas supply costs. However, PNG(NE) is also cognizant that its customers prefer stable rates and reduced rate volatility. Therefore, with the reduction in both the RSAM rate rider and commodity costs effective January 1, 2018, PNG(NE) submits that creating the proposed rate deferral mechanism to alleviate the impact of the anticipated rate increase in Test Year 2018 is prudent and beneficial to customers as it provides rate stability by reducing rate volatility. PNG is seeking this rate deferral mechanism across all its divisions for both Test Year 2018 and Test Year 2019.

For this purpose, PNG(NE) therefore seeks Commission approval to create an interest bearing rate deferral account in 2018 to be fully amortized in 2019.

1.4 Permanent Rates Requested

As noted previously, on December 19, 2017, the Commission issued Order G-193-17, approving the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Original Application, on an interim basis, effective January 1, 2018. Approval of interim rates is the usual practice of the Commission in these circumstances and ensures that final rates determined by the Commission in this proceeding can be applied beginning January 1, 2018. If the Commission ultimately determines in this proceeding that a change to PNG(NE)'s rates is necessary, then any difference between the final approved rates and the interim rates would be refunded to or collected from customers, as applicable. Final approved delivery rates for Test Year 2019 would become effective as permanent rates on January 1, 2019.

Based on the identified revenue deficiencies for Test Year 2018 and Test Year 2019, PNG(NE) is applying to the Commission for approval of permanent delivery rate increases effective January 1, 2018 and January 1, 2019 from rates determined per Decision 2017. The tables that follow summarize the allocation of the amended Test Year 2018 and Test Year 2019 revenue deficiencies, and the proposed delivery rate changes arising from this allocation.

Table 2: Amended Summary of Proposed Delivery Rate Changes - January 1, 2018

Customer Classification	Allocation of 2018 Revenue Deficiency	FSJ				DC			
		Test Year 2018 Delivery Charge	Proposed Rate Change from Decision 2017 to 2018		Decision 2017 Delivery Charge	Test Year 2018 Delivery Charge	Proposed Rate Change from Decision 2017 to 2018		Decision 2017 Delivery Charge
	$	$/GJ	$/GJ	%	$/GJ	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	450,479	4.311	0.251	6.2%	4.060	4.113	0.251	6.5%	3.862
Commercial									
Small Commercial Firm (Rate 2)	227,998	3.394	0.167	5.2%	3.227	2.857	0.167	6.2%	2.690
Large Commercial Firm (Rate 3)	42,877	2.541	0.120	5.0%	2.421	1.993	0.120	6.4%	1.873
Commercial Transport (Rate 23)	10,819	2.696	0.147	5.8%	2.549	2.148	0.147	7.4%	2.001
Total Commercial	281,693								
Small Industrial Sales (Rate 4)	44,451	1.465	0.087	6.3%	1.378	1.733	0.087	5.3%	1.646
Industrial Transport									
Rate 6	22,751	1.6521	0.0940	6.0%	1.5581	n/a	n/a	n/a	n/a
Rate 7	n/a	n/a	n/a	n/a	n/a	0.2050	-	0.0%	0.2050
Rate 10	16,298	0.6688	0.0506	8.2%	0.6182	n/a	n/a	n/a	n/a
Total Industrial Transport	39,049								
TOTAL	815,673								

Source: Tab Schedules, Tab 6, Pages 1-6; 2016-2017 RRA Compliance Filing

Table 3: Amended Summary of Proposed Delivery Rate Changes - January 1, 2019

Customer Classification	Allocation of 2019 Revenue Deficiency	FSJ				DC			
		Test Year 2019 Delivery Charge	Proposed Rate Change from 2018 to 2019		Test Year 2018 Delivery Charge	Test Year 2019 Delivery Charge	Proposed Rate Change from 2018 to 2019		Test Year 2018 Delivery Charge
	$	$/GJ	$/GJ	%	$/GJ	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	461,143	4.567	0.257	6.0%	4.311	4.369	0.257	6.2%	4.113
Commercial									
Small Commercial Firm (Rate 2)	237,785	3.565	0.171	5.0%	3.394	3.028	0.171	6.0%	2.857
Large Commercial Firm (Rate 3)	43,917	2.665	0.123	4.9%	2.541	2.117	0.123	6.2%	1.993
Commercial Transport (Rate 23)	11,076	2.847	0.151	5.6%	2.696	2.299	0.151	7.0%	2.148
Total Commercial	292,777								
Small Industrial Sales (Rate 4)	45,709	1.554	0.089	6.1%	1.465	1.822	0.089	5.1%	1.733
Industrial Transport									
Rate 6	22,896	1.7487	0.0966	5.8%	1.6521	n/a	n/a	n/a	n/a
Rate 7	n/a	n/a	n/a	n/a	n/a	0.2050	-	0.0%	0.2050
Rate 10	19,843	0.7184	0.0496	7.4%	0.6688	n/a	n/a	n/a	n/a
Total Industrial Transport	42,739								
TOTAL	842,368								

Source: Tab Schedules, Tab 6, Pages 21-26

For customers in the Fort St. John area, the average delivery rate increase (excluding Company use gas) for Test Year 2018 is estimated to be approximately $27 per year for a typical residential customer consuming 107.6 GJ per year. This represents an increase of 6.2% compared to Decision 2017 delivery rates. The Test Year 2019 average delivery rate increase over Test Year 2018 for a residential customer consuming 106.6 GJ per year is estimated to be approximately $27 per year representing a 6.0% increase. Similarly, for Test Year 2018, an average small commercial customer consuming 495.8 gigajoules per year will pay approximately $83 per year more for gas delivery service. This corresponds to an increase of 5.2% compared to Decision 2017 delivery rates. For Test Year 2019, the average delivery rate increase for a small commercial customer consuming 500.3 GJ per year is estimated to be $86 which represents a 5.0% increase over 2018.

For customers in the Dawson Creek area, the average delivery rate increase (excluding Company use gas) for Test Year 2018 is estimated to be approximately $25 per year for a typical residential customer consuming 97.5 GJ per year. This represents an increase of 6.5% compared to Decision 2017 delivery rates. The Test Year 2019 average delivery rate increase over 2018 for a residential customer consuming 96.3 GJ per year is estimated to be approximately $25 per year representing a 6.2% increase. Similarly, for Test Year 2018, an average small commercial customer consuming 555.8 GJ per year will pay approximately $93 per year more for gas delivery service. This corresponds to an increase of 6.2% compared to Decision 2017 delivery rates. For Test Year 2019, the average delivery rate increase for a small commercial customer consuming 566.0 GJ per year is estimated to be $97 which represents a 6.0% increase over 2018.

As noted, the amended cost of service forecast presented in this Amended Application has changed from that presented in the Original Application. The tables that follow summarize the changes to the allocation of the computed revenue deficiency and resultant rate impacts for each of the test years, including the impact of changes on the interim rates approved for Test Year 2018 effective January 1, 2018.

Table 4: Summary of Proposed Delivery Rate Changes - Amended vs Original - 2018

Customer Classification	Test Year 2018								
	Update			Change			Original		
	Allocation of Revenue	FSJ Delivery Charge	DC Delivery Charge	Allocation of Revenue	FSJ Delivery Charge	DC Delivery Charge	Allocation of Revenue	FSJ Delivery Charge	DC Delivery Charge
	$	$/GJ	$/GJ	$	$/GJ	$/GJ	$	$/GJ	$/GJ
Residential (Rate 1)	450,479	4.311	4.113	(167,171)	(0.108)	(0.108)	617,650	4.419	4.221
Commercial									
Small Commercial Firm (Rate 2)	227,998	3.394	2.857	(90,499)	(0.071)	(0.071)	318,497	3.465	2.928
Large Commercial Firm (Rate 3)	42,877	2.541	1.993	(15,375)	(0.052)	(0.052)	58,252	2.593	2.045
Commercial Transport (Rate 23)	10,819	2.696	2.148	(3,662)	(0.064)	(0.064)	14,481	2.760	2.212
Bulk CNG Service (Rate 30)	0	n/a	0.123	0	n/a	n/a	0	n/a	0.175
Total Commercial	281,693			(109,537)			391,230		
Small Industrial Sales (Rate 4)	44,451	1.465	1.733	(17,265)	(0.037)	(0.037)	61,716	1.502	1.770
Industrial Transport									
Rate 5	0	n/a	n/a	0	n/a	n/a	0	n/a	n/a
Rate 6	22,751	1.6521	n/a	(13,219)	(0.0392)	n/a	35,970	1.6913	n/a
Rate 7	n/a	n/a	0.2050	n/a	n/a	n/a	n/a	n/a	0.2050
Rate 9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Rate 10	16,298	0.6688	n/a	(17,826)	(0.0275)	n/a	34,124	0.6963	n/a
Rate 11	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Rate 12	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a
Total Industrial Transport	39,049			(31,045)			70,094		
TOTAL	815,673			(325,017)			1,140,690		

1 Table 5: Summary of Proposed Delivery Rate Changes - Amended vs Original - 2019

Customer Classification	Test Year 2019								
	Update			Change			Original		
	Allocation of Revenue	FSJ Delivery Charge	DC Delivery Charge	Allocation of Revenue	FSJ Delivery Charge	DC Delivery Charge	Allocation of Revenue	FSJ Delivery Charge	DC Delivery Charge
	$	$/GJ	$/GJ	$	$/GJ	$/GJ	$	$/GJ	$/GJ
Residential (Rate 1)	461,143	4.567	4.369	(164,241)	(0.218)	(0.218)	625,384	4.785	4.587
Commercial									
Small Commercial Firm (Rate 2)	237,785	3.565	3.028	(90,741)	(0.143)	(0.143)	328,526	3.708	3.171
Large Commercial Firm (Rate 3)	43,917	2.665	2.117	(15,483)	(0.103)	(0.103)	59,400	2.768	2.220
Commercial Transport (Rate 23)	11,076	2.847	2.299	(3,684)	(0.129)	(0.129)	14,760	2.976	2.428
Bulk CNG Service (Rate 30)	0	n/a	-	0	n/a	n/a	0	n/a	-
Total Commercial	292,777			(109,909)			402,685		
Small Industrial Sales (Rate 4)	45,709	1.554	1.822	(17,280)	(0.074)	(0.074)	62,989	1.628	1.896
Industrial Transport									
Rate 5	0	n/a	n/a	0	n/a	n/a	0	n/a	n/a
Rate 6	22,896	1.7487	n/a	(13,808)	(0.0786)	n/a	36,704	1.8273	n/a
Rate 7	n/a	n/a	0.2050	n/a	n/a	-	n/a	n/a	0.2050
Rate 9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Rate 10	19,843	0.7184	n/a	(17,473)	(0.0564)	n/a	37,316	0.7748	n/a
Rate 11	0	n/a	n/a	0	n/a	n/a	0	n/a	n/a
Rate 12	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a
Total Industrial Transport	42,739			(31,281)			74,021		
TOTAL	842,368			(322,711)			1,165,080		

1.5 Amended Approvals Sought

In this Amended Application, PNG(NE) is seeking an Order of the Commission granting the approvals as described below.

1) Approval, effective January 1, 2018, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the tables entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2018" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated into the Amended Application and to adjustments and undertakings identified through the regulatory review process.

2) Approval, effective January 1, 2019, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the tables entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2019" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated into the Amended Application and to adjustments and undertakings identified through the regulatory review process.

3) Approval of PNG(NE)'s proposal to create a short term interest bearing rate deferral account in 2018 to levelize the impact of the combined net revenue deficiencies for 2018 and 2019 to be fully amortized in 2019.

4) Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2018 and 2019, pursuant to sections 58 to 61 of the Utilities Commission Act, as detailed in Section 2.9 – Amortization, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, including:

    a) Further to Commission Order G-105-17, approval pursuant to sections 58 to 61 of the *Utilities Commission Act*, to move the 2016 unaccounted for gas (UAF) losses above 1.5 percent from the temporary UAF deferral account to the UAF volume deferral account and to be recovered from customers via the Company Use rider, PNG(NE)'s historic mechanism for recovering/refunding UAF losses/gains.

    b) Approval to eliminate the Legacy Deferred Income Taxes deferral account following the final amortization of the remaining balance in Test Year 2018;

c) Approval to eliminate the NPPRB Regulatory Asset Deferral account following the final amortization of the remaining balance in Test Year 2018;

5) Approval of the depreciation expense determined in this Amended Application based on the findings of a new depreciation study as set forth in set forth in Section 2.9 – Depreciation of this Amended Application.

6) Approval to continue the unaccounted for gas volume deferral account to record the difference between forecast and actual unaccounted for gas (UAF) volumes in Test Year 2018 and 2019 based on using a 1.0 percent of deliveries UAF loss factor for 2018 and 2019 and requiring PNG(NE) to apply for Commission approval to record actual 2018 or 2019 UAF losses above 1.5 percent in the deferral account.

A draft Commission Order for the approvals sought has been set out as Appendix A to this Amended Application.

All of which is respectfully submitted.

DATED at Vancouver, British Columbia this 28th day of February 2018.

PACIFIC NORTHERN GAS (N.E.) LTD.

Leigh Ann Shoji-Lee
President

1.6 Regulatory Process

1.6.1 Regulatory Process and Regulatory Timetable

In recent years, PNG(NE)'s revenue requirements applications have been subject to both written hearing processes and the negotiated settlement process. In the Original Application, PNG(NE) expressed its view that, consistent with the proceeding on PNG(NE)'s 2016-2017 revenue requirements application, a written hearing process with provision for two rounds of information requests would allow for an effective and efficient review of the instant Amended Application.

Order G-193-17 established a preliminary timetable with provision for comments by Interveners and PNG(NE) on further process. Based on feedback provided, on February 2, 2018 the Commission issued Order G-31-18 confirming a written hearing process under the following regulatory timetable and with the remaining actions for this proceeding.

Table 6: Regulatory Timetable

ACTION	DATE
PNG(NE) Submits Original Application	November 30, 2017
Interim Rates Established	January 1, 2018
Intervener and Interested Party Registration	January 12 2018
Intervener Comments on Further Process	January 24, 2018
PNG(NE) Reply Comments on Further Process	January 31, 2018
PNG(NE) Submits Amended Application	February 28, 2018
Commission Information Request No. 1 to PNG(NE)	April 5, 2018
Intervener Information Request No. 1 to PNG(NE)	April 12, 2018
PNG(NE) Responses to Information Requests No. 1	April 26, 2018
Commission and Intervener Information Request No. 2 to PNG(NE)	May 10, 2018
PNG(NE) Responses to Information Requests No. 2	May 25, 2018
PNG(NE) Written Final Argument	June 1, 2018
Intervener Written Final Argument	June 12, 2018
PNG(NE) Written Reply Argument	June 19, 2018

1.6.2 Scope of Regulatory Review

In consideration of PNG(NE)'s recent experience with its revenue requirements applications, the following scope limitation is proposed to increase the efficiency of the proceeding around this Amended Application.

Cost of Gas

PNG(NE) is not applying for Commission approval of the indicative gas supply cost recovery rates in this Amended Application. PNG(NE)'s gas supply costs are reviewed by the Commission under a separate regulatory review process, the quarterly review and approval of gas commodity costs. Gas costs presented in this Amended Application are indicative only and are consistent with those applied for in PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report and approved under Commission Order G-187-17. Consequently, PNG(NE) submits that it is not appropriate to review gas supply costs in the context of the review of PNG(NE)'s revenue requirements applications as to do so is an unnecessary duplication of effort on the part of all parties to this regulatory proceeding.

PNG(NE) notes that, despite the foregoing, reference is made in this Amended Application to the 2017 Fourth Quarter Gas Supply Cost Report in addressing its proposal for a rate deferral mechanism for Test Year 2018 and Test Year 2019 as per Section 1.3 – Proposed Rate Deferral Mechanism.

1.6.3 Principal Contact

All notices and other communications in connection with this Amended Application should be directed to:

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Vice President, Regulatory Affairs and Gas Supply
Pacific Northern Gas (N.E.) Ltd.
#2550 - 1066 West Hastings Street
Vancouver, British Columbia V6E 3X2
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1.7 Organization of the Amended Application

This Amended Application provides detailed information in support of PNG(NE)'s revenue requirements and the underlying proposed customer rates for Test Year 2018 and Test Year 2019. This Amended Application is comprised of two principle components:

Tab Application

Tab Application provides PNG(NE)'s complete Amended Application, including relevant narrative and schedules providing background and context for the current years' submission, including the following sections:

Tab 1 – Formal Amended Application – presents background information and details PNG(NE)'s formal Amended Application for approval of its 2018 and 2019 revenue requirements.

Tab 2 – Amended Forecast – includes narrative and schedules in support of forecast demand and forecast costs underlying the revenue requirements and the resultant rates.

Tab 3 – Other Matters – includes discussion on a variety of other issues relevant to the current application, including accounting policies, service quality metrics and other matters, as applicable.

Tab 4 – Appendices – includes reference and supporting material, including a draft Commission order, financial benchmark support and supporting reports and studies.

Tab Schedules

Tab Schedules provides the detailed financial information in support of the proposed permanent rates effective January 1, 2018, the permanent rates effective January 1, 2017, and the underlying revenue requirements as presented in this Amended Application, including the following schedules:

Tab 1 – Utility Income & Return

Tab 2 – Utility Rate Base

Tab 3 – Income Taxes

Tab 4 – Common Equity

Tab 5 – Return on Capital

Tab 6 – Rates

These financial regulatory schedules compare the Test Year 2018 and Test Year 2019 figures to the Decision 2017 figures. In some instances there are comparisons to Decision 2016 figures. The Decision 2016 and Decision 2017 amounts are those as determined under PNG(NE)'s 2016-2017 revenue requirements application and as approved by Commission Order G-132-16. Further, references to Commission directives under Order G-132-16 have been noted as Decision 2016-2017 in this Amended Application. For comparative purposes, PNG(NE) has provided the actual cost of service figures for the years 2013, 2014, 2015, 2016 and 2017.

Additional Information

PNG(NE) notes that it has previously submitted electronic PDF copies of the following documents as supplemental information to the Original Application to provide background and for the reference of participants to this proceeding:

- Organizational Chart (November 2017)
- Uniform Code of Accounts
- 2016 Annual Report to the BCUC
- 2012 Shared Services Study
- 2010 Overhead Capitalization Study
- 2009 Depreciation Study

Further, PNG(NE) notes that this Amended Application and the noted supplemental information have been made available on PNG's external website at: http://www.png.ca/regulatory-applications/.

2 Amended Forecast

This section sets out PNG(NE)'s forecast gas deliveries, margins and costs for 2018 and 2019. The forecast 2018 calendar year figures are identified in this Amended Application under the heading "Test Year 2018", and the forecast 2019 calendar year figures are identified in this Amended Application under the heading "Test Year 2019". Forecast margins are computed using currently approved rates and forecast 2018 and 2019 gas deliveries. The extent to which forecast revenues vary from forecast costs determines whether PNG(NE) is seeking Commission approval for rate increases or decreases.

To provide context for forecast 2018 and 2019 figures, the analysis that follows provides a comparison of forecast amounts for 2018 to amounts approved for 2017 as per the review of PNG(NE)'s 2016-2017 revenue requirements application (Decision 2017) as well as to 2017 Actual results, and a comparison of amounts forecast for 2019 to amounts forecast for 2018. Historical comparisons are also made to amounts approved for 2016 as per PNG(NE) 2016-2017 revenue requirements application (Decision 2016).

Tables are provided on the pages that follow, the first one comparing the Test Year 2018 cost of service described in this Amended Application to the Decision 2017 cost of service approved by the Commission. PNG(NE) is forecasting a revenue deficiency of approximately $0.816 million for Test Year 2018, comprised of a $0.728 million increase in the cost of service, a $0.253 million decrease in the forecast margin, with both of these effects offset in part by a credit of $0.165 million to reflect the impact of PNG(NE)'s rate deferral proposal to levelize the impact of rate increases for customers over the two-year period of this Amended Application.

The second table compares the Test Year 2019 cost of service to the Test Year 2018 cost of service, both as described in this Amended Application. PNG(NE) is forecasting a revenue deficiency of approximately $0.842 million for Test Year 2019, comprised of a $0.655 million increase in the cost of service, offset in part by a $0.149 million increase in the forecast margin, and the $0.337 million impact of PNG(NE)'s rate deferral proposal to levelize the impact of rate increases for customers over the two-year period of this Amended Application.

The discussion that follows addresses changes in forecast volumes and costs that underlie the forecast revenue deficiencies for Test Year 2018 and Test Year 2019, as well as the factors that have contributed to these changes.

Table 7: Cost of Service Comparison – Test Year 2018 vs Decision 2017

EXPENSES ($000's)	Test Year 2018	Decision 2017	Difference Total	Difference Subtotal
Operating				
Labour	2,280	2,192	88	
Other	3,651	3,360	291	
Sub-total	5,931	5,552	379	
Maintenance				
Labour	129	126	4	
Other	292	266	26	
Sub-total	421	392	29	
Administrative and General				
Total Company Benefits	774	781	(7)	
Other	2,131	2,190	(59)	
Sub-total	2,904	2,971	(66)	
Total (O, M, A & G) Excluding Co. Use	9,257	8,914	342	342
Transfers to Capital Operating	(230)	(181)	(49)	
Transfers to Capital Admin. & Gen.	(274)	(491)	217	
Property Taxes	1,305	1,373	(68)	
Depreciation	1,856	2,023	(167)	
Amortization	240	221	19	
Other Income	(274)	(267)	(7)	(55)
Total Expenses Excluding Co. Use Gas Cost	11,880	11,593	287	287
Income Taxes	436	468	(32)	
Return on Common Equity	2,698	2,618	80	
Short Term Debt	180	144	36	
Long Term Debt	1,572	1,216	356	439
Total Cost of Service Excluding Co. Use Gas Cost	16,765	16,039	726	726
Company Use Gas	141	189		
Total Cost of Service Including Co. Use Gas Cost	16,906	16,228		
2017 to 2018 Cost of Service Increase / (Decrease)			726	
2017 to 2018 Margin (Increase) / Decrease			255	
2018 Rate Deferral Increase / (Decrease)			(165)	
2018 Revenue Deficiency / (Sufficiency)			816	

Table 8: Cost of Service Comparison – Test Year 2019 vs Test Year 2018

EXPENSES ($000's)	Test Year 2019	Test Year 2018	Difference Total	Difference Subtotal
Operating				
Labour	2,329	2,280	49	
Other	3,708	3,651	56	
Sub-total	6,036	5,931	105	
Maintenance				
Labour	132	129	3	
Other	297	292	5	
Sub-total	429	421	8	
Administrative and General				
Total Company Benefits	769	774	(5)	
Other	2,188	2,131	57	
Sub-total	2,957	2,904	53	
Total (O, M, A & G) Excluding Co. Use	9,423	9,257	166	166
Transfers to Capital Operating	(284)	(230)	(54)	
Transfers to Capital Admin. & Gen.	(406)	(274)	(132)	
Property Taxes	1,371	1,305	66	
Depreciation	2,032	1,856	176	
Amortization	229	240	(11)	
Other Income	(274)	(274)	0	45
Total Expenses Excluding Co. Use Gas Cost	12,091	11,880	210	210
Income Taxes	464	436	28	
Return on Common Equity	2,923	2,698	226	
Short Term Debt	182	180	2	
Long Term Debt	1,760	1,572	188	444
Total Cost of Service Excluding Co. Use Gas Cost	17,419	16,765	655	655
Company Use Gas	176	141		
Total Cost of Service Including Co. Use Gas Cost	17,596	16,906		

2018 to 2019 Cost of Service Increase / (Decrease)	655
2018 to 2019 Margin (Increase) / Decrease	(149)
2018 Rate Deferral Increase / (Decrease)	165
2019 Rate Deferral Increase / (Decrease)	172
2019 Revenue Deficiency / (Sufficiency)	842

For illustrative purposes, PNG(NE) also provides the table that follows to compare the Test Year 2018 cost of service elements as per the Original Application to those per this Amended Application. A discussion of significant variances follows the table.

Table 9: Cost of Service Comparison – Test Year 2018 Amended vs Original

EXPENSES ($OOO's)	Amended Test Year 2018	Original Test Year 2018	Difference Total	Difference Subtotal
Operating				
Labour	2,280	2,280	0	
Other	3,651	3,674	(23)	
Sub-total	5,931	5,954	(23)	
Maintenance				
Labour	129	129	0	
Other	292	292	0	
Sub-total	421	421	0	
Administrative and General				
Total Company Benefits	774	869	(95)	
Other	2,131	2,151	(20)	
Sub-total	2,904	3,020	(115)	
Total (O, M, A & G) Excluding Company Use Gas Cost	9,257	9,395	(138)	(138)
Transfers to Capital Operating	(230)	(246)	16	
Transfers to Capital - Administrative & General	(274)	(339)	65	
Property Taxes	1,305	1,396	(91)	
Depreciation	1,856	1,877	(21)	
Amortization	240	251	(11)	
Other Income	(274)	(274)	0	(42)
Total Expenses Excluding Company Use Gas Cost	11,880	12,061	(181)	(181)
Income Taxes	436	381	55	
Return on Common Equity	2,698	2,746	(48)	
Short Term Debt	180	181	(1)	
Long Term Debt	1,572	1,658	(86)	(80)
Total Cost of Service Excluding Company Use Gas Cost	16,765	17,026	(261)	(261)
Company Use Gas Cost	141	144	(3)	
Total Cost of Service Including Company Use Gas Cost	16,906	17,170	(264)	
2017 to 2018 Cost of Service Increase / (Decrease)	726	987	(261)	
2017 to 2018 Margin (Increase) / Decrease	255	499	(244)	
2018 Rate Deferral Increase / (Decrease)	(165)	(345)	180	
2018 Revenue Deficiency / (Sufficiency)	816	1,141	(325)	

The Amended Application cost of service figures for Test Year 2018 primarily reflect the impacts of incorporating Actual 2017 results into the financial model, as well as the following noted changes:

Operating Expenses

The decrease reflects the lower shared services allocation primarily due to lower benefits loading as a result of the lower pension and non-pension post retirement expenses.

Administrative & General Expenses

The decrease primarily reflects the lower forecast pension and non-pension post-retirement benefits due to a decrease in the discount rate from 3.81% in the Original Application to 3.60% in the Amended Application, as well as the recognition of actuarial gains in the plans in 2017 impacting lower pension obligations and resultant pension expense for 2018. This also impacts the lower shared services allocation due to the lower benefits loading.

Transfers to Capital (Capitalized Overhead)

Change mainly reflects the lower benefits loading for Test Year 2018.

Property Taxes

The decrease reflects the updated forecast taking into account the actual property taxes paid in 2017.

Depreciation

The lower depreciation reflects the lower than originally forecast 2017 capital additions.

Amortization

The lower amortization of deferred charges reflects the lower than originally forecast additions in 2017.

Income Taxes

The increase mainly reflects a correction to the calculation of CCA.

Return on Equity

The lower return reflects the lower mid-year rate base due to lower capital investments than originally forecast under Decision 2016 and 2017.

Long Term Debt

Increase reflects lower debt rates and lower forecast mid-year rate base.

Forecast Margin

Higher forecast margin is primarily due to a higher forecast use per account for core customers and updated forecast deliveries for commercial and industrial customers, both amendments based on incorporating 2017 actual volumes into the forecasts.

For illustrative purposes, PNG(NE) provides the table that follows to compare the Test Year 2019 cost of service elements as per the Original Application to those per this Amended Application. A discussion of significant variances follows the table.

Table 10: Cost of Service Comparison – Test Year 2019 Amended vs Original

EXPENSES ($OOO's)	Amended Test Year 2019	Original Test Year 2019	Difference Total	Difference Subtotal
Operating				
Labour	2,329	2,329	0	
Other	3,708	3,734	(26)	
Sub-total	6,036	6,062	(26)	
Maintenance				
Labour	132	132	0	
Other	297	297	0	
Sub-total	429	429	0	
Administrative and General				
Total Company Benefits	769	889	(120)	
Other	2,188	2,214	(26)	
Sub-total	2,957	3,103	(146)	
Total (O, M, A & G) Excluding Company Use Gas Cost	9,423	9,595	(172)	(172)
Transfers to Capital Operating	(284)	(282)	(2)	
Transfers to Capital - Administrative & General	(406)	(476)	69	
Property Taxes	1,371	1,420	(49)	
Depreciation	2,032	2,022	10	
Amortization	229	227	1	
Other Income	(274)	(274)	0	29
Total Expenses Excluding Company Use Gas Cost	12,091	12,234	(143)	(143)
Income Taxes	464	472	(8)	
Return on Common Equity	2,923	2,934	(11)	
Short Term Debt	182	175	7	
Long Term Debt	1,760	1,709	51	40
Total Cost of Service Excluding Company Use Gas Cost	17,419	17,523	(103)	(103)
Company Use Gas Cost	176	176	0	
Total Cost of Service Including Company Use Gas Cost	17,596	17,698	(103)	
2018 to 2019 Cost of Service Increase / (Decrease)	655	497	158	
2018 to 2019 Margin (Increase) / Decrease	(149)	(36)	(113)	
2018 Rate Deferral Increase / (Decrease)	165	345	(180)	
2019 Rate Deferral Increase / (Decrease)	172	359	(187)	
2019 Revenue Deficiency / (Sufficiency)	842	1,165	(323)	

The Amended Application cost of service figures for Test Year 2019 primarily reflect the impacts of incorporating Actual 2017 results into the financial model, as well as the following noted changes:

Operating Expenses

The decrease reflects the lower shared services allocation primarily due to lower benefits loading as a result of the lower pension and non-pension post retirement expenses.

Administrative & General Expenses

The decrease primarily reflects the lower forecast pension and non-pension post-retirement benefits due to a decrease in the discount rate from 3.81% in the Original Application to 3.60% in the Amended Application, as well as the recognition of actuarial gains in the plans in 2017 impacting lower pension obligations and resultant pension expense for 2019. This also impacts the lower shared services allocation due to the lower benefits loading.

Transfers to Capital (Capitalized Overhead)

Change mainly reflects the lower benefits loading for Test Year 2018.

Property Taxes

The decrease reflects the updated forecast taking into account the actual property taxes paid in 2017.

Long Term Debt

The increase reflects a slightly higher interest rate based on the latest consensus forecast of 3-month treasury bill rates for 2019 from Econolink's January 2018 report, adjusted to a 3-month Bankers' Acceptance forecast.

Forecast Margin

Higher forecast margin is primarily due to a higher forecast use per account for core customers and updated forecast deliveries for commercial and industrial customers, both amendments based on incorporating 2017 actual volumes into the forecasts.

2.1 Demand Forecast, Revenue and Margin

The Test Year 2018 and Test Year 2019 forecast of gas deliveries determine the projected margin PNG(NE) will receive from its customers during 2018 and 2019 to recover the cost of serving those customers. PNG(NE)'s methodology for forecasting customer demand, including forecasts of Residential and Small Commercial Use per Account (UPA), is consistent with that applied in prior years.

The forecast gas delivery volumes and margin for Test Year 2018 and Test Year 2019 are summarized and compared to the Decision 2017 forecast amounts in the table below. Reductions in Test Year 2018 and Test Year 2019 amounts from Decision 2017 are indicated by figures in brackets. A discussion of significant variances follows.

Table 11: Forecast Gas Deliveries

Customer Classification	Test Year 2019 Deliveries	2019 to 2018 Change in Forecast		Test Year 2018 Deliveries	2018 to Decision 2017 Change in Forecast		Decision 2017 Deliveries	Actual 2017 Deliveries	Actual 2016 Deliveries	Actual 2015 Deliveries	Actual 2014 Deliveries	Actual 2013 Deliveries
	Deliveries	Deliveries	Margin	Deliveries	Deliveries	Margin	Deliveries	Deliveries	Deliveries	Deliveries	Deliveries	Deliveries
	GJ	GJ	$	GJ	GJ	$	GJ	GJ	GJ	GJ	GJ	GJ
Residential	1,796,601	(1,618)	8,800	1,798,219	(107,969)	(446,700)	1,906,188	1,782,446	1,484,039	1,616,961	1,893,878	1,735,123
Commercial												
Small Commercial Firm (Rate 2)	1,391,298	27,536	87,500	1,363,762	6,403	(8,800)	1,357,359	1,334,735	1,139,705	1,183,845	1,327,875	1,209,982
Large Commercial Firm (Rate 3)	355,900	-	100	355,900	(23,300)	(52,200)	379,200	321,130	307,510	304,467	342,428	318,107
Commercial Transport (Rate 23)	73,350	-	-	73,350	(9,550)	(14,900)	82,900	75,806	76,229	62,935	71,248	80,976
Total Commercial	1,820,548	27,536	87,600	1,793,012	(26,447)	(75,900)	1,819,459	1,731,671	1,523,444	1,551,247	1,741,551	1,609,065
Small Industrial Sales (Rate 4)	512,950	1,430	2,600	511,520	110,870	156,400	400,650	470,994	401,939	387,137	240,801	232,596
Industrial Transport												
Rate 5	-	-	-	-	-	-	-	-	-	216,413	300,967	33,806
Rate 6	237,000	(5,000)	(8,200)	242,000	24,060	37,400	217,940	255,341	208,618	346,385	424,324	450,879
Rate 7	980,025	-	-	980,025	-	-	980,025	101,633	404	-	-	-
Rate 9	-	-	-	-	-	-	-	-	-	-	18,791	20,299
Rate 10	400,170	77,960	58,400	322,210	130,210	74,200	192,000	170,846	204,264	190,965	207,253	256,986
Rate 11	-	-	-		-	-	-	-	11,193	50,122	49,852	92,390
Rate 12	-	-	-	-	-	-	-	-	-	-	-	-
Total Industrial Transport	1,617,195	72,960	50,200	1,544,235	154,270	111,600	1,389,965	527,820	424,479	803,885	1,001,187	854,360
Total	5,747,294	100,308	149,200	5,646,986	130,724	(254,600)	5,516,262	4,512,931	3,833,901	4,359,230	4,877,417	4,431,144

Source: Tab Financials, Tab 6, Page 9 and 30; Decision 2016-2017 RRA Compliance Filing

2.1.1 Residential Deliveries and Margin

PNG(NE) has updated its original customer count and UPAs for the test years under consideration. The following table summarizes changes to the residential customer forecast.

Table 12: Forecast Residential Customer Count and UPA

	Forecast			Actual									
Residential Customers - FSJ	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	11,192	11,057	11,068	10,962	10,887	10,625	10,270	9,996	9,780	9,579	9,440	9,238	9,110
Normalized Use per Account (GJ)	106.6	107.6	112.2	109.0	107.3	113.9	112.7	115.2	111.2	108.7	109.5	116.3	115.9

	Forecast			Actual									
Residential Customers - DC	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	6,397	6,352	6,517	6,312	6,274	6,250	6,103	5,956	5,839	5,724	5,596	5,386	5,307
Normalized Use per Account (GJ)	96.3	97.5	97.4	100.7	91.2	99.1	103.8	103.3	103.7	105.4	106.4	110.9	111.2

2.1.2 Small Commercial Deliveries and Margin

PNG(NE) has updated its original customer count and UPAs for the test years under consideration. The following table summarizes changes to the small commercial customer forecast.

Table 13: Forecast Small Commercial Customer Count and UPA

	Forecast			Actual									
Small Commercial Customers - FSJ	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	1,752	1,744	1,761	1,739	1,735	1,707	1,681	1,634	1,617	1,587	1,557	1,544	1,555
Normalized Use per Account (GJ)	500.3	495.8	515.3	499.4	524.2	517.9	486.3	492.1	498.3	461.2	466.5	514.9	522.4

	Forecast			Actual									
Small Commercial Customers - DC	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	915	913	902	907	905	892	876	862	844	836	816	793	782
Normalized Use per Account (GJ)	566.0	555.8	502.5	550.9	528.0	510.1	496.2	484.9	518.5	531.4	505.3	560.7	587.4

2.1.3 Other Customer Classes

Table 14: Forecast Other Customer Count

	Forecast			Actual									
Other Customer Classes - FSJ	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Large Commercial Sales	8	8	9	8	9	12	12	16	15	17	18	17	19
Commercial Transport	14	14	11	14	14	11	6	17	15	13	14	11	-
Small Industrial Sales	7	7	7	6	7	7	7	8	9	8	5	5	5
Small Industrial Transport	14	14	14	16	14	16	16	16	17	18	18	19	20

	Forecast			Actual									
Other Customer Classes - DC	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Large Commercial Sales	16	16	14	13	14	13	16	18	15	13	15	16	17
Commercial Transport	7	7	9	7	7	9	7	7	7	7	9	7	-
Small Industrial Sales	3	3	2	4	4	4	4	4	5	5	5	4	4
Small Industrial Transport	1	1	1	1	1	-	1	1	n/a	n/a	n/a	n/a	n/a

2.1.3.1 Large Commercial Deliveries and Margin

The large commercial sales forecasts in 2018 are approximately 23,300 GJ lower than Decision 2017 resulting in a margin decrease of approximately $52,000. The forecast deliveries are based on discussions with customers and a review of their historical usage. The forecast decrease is partly due to the hospital in Fort St. John using less gas compared to their historical usage as a result of milder winters and ongoing adjustments to their facilities to meet contractual energy efficiency targets. In addition, a CNG solutions company operating in Dawson Creek that was supplying CNG to drilling rigs and frack spreads has been acquired by a competitor that did not require a CNG station in the Dawson Creek service area and subsequently shut the facility down. Other minor volume changes include adjustments for reclassification of customers due to movement to Small Commercial Sales and from Commercial Transport.

Forecast volume requirements to the Commercial Transportation class in Fort St. John and Dawson Creek are approximately 9,600 GJ lower than Decision 2017 primarily due to a reclass of customers to Small Commercial and Large Commercial sales resulting in a margin decrease of approximately $15,000. PNG(NE) is not aware of any changes affecting deliveries for 2019.

2.1.3.2 Small Industrial Deliveries and Margin

The projected 2018 deliveries for this customer class are based on surveying PNG(NE)'s small industrial customers as well as a review of historical usage. The increase in forecast deliveries of approximately 111,000 GJ and increased margin of $156,000 for Test Year 2018 are primarily due to one customer's continued requirement for natural gas for electricity generation for their liquid nitrogen plant in Dawson Creek, offset in part by decreased usage by various other customers supplying services to the oil field industry. Test Year 2019 forecast deliveries and margin are expected to remain flat as discussions with the customer have indicated they plan to continue using natural gas for the next few years. A gas deliveries deferral account (ICDDA) is used to record the difference between forecast and actual deliveries for this customer.

2.1.3.3 Small Industrial Transport Deliveries and Margin

The projected 2018 deliveries for this customer class are based on the forecasts obtained from PNG(NE)'s small industrial transportation customers and a review of their historical usage. Overall, deliveries are forecast to increase by approximately 154,000 GJ with a corresponding margin increase of $112,000 compared to Decision 2017. The bulk of this increase (161,000 GJ) is attributable to the supply of fuel gas to a natural gas liquids separation facility north of Fort St. John commencing May 2018 based on a minimum take-or-pay contract demand of 240,000 GJ per year. This increased demand is contingent upon

Commision approval of PNG(NE)'s CPCN application to acquire and operate the fuel gas line to supply this facility. In addition to the above, the demand increase also reflects forecast fuel gas usage from the restart of two facilities that had previously ceased operation in early 2016, along with offsetting decreased demand resulting from the shut-in of several wells in the Fort St. John area. For 2019, most of the increased deliveries of approximately 73,000 GJ and increased margin of $51,000 reflect a full year of deliveries to the natural gas liquids separation facility in that year.

2.2 Cost of Gas

As noted in Section 1.6.2 – Scope of Regulatory Review, gas costs presented in this Amended Application are indicative only. PNG(NE)'s gas supply costs are reviewed by the Commission under a separate regulatory review process, the quarterly review and approval of gas commodity costs. As the gas supply costs are indicative only, and as PNG(NE) is not applying for Commission approval of the indicative gas supply rates in this Amended Application, PNG(NE) submits that it is not necessary to review these costs in the context of this Amended Application.

PNG(NE) has derived the indicative natural gas supply costs incorporated into this Amended Application based on average forward price strips for the five-day period ending November 21, 2017.

2.2.1 Cost of Gas Summary

The following table provides a summary of the indicative gas cost applied to Test Year 2018 and Test Year 2019, as well as Commission-approved gas costs for 2017 and 2018.

Table 15: Indicative Gas Cost

	Test Year 2019			Test Year 2018							
Customer Classification	Forecast Deliveries	Indicative Gas Cost Charge*	Indicative Gas Cost	Forecast Deliveries	Indicative Gas Cost Charge*	Indicative Gas Cost	2017 and 2018 Approved Gas Costs*				
							Jan 1, 2018	Oct 1, 2017	Jul 1, 2017 **	Apr 1, 2017**	Jan 1, 2017
	GJ	$/GJ	$	GJ	$/GJ	$	$/GJ	$/GJ	$/GJ	$/GJ	$/GJ
Residential	1,796,601	2.108	3,787,235	1,798,219	1.770	3,182,848	1.779	2.152	2.634	2.634	2.634
Small Commercial	1,391,298	2.110	2,935,639	1,363,762	1.768	2,411,131	1.778	2.159	2.643	2.643	2.643
Large Commercial	355,900	2.024	720,342	355,900	1.680	597,912	1.682	2.078	2.570	2.570	2.570
Small Industrial Sales	512,950	1.863	955,626	511,520	1.525	780,068	1.530	2.053	2.506	2.506	2.506
Total	4,056,749		8,398,841	4,029,401		6,971,959					

** Gas cost charges exclude rate riders*
*** No commodity rate changes in this period; provided for illustrative purposes*

Source: Tab Schedules, Tab 6, Page 16 and 36; 2017 Quarterly Gas Cost Submissions

2.2.2 Company Use Gas Requirements

Table 16: Company Use Gas Cost

Company Use Gas	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		Amount	%		Amount	%						
Cost ($)*	176,138	35,249	25.0%	140,889	(47,990)	(25.4%)	188,879	194,252	145,876	240,482	245,455	205,752
Requirements (GJ)												
Blowdowns and Losses	5,042	-	0.0%	5,042	0	0.0%	5,042	5,154	6,823	9,932	8,958	4,287
Lineheaters and Office	16,099	914	6.0%	15,185	1,263	9.1%	13,922	10,653	10,868	6,895	8,332	10,175
Line Pack Change	-			-			-	4,628				
Unaccounted for Gas (Gain)/Loss	57,473	1,003	1.8%	56,470	1,308	2.4%	55,162	(5,788)	203,081	44,957	(14,416)	12,458
	78,614	1,917	2.5%	76,697	2,571	3.5%	74,126	14,647	220,772	61,784	2,874	26,920

** Note: Includes Provincial taxes and levies*

Source: Tab Schedules, Tab 6, Page 18 and 38; 2016-2017 RRA Compliance Filing

The volume of company use gas forecast for Test Year 2018 and 2019 is slightly higher than the forecast under Decision 2017 primarily due to higher forecast deliveries. PNG(NE) primarily uses gas for station heating and office and shop heating. These uses are expected to be at levels comparable to recent years. The higher gas requirements and the impact of an increase in the carbon tax rate of $0.25 per GJ effective April 1, 2018 are more than offset by the effects of lower gas commodity costs forecast for Test Year 2018. The increase in company use cost for Test Year 2019 over Test Year 2018 reflects higher forecast commodity costs and a further carbon tax rate increase of $0.25 per GJ that will be effective April 1, 2019.

2.2.3 Unaccounted for Gas

The unaccounted for gas volume component of Company use gas has been set at 1.0 percent of deliveries for Test Years 2018 and 2019, the same figure used under Decision 2017. The foregoing is based on the assumption a UAF volume deferral account will continue in 2018 and 2019 with a UAF loss cap of 1.0 percent. As in prior years, PNG(NE) would be required to obtain Commission approval to record the impact of UAF losses above 1.5 percent.

Recovery of 2016 UAF Loss over 1.5 Percent Deferral Account

On February 24, 2017, PNG(NE) applied to the Commission for approval to record 2016 UAF losses above 1.5 percent in the UAF volume deferral account, allowing for all UAF losses to be recorded in the UAF volume deferral account and recovered from customers via the Company use rate rider. Under Order G-105-17, the Commission denied PNG(NE)'s request pending further review and directed PNG(NE) to establish a separate temporary short term interest bearing deferral account to record the 2016 UAF loss over 1.5 percent until such time as the disposition of the excess UAF has been determined.

The Commission further directed PNG(NE) to include in its next revenue requirements application a report summarizing the results of its further examination of all data and calculations and investigation into the reasons for the increased 2016 UAF loss and a proposal for the recovery of the 2016 UAF loss over 1.5 percent deferral account.

In compliance with these directives, PNG(NE) has included its Unaccounted for Gas Report for the Period January 2016 to December 2017 (UAF Report) as Appendix B.

PNG(NE) reiterates that UAF is a calculated variance resulting from various sources which may include loss of gas due to utility or third party activities and measurement inaccuracies both in the deliveries received and the deliveries to customers. However, it is primarily due to timing differences as a result of various factors and estimates used in the calculation of monthly unbilled revenues. As such, throughout PNG(NE)'s history there have been large

fluctuations in the monthly calculated UAF volumes and these fluctuations have included both significant gains and significant losses.

In the UAF Report, PNG(NE) notes that it has completed a detailed review of all the data and calculations that resulted in the 2016 UAF volume loss and that it has also reviewed the 2017 UAF calculations. Based on this review, PNG(NE) has concluded that although there were isolated incidents during 2016 that resulted in the recording of an unusually high UAF loss in this past year, PNG(NE)'s gas accounting practices are both thorough and consistent with industry standards. In addition, as shown in the report, the cumulative trend in UAF during 2017 has returned to within historic UAF boundaries.

Based on the foregoing, PNG(NE) requests Commission approval to transfer the 2016 UAF losses from the temporary deferral account back to the established UAF volume deferral account so that they may be recovered from customers via the Company use rate rider as has been consistently applied in the past.

2.3 Operating Expenses

Table 17: Forecast Operating Expenses

BCUC Account	$000's											
	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to Decision 2017 Change $	2018 to Decision 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
670 Supervision	476	9	2.0%	467	11	2.3%	456	428	462	479	428	431
675 Mains and Services	518	10	2.0%	508	(14)	(2.8)%	523	486	440	440	467	437
685 General Ops.	1,009	18	1.8%	991	286	40.5%	705	854	642	559	601	663
688 Other Gen. Ops.	673	13	2.0%	660	1	0.2%	659	675	533	632	601	554
711/713/714 Customer Care	629	15	2.4%	614	(35)	(5.4)%	649	570	562	623	551	501
712 Meter Reading	260	5	2.0%	255	6	2.3%	249	233	263	213	245	256
718 Uncollectible Accounts	52	(4)	(7.1)%	56	20	53.8%	36	111	36	26	-	-
Other inc. 665/673	1,006	50	5.3%	956	21	2.3%	934	945	935	1,237	1,031	891
Subtotal	4,624	118	2.6%	4,506	294	7.0%	4,212	4,301	3,873	4,209	3,923	3,731
Add: Shared Service Cost Allocation	1,588	23	1.5%	1,565	37	2.4%	1,529	1,529	1,515	1,446	1,364	1,398
Operating Expenses	6,212	141	2.3%	6,072	331	5.8%	5,741	5,830	5,388	5,655	5,288	5,129
Less: Cost of Gas - 665 Pipelines	(176)	(35)	25.0%	(141)	48	(25.4)%	(189)	(192)	(145)	(240)	(245)	(206)
Operating Expenses (Net of Company Use Cost of Gas)	6,036	105	1.8%	5,931	379	6.8%	5,552	5,638	5,243	5,415	5,042	4,924
Less: Transfers to Capital	(284)	(54)	23.3%	(230)	(49)	27.1%	(181)	(192)	(196)	(174)	(146)	(138)
Net Operating Expenses (Net of Transfers to Capital)	5,753	52	0.9%	5,701	330	6.1%	5,371	5,446	5,047	5,241	4,896	4,786

Source: Tab Schedules, Tab 1, Page 3

Gross operating expenses, before shared service cost allocations, are increasing from $4.212 million under Decision 2017 to $4.506 million in Test Year 2018, an increase of $294,000 or 7.0%. A further increase in operating expenses is forecast for Test Year 2019 to $4.624 million, increasing $118,000 or 2.6% over Test Year 2018. The reasons underlying the more significant operating expense changes from Decision 2017 to Test Year 2018, and from Test Year 2018 to Test Year 2019, are provided in the discussion that follows.

2.3.1 Account 670 – Supervision

The costs in this account cover the routine operating costs of the distribution system that cannot be charged to a specific code. Typical activities include: supervision; general planning and scheduling of current and future distribution projects and activities that are not yet fully-developed stand-alone projects; operations meetings; janitorial services; and upkeep of distribution offices and equipment.

Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

2.3.2 Account 675 – General Mains and Services

Activities related to the operation of the distribution system mains and services are recorded this account. This includes performing leak surveys, protecting facilities during work by others, locating and operating valves, etc.

Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

2.3.3 Account 685 – General Operations

The costs in this account cover the routine operating cost of the gas system that cannot be charged to a specific code. Typical activities include supervision, general planning and scheduling of current and future projects and activities that have are not yet fully developed stand-alone projects which cannot be assigned to distribution or transmission, operations meetings, janitorial services and upkeep of regional offices and equipment, office supplies, general communication equipment and monthly charges, travel and subsistence of supervisors and managers.

Forecast Test Year 2018 costs are $286,000 or 40.5% higher than Decision 2017. Factors contributing to this increase include: additional engineering projects including digital data mapping and the implementation of a geographical information system; increased labour costs attributable to a new position in the areas of engineering; asset management system licensing costs; and inflation. Test Year 2019 costs are forecast to be comparable to Test Year 2018.

2.3.4 Account 688 – Other General Operations

The costs in this account cover all types of allowable time off with pay, such as vacation, sick time and banked time off. In addition all safety and training costs (both third party and labour) are included in this account.

Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

2.3.5 Account 711/713/714 – Customer Care

Collectively these accounts include the majority of the activities that are performed in PNG's customer care centre as well as some time spent by customer service technicians in interacting with customers. The costs in Account 711 cover the labour, supplies and expenses to work on customer applications and contracts. The costs in Account 713 cover the labour, supplies and expenses to invoice and account for the gas used by Customers. It also includes an allocation of the costs of outsourcing of the CIS services. The costs in Account 714 cover the labour, supplies and expenses for work to receive and apply customer deposits, collect, balance and prepare reports on revenue from customers, check credit ratings, and collect delinquent accounts.

Costs for customer care are forecast to decrease in Test Year 2018 from Decision 2017 by $35,000 or 5.4% primarily due to a reduced allocation of Vertex Billing Services costs from PNG-West due to lower overall forecast costs for Test Year 2018, and to lower forecast data line costs.

Test Year 2019 costs are forecast to increase $15,000 or 2.4% primarily due to inflationary pressures.

2.3.6 Account 712 – Meter Reading

Meter reading costs are recorded in this account. Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

2.3.7 Account 718 – Uncollectible Accounts

PNG continually monitors and reviews its actual bad debt experience. Based on this ongoing review, PNG(NE) has forecast bad debt expense of $56,000 for Test Year 2018 and of $52,000 for Test Year 2019, compared to a provision of $36,000 for Decision 2017. These provisions are calculated based on PNG(NE)'s bad debt write-offs over the past 5 years and applying the average ratio to the forecast period revenues, excluding large industrial revenues.

2.3.8 Account 665/673 – Other

The accounts included in this line item are primarily related to pipeline services (665) and meter-related services (673). Forecast Test Year 2018 costs increase by $21,000 or 2.3% over Decision 2017, reflecting higher forecast close interval survey work for 2018 and higher costs forecast for odourant supply. Test Year 2019 costs increase over Test Year 2018 by $50,000 or 5.3%, primarily due to inflationary pressures on these costs.

2.3.9 Shared Services Cost Allocation

Please see Section 2.6 – Shared Services Cost Allocation for further discussion of this item.

2.3.10 Transfers to Capital

Please see Section 2.7 – Transfers to Capital (Capitalized Overhead) for further discussion of this item.

2.3.11 Cost of Gas

Please see Section 2.2.2 – Company Use Cost of Gas for further discussion of this item.

2.4 Maintenance Expenses

Table 18: Maintenance Expenses

BCUC Account	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
867 Regulating Stations	70	1	2.0%	69	21	45.6%	47	53	32	76	70	56
875 Mains and Services	168	3	1.7%	165	4	2.5%	161	93	151	85	187	153
878 Meters	73	1	2.0%	72	1	2.0%	71	92	150	145	77	68
All Other	118	2	2.0%	116	2	2.1%	114	44	32	30	86	109
Total	429	8	1.9%	421	29	7.5%	392	282	365	337	420	385

Source: Tab Schedules, Tab 1, Page 4

Planned maintenance activities are responsive to system needs and are at a level PNG(NE) considers will ensure facilities are kept in good working order to ensure continued safe, reliable and secure gas delivery service to its customers. Maintenance expenses are forecast to increase from $392,000 under Decision 2017 to $421,000 in Test Year 2018, up $29,000 or 7.5%, and are forecast to increase further in Test Year 2019, by $8,000 or 1.9% over Test Year 2018. A description of the nature of costs included in each account and reasons underlying the more significant expense changes are provided in the discussion that follows.

2.4.1 Account 867 – Regulating Stations

The costs in this account cover the labour, supplies and expenses to repair broken high pressure regulating and measurement stations and their constituent parts, repairs to tools and testing equipment, repairs to station grounds, fences and buildings, repairs to access roads and repainting.

Test Year 2018 costs are forecast to increase by $21,000 or 45.6% over Decision 2017, reflecting a new provision for contractor services for station valve maintenance that was not forecast for 2017. Test Year 2019 costs are comparable to Test Year 2018.

2.4.2 Account 875 – Mains and Services

The costs in this account cover the labour, supplies and equipment to repair broken distribution mains and services. Typical activities include: leak repairs, repairing broken mains and services, repairing distribution valves, pavement and lawn repair resulting from the excavations to repair broken mains and services.

Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

2.4.3 Account 878 – Meters

The costs in this account cover maintenance of gas meters. Typical activities include: inspecting and testing meters on customer premises or in the meter shop resulting from repairs, cleaning meters, repairing meters, painting meters and ancillary metering equipment, repairing meter testing equipment, rebuilding and overhauling meters and replacing defective or worn meter parts.

Forecast costs for Test Year 2018 and Test Year 2019 are comparable to recent experience.

2.4.4 All Other

The costs in this line include all other accounts not otherwise listed in the table. The largest of these accounts records expenses related to maintenance of the transmission system pipeline and facilities (865). Typical activities include maintenance and repairs to the right of way, access roads, line markers, the pipe and fittings themselves, investigative digs, and the cost of materials and supplies to perform the work.

Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

2.5 Administrative & General Expenses

Table 19: Administrative and General Expenses

	$000's											
BCUC Account	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to Decision 2017 Change $	2018 to Decision 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
721 Administration	24	0	2.0%	23	(19)	(44.6)%	42	39	36	57	(18)	45
722 Special Services - Audit/Legal	89	2	2.0%	87	(7)	(7.8)%	95	143	120	135	90	143
723 Insurance	97	3	2.8%	94	32	50.5%	63	71	72	77	76	76
725 Employee Ben.	769	(5)	(0.6)%	774	(7)	(0.9)%	781	742	756	773	710	877
728 General	76	1	2.0%	75	(1)	(0.8)%	75	74	73	71	61	57
Sub-Total	1,055	2	0.1%	1,053	(2)	(0.2)%	1,056	1,070	1,058	1,113	919	1,198
Add: Shared Service Cost Allocation - 721	1,566	41	2.7%	1,525	(72)	(4.5)%	1,596	1,596	1,519	1,443	1,249	1,197
Add: Shared Service Cost Allocation - 728	336	10	2.9%	327	8	2.5%	319	319	312	294	280	247
Administrative and General Expenses	2,957	53	1.8%	2,904	(66)	(2.2)%	2,971	2,985	2,889	2,850	2,447	2,641
Less: Transfers to Capital	(406)	(132)	48.3%	(274)	217	(44.2)%	(491)	(495)	(357)	(320)	(301)	(370)
Net Administrative and General Expenses (Net of Company Use Cost of Gas)	2,551	(80)	(3.0)%	2,631	151	6.1%	2,480	2,490	2,532	2,530	2,146	2,271

Source: Tab Schedules, Tab 1, Page 5

Gross administrative and general expenses, before shared service cost allocations, are decreasing from $1.056 million under Decision 2017 to $1.053 million in Test Year 2018, a decrease of $2,000 or 0.2%. Test Year 2019 costs are forecast to increase to $1.055 milion, an increase of $26,000 or 2.3% from Test Year 2018, primarily reflecting inflationary increases. The reasons underlying the more significant administrative and general expense changes are provided below.

2.5.1 Account 721 – Administration

This account captures the costs associated with the general administration for this division that are not chargeable to a specific operating function. They include an allocation of payroll administration charges and regulatory proceeding costs.

Test Year 2018 costs of $23,000 are forecast to be $19,000 or 44.6% less than Decision 2017, primarily due to the absence of a provision in 2018 for costs pertaining to a rate design initiative that was performed with internal resources in 2017. Test Year 2019 amounts reflect an inflationary cost increase.

2.5.2 Account 722 – Special Services – Audit/Legal

BCUC account 722 captures the fees and expenses of professional consultants and others for general services not applicable to a particular operating function. They are composed mainly of audit fees, legal fees and consulting fees.

Test Year 2018 and Test Year 2019 forecasts for these expenses are consistent with Decision 2017 amounts.

2.5.3 Account 723 – Insurance

Insurance is arranged by PNG on a consolidated basis to achieve economies of scale under the umbrella of the AltaGas group of companies. The premiums to PNG are then allocated among the PNG-West and PNG(NE) divisions in accordance with the Commission's approved methodology set forth under Decision 2005.

The Test Year 2018 insurance expense forecast was determined using the actual October 1, 2017 renewal of PNG's consolidated liability and property policies. Forecast insurance costs allocated to the PNG(NE) for Test Year 2018 are $32,000 greater than Decision 2017 due to an increase in the percentage allocation to PNG(NE) due to the shift of allocation components for replacement cost, employee count and plant in service towards PNG(NE). Test Year 2019 insurance costs reflect an inflationary increase.

2.5.4 Account 725 – Employee Benefits

2.5.4.1 Employee Benefit Program Costs

Overall, employee benefit costs included in BCUC Account 725 are forecast to decrease by $7,000 or 0.9% in Test Year 2018 from costs approved under Decision 2017 primarily due to lower pension and non-pension post-retirement benefit costs offset in part by higher costs for life, disability and medical programs. Employee benefit costs forecast for Test Year 2019 are expected to be $5,000 or 0.6% less than Test Year 2018 forecast costs primarily due to a further reduction in pension costs for Test Year 2019.

PNG(NE) notes that a new health spending account benefit for bargaining unit employees has been established as part of the 2017 negotiations in finalizing the collective agreement applicable to the period November 1, 2016 to October 31, 2019. Other than this change, there have been no significant changes to the PNG(NE) employee benefit plan since the last revenue requirements application approved under Decision 2017.

Pension, NPPRB and Other Programs

The majority of the increase in employee benefits costs for Test Year 2018 can be attributed to higher defined benefit pension (DB) and non-pension post-retirement benefit (NPPRB) program costs.

Table 20: Pension, NPPRB and Other Programs

	$000's											
Cost Element	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Company Pension Plans	264	(23)	(7.9)%	287	(19)	(6.2)%	306	326	316	354	306	406
NPPRB and Other	60	5	9.7%	55	(48)	(46.6)%	103	113	103	113	91	168
Total	325	(17)	(5.1)%	342	(67)	(16.4)%	409	439	419	467	397	574

Defined Benefit (DB) pension and non-pension post-retirement benefit (NPPRB) program costs are actuarially determined. Amounts presented in the table above reflect an updated valuation completed at December 2017. The decrease in DB and NPPRB costs for Test Year 2018 and Test Year 2019 over Decision 2017 are primarily a result of discount rates going down (3.81% to 3.60%) and as a result of actuarial gains in the plans recognized at the end of 2017. This caused lower pension and benefit obligations at the end of 2017, and therefore less expense for Test Year 2018 and Test Year 2019.

Other Program costs for Test Year 2018 and Test Year 2019 include provision for costs related to health spending accounts for bargaining unit employees. The health spending account benefit is a new benefit for this employee group that was established as part of the 2017 negotiations in finalizing the collective agreement applicable to the period November 1, 2016 to October 31, 2019.

Employee Savings Plan

Employee savings plan costs are forecast to increase in each of Test Year 2018 and 2019 over Decision 2017. The increases are primarily due to increased company-matching contributions to employee contributions as recent hires gain more years of service, from an initial 50% to 75%, then to 100% after six years of service, as per plan design. Further, employee and employer contributions are based upon a percentage of pay, therefore any wage increases result in increased employer contributions

The increase in expense also reflects a 1% improvement to the plan for non-bargaining unit employees that was implemented by PNG(NE) in 2013 to match the results of collective bargaining with union employees. In Decision 2013, the Commission denied the additional 1% increase in the Company-match under the employee savings plan for non-bargaining unit employees. The additional 1% increase was disallowed again under Decision 2017.

Based on these previous determinations, PNG(NE) has made a cost of service adjustment (See Section 2.5.8 – Cost Adjustments) for the 1% increase. As described in Section 2.5.8, this provision has been made without prejudice and inconsideration of the revenue deficiencies forecast for Test Year 2018 and Test Year 2019. PNG(NE) reserves the right to seek recovery of these costs in the future as a valid element of the cost of service.

Employee Life, Long-term Disability, Medical and Hospital Insurance

The costs of premiums for PNG(NE)'s life, disability and medical programs are forecast to increase in each of Test Year 2018 and 2019 over Decision 2017 as per annual quotes received from PNG(NE)'s benefits consultant. Employee wage increases and staff additions also contribute to the overall increase. PNG(NE)'s benefits consultant advises that the forecast increases are consistent with general industry trend factors for increased benefit plan costs.

Government-Sponsored Benefit Programs

PNG(NE) has forecast slight changes to government-sponsored CPP and EI plan costs, primarily due to anticipated increases to earnings caps for these plans.

2.5.4.2 Employee Benefit Load Rates

Employee benefits costs are used to derive a benefit load rate to be applied to base labour costs in order to include an appropriate allocation of employee benefit costs to base labour costs included in shared service cost recoveries, transfers to capital and transfer pricing related to non-regulated activities. The benefit load rates are computed for each employee affiliation (i.e. executive, non-bargaining unit, bargaining unit) and are updated on an annual basis to reflect forecast benefit costs (i.e. pension, non-pension, extended health care, savings plans, etc.). The table that follows summarizes historic benefit load rates applied.

Table 21: Employee Benefit Load Rates

Employee Affiliation	Test Year 2019	2019/2018 Change %	Test Year 2018	2018/Decision 2017 Change %	Decision 2017	Decision 2016	NSP 2014	Decision 2013
Executive	34.0%	0.1%	33.9%	(9.5)%	43.4%	41.4%	38.4%	56.3%
Non-bargaining Unit	32.0%	(1.1)%	33.1%	(4.6)%	37.7%	36.9%	37.6%	32.7%
Bargaining Unit - PNG-West	36.1%	(1.5)%	37.6%	(9.5)%	47.1%	47.9%	52.4%	66.5%
Bargaining Unit - PNG(N.E.)	37.5%	(1.3)%	38.7%	(10.8)%	49.5%	48.0%	47.2%	58.2%

Employee benefit load rates are generally forecast to be lower for Test Year 2018 and Test Year 2019 than they were under Decision 2017. This decrease is primarily due to lower Pension and NPPRB costs for Test Year 2018 and Test Year 2019 compared to Decision 2017 as discussed under Section 2.5.4.1 – Employee Benefit Program Costs.

2.5.5 Account 728 – General

BCUC Account 728 includes expenses incurred in connection with the general management of the Company not provided for elsewhere. For PNG(NE), they are comprised mainly of costs of regulation (BCUC fees) and donations. Costs for both Test Year 2018 and Test Year 2019 are forecast to be at levels comparable to recent experience.

PNG(NE) notes that 50% of donations are adjusted out of the cost of service as per a prior Commission directive. See Section 2.5.8 – Cost Adjustments.

2.5.6 Shared Services Cost Allocation

Please see Section 2.6 – Shared Services Cost Allocation for further discussion of this item.

2.5.7 Transfers to Capital

Please see Section 2.7 – Transfers to Capital (Capitalized Overhead) for further discussion of this item.

2.5.8 Cost Adjustments

Cost Adjustments are expenses expected to be incurred by PNG(NE) where the Commission has determined that it is not reasonable for either all or a portion of the expense to be recovered in rates. The table that follows shows the details of the disallowances of expected expenses, both historical and PNG(NE)'s applied-for changes relative to disallowances under Decision 2017.

Table 22: Forecast Cost Adjustments

	$000's						
Cost Adjustment	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017
		$	%		$	%	
50% of donations and sponsorships	(3)	(0)	2.0%	(2)	(0)	2.0%	(2)
1% of non-bargaining unit employee savings plan	(2)	(0)	3.2%	(2)	(0)	9.6%	(2)
Total	(5)	(0)	2.6%	(5)	(0)	5.6%	(5)

Source: Tab Schedules, Tab 1 Page 6

For Test Year 2018 and Test Year 2019, PNG(NE) has applied the Commission's 2013 Decision and disallowance of 50% for corporate donations and sponsorships, and the NSP 2014 disallowance of full recovery for PNG(NE)'s 1% improvement to the employee saving plan program costs for non-bargaining unit employees.

PNG(NE) has included the 1% employee savings plan cost adjustment for Test Year 2018 and Test Year 2019 in consideration of the forecast revenue deficiencies for these periods. This cost adjustment has been made without prejudice and PNG(NE) reserves the right to apply to recover the full amount of these expense items that may be forecast in future years.

As background on this program, in 2013 PNG(NE) implemented a 1% improvement to the employee savings plan for non-bargaining unit employees to match the recent results of collective bargaining with union employees. PNG(NE) submits that it should be able to recover these costs as a valid element of the cost of service on the following basis:

Generally organizations prefer to avoid more generous programs for bargaining unit groups versus their non-union staff.

The savings plan increase for the bargaining unit employees was negotiated with the IBEW to achieve an agreement with the IBEW rather than through larger wage increases. The company agreed to this incentive with the IBEW fully intending that PNG(NE) would not provide its management and exempt employees with a lesser benefit plan design.

PNG(NE) has identified that there are a number of companies within our industry sector offering employer matching contributions beyond 5%, thus at 6% the PNG(NE) plan remains competitive.

Further, PNG(NE)'s management and exempt employee compensation programs are integrated programs made up of several components each with its own purpose. Denying any one aspect of these packages may undermine the integrity of the program design. Each element under the plan design serves a specific purpose. Given the above, PNG(NE) believes it is reasonable to recover the full cost of the savings plan, as is the case with PNG(NE)'s other benefit programs.

2.6 Shared Services Cost Allocation to PNG(NE) FSJ/DC Division

As the parent company of PNG(NE), PNG provides a number of operational, administrative, accounting, regulatory and other services to support PNG(NE)'s FSJ/DC Division. These services are provided to PNG(NE) by PNG-West employees located in PNG's Vancouver corporate office and in its Terrace regional office. PNG allocates its costs for such shared services using a number of different cost allocators, including allocators based upon relative time, relative number of customers, relative number of employees and relative rate base.

PNG continues to apply the shared services cost allocation and recovery methodology for PNG(NE) as reviewed and approved under Decision 2013. A full discussion of factors contributing to the shared services cost allocations is provided in the respective PNG-West revenue requirements application. For reference, summary information is provided in the section that follows.

The table that follows provides a historic summary, by respective BCUC Account cost pool, of PNG-West shared services cost recoveries from PNG(NE) FSJ/DC, broken down by base costs and benefit load recoveries on labour costs included in base costs.

Table 23: Shared Services Cost Allocation from PNG-West

	$000's											
Allocated Costs	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
685 - General Operations	679	14	2.1%	665	101	17.8%	565	565	570	512	471	474
711/713/714 - Cust. Care	634	14	2.3%	620	(2)	(0.3)%	622	622	609	585	570	553
	1,313	28	2.1%	1,285	99	7.7%	1,186	1,186	1,179	1,097	1,041	1,027
725 - Benefits on:												
685 - General Operations	110	(2)	(1.9)%	112	(25)	(18.3)%	137	137	134	137	115	119
711/713/714 - Cust. Care	165	(3)	(1.8)%	168	(37)	(18.2)%	206	206	203	212	208	252
	275	(5)	(1.8)%	280	(62)	(22.3)%	342	342	336	349	323	371
Subtotal Operating	1,588	23	1.4%	1,565	37	2.3%	1,529	1,529	1,515	1,446	1,364	1,398
721 - Administration	1,274	41	3.3%	1,233	(23)	(1.9)%	1,257	1,257	1,203	1,117	974	931
725 - Benefits on:												
721 - Administration	292	0	0.1%	291	(48)	(14.2)%	340	340	316	326	274	267
	1,566	41	2.6%	1,525	(72)	(4.7)%	1,596	1,596	1,519	1,443	1,249	1,197
728 - Corporate	336	10	2.9%	327	8	2.5%	319	319	312	294	280	247
Subtotal Administrative and General	1,902	51	2.7%	1,851	(64)	(3.5)%	1,915	1,915	1,831	1,737	1,528	1,444
Total	3,491	74	2.1%	3,417	(27)	(0.8)%	3,444	3,444	3,346	3,183	2,892	2,843
Allocated Costs	2,924	79	2.7%	2,845	83	2.9%	2,762	2,762	2,694	2,508	2,295	2,205
Allocated Benefits	567	(5)	(0.8)%	572	(111)	(19.4)%	682	682	652	675	598	638
Total	3,491	74	2.1%	3,417	(27)	(0.8)%	3,444	3,444	3,346	3,183	2,892	2,843

The recovery by PNG-West of pooled shared service costs from the FSJ/DC Division has decreased by a modest amount for Test Year 2018 compared to Decision 2017, and then increase by an inflationary amount for Test Year 2019 compared to Test Year 2018, primarily reflecting lower benefit load rates due to lower pension and other post-retirement benefit costs as described under Section 2.5.4.2 – Employee Benefit Load Rates. Specific items of note for the PNG(NE) FSJ/DC Division include:

685 – General Operations

Test Year 2018 vs Decision 2017

- Increased cost allocation of approximately $76,000 due to:

  Overall PNG-West cost pool increase of approximately $198,000 primarily due to costs related to new engineering initiatives including digital data mapping and the geographic information system (GIS) project, as well for licensing costs for the computerized maintenance management system (CMMS). The increase in these cost pool elements has partially been offset by a reduction in labour costs as a result of increased capitalized labour costs from this pool due to greater capital expenditures planned for Test Year 2018, and also partially offset by a decrease in the employee benefit load factors applicable to PNG-West employee labour costs included in this cost pool (see Section 2.5.4.2 – Employee Benefit Load Rates).

  There has been an increase in the composite allocator due to a proportionate increase of the PNG(NE) FSJ/DC component for each of customer count and rate base over Decision 2017, increasing the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $12,000 due to:

  Overall PNG-West cost pool increase of approximately $32,000 primarily due to inflationary pressures on costs.

  Once again, there has been an increase in the composite allocator due to a proportionate increase of the PNG(NE) FSJ/DC component for each of customer count and rate base over Test Year 2018, increasing the cost allocation.

711/713/714 – Customer Care

Test Year 2018 vs Decision 2017

- Decreased cost allocation of approximately $39,000 due to:

  Overall PNG-West cost pool decrease of approximately $81,000 primarily due to the effect of a decrease in the employee benefit load factor on PNG-West bargaining unit employee labour costs included in the Terrace Customer Care Centre cost pool (see Section 2.5.4.2 – Employee Benefit Load Rates) and to a reduction in data line costs, offset in part by inflationary increases to other costs in this cost pool.

An increase in the composite and customer count allocators due to a proportionate increase of the PNG(NE) FSJ/DC component for each of rate base and customer count over Decision 2017 have partially offset the cost pool decrease effect on the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $11,000 due to:

  Overall PNG-West cost pool increase of approximately $22,000 primarily due to inflationary cost pressures on cost pool elements for Test Year 2019 over Test Year 2018.

  The increase in the composite indicator and the small increase in the customer count allocator for PNG(NE) FSJ/DC over Test Year 2018 have the effect of increasing the cost recovery.

721 – Administration

Test Year 2018 vs Decision 2017

- Decreased cost allocation of approximately $72,000 due to:

  Overall PNG-West cost pool decrease of approximately $253,000 due to a number of factors, including: a decrease in labour costs, reflecting differences in the salaries of former PNG executives that retired in 2016 and the salaries of replacements for those positions, as described in Section 2.5.1 Account 721 – Administration, as well as a decrease in employee benefit load factors on executive and non-bargaining unit employee labour costs included in the Vancouver Administration cost pool (see Section 2.5.4.2 – Employee Benefit Load Rates); a decrease in non-labour costs in the Vancouver Administration cost pool, reflecting lower contractor, travel, training, data and communication, and rent expenses, offset in part by general inflationary costs increases on all costs in this cost pool over Decision 2017 amounts.

  A small increase in the composite allocator due to a proportionate increase of the PNG(NE) FSJ/DC component for each of rate base and customer count over Decision 2017 have also contributed to the increase in the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $41,000 due to:

  Overall PNG-West cost pool increase of approximately $145,000 primarily due to inflationary labour and non-labour cost increases for Test Year 2019.

Again, an increase in the composite allocator due to a proportionate increase of the PNG(NE) FSJ/DC component for each of rate base and customer count over Test Year 2018 have also contributed to the increase in the cost recovery.

728 – Corporate

Test Year 2018 vs Decision 2017

- Increased cost allocation of approximately $8,000 due to:

  Overall PNG-West cost pool increase of approximately $24,000 primarily due to inflationary cost increases.

  An increase in the composite allocator due to a proportionate increase of the PNG(NE) FSJ/DC component for each of rate base and customer count over Decision 2017 have also contributed to the increase in the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $10,000 due to:

  Overall PNG-West cost pool increase of approximately $17,000 primarily due to inflationary cost increases for Test Year 2019 over Test Year 2018.

  An increase in the composite allocator due to a proportionate increase of the PNG(NE) FSJ/DC component for each of rate base and customer count over Test Year 2018 also have a minor effect on the increase in cost allocation.

As noted, PNG-West also recovers costs from PNG(NE) that pertain to specific third-party expenditures that have a common benefit, including CIS system services fees, internal and external audit fees and insurance premiums. The following items are of note:

713 – Vancouver Vertex Billing Services

Test Year 2018 vs Decision 2017

- Decreased cost allocation of approximately $24,000 due to:

  Overall cost pool decrease of approximately $52,000 primarily due to Decision 2017 including provision for external support services to assist with planning for a CIS replacement project, with no comparable expenditure in Test Year 2018. This decrease is offset in part by general inflationary cost increases.

  An increase in the customer count allocator due to a proportionate increase in the PNG(NE) FSJ/DC component for customer count over Decision 2017 has partially offset the effects of the cost pool decrease in this cost recovery.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $12,000 due to:

  Overall cost pool increase of approximately $24,000 primarily due to inflationary cost increases

  An increase in the customer count allocator due to a proportionate increase in the PNG(NE) FSJ/DC component for customer count over Test Year 2018 also contributes to the increase in the cost recovery.

722 – Vancouver Special Services

Test Year 2018 vs Decision 2017

- Increased allocation of approximately $8,000 due to:

  Overall cost pool increase of approximately $9,000 primarily due to inflationary increases in audit fees.

  No change to the composite allocator as effective 2015, to simplify the modelling of the allocation of these costs, PNG commenced making use of the composite allocator from the previously approved revenue requirements application, hence the allocator applied for this instance is that per Decision 2017.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $1,000 due to:

  Overall cost pool increase of approximately $4,000 primarily due to inflationary cost increases for Test Year 2019 over Test Year 2018.

  The same as for Test Year 2018 verses Decision 2017, no change to the composite allocator as effective 2015, to simplify the modelling of the allocation of these costs, PNG commenced making use of the composite allocator from the previously approved revenue requirements application, hence the allocator applied for this instance is that per Decision 2017.

723 – Vancouver Insurance

Test Year 2018 vs Decision 2017

- Increased cost recovery of approximately $33,000 due to:

  Overall cost pool increase of approximately $10,000 due to increased premiums.

A 5% increase in the composite insurance allocation factor due to the effects of an increase in the PNG(NE) components of consolidated replacement cost and plant in service compared to Decision 2017 has also contributed to the increase in the cost recovery

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $2,000 due to:

  Overall cost pool increase of approximately $11,000 due to inflationary cost increases for Test Year 2019 over Test Year 2018.

  A very minor increase in the composite insurance allocation factor also contributes to the increased cost allocation.

2.7 Transfers to Capital (Capitalized Overhead)

PNG(NE) continues to apply the capital overhead allocation methodology approved under NSP 2011, with minor amendments approved under Decision 2012, to calculate the transfers of budgeted operating, administrative and general expenses to Test Year capital projects, and continues to use the same overhead capitalization rates for both rate setting and external reporting purposes.

The methodology includes the following allocations:

- corporate and management salary and benefit costs based on estimated time in support of forecast capital activities and allocated based on forecast divisional capital expenditures;
- support staff (accounting and warehouse) labour and benefit costs based on estimated time in support of forecast capital activities and allocated based on forecast divisional capital expenditures; and
- field staff benefit costs (see Section 2.5.4.2 – Employee Benefit Load Rates) based on estimated direct capital labour costs for each division.

Table 24: Transfers to Capital

	$000's											
Expense Item	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Operating	(284)	(54)	23.3%	(230)	(49)	27.1%	(181)	(192)	(196)	(174)	(146)	(138)
Administrative and General	(406)	(132)	48.3%	(274)	217	(44.2)%	(491)	(495)	(357)	(320)	(301)	(370)
Total	(690)	(186)	36.9%	(504)	168	(25.0)%	(672)	(687)	(553)	(494)	(447)	(508)

Source: Tab Schedules, Tab 1, Pages 3 and 5

Total Transfers to Capital for Test Year 2018 are forecast to be lower in comparison to Decision 2017 primarily due to the effect of the PNG(NE) FSJ/DC forecast capital expenditures for Test Year 2018 decreasing to 31.4% of consolidated capital expenditures from 47.5% for Decision 2017. Transfers to capital for Test Year 2019 are forecast to increase due to forecast capital expenditures increasing to 60.7% of consolidated capital expenditures from 31.4% for Test Year 2018.

2.8 Property Taxes

Table 25: Property Taxes

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Property taxes	1,200	24	2.0%	1,177	9	0.7%	1,168	1,168	1,145	1,045	1,043	1,039
1% in lieu	171	42	32.8%	129	(77)	(37.4)%	205	205	205	160	158	188
Total	1,371	66	5.0%	1,305	(68)	(5.0)%	1,373	1,373	1,350	1,205	1,202	1,227

Source: Tab Schedules, Tab 1, Page 7

Total property taxes were $1,330,000 in 2017 resulting in a $43,000 property tax credit deferral which will be amortized in Test Year 2018. The Test Year 2018 and Test Year 2019 property taxes based on assessed values have been set at a 2% inflationary increase relative to Decision 2017. The 1 percent in lieu component of property taxes is based on revenues inside municipal boundaries and is affected by service rates and customer demand, with the Test Year 2018 and Test Year 2019 forecast amounts reflecting forecast changes in these variables from Decision 2017.

2.9 Depreciation

2.9.1 Depreciation Expense

The depreciation expense forecast for Test Year 2018 and Test Year 2019 reflects the findings of the recently completed depreciation study based on plant in service at December 31, 2016. The result is a reduction in depreciation expense compared to that which would have been calculated under the rate previously in place based on the parameters of a prior study, with Test Year 2018 depreciation expense decreasing to $1.856 million from $2.023 million for Decision 2017. Test Year 2019 depreciation expense is forecast to be $2.032 million. Further information on the depreciation study, and the implications of changes incorporated into the determination of depreciation expense is presented in the discussion that follows.

2.9.2 Depreciation Study and Rates

PNG(NE) last received approval to update its depreciation rates effective January 1, 2011 in the 2011 Negotiated Settlement Agreement (2011 NSP) approved under Commission Order G-93-11. The rates set at that time were based on a depreciation study conducted in 2010 by Gannett Fleming Inc. (acquired by Concentric Advisors ULC (Concentric) in 2017) based on plant in service at December 31, 2009 (2010 Depreciation Study).

PNG engaged Concentric to undertake a review of the depreciation rates for all service areas based on plant in service at December 31, 2016 (2017 Depreciation Study). A copy of the 2017 Depreciation Study is included as Appendix C. The 2017 Depreciation Study includes recommendations for both depreciation rates and net salvage rates.

PNG notes that it has deviated from the recommendations of the 2017 Depreciation Study on certain matters, as described below:

Net Salvage Values

The 2017 Depreciation Study makes recommendations on net salvage rates for certain accounts. The 2010 Depreciation Study included only recommendations for positive salvage values (i.e. anticipated proceeds on disposition) for certain accounts. In addition to recommendations for positive salvage values, the 2017 Depreciation Study also incorporates recommendations for negative salvage values (i.e. anticipated retirement costs) as directed by the Commission.

<u>Positive Salvage Values</u>

The 2010 Depreciation Study recommended positive salvage values for Account 484 – Transport Equipment and Account 485 – Heavy Work Equipment. PNG incorporated the positive salvage recommendation for Account 484 – Transport Equipment in its depreciation

provision as it determined that the recommended salvage was reflective of its experience of realizing proceeds on the disposition of assets in this account. For Account 485 – Heavy Work Equipment, PNG made the decision to not to incorporate the positive salvage recommendation based on the company's experience of owning and operating the equipment in this account for the entirety of their useful lives and of not realizing any proceeds on disposition.

PNG continues to abide by its previous determination on this matter and continues to only make provision for positive salvage on assets in Account 484 – Transport Equipment. If PNG(NE) were to record a provision for positive salvage in its depreciation of Account 485 – Heavy Work Equipment, depreciation expense for Test Year 2018 and Test Year 2019 would be lower by $11,900 and $12,300, respectively.

Negative Salvage Values

As noted, an element new to the 2017 Depreciation Study is the recommendation to incorporate negative salvage values into depreciation rates for certain accounts. This methodology provides for the recovery of the anticipated cost of removal at the end of an assets life through depreciation expense, as compared to PNG's historic practice of collecting the cost of removal in the year of occurrence.

While PNG recognizes that incorporation of negative salvage in depreciation rates matches with cost of the asset to the service it provides and preserves intergenerational equity, PNG has made the decision to not make provision for negative salvage on any of the applicable accounts identified in the 2017 Depreciation Study. PNG's basis for not incorporating negative salvage at this time is the materiality of the negative salvage estimates and the significant adverse rate impacts that will result from incorporating these estimates into depreciation expense. If PNG(NE) were to record a provision for negative salvage in its depreciation for the applicable accounts, depreciation expense for Test Year 2018 and Test Year 2019, would be greater by $823,000 million and $857,000 million, respectively.

Depreciation of Land Rights

Consistent with the 2010 Depreciation Study, the 2017 Depreciation Study recommends the depreciation of Land Rights (Accounts 461, 471 and 481) over a period of 75 years. At the time of implementing the recommendations of the 2010 Depreciation Study, PNG made the determination that its Land Rights had an indefinite life and as such should not be depreciated.

PNG continues to abide by this previous determination and has made no provision for depreciation of Land Rights in this Amended Application. If PNG(NE) were to record a provision for depreciation of Land Rights, depreciation expense for each of Test Year 2018 and Test Year 2019 would be greater by $9,900.

2.9.2.1 Depreciation Rates

Consistent with the prior study, Concentric has estimated the depreciation rates using various statistical methods, operation interviews with PNG staff and informed judgment based on their experience in the natural gas industry. For most accounts, the annual and accrued depreciation has been calculated by the straight-line method using the average life group procedure for the assets in a particular class. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. The application of these depreciation methodologies to the specified accounts in the 2017 Depreciation Study is consistent with those applied in the 2010 Depreciation Study.

A key finding in the 2017 Depreciation Study was the extension of the useful life of assets in many of the accounts. This finding is consistent with peer group utilities and management's expectations and estimates. The incorporation of this finding has had the effect of reduced depreciation expense for both Test Year 2018 and Test Year 2019.

2.9.2.2 Net Salvage

PNG(NE) does not currently record a provision for the estimated cost to ultimately retire assets currently in use (negative salvage value). PNG(NE), like many utilities, prefers to record actual costs of removal at the time incurred. This treatment is consistent with the practice of other utilities and is an allowable method under the Commission's Uniform System of Accounts.

PNG(NE) most recently obtained Commission approval to record depreciation (without a provision for negative salvage) in the 2011 Negotiated Settlement Agreement approved under Commission Order G-93-11. In the Commission decision on the PNG-West 2012 revenue requirements application approved under Commission Order G-130-12, PNG-West was directed to provide an analysis of the potential use of negative salvage accounting in its next revenue requirements application. In the Commission decision on the PNG-West 2013 revenue requirements application, approved under Commission Order G-114-13, the Commission accepted PNG-West's proposal to include the evaluation of the potential of using negative salvage accounting in it next depreciation study.

As directed by the Commission, the 2017 Depreciation Study incorporates recommendations for negative salvage values (i.e. anticipated retirement costs). However, PNG has made the decision to not make provision for negative salvage on any of the applicable accounts identified in the 2017 Depreciation Study. PNG's basis for not incorporating negative salvage is the materiality of the negative salvage estimates and the significant adverse rate impacts that will result from incorporating these estimates into depreciation expense at this time.

2.10 Amortization

The table below provides the gross amortization for specific deferral accounts and then a deduction of the future income taxes at the bottom of the table to show the after-tax amortization expense for Test Year 2018 and Test Year 2019 compared to Decision 2017.

Table 26: Amortization Expense

	Account Type		Amortization Expense ($000's)				
Deferral Account	Rate Base - RB WACD Int - WACD Short-term Int - STI	Amortization Period (in Years)	Test Year 2019	2019 to 2018 Change	Test Year 2018	2018 to Decision 2017 Change	Decision 2017
Plant Gains and Losses	RB	5	164	(52)	216	65	151
Demand Side Management	RB	5	54	33	21	(27)	48
Resource Plans	STI	1	0	(7)	7	7	0
BCUC Fees	STI	1	0	3	(3)	(3)	0
Short Term Interest	STI	1	0	6	(6)	(6)	(0)
Long Term Interest	STI	1	0	10	(10)	(9)	(1)
Property Tax Variance	STI	1	0	1	(1)	(1)	0
BCUC Hearing & CAP/ROE App.	STI	1	0	81	(81)	(81)	0
DC Industrial Deliveries	STI	1	0	(75)	75	75	0
Old Revolving Debt Issue Costs	STI	1	(0)	(6)	6	6	0
Permanent to Interim Rate Adj	STI	1	0	0	0	0	0
Revenue Requirement Adj	STI	1	0	0	0	0	0
Investigative Digs	STI	1	0	19	(19)	(19)	0
Pension / NPPRB	WACD	3	11	(0)	11	11	0
Legacy Deferred Income Taxes	IntB	6	0	77	(77)	2	(79)
Non-Pension Benefits Obligations	N/A	6	0	(102)	102	(0)	102
		Subtotal	229	(11)	240	20	220
		Future Income Taxes	(34)	(14)	(20)	11	(31)
		Net Total	194	(25)	220	31	189

Under Tab Schedules, Tab 1, page 1, the computation of Utility Income and Return presents the gross amortization expense figure in computing earned return and then presents an offsetting deduction to income tax expense equal to the future income tax associated with the amortization expense. More detailed commentary is provided below in the context of each deferral account.

Plant Gains and Losses

Under Decision 2012, the Commission approved the use of this deferral account to track the historical extraordinary plant losses, the under depreciated value of assets that were retired but not fully depreciated (i.e. recoverable from customers) or over depreciated (i.e. to be credited to customers), to record gains and losses from the disposition of assets in the ordinary course of business and to record costs incurred when assets are taken out of service. The Commission also directed PNG(NE) to track these components separately and to amortize these Plant Gains and Losses deferral accounts over five years. These components categorized as extraordinary, ordinary, salvage value and retirement costs are noted in Tab 2, Pages 10 to 12.

The increase in amortization in Test Year 2018 compared to Decision 2017 reflects the amortization of additions of $215,000 of net plant losses recorded in 2016 and additions of $122,000 of plant gains or losses or salvage values arising from the disposal or retirement of assets in 2017.

The decrease in amortization in 2019 compared to Test Year 2018 reflects nil amortization of assets that were retired prior to 2014 that are fully amortized by the end of 2018.

Demand Side Management

In June 2015, PNG and PNG(NE) submitted a Consolidated Energy Management and Efficiency Program Funding Application (Demand Side Management (DSM) Funding Application) seeking approval for funding of various DSM programs and proposed that the DSM expenditures (for PNG(NE): $55,000 in 2015; $182,000 in 2016; and $165,000 in 2017) be included in a rate base deferral account. Under Commission Order G-203-15A, PNG(NE) was directed to amortize these DSM expenditures over a 5-year period.

The amortization in Test Year 2018 and Test Year 2019 reflect actual DSM expenditures incurred of $55,000 in 2015 and $16,000 in 2016, and $33,000 in 2017 and forecast expenditures of $165,000 in Test Year 2018. In accordance with order G-203-15A, details of PNG's DSM programs and expenditures are reported to the Commission in an annual report that must be filed by April 30th of the immediately following year. This report also provides a comparison of accepted budget to expenditures actually incurred, a description of key milestones achieved in the delivery of programs, an update on new programs or expansion of programs, as well as an evaluation of the programs.

Resource Plans

This deferral account records the variance between actual and forecast costs incurred in the PNG(NE) Resource Plans filed every few years. The Test Year 2018 amortization reflects PNG(NE)'s share of the costs incurred to participate in the 2016 BC Conservation Potential Review for electricity and natural gas undertaken by the utilities in British Columbia.

BCUC Fees

This account records the variance between actual and forecast BCUC fees. In 2016, PNG(NE) recorded a credit deferral of $1,000 and has recorded a credit deferral addition of $3,000, both to be fully amortized in Test Year 2018. This remains an interest bearing deferral account with a one year amortization period.

Short Term Interest and Long Term Interest

The short term interest deferral account records the impact of differences between the underlying customer security deposit and short term operating line interest rates. The long term interest deferral account records the impact of differences between the underlying long term forecast interest rates and actual interest rates. There will be no changes to how these deferral accounts will be administered in Test Years 2018 and 2019 compared to what has applied over the last several years. Each remains an interest bearing deferral account with a one year amortization period.

Property Tax Variance

This deferral account records the difference between budgeted property tax costs used for rate-setting purposes and actual costs incurred. The Test Year 2018 amortization reflects the actual 2016 addition of $41,000 offset by the actual credit addition for 2017 of $43,000.

BCUC Hearing & CAP/ROE App

This deferral account records the variance between budgeted costs used in rate-setting purposes and actual costs incurred. The 2016 addition of $36,000 and 2017 addition of $42,000 to this deferral account noting positive variances for actual BCUC hearing costs are fully amortized with interest in Test Year 2018. This remains an interest bearing deferral account with a one year amortization period.

DC Industrial Deliveries

This deferral account records the variance between the forecast margin used to set rates and actual margin recovery from two industrial customers located in the Dawson Creek service area. The Test Year 2018 amortization reflects the 2016 lower than forecast deliveres partially offset by the 2017 higher than forecast deliveries to these industrial customers.

Old Revolving Debt Issue Costs

This deferral account represents the unamortized balance of debt issue expenses relating to the existing 2015 Revolving Term Facility. In accordance with PNG(NE)'s refinancing application dated November 23, 2017, upon termination of the existing Revolving Term Facility, the unamortized balance of the debt issue expenses would be transferred into this account for amortization over what would have been the remaining term of the current Revolving Term Facility had it not been replaced prior to maturity. The deferral account balances currently reflect termination of the existing Revolving Term Facility on November

30, 2017 and amortization of the account balance over the period December 2017 through May 2018.

Investigative Digs

Also in Decision 2013, PNG(NE) was directed to record the costs of investigative digs in its cost of service and establish a new deferral account for any variances in actual investigative costs incurred that are to be amortized the following year. There is nil amortization for for Test Yeas 2018 2019 is nil as PNG(NE) has not forecast any variances for 2016 and 2017.

UAF Losses 2016

This short term interest bearing deferral account was established under Order G-105-17 following the Commission's decision to deny PNG(NE)'s Application for Approval of 2016 UAF losses above 1.5 Percent. PNG(NE)'s proposal for the recovery of these losses is addressed in Section 2.2.3 – Unaccounted for Gas of this Amended Application.

Legacy Deferred Income Taxes

This account records the legacy FSJ/DC deferred income taxes which the Commission directed PNG(NE) to amortize the remaining balance over 6 years in PNG(NE)'s pension and non-pension post-retirement benefits plans application's Decision (Order G-89-13) and reiterated the same directive in Decision 2013 (Order G-131-13). This deferral account earns interest at PNG(NE)'s WACD with such interest being amortized in the year earned in addition to the amortization of the principal balance. Test Year 2018 reflects the final year of amortization of the legacy deferred income taxes. PNG(NE) therefore requests the dissolution of this deferral account after Test Year 2018.

Non-Pension Benefits Obligations

Under Decision 2012, the Commission approved PNG(NE)'s request to establish a regulatory asset equal to the Non-Pension Post-Retirement Benefit (NPPRB) unamortized transitional liability in a non-interest bearing deferral account to be amortized into rates over 7 years. Under the 2013 Pension Decision, the Commission approved PNG's request to establish a NPPRB Regulatory Asset Deferral account equal to the historical unrecovered NPPRB expense. This account is to be a non-rate base, non-interest bearing account with no further additions and is to be amortized over six years commencing January 1, 2013 with an equal and offsetting amortization of the deferred income tax balance (see Legacy Deferred Income Taxes. Test Year 2018 represents the sixth and final year of this amortization, therefore there is no amortization provided for in Test Year 2019. PNG(NE) therefore requests the dissolution of this deferral account after Test Year 2018.

2.11 Miscellaneous Other Income & Credits

Table 27: Miscellaneous Operating Revenues and Credits

Revenue/Credit Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Penalty charges	90	-	0.0%	90	5	6.1%	85	74	70	84	86	83
Connection fees	138	-	0.0%	138	-	0.0%	138	134	125	127	140	138
Overheads recovered	44	-	0.0%	44	17	65.4%	26	18	47	40	40	13
Other	2	-	0.0%	2	(15)	(86.5)%	18	-	6	5	43	10
Total	274	-	0.0%	274	7	2.6%	267	227	249	256	309	244

Source: Tab Schedules, Tab 1, Page 8

The other income for Test Year 2018 and Test Year 2019 is forecast based on recent experience and is comparable to other income for Decision 2017.

2.12 Income Taxes

Table 28: Income Taxes

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Income Taxes	498	42	9.3%	456	(43)	(8.6)%	499	502	311	182	409	204
Future Income Taxes	(34)	(14)	n/a	(20)	11	n/a	(31)	(31)	9	144	46	103
Total	464	28	6.4%	436	(32)	(6.8)%	468	471	320	326	456	307

Source: Tab Schedules, Tab 3, Page 1

The Test Year 2018 and Test Year 2019 income taxes reflect the recent increase to 27% in the corporate rate applicable to British Columbia commencing January 1, 2018. This rate is 1% higher than the rate that applied in 2017.

The Test Year 2018 income tax provison is $32,000 lower than the Decision 2017 provision. An increase in return on equity combined with the increased tax rate is more than offset by capital cost related timing differences. The credit timing differences have increased due to capital cost allowance (CCA) deductions allowed for tax purposes rising at the same time as the proposed depreciation provision falls in accordance with PNG(NE)'s recent depreciation study. Both the increased return on equity and the rising CCA deductions are due to the relatively large capital additions in PNG(NE) over the Decision 2017 to Test Year 2018 period. The 2018 provision for amortization of future income taxes has been increased by $2,000 to adjust for the impact that the corporate tax rate increase in British Columbia has had on the aggregate future income tax (FIT) provision for PNG(NE)'s deferred charges.

The $28,000 increase in the income tax provision for Test Year 2019 over Test Year 2018 is largely attributable to: (i) reduced credit timing differences due to there not being any contributions to PNG(NE)'s retirement compensation arrangement related to the recovery of historical non-pension post retirement expenses; and, (ii) a further increase in the return on equity. The tax deductible contributions to PNG(NE)'s retirement compensation arrangement were made using historical non-pension post retirement expense recoveries which will be completed in 2018.

2.13 Rate Base

2.13.1 Plant in Service

2.13.1.1 Capital Additions

The capital expenditure program for PNG(NE) varies year-to-year depending on requirements for new or replacement facilities and equipment. The table that follows provides a historic view of recent capital expenditure levels (excluding work in progress).

Table 29: Capital Expenditures

	$000's											
Capital Expenditure Element	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Expenditure Including Overhead	7,094	(906)	(11.3)%	8,001	3,277	69.4%	4,724	5,406	5,892	6,846	7,102	7,731
Less: Capitalized Overhead	(818)	(251)	44.2%	(567)	167	(22.7)%	(734)	(765)	(625)	(550)	(537)	(565)
Net Expenditures Before Overhead	6,276	(1,157)	(15.6)%	7,433	3,444	86.3%	3,990	4,641	5,267	6,296	6,565	7,166

Source: Tab Schedules, Tab 2, Page 2 to 5

Significant Capital Expenditures

The tables that follow set out planned capital additions for each of Test Year 2018 and Test Year 2019 broken down by capital project items with a cost in excess of $50,000, and reflecting what Plant in Service Accounts will be impacted. Also note that the table provides a categorization of the capital expenditure, including:

System Betterment – includes expenditures to ensure the ongoing safety, reliability and integrity of the transmission and distribution systems; for system reinforcements, renewals and alterations to the distribution and transmission systems to ensure adequate capacity exists to meet existing and forecast load requirements; and for meter recall and meter exchange programs.

New Business – includes expenditures for the installation of new mains, services, meters and other facilities to provide service to new customers.

General Plant – includes expenditures for equipment, tools, facilities and IT hardware.

General Plant Intangibles – includes IT software & licenses.

Test Year 2018 – Significant Capital Expenditures

Table 30: Test Year 2018 Capital Expenditures

2018 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	Budgeted Cost Excluding Overhead
Planned - Recurring			
New Services	NB	473	848,957
Distribution Main Improvement - Mechanical Couplings	SB	475	490,188
Distribution Main Improvement - Other	SB	475	460,941
Distribution Mains	NB	475	444,737
Distribution Main Improvement - PE2306 Replacement	SB	475	320,476
Meter and Regulator Purchases	NB	474/478	254,847
Mobile/Heavy Equipment	GP	484/485	204,643
New/Replacement Tools and Equipment	GP	486	90,372
New/Replacements Meters	NB	474	55,524
			3,170,685
Other Minor Projects <$50,000	Various	Various	41,382
Subtotal			3,212,068
Planned - Non-recurring			
North Pine Pipe Purchase - FSJ	NB	465	1,700,000
DC Gate #1 Station Replacement	SB	467	1,121,300
Cecil Lake Aluminum Replacement - FSJ	SB	465	282,423
Geotechnical Information System	GP	487	242,128
Main Repairs and Assessments	SB	475	235,855
Replace Line Heaters	SB	467	222,988
Steel Main Replacement - DC	SB	465	158,245
Underground Fitting Removal - DC	SB	465	140,054
			4,102,992
Other Minor Projects <$50,000	Various	Various	118,371
Subtotal			4,221,363
Total Capital Expenditures without Overhead			7,433,431

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

The specific major capital projects identified in the table above account for substantively all of the capital expenditures forecast for 2018, excluding overhead. The balance of 2018 expenditures represent a number of minor capital projects budgeted to ensure PNG(NE) continues to provide its customers with safe, reliable and secure gas delivery service in 2018 and the future. Further details on the noted major capital projects for 2018 are provided in the discussion that follows.

Planned – Recurring Capital Expenditures

New Services ($849,000)

The forecast 2018 expenditures in this area include installing new distribution service lines to meet the needs of new customers.

Distribution Main Improvements – Couplings ($490,000); Other ($461,000); PE2306 Replacement ($320,000)

For Test Year 2018, the removal of mechanical couplings on the distribution system of Dawson Creek and Fort St. John will continue at a forecast cost of $490,000. The replacement of PE2306 pipe at an estimated cost of $320,000 will also occur. The installed mechanical couplings and PE 2306 piping have been shown to experience failures and pose a risk to the interity of the natural gas supply system. These ongoing integrity projects are focused on reducing the risk to sytem integrity and improving system safety and reliability. Other distribution main improvements include a provision of $461,000 for the lowering of distribution main in public thoroughfares to meet the needs of changes to the surrounding roadway and to avoid conflict with new civil works and ensure the on-going safety of the pipe.

Distribution Mains ($445,000)

The forecast 2018 expenditures relate to new distribution mains and are all related to providing service to new customers (residential, commercial, industrial) throughout the Fort St. John and Dawson Creek service areas. Growth continues in the region with both residential and commercial growth and the resultant economic development has created opportunities to provide natural gas infrastructure to service this demand.

Meter and Regulator Purchases ($255,000)

Historically the meter testing and re-verification process has been utilized to minimize the lifecycle cost of the meters while ensuring compliance with the accuracy requirements established in the *Electricity and Gas Inspection Act*. However, the useful life of a meter is not infinite and ultimately they must be replaced as they become no longer economical to re-build. The number of meters that require replacement rises as the average age of the meters in service increases. The 2018 budget for replacing meters which are not suitable for repair and for acquiring new incremental meters (for new customers) is $255,000.

Mobile/Heavy Equipment ($205,000)

In Test Year 2018, PNG(NE) will be replacing two pick-up trucks, one three-quarter ton pick-up and one half-ton pick-up, with the same vehicle type as the old units meet the replacement criteria of 7 years or 160,000 km, whichever comes first. Details of the vehicles to be replaced are as shown below:

Unit #	Year Purchased	Status
825	2011	>7 years
268	2010	>7 years

New/Replacement Tools and Equipment ($90,000)

There are a variety of minor components that are included in this expenditure item. Tools, equipment or instruments range in cost between $1,000 and $14,000.

New/Replacement Meters ($56,000)

Costs included in this classification relate to incidental installation costs for meter sets, including manifolds and meter guards.

Planned – Non-recurring Capital Expenditures

North Pine Pipeline – FSJ ($1,700,000)

On December 4, 2017, PNG(NE) filed an application for a Certificate of Public Convenience and Necessity (CPCN) to acquire ownership of and to operate a new 5.3 kilometer fuel gas pipeline that will provide natural gas transportation service to the AltaGas Northwest Processing Limited Partnership at its North Pine Facility. The contractual arrangements have a price cap of $1.8 million, however, recent estimates put the capital expenditure closer to $1.7 million.

Replace Dawson Creek #1 Gate Station – DC ($1,121,000)

As the main natural gas regulating station that supplies the City of Dawson Creek, the Dawson Creek #1 Gate Station is critical infrastructure for PNG(NE). The station is at end of life, with a building structure that is failing and obsolete, and redundant piping and equipment within. The station is a vault style with limited access/egress in the case of an emergency, and piping, valve, and fitting arrangements within the station yard do not meet current standards for safe operation. This replacement project is required to ensure the station and related facilities are in full compliance with safety and integrity related standards

and regulations. At this time, PNG has compleed the front-end engineering and has developed a thorough Class III estimate, including complete vendor budgetary pricing for all materials and services.

Cecil Lake Aluminum Replacement – FSJ ($282,000)

The scope of this project is to replace the aluminum pipeline infrastructure in the Cecil lake area. In 2018, PNG(NE) will engage in planning, engineering, permitting and procurement, with full construction planned in 2019. The reason for the replacement is that aluminum natural gas pipelines are no longer commonly used, posing an integrity risk. Further, PNG(NE) currently does not have the in-house specialized training or tooling to respond and repair emergency events. With this limitiation, a phased approach is planned that will have the piping replaced with standard PE piping. This will allow area resources to better respond to and execute emergency repairs as well as conduct standard maintenance activities.

Geographic Information System ($242,000)

PNG plans to implement a Geographic Information System (GIS) to improve its asset management capacity as it sees its current system and processes as untenable over the long term. In the third quarter of 2017, PNG engaged an engineering/geomatics consultancy firm to execute a needs assessment and requirements project to support the GIS initiative. The primary motivating factors for moving forward with a GIS implementation are: (1) develop an authoritative system of record with regard to PNG's assets; (2) provide an enterprise-wide system to allow PNG staff (particularly field staff) to operate much more efficiently and consistently; (3) improve integration between key business systems; (4) improve capabilities and capacity for reporting and regulatory compliance (i.e. CSA standards, BC Oil and Gas Commission and Technical Safety BC regulations, Association of Professional Engineers and Geoscientists of BC (APEGBC) bylaws); and (5) incorporate contemporary industry best-practices and technology to PNG's operations. Based on a comprehensive assessment of alternatives, PNG has plans to execute implementation recommendations over a three-year period (2018 to 2020). The overall project cost is estimated at $2.4 million, which will be incurred over three years and will be shared by PNG-West and PNG(NE) service areas.

Main Repairs and Assessments ($235,000)

This program has been developed to address the results of Close Interval Surveys (CIS) on the transmission pipeline system. The PNG(NE) transmission pipeline system is generally too small of diameter to have inline inspection (ILI) tools, so to comply with integrity management planning and industry standards, CIS have been conducted. The expenditures will be focused on assessing and repairing damaged pipelines identified through CIS.

Line Heater Replacements ($223,000)

This item consists of replacing line heaters at stations in the Baldonnel and Kiskatinaw areas. The two line heaters have reached the end of their useful life and are no longer fit for service as the load requirements have increased beyond their capabilities. As reliable operation can no longer be assured, each of the above heaters will be replaced with contemporary line heater technology which will reduce fuel gas consumption and eliminate the possibility of an ethylene glycol spill should there be a failure of the line heater.

Steel Main Replacement – DC ($158,000)

The original high pressure pipelines serving Dawson Creek were installed in the mid-1950's. Pipe of this vintage needs to be replaced to ensure the future integrity and reliability of the pipeline system. A replacement program has been initiated to identify all steel piping systems by age and material composition. Once steel piping is risk ranked, a plan will be executed that will result in the removal of the vintage steel pipe and replacement with either new steel construction or PE piping. This will ensure continued safe and reliable operation of the natural gas distribution system.

Underground Fitting Removal – DC ($140,000)

Historically, piping installation techniques allowed for the use of underground flanged/bolted connections. Over time, with ground movement and typical corrosion and aging, these types of connection are more susceptible to exhibiting leaks. The current high pressure mains in the Dawson Creek area were constructed with this method and now pose an increasing risk to safety, operation and system integrity. Investigative digs and analysis will be executed to locate, identify and remove these fittings on the high pressure natural gas system.

Test Year 2019 – Significant Capital Expenditures

Table 31: Test Year 2019 Capital Expenditures

2019 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	Budgeted Cost Excluding Overhead
Planned - Recurring			
New Services	NB	473	1,021,938
Distribution Mains	NB	475	586,551
Distribution Main Improvement - Mechanical Couplings	SB	475	510,187
Distribution Main Improvement - Other	SB	475	479,793
Mobile/Heavy Equipment	GP	484/485	381,609
Distribution Main Improvement - PE2306 Replacement	SB	475	333,479
Meter and Regulator Purchases	NB	474/478	265,143
New/Replacements Meters	NB	474	57,921
			3,636,620
Other Minor Projects <$50,000	Various	Various	26,855
Subtotal			3,663,474
Planned - Non-recurring			
Cecil Lake Aluminum Replacement - FSJ	SB	465	1,065,402
Geotechnical Information System	GP	487	376,860
Main Repairs and Assessments	SB	475	287,465
Station Modifications	SB	467	166,629
Steel Main Replacement - DC	SB	465	156,068
Baldonnel Line Lowering - Phase 1 - FSJ	SB	465	140,814
Underground Fitting Removal - DC	SB	465	140,001
Block Valve Installation - DC	SB	465	103,534
Structure Improvements	GP	482	95,880
Pennwest Pipeline Replacement FEED Study	SB	465	80,000
			2,612,652
No Other Minor Projects <$50,000	Various	Various	-
Subtotal			2,612,652
Total Capital Expenditures without Overhead			6,276,127

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

The specific major capital projects identified in the table above account for substantively all of the capital expenditures forecast for 2019, excluding overhead. The balance of 2019 expenditures represent a number of minor capital projects budgeted to ensure PNG(NE) continues to provide its customers with safe, reliable and secure gas delivery service in 2018 and the future. Further details on the noted major capital projects for 2019 are provided in the discussion that follows.

Planned – Recurring Capital Expenditures

New Services ($1,022,000)

The forecast 2019 expenditures in this area include installing new distribution service lines to meet the needs of new customers.

Distribution Mains ($587,000)

The forecast 2019 expenditures relate to new distribution mains and are all related to providing service to new customers (residential, commercial, industrial) throughout the Fort St. John and Dawson Creek service areas.

Distribution Main Improvements – Couplings ($510,000); Other ($480,000); PE2306 Replacement ($333,000)

Further to the Test Year 2018 capital expenditures, the removal of mechanical couplings on the distribution system of Dawson Creek and Fort St. John will continue in Test Year 2019 at a forecast cost of $510,000. The replacement of PE2306 pipe at an estimated cost of $333,000 will also occur. Both of these activities will assist in ensuring the long term, safe and reliable operation of the distribution system. Other distribution main improvements include a provision of $480,000 for the lowering of distribution main in public thoroughfares to meet the needs of changes to the surrounding roadway and to avoid conflict with new civil works and ensure the on-going safety of the pipe.

Mobile/Heavy Equipment ($382,000)

In Test Year 2019, PNG(NE) will be replacing four three-quarter-ton pick-up trucks and two half-ton pick-up with the same type of vehicles as the old units meet the replacement criteria of 7 years or 160,000 km, whichever comes first. Details of the vehicles to be replaced are as shown below:

Unit #	Year Purchased	Status
826	2011	>7 years
829	2011	>7 years
847	2012	>7 years / >160,000 km
851	2012	>7 years / >160,000 km
871	2013	>160,000 km
878	2013	>160,000 km

Also forecast for Test Year 2019 is the replacement of an enclosed trailer and an air compressor, both of which have reached the end of their useful life.

Meter and Regulator Purchases ($265,000)

Historically the meter testing and re-verification process has been utilized to minimize the lifecycle cost of the meters while ensuring compliance with the accuracy requirements established in the *Electricity and Gas Inspection Act*. However, the useful life of a meter is not infinite and ultimately they must be replaced as they become no longer economical to re-build. The number of meters that require replacement rises as the average age of the meters in service increases. The 2019 budget for replacing meters which are not suitable for repair and for acquiring new incremental meters (for new customers) is $265,000.

New/Replacement Meters ($58,000)

Costs included in this classification relate to incidental installation costs for meter sets, including manifolds and meter guards.

Planned – Non-recurring Capital Expenditures

Cecil Lake Aluminum Replacement – FSJ ($1,065,000)

The scope of this project is to replace the aluminum pipeline infrastructure in the Cecil Lake area, as described in the discussion of 2018 signficiant expenditures. This is the second phase of the project. With planning, engineering, procurement and permitting completed in 2018, PNG(NE) will move into full construction in 2019.

Geographic Information System ($377,000)

Further to the description for 2018 capital projects, this expenditure represents the second year of a 3-year implementation program for PNG's corporate GIS being pursued in order to improve its asset management capacity. Funds will be allocated to IT related costs, business applications, data acquisition, training and administration. During this stage, PNG expects to be in a position where significant amounts of data have been collected and integrated into the Esri geodatabase platform.

Main Repairs and Assessments ($287,000)

Further to the description for 2018 capital projects, this item represents 2019 expenditures related to assessing and repairing damaged pipelines identified through CIS.

Station Modifications ($167,000)

Site 10 gate station is to be relocated to reduce the risk to employees while servicing the station and also to reduce the risk to the station in the event of a vehicle collision. This older generation regulating station will be replaced by a new station designed as per PNG(NE)'s regulating station standards that will be relocated away from the busy intersection, improving employee safety and ensuring station integrity.

Steel Main Replacement – DC ($156,000)

Further to the description for 2018 capital projects, this item represents the 2019 expenditures related to the program to replace vintage steel pipe with either new steel construction or PE piping to ensure continued safe and reliable operation of the natural gas distribution system.

Baldonnel Line Lowering – Phase 1 – FSJ ($141,000)

PNG(NE) must lower its lines at Baldonnel due to geotechnical concerns at a nearby sewage lagoon and coulee. Phase 1 includes all aspects required to develop a technical design, geotechnical review, geotechnical drilling, fish habitat assessments, regulatory requirements and permitting. PNG(NE) Phase 2 will be the construction phase expected to take place in 2020.

Underground Fitting Removal – DC ($140,000)

Further to the description for 2018 capital projects, this represents the 2019 expenditures related to an underground fitting removal program consisting of investigative digs and analysis to locate, identify and remove underground flanged/bolted fittings on the high pressure natural gas system.

Block Valve Installation – DC ($104,000)

Isolation valves are used to isolate specific segments of the pipeline system for emergency response and planned maintenance. Having sufficient numbers of isolation valves with adequate spacing for response purposes is a requirement of CSA Z662.

Structure Improvements ($96,000)

Structural improvements are required at the Dawson Creek yard. This site encompasses office facilities, materials storage and equipment storage. The current hard surface paving in the complex is breaking up and creating hazards, therefore it will be removed, a solid base established and hard surface paving will follow.

Replace PennWest Pipeline – DC ($80,000)

The PennWest pipeline connects the Spectra MS 52 Meter Station to the Sunrise Lateral, the main feed to the Dawson Creek natural gas system. PNG(NE) is of the belief that the 1940's era 2.4 km pipeline has likely reached the end of its life, with a high probability of needing replacement. This project involves completing the engineering assessment and pre-FEED work to make a final determination regarding replacement and developing a cost estimate.

Carryforward Projects

At this time, PNG(NE) is unable to anticipate major projects from Test Year 2018 that may be carried forward to Test Year 2019.

Capitalized Overhead Allocation

Gross capital additions include capitalized overheads comprised of capitalized operating, administrative and general and equipment depreciation expense amounts. Additional information on capitalized operating and capitalized administrative and general expenses can be found in Section 2.7 – Transfers to Capital (Capitalized Overhead).

PNG(NE) also capitalizes depreciation expenditures related to equipment in certain asset classes that is directly involved in capital projects, specifically BCUC 484 – Transportation Equipment and BCUC 485 – Heavy Work Equipment. The allocation methodology involves applying the actual percentage of equipment hours used for capital work of the total equipment hours worked to allocate the actual depreciation expense to capital projects.

2.13.1.2 Contributions in Aid of Construction

PNG(NE) receives contributions in aid of construction (CIAC) in the form of a cash payment by a customer towards a project that is related to their service request, either provided on their own initiative or as may be required in order for the project in question to be deemed economic. CIACs have the effect of decreasing the applicable capital costs rolled into PNG(NE)'s rate base. Details of forecast and historic CIACs received by PNG(NE) can be found under Tab Schedules, Tab 2, page 30.

2.13.1.3 Depreciation Expense

As noted previously under Section 2.9 – Depreciation, depreciation expense is calculated using depreciation rates determined following the recently completed 2017 Depreciation Study and the historical methodology of recording depreciation on additions to plant and equipment commencing in the following year an asset is placed in service. Details of forecast and historic accumulated depreciation, including Test Year 2018 and Test Year 2019 Depreciation Expense, can be found under Tab Schedules, Tab 2, on pages 7 through 10.

2.13.2 Post-Retirement Benefit Plans

Pension Funding and Expense

The details of PNG(NE)'s pension funding and expense rate base item is found under Tab Schedules, Tab 2, page 32. PNG(NE) has calculated its rate base pension asset in accordance with the 2013 Decision on its consolidated 2012 Pension and Non-Pension Benefits Application. Forecast cash contributions to PNG(NE)'s pension plan for Test Year 2018 and Test Year 2019 reflect expected normal cash contributions as well as special contributions. PNG(NE) notes that its 2016 pension valuation identified a solvency deficiency such that, commencing once again in 2017, there is a requirement for PNG(NE) to make special cash contributions to its registered pension plan.

Non-Pension Post Retirement Benefits

While PNG(NE) does not have a rate base asset or credit associated with non-pension post-retirement benefits (NPPRB) due to the Commission's requirement that PNG(NE) continue to contribute funds recovered from customers in excess of NPPRB premiums paid to its retirement compensation arrangement (RCA), PNG(NE) has provided continuity schedules under Tab Schedules, Tab 2, page 33. As shown in the referenced schedule, PNG(NE) expects to make cash contributions of $128,000 to its RCA in Test Year 2018, up from $174,000 in Decision 2017. However, the cash contributions are expected to drop to $94,000 in Test Year 2019 as Test Year 2018 represents the sixth and final year of amortization of regulatory assets associated with historical NPPRB expense. In accordance with the Commission's 2012 and 2013 decisions on these matters, the amortization recovered in PNG(NE)'s rates has been contributed to PNG(NE)'s RCA. PNG(NE) notes that the Test Year 2018 amortization amount of $102,000 is unchanged from Decision 2017.

2.13.3 Deferral Accounts

Schedules supporting PNG(NE)'s deferral accounts can be found under Tab Schedules, Tab 2, pages 12 through 15, including continuity schedules that detail additions/reductions to and amortization of individual account balances. Further details on individual deferral accounts can be found in Section 2.10 – Amortization, including historical background information and information on the classification of each account.

2.13.4 Working Capital

Cash Working Capital

The table below provides a history of PNG(NE)'s cash working capital requirements as calculated in accordance with previous Commission decisions. Further information on Cash Working Capital can be found under Tab Schedules, Tab 2, pages 16 through 28.

Table 32: Cash Working Capital

	Test Year	2019 to 2018 Change		Test Year	2018 to Decision 2017 Change		Decision	Actual	Actual	Actual	Actual	Actual
	2019	$	%	2018	$	%	2017	2017	2016	2015	2014	2013
Revenue lag days	58.1	(0.0)	(0.0)%	58.1	(0.1)	(0.1)%	58.2	58.2	58.2	57.8	57.6	57.7
Expense lead days	35.0	0.3	1.0%	34.7	(1.4)	(3.9)%	36.1	34.0	31.5	35.8	37.4	35.3
Net lag days	23.1	(0.4)	(1.5)%	23.4	1.3	6.0%	22.1	24.2	26.7	22.0	20.2	22.4
(000's)												
Annual expenses	$ 19,774	$ 1,550	8.5%	$ 18,224	$ (3,188)	(14.9)%	$ 21,412	$ 19,248	$ 15,102	$ 21,716	$ 26,562	$ 20,782
Operating working capital requirement	$ 1,251	$ 80	6.9%	$ 1,170	$ (125)	(9.7)%	$ 1,295	$ 1,274	$ 1,105	$ 1,307	$ 1,466	$ 1,274
Adjustments:												
Budget Billing Plan	(511)	(19)	3.9%	(492)	36	(6.9)%	(529)	(228)	(772)	(1,088)	(960)	(567)
Allowance for Doubtful Accounts	(81)	(53)	186.5%	(28)	53	(65.1)%	(81)	(31)	(44)	(62)	(81)	-
Carbon Tax	94	6	6.7%	88	6	7.2%	82	74	65	71	81	79
GST	68	(0)	(0.4)%	68	2	2.8%	66	53	57	85	104	63
PST & ICEF Levy	21	2	8.7%	19	(0)	(2.2)%	20	21	17	24	29	-
HST	-	-	n/a	-	-	n/a	-	-	-	-	-	69
Cash working capital	$ 841	$ 16	1.9%	$ 825	$ (29)	(3.3)%	$ 854	$ 1,164	$ 427	$ 338	$ 639	$ 918

Source: Tab Schedules, Tab 2, Page 16 and 23

PNG(NE) has not completed new lead/lag studies for its 2018-2019 revenue requirements application and therefore relies on lead/lag analysis in accordance with previous Commission decisions. Cash working capital requirements decrease in Test Year 2018 relative to Decision 2017 largely as a result of lower gas acquisition costs. The reductions in working capital requirements due to lower gas costs are expected to be partially offset by a lower budget billing credit and a lower allowance for doubtful accounts. Operating working capital requirements increase in Test Year 2019 over Test Year 2018 due to expected higher expenses of which the majority is rising gas acquisition costs.

Other Working Capital

Details of Other Working Capital are found under Tab Schedules, Tab 2, page 22 and 29. The reduction in the Test Year 2018 provision of $510,000 relative to the Decision 2017 provision of $838,000 is due to the reduced commodity cost of gas being reflected in projected gas storage inventories. In Test Year 2019 the provision for Other Working Capital increases to $818,000 due to expected increases in the commodity cost of natural gas being reflected in gas storage inventories.

For context, the simple average Station 2 strip in Decision 2017 was $2.34 per GJ, dropping to $1.29 per GJ in Test Year 2018 before rising again to $1.71 per GJ in Test Year 2019.

2.14 Capital Structure and Return on Capital

Table 33: Capital Structure

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Short-term Debt												
Balance ($000's)	4,053	684	20.3%	3,369	488	16.9%	2,881	1,958	6,188	3,964	2,489	3,762
Proportion (%)	5.26%	0.04%	0.82%	5.22%	(0.00)%	(0.08)%	5.22%	2.91%	9.76%	6.67%	4.52%	7.80%
Long-term Debt												
Balance ($000's)	41,421	6,683	19.2%	34,738	5,058	17.0%	29,680	37,199	30,550	30,139	30,100	24,444
Proportion (%)	53.74%	(0.04)%	(0.08)%	53.78%	0.00%	0.01%	53.78%	55.20%	48.20%	50.70%	54.61%	50.68%
Common Equity												
Balance ($000's)	31,601	5,120	19.3%	26,481	3,854	17.0%	22,627	28,228	26,645	25,347	22,533	20,025
Proportion (%)	41.00%	0.00%	0.00%	41.00%	0.00%	0.00%	41.00%	41.89%	42.04%	42.64%	40.88%	41.52%
Total Capitalization ($000's)	77,075	12,487	19.3%	64,588	9,401	17.0%	55,187	67,384	63,383	59,450	55,122	48,231

Source: Tab Schedules, Tab 5, Page 1

2.14.1 Financing Costs

Table 34: Interest Expense

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Short-term Debt	182	2	1.4%	180	36	25.1%	144	93	218	127	75	153
Long-term Debt	1,760	188	12.0%	1,572	356	29.3%	1,216	1,237	993	1,166	1,161	1,065
Total	1,942	191	10.9%	1,751	392	28.8%	1,359	1,329	1,211	1,294	1,237	1,217

Source: Tab Schedules, Tab 5, Pages 2 and 3

Short-term Debt Interest Expense

The short-term debt component of PNG(NE)'s capital structure for rate making purposes is set to comprise approximately 5 percent of rate base in Test Year 2018. The 5 percent level reflects the fact that the substantial majority of assets comprising rate base are long-term in nature and should be funded with capital that is also long-term in nature.

The short-term debt interest expense for 2018 is higher than 2017 due to an 84 basis point increase in underlying forecast interest rates as well as an increased amount of short-term debt due to rate base growth. The increase in the underlying interest rate is partially offset by the lower credit spread reflected in the proposal that PNG(NE) has obtained from its operating lender for which PNG(NE) received BCUC approval per Order G-185-17.

In Test Year 2019, PNG(NE)'s short-term debt expense is almost flat relative to 2018 as the forecast increase of 52 basis points in underlying interest rates in 2019 relative to 2018 is offset by a lower allocation of fees and expenses associated with the operating line shared with PNG.

The forecast of the underlying prime rate for operating line borrowings in both Test Year 2018 and Test Year 2019 is a consensus forecast of the increase in the average 90-day

treasury bill rate for 2018 and 2019 respectively, relative to the actual 2017 90-day treasury bill rate which is then added to the actual 2017 average prime rate. The consensus forecast for the 2018 and 2019 90-day treasury bill rates were obtained from the January 2018 Econolink Report, which unfortunately no longer publishes a consensus prime rate forecast. The 90-day treasury bill rate forecasts used by PNG(NE) is shown in the extract of page 11 from the January 2018 Econolink Report included as Appendix D. PNG(NE)'s new credit spread of 20 basis points is added to the prime rate forecast for deemed draws on its operating line. The forecast customer deposit interest rate for Test Year 2018 and Test Year 2019 has also been increased from Decision 2017 by the increase in the forecast average prime rate for 2018 as noted above. In addition to the interest rate increase, the increase in short term debt expense in 2018 and 2019 also reflects a provision for operating line renewal fees in those years while 2017 did not require a provision for renewal fees.

The forecast customer deposit interest rate for Test Year 2018 and Test Year 2019 has been increased from Decision 2017 by the increase in the forecast average prime rates for 2018 and 2019 as noted above. In addition to the interest rate, the increase in short term debt expense in Test Year 2018 and Test Year 2019 relative to Decision 2017 also reflects a provision for operating line renewal fees in those years while 2017 did not require a provision for renewal fees.

PNG(NE) proposes to continue the use of a deferral account to capture expense differences arising from interest rate variances between the test year forecast and actual rates on its floating rate operating line.

Long-term Debt Interest Expense

PNG(NE)'s Test Year 2018 forecast interest expense on long-term debt increases significantly relative to Decision 2017 due to a combination of a higher average effective interest rate and an increased amount of long-term debt in PNG(NE)'s proposed capital structure. The higher average effective interest rate in 2018 reflects a number of factors. First, the forecast increase in underlying market interest rates, as discussed in the section above on short-term debt, is the most significant factor. PNG(NE)'s forecast of 3-month Bankers' Acceptance (BA) rates is more than 80 basis points higher in 2018 than it was for Decision 2017.

In addition to the increasing underlying market interest rates, the key additional factors affecting the 2018 average effective interest rate are related to PNG(NE)'s proposed refinancing for which it received Commission approval per Order G-185-17. The refinancing includes a new smaller revolving term facility with a credit spread that is 25 basis points lower than PNG(NE)'s existing revolving term facility, as well as a fixed rate 10-year term note at 4.20%, which is 35 basis points higher than the interest rate under PNG(NE)'s existing revolving term facility using PNG(NE)'s 2018 forecast of underlying market interest rates.

For PNG(NE)'s revolving term facility, the forecast of the applicable interest rate is based on the consensus forecast of 3-month treasury bill rates for 2018 from Econolink's January 2018 report. The 3-month treasury bill rate forecast used by PNG(NE) is shown in the extract of page 11 from the January 2018 Econolink Report included as Appendix D. The historical ten-year average of the differential between 3-month treasury bill rates and 3-month Bankers' Acceptance rates are added to the forecast 2018 3-month treasury bill rate to derive the forecast of the underlying 3-month Bankers' Acceptance rate for PNGNE)'s revolving term facility.

The Test Year 2019 provision for long-term debt interest expense is higher than the Test Year 2018 provision reflecting a higher interest rate on PNG(NE)'s floating rate debt instrument due to the forecast 52 basis point increase in underlying 3-month Bankers' Acceptance rates in 2019 relative to 2018 as well as increases in the amount of long term debt outstanding.

For Test Year 2019, the interest rate forecast for PNG(NE)'s floating rate long-term debt rate instrument is based on consensus forecast of 3-month treasury bill rates for 2019 from Econolink's October January 2018 report, adjusted to a 3-month Bankers' Acceptance forecast using the same methodology as described above for 2018.

Planned Refinancing Activities

PNG(NE)'s only planned refinancing activity for 2018 and 2019 is the renewal of its operating line in mid-2019.

2.14.2 Allowed Capital Structure and Return on Equity

Table 35: Return on Common Equity

	$000's											
Common Equity	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Rate of Return on Equity	9.25%	n/a	0.0%	9.25%	n/a	0.0%	9.25%	9.01%	8.24%	8.17%	9.47%	8.41%
Common Equity Thickness	41.00%	n/a	0.0%	41.00%	n/a	0.0%	41.00%	41.89%	42.04%	42.64%	40.88%	41.52%
Common Equity ($000's)	31,601	2,439	7.7%	29,162	870	3.0%	28,292	28,228	26,645	25,347	22,533	20,025
Return on Equity ($000's)	2,923	226	7.7%	2,698	80	3.0%	2,617	2,543	2,197	2,070	2,134	1,685

Source: Tab Schedules, Tab 4, Page 1

For the purposes of this Amended Application for both Test Year 2018 and Test Year 2019, PNG(NE) has used the Decision 2017 approved rate of return on common equity (ROE) of 9.25% and common equity thickness of 41.00% following the issuance of the Stage 2 GCOC Decision in 2014 and the Decision on the Fortis BC Energy Inc.'s (the Benchmark Utility) Application for its Common Equity Component and Return on Equity for 2016. In the latter, the Commission ordered no changes to the Benchmark Utility's common equity component

and no changes to the ROE, and noted that these metrics would remain in effect until otherwise determined by the Commission. In addition, the Automatic Adjustment Mechanism Formula was suspended indefinitely.

2.15 Proposed Rate Changes

The following section explains the methodologies used by PNG(NE) to calculate the rates PNG(NE) is asking the Commission to approve effective January 1, 2018 and January 1, 2019. The material underpinning the rate calculations is provided under Tab Schedules, Tab 6 of this Amended Application.

2.15.1 Allocation of Revenue Deficiency

PNG(NE) has allocated the Test Year 2018 and Test Year 2019 revenue deficiencies to its customers using the projected gross margins for those years by customer class as the allocator. This is consistent with the methodology approved by the Commission over the past several years.

2.15.2 Derivation of Forecast Test Year Gas Deliveries and Gross Margin

PNG(NE) has included under Tab Schedules, Tab 6 detailed schedules showing the derivation of the forecast Test Year 2018 and Test Year 2019 gas deliveries by applying the forecast use per account to the forecast average number of customers in the case of the residential and small commercial customers. The annual forecast of deliveries to other customer classes is provided for each of the Fort St. John and Dawson Creek service areas. This enables one to balance the figures shown under Tab Schedules, Tab 1 for sales and transportation service with the corresponding figures shown under Tab Schedules, Tab 6.

Similarly, the derivation of projected margin recovery in the Test Year using current rates is shown on schedules included under Tab Schedules, Tab 6 to verify the figures provided in the summary sheets. There may be some small differences between the detailed schedules and the summary schedules due to rounding that occurs when utilizing large spreadsheets to calculate gross revenue, delivery margin and gas supply costs.

2.15.3 RSAM Rate Rider

Tables are provided under Tab Schedules, Tab 6 to show the projected year-end 2017 RSAM balance and the derivation of the RSAM riders for Test Year 2018 and Test Year 2019 assuming a two-year amortization of the projected balances. The two-year amortization period was approved by the Commission for the 2012 Revenue Requirement in order to ensure compliance with US GAAP. The decrease in the forecast RSAM rate rider reflects the slightly lower additions to the 2017 RSAM pools as a result of milder weather experienced

during 2017 compared to 2015 RSAM pools and lower forecast deliveries for core customers 2018.

2.15.4 Gas Supply Cost Charge Changes and GCVA Riders

The January 1, 2018 gas supply cost recovery rates shown in the "Summary of Proposed/Indicative Rates Effective January 1, 2018" and the January 1, 2019 gas supply cost recovery rates shown in the "Summary of Proposed/Indicative Rates Effective January 1, 2019" are based on the cost of gas shown at Tab Schedules, Tab 1, Page 1, Line 16 for each respective year. The forecast costs of gas for 2018 and 2019 were calculated using PNG(NE)'s gas cost flow through model updated to reflect the 2017/2018 gas supply and price arrangements entered into by PNG(NE) with its gas suppliers and to reflect the impact of the forecast gas prices contained in a recent forward gas price strip (based on the average of 5-day forward strip ending November 21, 2017).

PNG(NE)'s revenue requirement model is designed to show the recovery of forecast gas supply costs on a flow-through basis. In other words, the net margin (i.e. gross revenue less forecast cost of sales) will be the same regardless of what projected gas supply prices are used to calculate gas supply costs. Gas costs presented in this Amended Application are indicative only and are consistent with those applied for in PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report and approved under Commission Order G-187-17.

Tables under Tab Schedules, Tab 6 entitled "Derivation of Test Year Forecast Gas Supply Cost" show the derivation of the cost of sales figure shown at Tab Schedules, Tab 1, Page 1, Line 16 for Test Year 2018 and for Test Year 2019. The forecast deliveries by customer class multiplied by the indicative gas supply prices by customer class generates the cost of sales figure for each customer class.

2.15.5 Determination of 2018 and 2019 Company Use Gas Cost Rate

The Test Year 2018 and Test Year 2019 projected cost of Company use gas is calculated as part of the cost of gas calculation previously described and the quantity of gas PNG(NE) expects to purchase for Company use. The most significant portion of Company use gas is the requirement for fuel for lineheaters and office heating. The calculation of the indicative unit Company use gas cost recovery rate is shown on a schedule under Tab Schedules, Tab 6. PNG(NE) divides the forecast cost of Company use gas by total deliveries to all customers to determine the recovery rate to be embedded in rates. The Company use gas delivery rate presented in this Amended Application are indicative only and consistent with that applied for in PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report and approved under Commission Order G-187-17.

2.15.6 Bill Comparison – Current and Proposed Rates

PNG(NE) includes under Tab Schedules, Tab 6 a comparison of the projected annual gas bills for residential and small commercial customers using current rates effective October 1, 2017 (as customer rates were last changed at this time) and those proposed for January 1, 2018. The latter are also compared to the proposed January 1, 2019 rates. The bill comparison focuses on the delivery rate increase that is required to recover the forecast 2018 and 2019 revenue deficiencies (including the Company use gas cost). PNG(NE) has also included the gas supply cost related rates for January 1, 2018 which were approved as part of PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report. The bill comparisons for each of the Fort St. John and Dawson Creek service areas are separately discussed below since the delivery rates are different in each service area.

Fort St. John

For Test Year 2018, the average rate increase for residential customers is estimated to be 5.8 percent on the delivery charge component of rates or $26 per year for an average customer. The projected bundled average rate of $8.320 per GJ is $25.466 per GJ lower than the current electricity equivalent rate of $33.786 per GJ assuming a 90 percent gas to electricity efficiency factor and using the step 2 electricity rate applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 4.7 percent on the delivery charge component of rates or $77 per year for an average customer. The projected bundled average rate of $6.790 per GJ is $23.111 per GJ lower than the current electricity equivalent rate of $29.901 per GJ assuming a 90 percent gas to electricity efficiency factor.

For Test Year 2019, the average rate increase for residential customers is estimated to be 6.1 percent on the delivery charge component of rates or $28 per year for an average customer. The projected bundled average rate of $8.794 per GJ is $24.992 per GJ lower than the current electricity equivalent rate of $33.786 per GJ assuming a 90 percent gas to electricity efficiency factor and using the step 2 electricity rate currently applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 5.2 percent on the delivery charge component of rates or $89 per year for an average customer. The projected bundled average rate of $7.174 per GJ is $22.727 per GJ lower than the current electricity equivalent rate of $29.901 per GJ assuming a 90 percent gas to electricity efficiency factor.

Dawson Creek

For Test Year 2018, the average rate increase for residential customers is estimated to be 6.1 percent on the delivery charge component of rates or $23 per year for an average customer. The projected bundled average rate of $8.203 per GJ is $25.584 per GJ lower than the current electricity equivalent rate of $33.786 per GJ assuming a 90 percent gas to electricity efficiency factor and using the step 2 electricity rate applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 5.7 percent on the delivery charge component of rates or $86 per year for an average customer. The projected bundled average rate of $6.235 per GJ is $23.666 per GJ lower than the current electricity equivalent rate of $29.901 per GJ assuming a 90 percent gas to electricity efficiency factor.

For Test Year 2019, the average rate increase for residential customers is estimated to be 6.4 percent on the delivery charge component of rates or $25 per year for an average customer. The projected bundled average rate of $8.681 per GJ is $25.106 per GJ lower than the current electricity equivalent rate of $33.786 per GJ assuming a 90 percent gas to electricity efficiency factor and using the step 2 electricity rate currently applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 6.2 percent on the delivery charge component of rates or $101 per year for an average customer. The projected bundled average rate of $6.276 per GJ is $23.626 per GJ lower than the current electricity equivalent rate of $29.901 per GJ assuming a 90 percent gas to electricity efficiency factor.

2.15.7 Applied for Rates are Just and Reasonable

PNG(NE) submits that the rate increases applied for under this Amended Application are just and reasonable based on long standing regulatory principles applied by the Commission in the exercise of its rate setting responsibilities under the *Utilities Commission Act*. In preparing each revenue requirements application, PNG(NE)'s senior management team keeps in mind the Commission's requirement to balance the need of PNG(NE) to recover its reasonable and prudent costs with the need to ensure ratepayers are charged fair and reasonable rates. PNG(NE) considers rates are fair and reasonable if the following criteria are met:

- Rates are set at a level that provide sufficient margin to enable PNG(NE) to provide safe, reliable and secure gas delivery service to its customers.

PNG(NE)'s financial integrity is maintained which includes being able to meet financial covenants under outstanding debt instruments and to retain an investment bond rating.

PNG(NE) has taken prudent steps to manage its costs to ensure there are no unnecessary or unreasonable costs included in the applied for cost of service.

PNG(NE)'s rates are competitive with other energy sources and thereby provide a reasonable probability of preventing declining recovery of margin due to customers converting to alternative energy sources or reducing gas consumption.

PNG(NE)'s shareholder has the opportunity to earn a reasonable rate of return on its equity investment in PNG(NE).

Earlier in this Amended Application PNG(NE) explained in detail the reasons why operating, maintenance, administrative and general expenses in 2018 and 2019 have changed from those budgeted under Decision 2017. The level of costs presented and for which PNG(NE) seeks approval will reasonably ensure that PNG(NE) can provide safe, reliable and secure gas delivery service at an appropriate level. PNG(NE) has taken prudent steps to manage its 2018 and 2019 budgeted costs and submits there are no unnecessary or unreasonable costs included in its 2018 and 2019 budgeted costs.

In summary, the rates applied for under this Amended Application are just and reasonable having regard to the regulatory principles the Commission applies when determining whether rates are just and reasonable pursuant to the *Utilities Commission Act*.

3 Other Matters

3.1 Capital Expenditure Reporting – Actual vs Decision

In Decision 2012, PNG(NE) was directed to provide a more fulsome capital addition expenditure reporting to improve transparency on a project-by-project and year-by-year basis. On a go-forward basis PNG(NE) was directed to provide more detailed budget variance analysis in the context of its capital additions forecasting and to provide a schedule showing forecast plant additions compared to actual capital additions with explanatory information on all material differences. In this section, PNG(NE) provides a summary of actual capital expenditures for 2016 and 2017 compared to those approved under Decision 2016 and Decision 2017, respectively, along with explanations for significant variances.

3.1.1 2016 Capital Expenditure Variance Analysis

Table 36: 2016 Capital Expenditure Variance Analysis

2016 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	2016 Actual Expenditure Excluding Overhead	2016 Approved Expenditure Excluding Overhead	Variance (Over) Under Expenditure
Planned - Recurring					
New Services	NB	473	850,222	1,482,013	631,790
Distribution Mains	NB	475	110,292	554,508	444,215
Distribution Main Improvement - Mechanical Couplings	SB	475	473,153	468,581	(4,572)
Mobile/Heavy Equipment	GP	484/485	578,261	389,130	(189,131)
Distribution Main Improvement - PE2306 Replacement	SB	475	361,791	328,498	(33,292)
Distribution Main Improvement - Other	SB	475	1,023,400	300,435	(722,966)
Meter and Regulator Purchases	NB	474/478	254,746	245,822	(8,924)
New/Replacement Tools and Equipment	GP	486	58,737	76,194	17,457
New/Replacements Meters	NB	474	41,286	52,352	11,066
			3,751,888	3,897,532	145,644
Other Minor Projects <$50,000	various	Various	53,511	1,683	(51,828)
Computing Hardware/Software	GP/GP-I	487	53,511	1,683	(51,828)
Subtotal			3,805,399	3,899,215	93,817
Planned - Non-recurring					
BC Hydro Site C	NB	475	403,315	1,063,069	659,754
Regional LNG Facility	NB	475	281,622	366,546	84,924
Station Modifications	SB	467	-	364,386	364,386
Indian Creek Line Relocation MP 5/6	SB	465	54,657	257,061	202,404
Structure Improvements	GP	482	179,948	173,746	(6,202)
Electrical and Communications Improvements	SB	467	99,938	102,738	2,799
PennWest Pipeline Remediation	SB	465	14,909	98,274	83,365
Phase 1 Piping ID DC Gate	SB	467	28,797	92,487	63,690
Replace Line Heaters	SB	467	55,224	73,440	18,216
			1,118,411	2,591,745	1,473,333
Other Minor Projects <$50,000	various	Various	173,883	31,012	(142,871)
Aluminum Line Replacement Cleanup	SB	465	128,454	31,012	(97,442)
Other Minor Projects	SB	465/468	45,429	-	(45,429)
Subtotal			1,292,294	2,622,757	1,330,463
Carryforward Projects					
Wonowan Unloading Post - FSJ	NB	477	77,631	71,583	(6,048)
Main Ex NE 34 82 18 Loewen FSJ	NB	475	92,049	-	(92,049)
Subtotal			169,680	71,583	(98,097)
Total Capital Expenditures without Overhead			5,267,373	6,593,555	1,326,182

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

Further details on forecast 2016 capital expenditure variances in excess of $50,000 are provided in the discussion that follows.

New/Replacement Services (less than approved by $632,000)

The capital forecast for this item was based on previous years activity and estimates for new construction to include installing new distribution service lines to meet the needs of new customers. This variance is due to the fact that all areas experienced a economic down turn in construction activity in 2016.

Distribution Mains (less than approved by $444,000)

The capital forecast for this item was based on previous years activity and estimates for new construction to include installing new distribution mains to meet the needs of new growth and system reliability. This variance is due to the fact that all areas experienced a economic down turn in construction activity in 2016.

Mobile/Heavy Equipment (greater than approved by $189,000)

This variance is due to the unplanned replacement of a backhoe stolen from the gated compound in Dawson Creek.

Distribution Main Improvements – Other (greater than approved by $723,000)

This variance is primarily due to unbudgeted line lowerings in Fort St. John as a result of Ministry of Transportation and Infrastructure construction work on Old Fort Road, as well as continued fusion tee replacements.

Computing Hardware/Software (greater than approved by $52,000)

This variance is primarily due to the company-wide initiative to upgrade the current phone system to Cisco VoIP, as well as the upgrade of security cameras.

Planned – Non-recurring Capital Expenditures

BC Hydro Site C (less than approved by $660,000)

This variance is due to an acceleration of the construction work for this project in late 2015 in order to meet the customer's service request. The 2016 forecast costs of $1,063,000 cover costs of $600,000 incurred in 2015. As noted in the section on carryforward projects below, the total project spend over 2015/2016 was $1,007,000 compared to budget of $1,063,000.

Regional LNG Facility (less than approved by $85,000)

The construction of the pipe and the meter station was under budget by approximately $85,000.

Station Modifications (less than approved by $364,000)

This variance is due to the deferral of certain low-priority projects in this category to 2020 in order to balance completion of more pressing capital projects with the availability of resources to complete the work.

Indian Creek Line Relocation MP 5/6 (less than approved by $202,000)

This variance is primarily due to a shift in the timing of anticipated construction work to 2017. In spring 2016, PNG(NE) undertook the preliminary work to investigate damage and determine appropriate corrective actions. Due to permitting and the increased work required to repair the line, the construction aspect of this project was carried forward to 2017.

PennWest Pipeline Remediation (less than approved by $83,000)

PNG(NE) conducted preliminary survey work for this project, however, there were complications with landowner and regulatory issues. PNG(NE) continues to believe there are integrity risks with this pipeline and has proposed funds in 2018 to carry out an engineering feasibility assessment on pipeline.

Phase 1 Piping ID DC Gate (less than approved by $64,000)

This variance is due to timing delays. The funds expended in 2016 were used to undertake a detailed survey and address safety concerns. Detailed engineering and design work was completed in 2017 with plans for construction in 2018.

Aluminum Line Replacement Cleanup (greater than approved by $97,000)

This variance is due to legal and land survery costs incurred in 2015 but not accrued for in that fiscal year.

Carryforward Projects

Main Extension NE 34 82 18 Loewen FSJ (greater than approved by $92,000)

Due to the late arrival of the fabricated assembly it was not possible to complete the Wonowon Unloading Facility project in 2015 and the project was carried to 2016 for completion. This cost variance is primarily due to labor costs being greater than foecast.

Originally Estimated Project Expenditures

The table included at the beginning of this section has a column with a reference to “approved expenditure”. This amount represents the originally planned estimate of expenditures for the projects noted. A variance from this assertion is for projects carried forward from prior periods. PNG(NE) includes the table that follows to present supplemental information that allows for a comparison of the total project cost at completion to the originally estimated project expenditure.

Table 37: 2016 Capital Expenditure Carryforward – Original Cost Variance Analysis

2016 Carryforward Projects	Project Type*	Plant in Service Account Number	Project Year	2015 Expenditure Excluding Overhead	2016 Expenditure Excluding Overhead	Total Project Cost at Completion Excluding Overhead	Originally Estimated Expenditure Excluding Overhead	Variance (Over) Under Expenditure
Carryforward Projects								
Regional LNG Facility	NB	461/463/465/ 467	2015/2017	4,188	281,623	285,811	366,545	80,734
Main Ex NE 34 82 18 Loewen FSJ	NB	475	2015/2016	155,648	92,049	247,697	216,252	(31,445)
BC Hydro Site C	NB	475	2015/2016	603,406	403,315	1,006,721	1,063,069	56,348
Wonowan Unloading Post - FSJ	NB	477	2015/2016	66,900	77,631	144,531	150,000	5,469
Total				830,142	854,618	1,684,760	1,795,866	111,106

** SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles*

Additional information on these projects can be found in the preceding discussion.

3.1.2 2017 Capital Expenditure Variance Analysis

Table 38: 2017 Capital Expenditure Variance Analysis

2017 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	2017 Actual Excluding Overhead	2017 Approved Expenditure Excluding Overhead	Variance
Planned - Recurring					
New Services	NB	473	622,794	1,512,610	889,816
Distribution Mains	NB	475	179,419	565,932	386,512
Distribution Main Improvement - Mechanical Couplings	SB	475	463,046	478,145	15,099
Distribution Main Improvement - PE2306 Replacement	SB	475	361,482	335,213	(26,269)
Distribution Main Improvement - Other	SB	475	1,452,581	316,037	(1,136,544)
Meter and Regulator Purchases	NB	474/478	193,198	250,738	57,540
Mobile/Heavy Equipment	GP	484/485	172,004	96,200	(75,804)
New/Replacements Meters	NB	474	34,318	53,553	19,235
			3,478,842	3,608,428	129,586
Other Minor Projects <$50,000	Various	Various	54,363	39,823	(14,540)
Subtotal			3,533,205	3,648,251	115,046
Planned - Non-recurring					
Looping Rolla Lateral - DC	SB	467	-	146,381	146,381
Phase 2 Piping ID DC Gate	SB	467	77,406	90,658	13,253
Replace Line Heaters	SB	467	41,400	64,505	23,105
Unspecified Other System Betterments	SB	465	95,865	-	(95,865)
			214,671	301,544	86,873
Other Minor Projects <$50,000	Various	Various	59,288	40,985	(18,302)
Subtotal			273,958	342,529	68,571
Carryforward Projects					
Indian Creek Line Relocation	SB	465	848,549	-	(848,549)
PennWest Pipeline Remediation - cancelled project	SB	465	(14,909)	-	14,909
Subtotal			833,639	-	(833,639)
Total Capital Expenditures without Overhead			4,640,803	3,990,780	(650,023)

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

Further details on forecast 2017 capital expenditure variances in excess of $50,000 are provided in the discussion that follows.

New/Replacement Services (less than approved by $890,000)

The capital forecast for this item was based on previous years' activity and estimates for new construction to include installing new distribution service lines to meet the needs of new customers. This variance is due to the fact that the areas experienced an economic downturn in construction activity in 2017 and actual activity was below anticipated levels.

Distribution Mains (less than approved by $387,000)

The capital forecast for this item was based on previous years' activity and estimates for new construction to include installing new distribution mains to meet the needs of new growth and system reliability. Similar to new/replacement services, this variance is primarily due to the economic downturn in construction activity in 2017.

Distribution Main Improvements – Other (greater than approved by $1,137,000)

This variance is primarily due to acceleration of electrofusion tee replacement activity during the year beyond that originally planned ($1,122,000) due to the reassessment of the work as high risk and necessary to ensure system safety and reliability. PNG(NE) notes that the cost of this initiative were offset in part by a CIAC of $325,000 from the contractor who undertook the original installation. Also of note is that this expenditure includes $171,000 incurred in 2017 for finalize repairs on the Pouce River washout which occurred in late 2016.

Meter and Regulator Purchases (less than approved by $58,000)

This variance is due to lower than planned regulator purchases for the Dawson Creek service area.

Mobile/Heavy Equipment (greater than approved by $76,000)

This variance is primarily due to the unplanned purchase of Unit 992 to replace an unreliable Unit 830 in order to ensure the continued ability to execute work.

<u>Planned – Non-recurring Capital Expenditures</u>

Looping of Rolla Lateral - DC (less than approved by $146,000)

This item was planned for an upgrade of the Rolla lateral station in Dawson Creek. This project was deferred due to a shift in capital priorities for 2017.

Unspecified Other System Betterments (greater than approved by $96,000)

These expenditures were incurred for necessary repairs to several pipe exposures due to washout, including the Moore Subdivision, Barrette Road, Woods Road and the right-of-way at Mile 64 ROW).

Carryforward Projects

Indian Creek Line Relocation (greater than approved by $849,000)

This variance is primarily due to a shift in the timing of anticipated construction work from 2016 to 2017, and to an increase in project scope informed by futher analysis of the work required to repair the line slippage than was anticipated when originally forecast in 2015.

Originally Estimated Project Expenditures

The table included at the beginning of this section has a column with a reference to "approved expenditure". This amount represents the originally planned estimate of expenditures for the projects noted. A variance from this assertion is for projects carried forward from prior periods. PNG(NE) includes the table that follows to present supplemental information that allows for a comparison of the total project cost at completion to the originally estimated project expenditure.

Table 39: 2017 Capital Expenditure Carryforward – Original Cost Variance Analysis

2017 Carryforward Projects	Project Type*	Plant in Service Account Number	Project Year	2016 Expenditure Excluding Overhead	2017 Expenditure Excluding Overhead	Total Project Cost at Completion Excluding Overhead	Originally Estimated Expenditure Excluding Overhead	Variance (Over) Under Expenditure
Carryforward Projects								
Indian Creek Line Relocation	SB	461/465	2016/2018	54,657	848,548	903,205	257,061	(646,144)
PennWest Pipeline Remediation	SB	465	2016/2017	14,909	(14,909)	-	98,274	98,274
M/L Repair Pouce River Washout - DC	SB	475	2016/2017	10,623	171,442	182,065	-	(182,065)
Total				80,189	1,005,081	1,085,270	355,335	(729,935)

** SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles*

Additional information on these projects can be found in the preceding discussion.

3.2 Cost of Service Reporting – Actual vs Decision

3.2.1 2016 Cost of Service Variance Analysis

The table below compares the Actual 2016 cost of service to the Decision 2016 cost of service as approved by the Commission. Explanations of significant variances are provided on the pages following the comparison table.

Table 40: 2016 Cost of Service Variance Analysis

EXPENSES ($OOO's)	Actual 2016	Decision 2016	Difference Total	Difference Subtotal
Operating				
Labour	2,304	2,018	286	
Other	2,987	3,225	(238)	
Sub-total	5,291	5,243	48	
Maintenance				
Labour	105	123	(18)	
Other	260	242	18	
Sub-total	365	365	0	
Administrative and General				
Total Company Benefits	756	777	(21)	
Other	2,132	2,099	34	
Sub-total	2,889	2,876	13	
Total (O, M, A & G) Excluding Company Use Gas Cost	8,544	8,484	61	61
Transfers to Capital Operating	(244)	(196)	(48)	
Transfers to Capital - Administrative & General	(357)	(454)	97	
Property Taxes	1,350	1,350	0	
Depreciation	1,836	1,835	2	
Amortization	26	26	(0)	
Other Income	(249)	(267)	18	69
Total Expenses Excluding Company Use Gas Cost	10,907	10,777	130	130
Income Taxes	320	391	(71)	
Return on Common Equity	2,197	2,450	(252)	
Short Term Debt	218	129	89	
Long Term Debt	993	1,088	(95)	(330)
Total Cost of Service Excluding Company Use Gas Cost	14,636	14,836	(200)	(200)
Company Use Gas Cost	146	140	6	
Total Cost of Service Including Company Use Gas Cost	14,782	14,975	(194)	

3.2.1.1 Operating Expenses

Operating expenses for 2016 were $53,000 or 1.0% greater than forecast as per Decision 2016. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2016 amounts follows.

Table 41: Operating Expenses - 2016

BCUC Account	$000's			
	2016		Difference	
	Actual	Decision	$	%
670 Supervision	462	417	45	10.9%
675 Mains and Services	440	440	0	0.1%
685 General Ops.	690	671	20	2.9%
688 Other Gen. Ops.	533	596	(63)	(10.6)%
711/713/714 Customer Care	562	587	(24)	(4.2)%
712 Meter Reading	263	244	19	7.7%
718 Uncollectible Accounts	36	36	(0)	n/a
Other inc. 665/673	935	878	57	6.4%
Subtotal	3,921	3,868	53	1.4%
Add: Shared Service Cost Allocation	1,515	1,515	-	0.0%
Operating Expenses	5,436	5,383	53	1.0%
Less: Cost of Gas - 665 Pipelines	(145)	(140)	(5)	3.8%
Operating Expenses (Net of Company Use Cost of Gas)	5,291	5,243	48	0.9%
Less: Transfers to Capital	(244)	(196)	(48)	24.4%
Net Operating Expenses (Net of Transfers to Capital)	5,047	5,047	(0)	(0.0)%

Source: Tab Schedules, Tab 1, Page 3

Account 670 – Supervision

The actual costs for 2016 included in this account are $45,000 or 10.9% greater than those approved under Decision 2016. The variance can primarily be attributed to unanticipated contractor costs related to work on regulating stations. In addition, some cost misallocations have been identified, including purchasing card materials purchases charged to the default home code rather than allocating to related tasks.

Account 688 – Other General Operations

The actual costs for 2016 included in this account are $63,000 or 10.6% less than those approved under Decision 2016. This variance is primarily due to lower than anticipated training costs due do lack of resource availability and employee scheduling.

Account 665/673 – Other

The actual costs for 2016 included in all other accounts not specifically identified above are $57,000 or 6.4% greater than those approved under Decision 2016. This variance is primarily due to additional contractor services required to support meter recalls.

3.2.1.2 Maintenance Expenses

On an overall basis, maintenance expenses for 2016 came in equal to those anticipated as per Decision 2016. The distribution of offsetting variances in individual BCUC Accounts is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2016 amounts follows.

Table 42: Maintenance Expenses - 2016

BCUC Account	2016		Difference	
	Actual	Decision	$	%
867 Regulating Stations	32	46	(14)	(31.1)%
875 Mains and Services	151	153	(3)	(1.6)%
878 Meters	150	69	81	117.4%
All Other	32	96	(64)	(66.9)%
Total	365	365	0	0.1%

Source: Tab Schedules, Tab 1, Page 4

Account 867 – Regulating Stations

The actual costs for 2016 included in this account are $14,000 or 31.1% less than those approved under Decision 2016. A review of this variance indicates the primary cause to be lower labour costs that forecast. Maintenance activities vary year to year depending on the issues identified during regular operations and servicing activities.

Account 878 – Meters

The actual costs for 2016 included in this account are $81,000 or 117.4% greater than those approved under Decision 2016. This variance is primarily due to increased contractor charges for meter maintenance and reseal on meter recalls that were carried over from 2015 to 2016.

All Other

The actual costs for 2016 included in all other accounts not specifically identified (including accounts 865 and 885) are $64,000 or 66.9% less than those approved under Decision 2016. This variance is primarily due to less repairs required than anticipated in forecast amounts.

3.2.1.3 Administrative & General Expenses

Administrative and General expenses for 2016 were $110,000 or 4.5% greater than forecast as per Decision 2016. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2016 amounts follows.

Table 43: Administrative and General Expenses - 2016

BCUC Account	$000's			
	2016		Difference	
	Actual	Decision	$	%
721 Administration	36	41	(5)	(12.0)%
722 Special Services - Audit/Legal	120	92	28	30.1%
723 Insurance	72	61	12	19.4%
725 Employee Ben.	756	777	(21)	(2.7)%
728 General	73	74	(1)	(1.3)%
Sub-Total	1,058	1,045	13	1.2%
Add: Shared Service Cost Allocation - 721	1,519	1,519	-	0.0%
Add: Shared Service Cost Allocation - 728	312	312	-	0.0%
Administrative and General Expenses	2,889	2,876	13	0.4%
Less: Transfers to Capital	(357)	(454)	97	(21.4)%
Net Administrative and General Expenses (Net of Company Use Cost of Gas)	2,532	2,422	110	4.5%

Source: Tab Schedules, Tab 1, Page 5

Account 721 – Administration

The actual costs for 2016 included in this account are $5,000 or 12.0% lower than those approved under Decision 2016. This variance is due to actual costs being less than anticipated in forecast amounts.

Account 722 – Special Services – Audit/Legal

The actual costs for 2016 included in this account are $28,000 or 30.1% greater than those approved under Decision 2016. This account is over budget mainly due to higher contractor costs in the area of general regulatory support.

Account 723 – Insurance

The actual costs for 2016 included in this account are $12,000 or 19.4% greater than those approved under Decision 2016 primarily due an error in allocation factors in the forecast amount that resulted in the allocation to PNG(NE) being less than it should, and an offsetting overallocation to PNG-West. This error has been corrected.

3.2.1.4 Other Items

Transfers to Capital (Capitalized Overhead)

Transfers to Capital for 2016 were $97,000 less than forecast as per Decision 2016. Administrative and General transfers to capital were less than forecast due to lower internal labour costs on capital projects than forecast resulting in a lower allocation of employee benefit costs on direct field labour costs.

Property Taxes

Property taxes for 2016 are consistent with that forecast as per Decision 2016.

Depreciation

Depreciation expense for 2016 is consistent with that forecast as per Decision 2016.

Amortization

Amortization for 2016 is consistent with that forecast as per Decision 2016.

Other Income

Amortization for 2016 is consistent with that forecast as per Decision 2016.

Income Taxes

Income taxes for 2016 are $70,000 less than forecast as per Decision 2016 due to lower mainly as a result of lower deliveries than forecast.

Return on Common Equity

Actual Return on Common Equity for 2016 is $251,000 lower than forecast as per Decision 2016. This reflects the lower deliveries and lower margin recovered in 2016 compounded by higher actual operating expenditures.

Short Term Debt

Interest and other expense on Short Term Debt for 2016 is $89,000 greater than forecast as per Decision 2016. This is largely due to PNG(NE) using more short-term debt than planned per Decision 2016.

Long Term Debt

Interest on Long Term Debt for 2016 is $95,000 lower than forecast as per Decision 2016. This is largely due to PNG(NE) using more short term debt and more common equity in its actual capital structure than approved by the Commission per Decision 2016.

Company Use Gas Cost

Company Use Gas Cost for 2016 is consistent with that forecast as per Decision 2016.

3.2.2 2017 Cost of Service Variance Analysis

The table below compares the Actual 2017 cost of service to the Decision 2017 cost of service as approved by the Commission. Explanations of significant variances are provided on the pages following the comparison table.

Table 44: 2017 Cost of Service Variance Analysis

EXPENSES ($OOO's)	Actual 2017	Decision 2017	Difference Total	Difference Subtotal
Operating				
Labour	2,680	2,192	489	
Other	2,958	3,360	(402)	
Sub-total	5,638	5,552	86	
Maintenance				
Labour	86	126	(39)	
Other	195	266	(71)	
Sub-total	282	392	(111)	
Administrative and General				
Total Company Benefits	745	781	(36)	
Other	2,240	2,190	50	
Sub-total	2,985	2,971	14	
Total (O, M, A & G) Excluding Company Use Gas Cost	8,904	8,914	(10)	(10)
Transfers to Capital Operating	(192)	(181)	(11)	
Transfers to Capital - Administrative & General	(495)	(491)	(4)	
Property Taxes	1,373	1,373	0	
Depreciation	1,982	2,023	(41)	
Amortization	220	221	(1)	
Other Income	(227)	(267)	40	(16)
Total Expenses Excluding Company Use Gas Cost	11,566	11,593	(26)	(26)
Income Taxes	471	468	3	
Return on Common Equity	2,544	2,617	(74)	
Short Term Debt	93	144	(51)	
Long Term Debt	1,237	1,216	21	(101)
Total Cost of Service Excluding Company Use Gas Cost	15,910	16,037	(127)	(127)
Company Use Gas Cost	192	189	3	
Total Cost of Service Including Company Use Gas Cost	16,102	16,226	(124)	

3.2.2.1 Operating Expenses

Operating expenses for 2017 were $76,000 or 1.4% greater than forecast as per Decision 2017. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2017 amounts follows.

Table 45: Operating Expenses - 2017

BCUC Account	$000's			
	2017		Difference	
	Actual	Decision	$	%
670 Supervision	428	456	(29)	(6.3)%
675 Mains and Services	486	523	(37)	(7.1)%
685 General Ops.	854	705	149	21.2%
688 Other Gen. Ops.	675	659	16	2.4%
711/713/714 Customer Care	570	649	(79)	(12.1)%
712 Meter Reading	233	249	(16)	(6.6)%
718 Uncollectible Accounts	111	36	74	203.5%
Other inc. 665/673	945	934	10	1.1%
Subtotal	4,301	4,212	89	2.1%
Add: Shared Service Cost Allocation	1,529	1,529	(0)	(0.0)%
Operating Expenses	5,830	5,741	89	1.6%
Less: Cost of Gas - 665 Pipelines	(192)	(189)	(3)	1.6%
Operating Expenses (Net of Company Use Cost of Gas)	5,638	5,552	86	1.6%
Less: Transfers to Capital	(192)	(181)	(11)	5.8%
Net Operating Expenses (Net of Transfers to Capital)	5,446	5,371	76	1.4%

Source: Tab Schedules, Tab 1, Page 3

Account 670 – Supervision

The actual costs for 2017 included in this account are $29,000 or 6.3% lower than those approved under Decision 2017. The variance can primarily be attributed to less administrative time required for planning activities due to low activity as a result of the economic downturn in the area.

Account 675 – Mains and Services

The actual costs for 2017 included in this account are $37,000 or 7.1% lower than those approved under Decision 2017. The variance can primarily be attributed to the effects of the general economic downturn in the area and less activity, requiring less time for line locates and operations activities for the distribution systems.

Account 685 – General Operations

The actual costs for 2017 included in this account are $149,000 or 21.2% greater than those approved under Decision 2017. This variance is primarily due to an increase in internal labour dedicated to vehicle maintenance rather than outsourcing these activities.

Account 711/713/714 – Customer Care

The actual costs for 2017 included in this account are $79,000 or 12.1% less than those approved under Decision 2017. The variance can primarily be attributed to lower than forecast contract costs for the customer billing system, lower than forecast data line charges, and lower than forecast meter reading costs.

Account 718 – Uncollectible Accounts

The actual costs for 2017 included in this account are $74,000 or 203.5% greater than those approved under Decision 2017. The variance can primarily be attributed to a project to review overdue accounts and to update the allowance for doubtful accounts. PNG(NE) notes that through the Negotiated Settlement Process for PNG(NE)'s 2014 Revenue Requirement Application, PNG(NE) agreed to significantly reduce the Allowance for Doubtful Accounts and record this credit to a deferral account which was subsequently amortized in 2015. PNG(NE) plans to further review its bad debts and collections process to ensure it is managed effectively.

3.2.2.2 Maintenance Expenses

On an overall basis, maintenance expenses for 2017 were $111,000 or 28.2% lower than forecast as per Decision 2017. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2017 amounts follows.

Table 46: Maintenance Expenses - 2017

BCUC Account	$000's			
	2017		Difference	
	Actual	Decision	$	%
867 Regulating Stations	53	47	6	12.9%
875 Mains and Services	93	161	(68)	(42.4)%
878 Meters	92	71	21	30.1%
All Other	44	114	(70)	(61.4)%
Total	282	392	(111)	(28.2)%

Source: Tab Schedules, Tab 1, Page 4

Account 867 – Regulating Stations

The actual costs for 2017 included in this account are $6,000 or 12.9% greater than those approved under Decision 2017. A review of this variance indicates the primary cause to be unforeseen non-routine maintenance for the Hutterite station. Maintenance activities vary year to year depending on the issues identified during regular operations and servicing activities.

Account 875 – Mains and Services

The actual costs for 2017 included in this account are $68,000 or 42.4% less than those approved under Decision 2017. This variance is primarily due to the economic downturn in the area and less repairs required than forecast.

Account 878 – Meters

The actual costs for 2017 included in this account are $21,000 or 30.1% greater than those approved under Decision 2017. This variance is primarily due to a greater number of meter recalls than anticipated. The number of actual recalls undertaken is driven by Measurement Canada regulations.

All Other

The actual costs for 2017 included in all other accounts not specifically identified (including accounts 865 and 885) are $70,000 or 61.4% less than those approved under Decision 2017. This variance is primarily due to fewer repairs required than forecast.

3.2.2.3 Administrative & General Expenses

Administrative and General expenses for 2017 were $10,000 or 0.4% greater than forecast as per Decision 2017. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2017 amounts follows.

Table 47: Administrative and General Expenses - 2017

BCUC Account	$000's			
	2017		Difference	
	Actual	Decision	$	%
721 Administration	39	42	(3)	(7.2)%
722 Special Services - Audit/Legal	143	95	49	51.8%
723 Insurance	71	63	8	13.0%
725 Employee Ben.	742	781	(38)	(4.9)%
728 General	74	75	(1)	(1.9)%
Sub-Total	1,070	1,056	14	1.4%
Add: Shared Service Cost Allocation - 721	1,596	1,596	(0)	(0.0)%
Add: Shared Service Cost Allocation - 728	319	319	(0)	(0.0)%
Administrative and General Expenses	2,985	2,971	14	0.5%
Less: Transfers to Capital	(495)	(491)	(4)	0.9%
Net Administrative and General Expenses (Net of Company Use Cost of Gas)	2,490	2,480	10	0.4%

Source: Tab Schedules, Tab 1, Page 5

Account 722 – Special Services – Audit/Legal

The actual costs for 2017 included in this account are $49,000 or 51.8% greater than those approved under Decision 2017. This account is over budget primarily due to the costs related to a Geographic Information System (GIS) assessment study undertaken during the year (see discussion of this initiative in Section 2.13.1.1 – Plant in Service).

Account 723 – Insurance

The actual costs for 2017 included in this account are $8,000 or 13.0% greater than those approved under Decision 2017 primarily due to an increase in the PNG(NE) components of consolidated replacement cost in the composite insurance allocation factor resulting in a greater allocation of the consolidated insurance expense to PNG(NE).

Account 725 – Employee Benefits

The actual costs for 2017 included in this account are $38,000 or 4.9% lower than those approved under Decision 2017. This variance is due to lower benefit costs attributable to vacant positions during the period, mainly as a result of retirements.

3.2.2.4 Other Items

Transfers to Capital (Capitalized Overhead)

Operating transfers to capital for 2017 were $11,000 greater than forecast as per Decision 2017 primarily due to greater capital expenditures in 2017 than forecast resulting in a greater allocation of employee benefit costs on direct field labour. Administrative & General transfers to capital for 2017 are consistent with that forecast as per Decision 2017.

Property Taxes

Property taxes for 2017 are consistent with that forecast as per Decision 2017.

Depreciation

Depreciation expense for 2017 is lower than forecast as per Decision 2017 by $41,000 primarily due to lower than forecast 2016 capital additions (net of retirements).

Amortization

Amortization for 2017 is consistent with that forecast as per Decision 2017.

Other Income

Other income for 2017 is lower than forecast as per Decision 2017 by $40,000 primarily due to lower penalty and connection fees than estimated and lower overhead revenue billed out for 3rd party line hits than forecast.

Income Taxes

Income taxes for 2017 are consistent with that forecast as per Decision 2017.

Return on Common Equity

Actual Return on Common Equity for 2017 is $74,000 lower than forecast as per Decision 2017. This reflects the lower margin recovered from customers in 2017.

Short Term Debt

Interest and other expense on Short Term Debt for 2017 is $51,000 lower than forecast as per Decision 2017. This is largely due to PNG(NE) using less short term debt than planned in 2017.

Long Term Debt

Interest on Long Term Debt for 2017 is consistent with that forecast as per Decision 2017.

Company Use Gas Cost

Company Use Gas Cost for 2017 is consistent with that forecast as per Decision 2017.

3.3 Identified Service Quality Metrics

Under Commission Order G-192-11, PNG(NE) was directed to report on a number of key service quality metrics. The requested data for the Dawson Creek and Fort St. John service area is provided in the following table.

Table 48: Service Quality Metrics

Service Quality Metric	2017	2016	2015	2014	2013
Number of Emergency Calls	331	448	579	403	423
Average Response Time per Call	16 minutes	17 minutes	18 minutes	19 minutes	21 minutes
Number of Calls with a Response Time over 40 Minutes	2	12	15	24	20
Number of Underground Leaks	24	16	11	8	18
Number of Reportable Environmental Incidents	–	–	–	–	–
Lost-time Injury Frequency Rate *	2.07	2.84	1.01	1.19	–
Customer Complaints to the BCUC **	2	–	–	1	1

* Reflects PNG consolidated rate; not tracked by individual service area

** Information reflects Commission's March 31 fiscal year end (i.e. data for 2017 is from April 1, 2016 to March 31, 2017)

3.4 Other Matter to Be Addressed from Prior Year Decisions

3.4.1 Directives from the 2016-2017 Revenue Requirements Application

Under Order G-132-16, the Commission directed PNG(NE) to address the following matters in its 2018-2019 Revenue Requirements Application:

> The establishment of a new regulatory account bearing interest at PNG(NE)'s weighted average cost of debt to record the net impact on PNG's 2016 and 2017 rates arising from the Commission's decision on the FortisBC Energy Inc. (FEI) Application for Common Equity Component and Return on Equity 2016 (directive 4.b.). PNG(NE) notes that there were no changes to its common equity component or rate of return on equity arising from the Commission's decision on the FEI application, therefore the establishment of a new regulatory account was not necessary.
>
> PNG(NE) must file an application with the Commission to obtain approval to record UAF losses above 1.5 percent in the UAF volume deferral account (directive 5). See Section 3.4.2 – Directives from the Application for Approval of 2016 Unaccounted for Loss above 1.5 Percent that follows, as well as Section 2.2.3 – Unaccounted for Gas.
>
> PNG(NE) was directed in future RRAs to file a copy of its Annual Pipeline Risk Mitigation Report or equivalent, together with any additional explanations or documentation required to support each significant category of forecast pipeline operating, maintenance and capital expenditure in each test period (directive 8). Given the sensitivity of certain operational and risk information contained in the 2017 Annual Pipeline Risk Mitigation Report, PNG(NE) has filed this document on a confidential basis as Appendix E to this Amended Application. PNG(NE) notes that explanations to support the need for each significant category of forecast pipeline operating, maintenance and capital expenditures have been provided in the applicable sections of this Amended Application's narrative.

3.4.2 Directives from the Application for Approval of 2016 Unaccounted for Loss above 1.5 Percent

On February 24, 2017, PNG(NE) applied to the Commission for approval to record 2016 UAF losses above 1.5 percent in the UAF deferral account, allowing for all UAF losses to be accounted for and recovered from customers on a consistent basis. Under Order G-105-17, the Commission denied PNG(NE)'s request and directed PNG(NE) to establish a separate temporary deferral account to record the 2016 UAF loss over 1.5 percent until such time as the disposition of the excess UAF has been determined.

The Commission further directed PNG(NE) to include in its next revenue requirements application a report summarizing the results of its further examination of all data and calculations and investigation into the reasons for the increased 2016 UAF loss and a proposal for the recovery of the 2016 UAF loss over 1.5 percent deferral account. This matter has been addressed in Section 2.2.3 – Unaccounted for Gas and the requested report has been filed as Appendix B.

3.4.3 Other Directives

In the Generic Cost of Capital (GCOC) Proceeding Stage 2 Decision as per Order G-47-14, the Commission directed the PNG utilities to include an updated business risk assessment in all future revenue requirements applications. An updated business risk assessment, as directed by the Commission, is appended to this Amended Application as Appendix F.

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APPENDIX B – 2016 Unaccounted For Loss Report

APPENDIX C – 2017 Depreciation Study (Concentric)

APPENDIX D – Econolink Extract – January 2018

APPENDIX E – 2017 Pipeline Risk Mitigation Report (filed confidentially)

APPENDIX F – Business Risk Assessment – 2018 Update

APPENDIX A – Draft Commission Order

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Utilities Commission

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ORDER NUMBER
G-xx-18

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
2018-2019 Revenue Requirements Application
For the PNG (N.E.) Service Area

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on July xx, 2018

ORDER

WHEREAS:

A. On November 30, 2017, Pacific Northern Gas (N.E.) Ltd. [PNG(NE)] filed its 2018-2019 Revenue Requirements Application (RRA) for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions with the Commission pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA) seeking, among other things, approval to increase 2018 delivery rates as a result of a net increase in cost of service offset by increased deliveries (Applications);

B. By Order G-193-17 dated December 19, 2017, the Commission approved the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Applications on an interim and refundable basis, effective January 1, 2018. The Commission also established a preliminary regulatory timetable;

C. The British Columbia Old Age Pensioners' Organization et al. (BCOAPO) registered as interveners;

D. By Order G-31-18 dated February 2, 2018, the Commission established a written public hearing process, which directed PNG(NE) to file its updated applications on February 28, 2018, and included two rounds of Commission and intervener information requests, followed by final and reply arguments;

E. On February 28, 2018, PNG(NE) filed its updated applications for the FSJ/DC and TR divisions (Amended Applications); and

F. The Commission has considered the Applications, Amended Applications, evidence and submissions of the parties.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons for decisions attached as Appendix A to this order, the British Columbia Utilities Commission orders as follows:

1. Pacific Northern Gas (N.E.) Ltd.'s [PNG(NE)] request for recovery of the 2018 revenue requirement and resultant delivery rate changes presented in the Amended Applications for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions are approved on a permanent basis, effective January 1, 2018, subject to the adjustments identified by PNG(NE) in information requests and in argument as well as to the adjustments outlined in these directives.

2. The Rate Stabilization Adjustment Mechanism riders set forth in the Amended Applications are approved on a permanent basis, effective January 1, 2018.

3. PNG(NE)'s request for recovery of the 2019 revenue requirement and resultant delivery rate changes presented in the Amended Applications for the FSJ/DC and TR divisions are approved on a permanent basis, effective January 1, 2019, subject to the adjustments identified by PNG(NE) in information requests and in argument as well as to the adjustments outlined in these directives.

4. The following changes and additions to PNG(NE)'s regulatory accounts are approved:

    a. The creation of new regulatory accounts for the PNG(NE) FSJ/DC and TR divisions bearing interest at each division's respective short-term interest rate to levelize the impact of the combined net revenue deficiencies for divisions for 2018 and 2019 to be fully amortized in 2019;

    b. The transfer of the PNG(NE) FSJ/DC 2016 unaccounted for gas (UAF) losses above 1.5 percent from the temporary UAF deferral account to the UAF volume deferral account to be recovered from FSJ/DC division customers via the Company Use rider, and dissolution of the temporary UAF deferral account; and

    c. The dissolution of the PNG(NE) FSJ/DC and TR division Legacy Deferred Income Taxes deferral account and the NPPRB Regulatory Asset Deferral account.

5. PNG(NE) FSJ/DC is approved to continue the use of the unaccounted for gas (UAF) volume deferral account on the basis that the UAF volume forecast for Test Year 2018 and Test Year 2019 are set based on using 1.0 percent of deliveries UAF loss factor. PNG(NE) FSJ/DC must file an application with the Commission to obtain approval to record UAF losses above 1.5 percent in this deferral account.

6. PNG(NE) TR is approved to continue the use of the unaccounted for gas (UAF) volume deferral account on the basis that the UAF volume forecast for Test Year 2018 and Test Year 2019 are set at zero with PNG(NE) TR recording the variance between zero and a loss of up to 1.0 percent without requiring further Commission approval. PNG(NE) TR must file an application with the Commission to obtain approval to record UAF losses above 1.0 percent in this deferral account.

7. PNG(NE) is approved to apply the depreciation rates proposed for the FSJ/DC and TR divisions that exclude any new net salvage rate provisions, effective January 1, 2018.

8. PNG(NE) is directed to re-calculate the 2018 and 2019 revenue deficiencies and delivery rate changes for the FSJ/DC and TR divisions in a compliance filing and file revised regulatory schedules with the Commission reflecting the changes outlined in this order and further described in the attached reasons for decision by no later than 30 days from the date of this order.

9. PNG(NE) is directed to collect from/refund to customers the difference between the 2018 interim rates and the 2018 permanent rates for the FSJ/DC and TR divisions over the balance of 2018. PNG(NE) must inform all customers of permanent rates by way of written notice to be included with their next customer invoice.

10. PNG(NE) is directed to file its next RRA for the FSJ/DC and TR divisions for a period of two years encompassing a test period of 2020 and 2021.

DATED at the City of Vancouver, in the Province of British Columbia, this (xx) day of July 2018.

BY ORDER

(X. X. last name)
Commissioner

APPENDIX B – 2016 Unaccounted For Loss Report

PACIFIC NORTHERN GAS (N.E.) LTD.

UNACCOUNTED FOR GAS REPORT

FOR THE PERIOD:
JANUARY 2016 TO DECEMBER 2017

February 15, 2018

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1 OVERVIEW

The British Columbia Utilities Commission (Commission) approved the 2016-2017 Revenue Requirements Application for the Pacific Northern Gas (N.E.) Ltd. (PNG(N.E.)) division by Order G-132-16 dated August 10, 2016. Pursuant to directive 5 of this Order the Commission approved PNG(N.E.)'s continued use of the unaccounted for gas (UAF) volume deferral account on the basis that the UAF volume forecast for Test Year 2016 and Test Year 2017 be set at zero with PNG(N.E.) recording the variance between zero percent and a loss of up to 1.5 percent in the UAF volume deferral account without having to seek further Commission approval of the deferral. PNG(N.E.) was also directed to file an application with the Commission to obtain approval to record UAF losses above 1.5 percent in the UAF volume deferral account. These directives are consistent with those made on other recent PNG(N.E.) revenue requirement applications.

For 2016, PNG(N.E.) recorded a UAF loss on its Fort St. John and Dawson Creek systems of 203,081 gigajoules (GJ) or 5.3 percent of deliveries to its sales and transport customers. On February 24, 2017, PNG(N.E.) applied to the Commission for approval to record 2016 UAF losses above 1.5 percent in the UAF deferral account, allowing for all UAF losses to be accounted for and recovered from customers on a consistent basis (UAF Loss Application). Under Order G-105-17, the Commission denied PNG(N.E.)'s request and directed PNG(N.E.) to establish a separate temporary deferral account to record the 2016 UAF loss over 1.5 percent until such time as the disposition of the excess UAF has been determined.

The Commission further directed PNG(N.E.) to include in its next revenue requirements application a report summarizing the results of its further examination of all data and calculations and investigation into the reasons for the increased 2016 UAF loss and a proposal for the recovery of the 2016 UAF loss over 1.5 percent.

In response to the Commission's directive, PNG(N.E.) provides this report presenting the results of PNG(N.E.)'s investigation into the cause or causes of the increased UAF loss on the Fort St. John and Dawson Creek systems in 2016.

2 DISCUSSION OF THE 2016 UAF VOLUMES

This report presents the findings of PNG(N.E.)'s review of its gas measurement and accounting practices related to the calculation of the monthly UAF on its Fort St. John and Dawson Creek systems from January 2016 to December 2017. The purpose of the review was: (i) to compare the magnitude, month-to-month volatility and trend in UAF volumes in 2016 and 2017 to historical magnitudes, volatilities and trends; (ii) to verify that the data entered into PNG(N.E.)'s internal STATS reports are accurate and that the UAF volumes have been correctly calculated; and (iii) to determine the root cause for any deviations during 2016 from the historically established pattern of monthly UAF volumes.[1]

2.1 UAF Trends

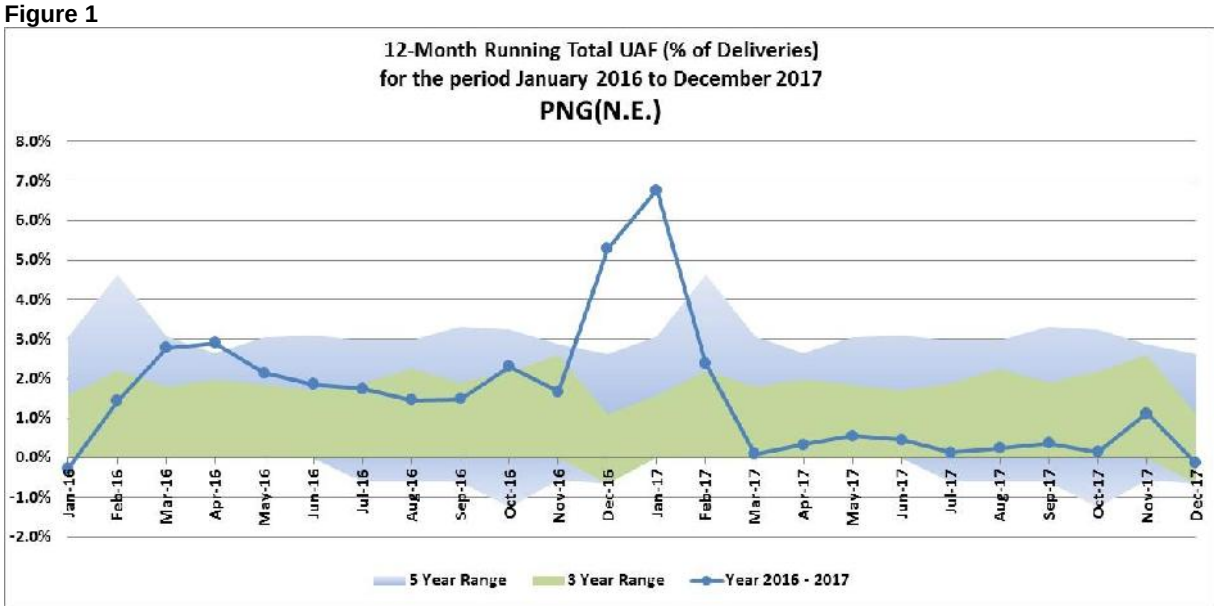
Figure 1 below illustrates the running 12-month total UAF expressed as a percentage of deliveries summed over the same period. The period spanned by this chart is from January 2016 through December 2017 during which time the running 12-month total UAF exceeded its historical range only during the period from December 2016 to January 2017. A reversal of these losses occurred over the following two months (February and March 2017) with the result that the running 12-month total UAF returned to within historical bounds.

Notable also, is the increase in the running 12-month total UAF in February and March 2016. A similar trend was exhibited by the UAF on the PNG-West system.

Figure 2 presents a multi-year historical perspective of the trend in UAF losses. In the period beginning January 2012 through December 2017, accumulated UAF as a portion of accumulated deliveries has ranged between -3.22 percent and +2.07 percent. After reaching +1.66 percent in January 2017, the accumulated balance has decreased and stands at 1.03 percent in December 2017.

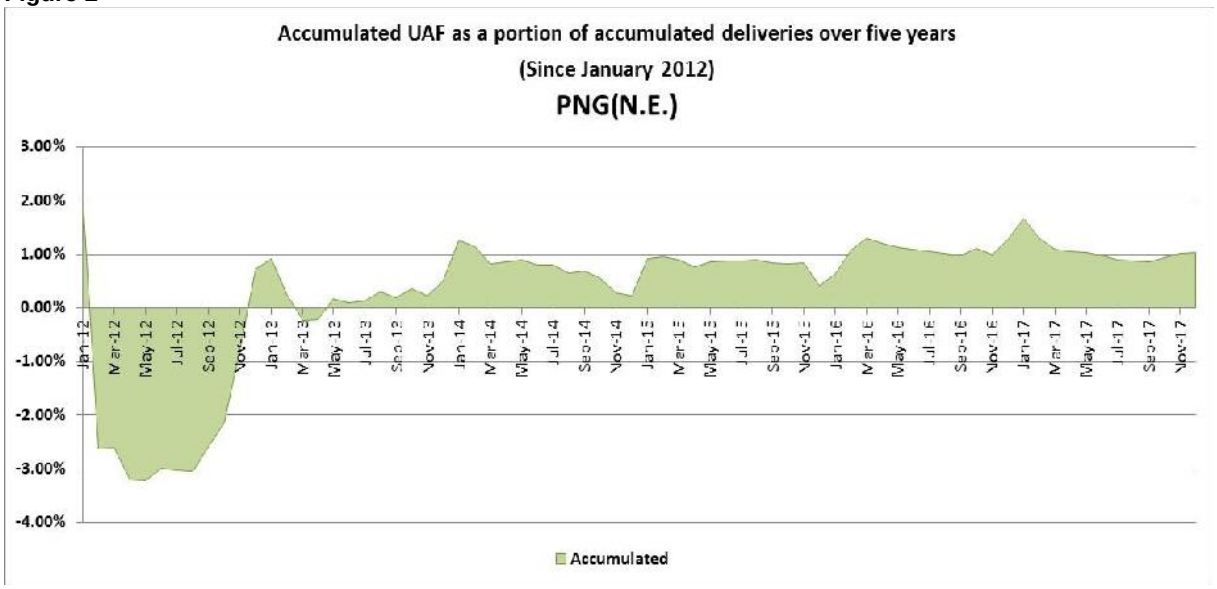
[1] PNG(N.E.)'s internal STATS reports are Excel based reports that calculate the monthly UAF from metered gas volume receipts and deliveries, month-end accrued delivery estimates, and company use gas.

Figure 1



The left most marker on the blue line represents the total UAF volume for the 12 months ending January 2016; the right most marker represents the 12 month total UAF over the period January 2017 to December 2017. The blue and green shaded areas represent the range of 12-month running total UAF during the periods 2013 – 2015 and 2011 – 2015, respectively.

Figure 2



While abnormally large UAF gains or losses in each month are examined for their cause, often times such deviations are reversed over the next two months, owing to an under- or over-statement of either the residential or small commercial unbilled estimate. Any persistent gain beyond the three months is generally considered to be due to some other underlying

cause and such a trend triggers a more in depth examination of all metered data, data conversion factors and physical changes at custody transfer receipt points. In light of the trend presented in Figure 1, PNG(N.E.) has focused its examination on the months of February, March, and December 2016, and on January 2017.

2.2 Adjustments to UAF Volumes

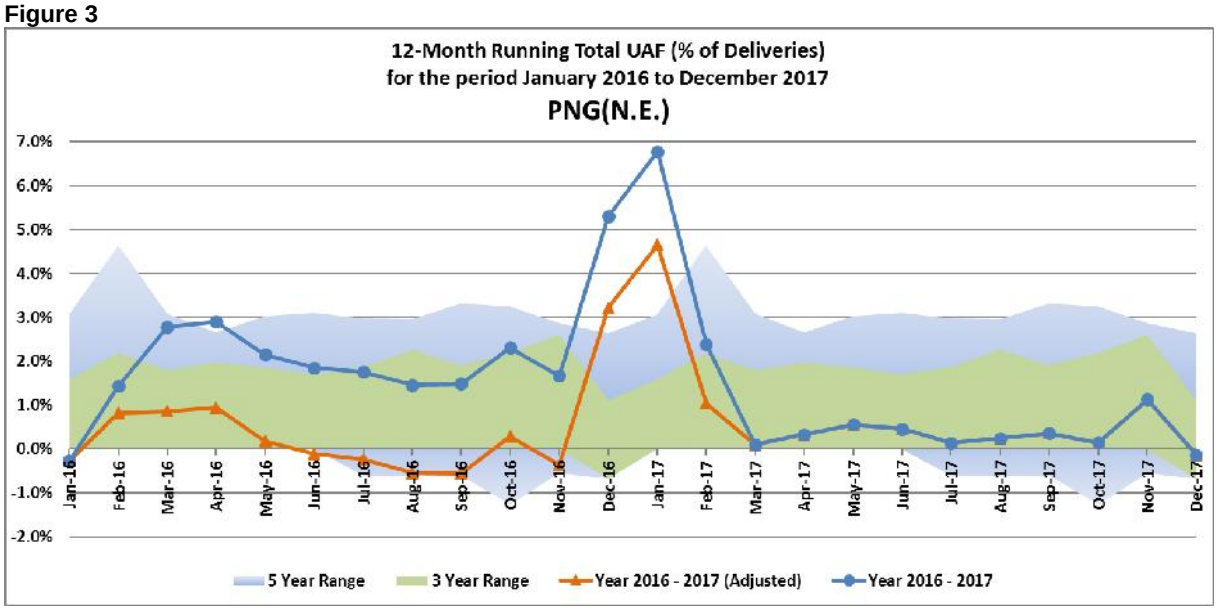
A determination of the monthly UAF volume is dependent upon an unbilled estimate; in other words, an estimate of the volume of natural gas delivered to residential and small commercial customers but not yet billed. This amount is estimated based on the number of unbilled days of service (DOS) from when a customer was last billed, to the end of the current calendar month. In February 2016, PNG(N.E.) implemented a change in how the unbilled DOS are reported. The change in reporting resulted in a reduction in the estimate of unbilled consumption of residential customers, and a resultant increase in the monthly UAF loss, during the months of February and March 2016. PNG(N.E.) has determined the impact of the change in the reporting of unbilled DOS, and presented this in Table 1. The impact of the change in the unbilled DOS report on the 2016 UAF volume is approximately 80,000 GJ, or approximately 40 percent of the UAF volume recorded in 2016.

Table 1

UAF (GJ)	Original	Adjustment	Updated
February 2016	84,881	(26,028)	58,853
March 2016	50,261	(53,916)	(3,654)
Total	**135,143**	**(79,944)**	**55,199**

The following chart (Figure 3) presents the trend shown in Figure 1, but adjusted to account for the impact of the change in the unbilled DOS report. After accounting for the impact of the change in the unbilled DOS report, the running 12-month total UAF remains below 1.5 percent of deliveries for all but the period from December 2016 to January 2017.

Figure 3



2.3 December 2016 and January 2017 UAF Volumes

PNG(N.E.) has completed a review of the data and calculations associated with the determination of the UAF volumes for December 2016 and January 2017. Included in the review was an examination of:

a) the spreadsheets used to calculate the UAF volumes for errors;

b) PNG(N.E.)'s volume accounting and billing system ("Banner");

c) the estimate of unbilled consumption to the end of the calendar month of the residential and small commercial classes (the "unbilled estimates");

d) the gas volumes reporting processes at Enbridge; specifically, the application of unit conversions and heating values in the conversion of metered volumes to units of GJ, and the reporting of both volume and energy on Enbridge's statement of deliveries; and

e) deliveries to the large commercial, industrial and transport customers for any deviations from expected trends.

PNG(N.E.) has determined that the most likely cause of the significant UAF volume during December 2016 is a residential and small commercial unbilled estimate that did not correctly reflect the impact of the sudden and significant cold snap that occurred during the middle of

December. PNG(N.E.) has not found a probable cause for the high UAF volume recorded in January 2017 but PNG(N.E.) notes that the January UAF loss was subsequently reversed over the following two months (February and March 2017). This pattern is consistent with an under-statement of the residential or small commercial unbilled estimates in January.

PNG(N.E.) periodically evaluates its unbilled estimation method. At this time, PNG(N.E.) has not found compelling evidence that a change to its method is warranted. However, PNG(N.E.) continues to evaluate improvements to its methodology as better information on residential and commercial customer behaviour becomes available.

2.4 2017 Calendar Year UAF Volume

The UAF Volume for the 12 months to the end of December 2017 has again fallen to well below the Commission approved threshold of 1.5 percent. The 2017 UAF volume is a surplus of 5,788 gigajoules, equivalent to 0.13 percent of deliveries.

3 CONCLUSIONS AND RECOMMENDATIONS

PNG(N.E.) has reviewed the data and calculations supporting the determination of the monthly UAF volumes on the PNG(N.E.) system and identified adjustments accounting for approximately 80,000 GJ, or approximately 40 percent of the UAF volume recorded in 2016. After accounting for these adjustments, the running 12-month total UAF trend falls within, or very close to, the five-year historical bounds in every month of 2016 except for December. As well, with the exception of January 2017, the running 12-month total UAF trend also falls within the historical bounds for the period from February to December 2017.

The probable cause of the deviation from historical trends that occurred in December 2016 and January 2017 is an under estimation of the residential and small commercial unbilled consumption. UAF losses in these two months have been reversed in subsequent months and the trend in UAF has returned to historical patterns.

PNG(N.E.) remains diligent in monitoring its UAF volumes, identifying anomalous values and trends, and in examining the cause or causes of those anomalies. PNG(N.E.) has, in this instance, found causes for the anomalous UAF volumes recorded in 2016. No systemic and ongoing issues have been identified. The change in the unbilled DOS report created a one-time impact on the UAF volumes recorded in February and March, 2016. The impact of a cold snap in December 2016 on the unbilled estimate is an isolated event, albeit one that may occur again in the future. In an effort to improve its unbilled estimate under these circumstances, PNG(N.E.) continues to evaluate the costs and benefits of accessing more accurate customer information, such as may be provided using advanced metering infrastructure (AMI), or through a renewed residential end-use survey (REUS).

To summarize, PNG(N.E.) experienced an amount of UAF in 2016 that exceeded the historical range. All of the excess UAF can be explained by isolated events affecting the UAF additions in February, March and December. A change in how the unbilled DOS are reported affected the UAF additions in February and March, and the unbilled estimate did not correctly reflect the impact of a cold snap in December.

Through its diligent review of the causes of the UAF in 2016, PNG(N.E.) has achieved a high degree of confidence that these causes were isolated events affecting only three months

during 2016, rather than systemic issues that may continue to result in UAF volumes that are higher than historic levels. The trend in UAF after December 2016 has returned to within historic boundaries, supporting PNG(N.E.)'s position.

In view of the foregoing, PNG(N.E.) submits that its review has confirmed its gas accounting practices to be thorough and consistent with industry standards. PNG(N.E.) therefore requests Commission approval to record the 2016 actual UAF losses of 5.3 percent, or 203,081 GJ in the UAF volume deferral account, consistent with Commission directives for prior years.

The total 2016 UAF loss amounts to $385,448 before tax (i.e. 203,081 GJ's times $1.898/GJ, which is the approved Company use gas commodity cost applied throughout 2016). The difference between the 1.5 percent UAF not requiring further Commission approval and the 5.3 percent actual UAF is 145,572 GJs which amounts to $276,296 before tax (i.e. 145,572 GJs times $1.898/GJ).

APPENDIX C – 2017 Depreciation Study

(Concentric)

VANCOUVER, BRITISH COLUMBIA

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2016

PREPARED FOR
PACIFIC NORTHERN GAS LTD
VANCOUVER, BRITISH COLUMBIA

AUGUST 25, 2017

WWW.CEADVISORS.COM

PACIFIC NORTHERN GAS LTD
Vancouver, British Columbia

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUAL RATES AS OF DECEMBER 31, 2016

CONCENTRIC ADVISORS ULC

Calgary, Alberta

CONCENTRIC ADVISORS

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EXECUTIVE SUMMARY

Pursuant to Pacific Northern Gas Ltd.'s ("PNG." or "Company") request, Concentric Advisors ULC ("Concentric") conducted a depreciation study related to natural gas distribution and general plant accounts as of December 31, 2016. The purpose of this study was to determine the annual depreciation accrual rates and amounts applicable to the original cost of gas plant as of December 31, 2016.

The depreciation rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The depreciation rates are based on the straight-line method using the average service life group procedure and were applied on a remaining life basis. The calculations were based on attained ages, estimated average service life, and forecasting net salvage characteristics for each depreciable group of assets.

While the methodology adopted in this study is generally consistent with that applied in determining the depreciation rates as per the 2009 depreciation study completed by Gannett Fleming, Concentric notes that it is proposing a change from PNG's last approved depreciation study. This study makes provision of the recovery of cost of removal to be collected through depreciation expense, as compared to the current collection of cost of removal in the year of occurrence. The inclusion of an allowance for net salvage provides for the proper matching of expenses to revenues and ensures for accurate intergenerational equity.

Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to natural gas plant in service as of December 31, 2016 as summarized by Tables 1A COR, 1B COR, 1C COR and 1D COR for components of Life. Tables 1E has also shown to illustrate the combined impacts for the Fort St. John and Dawson Creek combined entity. Detailed supporting data and calculations are provided within the study.

In BCUC Order G-130-12, the Commission directed "In PNG's next Revenue Requirements Application, it should provide an analysis of the potential use of negative salvage accounting. Also, in PNG's next depreciation study, the depreciation expert should be engaged to provide depreciation rates as well as negative salvage provision rates for each asset class. These two items should be presented separately from each other and the basis for the determination of negative salvage rates should be disclosed."

As a result of this Order, Concentric Advisors has added Tables 2A, 2B, 2C and 2D which are summary tables of the calculated annual accrual for depreciation expense and rates on a net salvage basis. Tables 2E has also been added to illustrate the combined impacts for the Fort St. John and Dawson Creek combined entity. Furthermore, the basis for Concentric Advisors determination of each applicable fixed asset account's net salvage has been provided in Part II as Survivor Curve and Net Salvage Judgements.

Detailed supporting data and calculations are further provided within the study.

In BCUC Order G-114-13, the Commission directed "The Commission Panel accepts that it continues to be appropriate for PNG to record the costs of asset retirements in the ordinary course of business to the Plant Gains and Losses deferral account as they are incurred. However, the Panel is supportive of PNG's decision to include an evaluation of the potential of using negative salvage accounting in its next Depreciation Study. Our expectation is that this evaluation will include a thorough examination of the pros and cos of utilizing negative salvage accounting and the costs of its implementation." In this regard, Concentric Advisors has provided its examination of utilizing net salvage in PNG's depreciation rates in Part I - Basis of The Study – Depreciation Net Salvage.

This study results in a consolidated annual depreciation expense accrual of $10.0 million when applied to depreciable plant balances as of December 31, 2016. The report study results are summarized at an aggregate functional group level and then at a system level as follows:

TOTAL CONSOLIDATED
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

	ORIGINAL COST	ANNUAL ACCRUAL	
PLANT GROUP	$'s	%'s	$'s
(1)	(2)	(3)	(4)
GATHERING	3,889,174	4.43	172,412
PROCESSING	33,200	2.70	895
TRANSMISSION	223,758,907	1.77	3,964,563
DISTRIBUTION	148,594,698	3.03	4,501,365
GENERAL	23,817,468	5.52	1,315,139
TOTAL PLANT IN SERVICE	**400,093,446**	**2.49**	**9,954,374**

WEST SYSTEM
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

	ORIGINAL COST	ANNUAL ACCRUAL	
PLANT GROUP	$'s	%'s	$'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	33,200	2.70	895
TRANSMISSION	199,842,201	1.74	3,480,895
DISTRIBUTION	65,880,621	3.34	2,201,711
GENERAL	16,873,587	5.66	955,644
TOTAL PLANT IN SERVICE	**282,629,608**	**2.35**	**6,639,145**

FORT ST. JOHN
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

	ORIGINAL COST	ANNUAL ACCRUAL	
PLANT GROUP	$'s	%'s	$'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	-		-
TRANSMISSION	13,097,887	1.97	257,916
DISTRIBUTION	53,962,473	2.58	1,394,625
GENERAL	2,347,674	5.25	123,225
TOTAL PLANT IN SERVICE	**69,408,034**	**2.56**	**1,775,766**

DAWSON CREEK
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	-		-
TRANSMISSION	8,639,235	2.07	178,668
DISTRIBUTION	25,785,055	3.12	803,893
GENERAL	3,924,576	5.65	221,905
TOTAL PLANT IN SERVICE	**38,348,866**	**3.14**	**1,204,466**

TUMBLER RIDGE
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GATHERING	3,889,174	4.43	172,412
PROCESSING	-		-
TRANSMISSION	2,179,584	2.16	47,084
DISTRIBUTION	2,966,549	3.41	101,136
GENERAL	671,631	2.14	14,365
TOTAL PLANT IN SERVICE	**9,706,938**	**3.45**	**334,997**

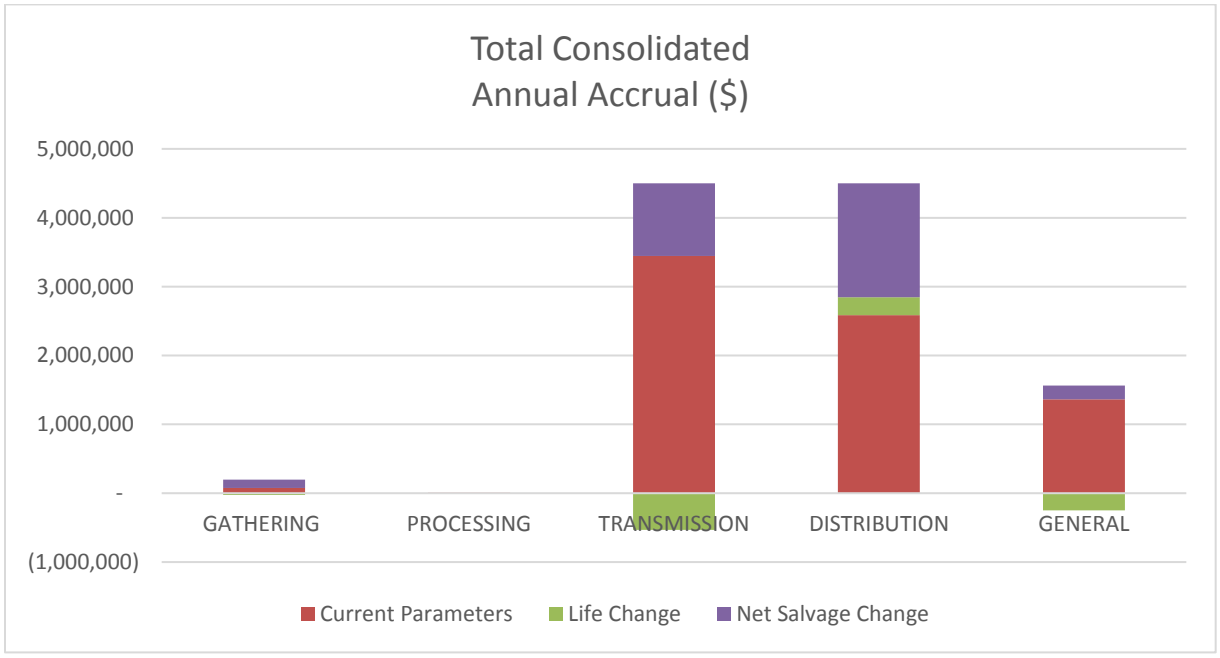
FORT ST. JOHN & DAWSON CREEK
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	-		-
TRANSMISSION	21,737,122	2.01	436,584
DISTRIBUTION	79,747,528	2.76	2,198,518
GENERAL	6,272,250	5.50	345,130
TOTAL PLANT IN SERVICE	**107,756,900**	**2.77**	**2,980,232**

Finally, the application of the current depreciation parameters, applied to the 2016 depreciable balances, would result in an approximate $7.6M annual expense accrual. The recommended life parameter changes results in an annual expense accrual decrease of approximately $.1M. The recommended net salvage parameter changes result in an annual expense accrual increase of approximately $2.6M. These changes are further detailed by account in Tables 2 (and in each account's detailed Survivor Curve and Net Salvage Judgements) and summarized at an aggregate functional group level and then at a system level as follows:

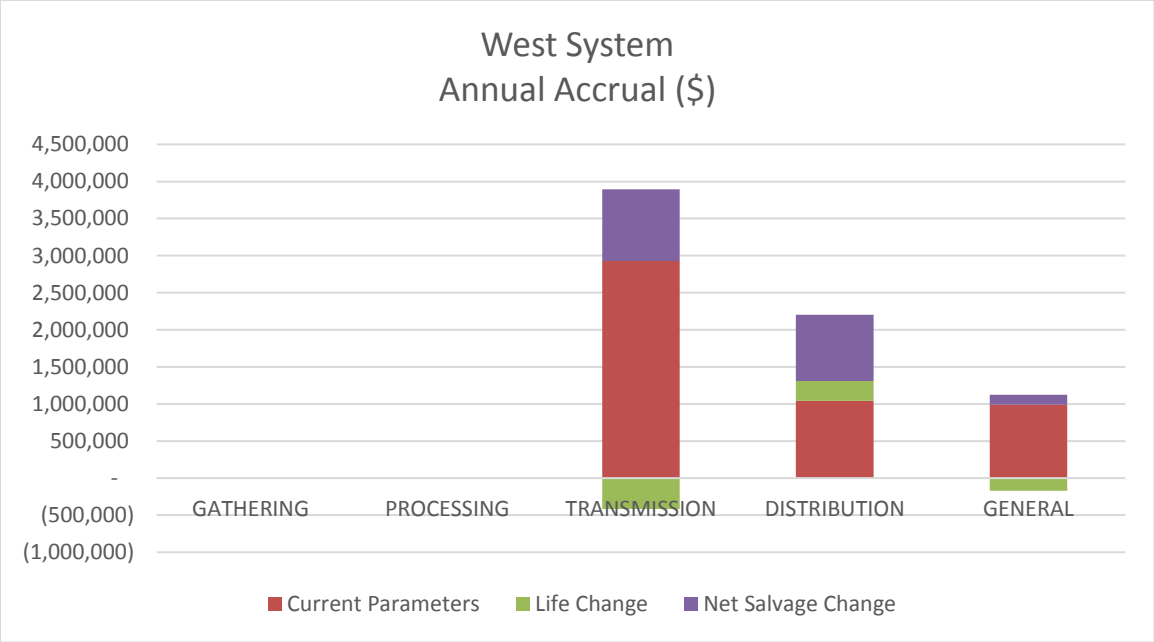
TOTAL CONSOLIDATED
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	75,854	(25,319)	121,877	172,412
PROCESSING	895	-	-	895
TRANSMISSION	3,443,170	(534,507)	1,055,900	3,964,563
DISTRIBUTION	2,583,730	261,748	1,655,887	4,501,365
GENERAL	1,364,089	(247,136)	198,186	1,315,139
TOTAL PLANT IN SERVICE	**7,467,738**	**(545,214)**	**3,031,850**	**9,954,374**



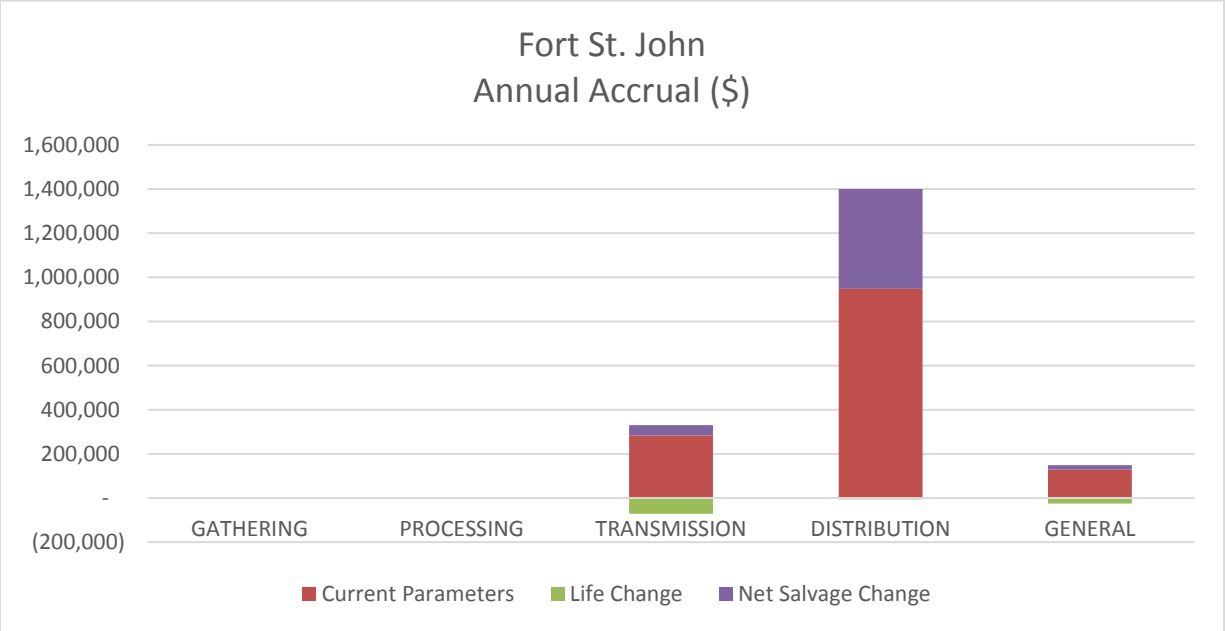
WEST SYSTEM
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	895	-	-	895
TRANSMISSION	2,928,435	(414,576)	967,036	3,480,895
DISTRIBUTION	1,043,087	264,917	893,707	2,201,711
GENERAL	990,462	(168,823)	134,005	955,644
TOTAL PLANT IN SERVICE	**4,962,879**	**(318,482)**	**1,994,748**	**6,639,145**



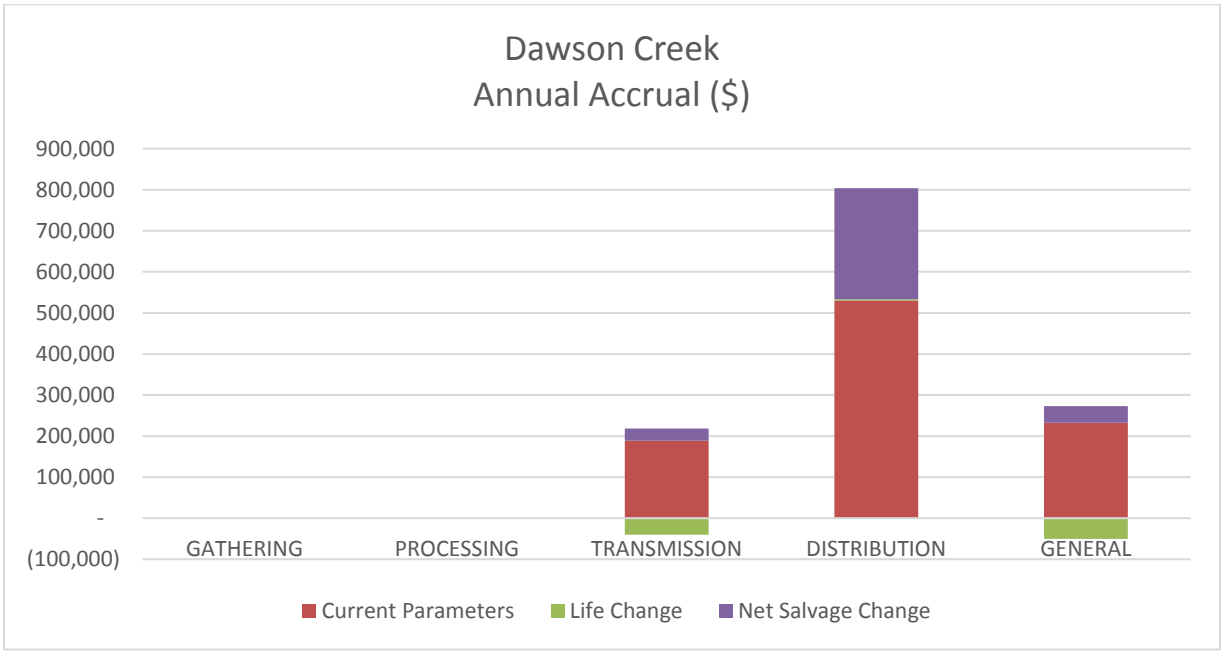
FORT ST. JOHN
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	-	-	-	-
TRANSMISSION	283,959	(72,071)	46,028	257,916
DISTRIBUTION	947,377	(6,351)	453,599	1,394,625
GENERAL	127,961	(25,432)	20,696	123,225
TOTAL PLANT IN SERVICE	**1,359,297**	**(103,854)**	**520,323**	**1,775,766**



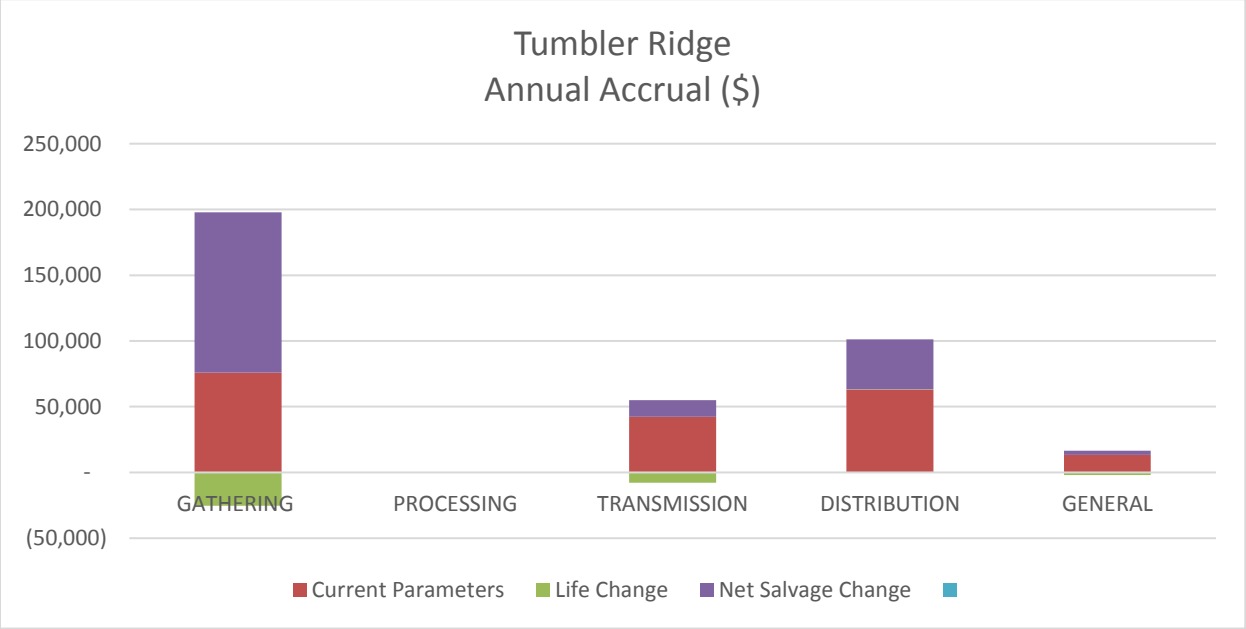
DAWSON CREEK
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	-	-	-	-
TRANSMISSION	188,540	(40,045)	30,173	178,668
DISTRIBUTION	530,225	3,002	270,666	803,893
GENERAL	232,261	(50,816)	40,460	221,905
TOTAL PLANT IN SERVICE	**951,026**	**(87,859)**	**341,299**	**1,204,466**



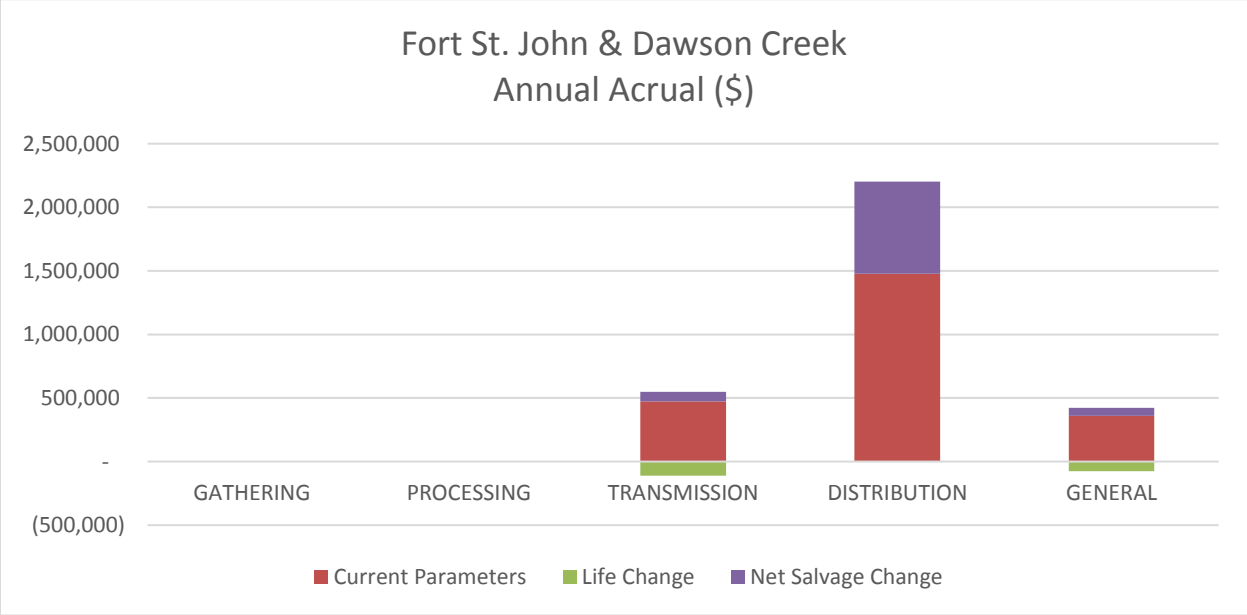
TUMBLER RIDGE
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	75,854	(25,319)	121,877	172,412
PROCESSING	-	-	-	-
TRANSMISSION	42,236	(7,815)	12,663	47,084
DISTRIBUTION	63,041	180	37,915	101,136
GENERAL	13,405	(2,065)	3,025	14,365
TOTAL PLANT IN SERVICE	**194,536**	**(35,019)**	**175,480**	**334,997**



FORT ST. JOHN & DAWSON CREEK
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	-	-	-	-
TRANSMISSION	472,499	(112,116)	76,201	436,584
DISTRIBUTION	1,477,602	(3,349)	724,265	2,198,518
GENERAL	360,222	(76,248)	61,156	345,130
TOTAL PLANT IN SERVICE	**2,310,323**	**(191,713)**	**861,622**	**2,980,232**



PART I. INTRODUCTION

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Pacific Northern Gas Ltd. to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of Pacific Northern Gas Ltd.'s gathering, processing, transmission, distribution and general plant assets as of December 31, 2016. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the natural gas plant in service.

The service life and net salvage estimates resulting from the study were based on: informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2016; a review of company practice and outlook as they relate to plant operation and retirement; review of the company's upcoming capital and retirement projects; and consideration of current practice in the natural gas industry, including knowledge of service lives and net salvage estimates used for other natural gas utilities.

PLAN OF REPORT

Part I. Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II. Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life and net salvage studies. Part III. Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV. Results of Study, presents summaries by depreciable group of annual and accrued depreciation. Part V presents the results of the Retirement Rate and Service Life Statistics and Part VI presents Net Salvage Analysis. Detailed tabulations of annual and accrued depreciation are presented in Part VII of this report. An overview of Iowa curves and the Retirement Rate Analysis are set forth in Appendix A of the report. An overview of the net salvage analysis is presented in Appendix B of this report.

Depreciation - Life

For most accounts, the annual and accrued depreciation were calculated by the straight-line method using the average life group ("ALG") procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and salvage.

The straight-line method, average life group procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Concentric recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.

Depreciation – Net Salvage

This study recommends the incorporation of cost of removal (net negative salvage) in PNG's depreciation rates. The incorporation of negative net salvage has resulted in an approximate increase of $3.0M or 30 percent of PNG's total forecast $10.0M depreciation expense. Concentric Advisors recognizes the magnitude of including net negative salvage in depreciation rates. However, Concentric Advisors views that delaying the introduction of negative net salvage will increase the inter-generational inequity from customers that pay for the eventual removal costs from those that benefitted from those removed assets. The inclusion of an allowance for net salvage provides for the proper matching of expenses to revenues and ensures for accurate intergenerational equity. In other words, customers of PNG that benefit from the usage of their assets should also pay proportionately for those asset's eventual costs of demolishing, dismantling, tearing down or otherwise removing including the cost of transportation and handling incidental thereto. Allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accordance with authoritative texts and most Uniform Systems of Accounting including those published in Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission. The recovery of the net salvage in the depreciation rates is

widely accepted throughout North America, including Fortis BC Energy. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage. The longer the delay in recognizing net negative salvage, the higher future depreciation rate will be as PNG's depreciation rates are based on its net book value amortized over a remaining life basis. Each year of delay will increase the differential between booked net book value and calculated net book[1] value. As such, the resultant depreciation rates will increase proportionately.

The inclusion of net salvage percentages is widely accepted in regulatory jurisdictions throughout North America. Depreciation is not simply the allocation of original cost to expense. In the most widely used definition of depreciation for regulated utilities, the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts defines depreciation as "the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of property in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." The operative words in this definition are "*service value"*. The FERC Uniform System of Accounts goes on to define service value as "the difference between the original cost and the net salvage value of the utility plant". The service value rendered by an asset, i.e. depreciation, must reflect both its original cost and its net salvage. The FERC further defines "net salvage value" to mean the salvage value of property retired less the cost of removal, with "cost of removal" being defined as the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto.[2]

Allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accordance with authoritative texts[3] and most Uniform Systems of

[1] Calculated net book value (or Calculated Accumulated Depreciation) is the theoretical value for the accumulated depreciation reserve which is assumed to be applicable, and thus calculated, to the original date of installation.

[2] All referenced definitions are as per Chapter 1 – Federal Energy Regulatory Commission, Department of Energy, and Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, Definitions Section.

[3] Such as Depreciation Systems, Frank K. Wolf and W. Chester Fitch, Published, Iowa State University Press,

Accounting including those published in Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage. Additionally, the FERC Uniform System of Accounts requires that depreciation be recognized through accrual accounting. That is, the service value of an asset must be accrued during the life of the asset. Since net salvage is a part of the service value, it must be accrued during the life of the related asset in order to comply with the FERC Uniform System of Accounts. As such, regulatory decisions that require the expensing of costs of removal or that mandate the inclusion of costs of removal of retired plant as part of future capital costs of replacement plant need to understand that the decisions are in contrast to the FERC published and long-followed net salvage concepts from regulatory jurisdictions throughout North America. The revenue requirements that result from any type of "*expensing as incurred*" option are greater than the revenue requirements that result from accruing for net salvage during the life of the related asset for a regulated utility that includes a rate of return in its revenue requirement. Although a comparison of the current revenue requirements related to a net salvage accrual and the current revenue requirements related to expensing of net salvage may indicate that the accrual is higher at a single point in time, over time the revenue requirements and the present value of those revenue requirements will be less if the net salvage cost is accrued over the life of the asset. The reason for the lower revenue requirements with the accrual of net salvage is the impact of the accruals on rate base. That is, as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods

Many jurisdictions across Canada recognize the regulatory benefit and fairness to the inclusion of the recovery of the net salvage requirements over the period of time that assets are providing regulatory service. Regulatory decisions allowing the inclusion of net salvage

1994; and Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute, 1997.

percentages have been rendered by the following Canadian regulatory bodies for rates that are currently in place:

- The British Columbia Utilities Commission
- The Alberta Utilities Commission
- The Manitoba Public Utilities Board
- The Ontario Public Utilities Board
- The Regie de l'Energie du Quebec
- The Nova Scotia Utility and Review Board
- The Newfoundland and Labrador Board of Commissioners of Public Utilities
- Northwest Territories Public Utilities Board
- The National Energy Board of Canada

However, it is noted that not all utilities request recovery of net salvage within depreciation rates. The policy decision to recover net salvage within depreciation is made by the specific utility after consideration is given to all relevant factors, including:

- The accounting jurisdiction and principles being followed for financial disclosure purposes (US GAAP versus IFRS or modified IFRS);
- The potential for re-use of assets or facilities;
- The requirement for the utility to report an Asset Retirement Obligation;
- Review of the current funds for site removal and restoration;
- Materiality of the net salvage estimates; and
- Nature of retirement activity (interim or final retirement).

As such, it is not possible to conclude that all utilities within any jurisdiction either include or exclude net salvage recovery.

The BCUC has recently allowed the inclusion of costs of removal (net negative salvage) in the depreciation rates of FortisBC Energy, Inc. (formally Terasen Gas). In a 2011 Application before the BCUC in respect of 2012/2013 Revenue Requirements and Rates, FortisBC Energy Inc. Utilities ("FEU") requested a change to its practice of collecting salvage costs from ratepayers. FEU identified four possible methods to recover negative salvage

values from ratepayers: (i) the traditional approach (ie. as presented in this Application); (ii) a "pay-as-you-go" approach; (iii) Asset Retirement Obligation (ARO) style accounting; and (iv) a Hybrid approach (i.e. a combination of the traditional approach and ARO style accounting). FEU sought approval to adopt the traditional approach during the test period for all retirement obligations that are not AROs as defined by GAAP.

Under its 2011 Application to the BCUC, FEU sought approval for inclusion into its depreciation rate calculations, a provision for net salvage calculated in accordance with the "traditional" approach. The net salvage percentages were estimated in a Depreciation Study filed with the application. This application was a change from the approach used in a prior 2008 negotiated settlement which incorporated a pay-as-you-go approach which was considered to be more consistent with the BCUC 2005 BC Hydro Decision. However, in its 2011 Application FEU submitted the following arguments in support of its proposal to return to the tradition method of recovering net salvage through inclusion in the depreciation rate calculations:

- that the 3 years of history in using a pay-as-you-go method showed a large level of volatility;
- using a pay-as-you-go approach in the circumstance of actual retirement costs being forecast to increase as the assets near the end of their average useful lives, results in tomorrow's ratepayers paying to retire assets used today;
- The traditional negative salvage approach is a common, widely used practice amongst comparable utilities across the country and is also the method of accounting for salvage costs generally accepted for use in the United States within the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts.

After consideration of the above arguments, the BCUC ruled as follows:

> *The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a "pay as you go system" to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted. While net negative salvage rates are an*

estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.[4]

The above BCUC decision regarding the FEU Application clearly indicates that the BCUC understood the issues with a pay-as-you-go approach, and was willing to approve the inclusion of the net salvage estimates within the depreciation rate calculations, notwithstanding its prior BC Hydro decision.

Since the changes in the Financial Reporting Standards in the early 2000s, many depreciation studies completed by Larry Kennedy have developed separate provisions relating to the recovery of original cost of investment and for the recovery of costs of removal. In particular, this approach has been followed in applications completed for the following regulated utilities:

- FortisBC Energy Inc. related to a 2010 depreciation study approved by the BCUC in 2012, following a 2011 hearing;
- All regulated electric utilities in the province of Alberta (as specifically prescribed by the minimum filing requirements for Alberta electric utilities[5]);
- All regulated gas utilities in the Province of Alberta;
- Enbridge Consumers Gas in a 2012 Application to the Ontario Energy Board; and
- Gaz Metro in a 2010 Application to the Regie de l'Energie du Quebec.

The issue of recovery of net salvage requirements has received attention in virtually all recent depreciation applications in most jurisdictions across Canada. In particular, the issue was recently reviewed in the following jurisdictions:

[4] BCUC Order G-44-12 resulting from an Application by The FortisBC Energy Utilities in respect of 2012/2013 Revenue Requirements and Rates, pages 83-84.
[5] As prescribed by the Alberta Energy and Utilities Board (EUB) Bulletin 2006-25 issued May 8, 2006 for implementation on January 1, 2009.

- As indicated previously in this evidence, in applications in British Columbia by FortisBC Energy Inc. and separately for FortisBC Inc., the BCUC recently approved the reinstatement of net negative salvage costs. The BCUC approval was based on using the same calculation methods, as used in this current Yukon Electrical Company Limited ("YECL") application, for FortisBC Energy Inc. and suggested that FortisBC Inc. should consider the inclusion of net salvage in future applications.
- In Alberta, the Office of the Utility Consumers Advocate (the "UCA") has been extremely active in attempting to limit the amount of net salvage costs that are recovered through depreciation. While the UCA has, on a number of occasions, questioned the level of net salvage percentages, the UCA does not dispute the concept of recovery of net negative salvage. As such, the issue of net salvage in Alberta generally is an issue of the amount of recovery, rather than a dispute regarding the recoverability of the estimated costs of removal.
- In Ontario, Enbridge Gas Distribution and Union Gas have both recently filed applications that include very large provisions for the recovery of net salvage. Both applications included a depreciation study that calculated and applied the net salvage estimates in the same manner as used by Larry Kennedy in the current YECL application. The 2011 application by Union Gas did not result in any intervener evidence regarding the inclusion of costs of removal in the revenue requirement and the Ontario Energy Board (OEB) approved a revenue requirement incorporating a cost of removal provision. Enbridge Gas Distribution filed a 2012 depreciation study that also included the recovery of costs of removal in the depreciation rate calculations. The Enbridge study was settled via a negotiated settlement however, the settlement filed with and ultimately approved by the OEB included large provisions for net negative salvage. It is also noted that approval of the recovery of net salvage within depreciation rates has a long standing history before the OEB.
- In Quebec, Gaz Metro filed a depreciation study in 2011 that included a provision for net salvage. The application was approved after some debate with regard to

the ability of the company to reconcile regulatory and GAAP compliant financial statements. The procedure for development of a separate set of depreciation accrual rates (as described in previous sections of this evidence) was used by Gaz Metro to provide assurance to the regulator that the financial disclosure books and the regulatory sub-ledgers could be reconciled.

- Utilities in Nova Scotia, New Brunswick, and Newfoundland (Newfoundland Power) have all filed depreciation studies including provisions for net salvage. Generally, in these applications, the concept of the inclusion of the net salvage in the depreciation rates has not been the subject of opposing evidence and has been consistently approved by the regulators in those jurisdictions.
- The National Energy Board of Canada of Canada has commissioned a wide sweeping regulatory process - the Land Matter Consultative Initiative (LMCI) to consider the issues of site restoration and net salvage. This LMCI process has been on-going for a couple of years, with an oral hearing completed in 2012. The NEB has just released Decision MH-001-2012, which mandates NEB pipelines to include a recovery of pipeline abandonment costs in the revenue requirements of the company.

The appropriateness and accuracy of included net salvage costs into PNG's rates should be reviewed during each depreciation study to ensure they reflect that the most up to date information has been incorporated into net salvage rate development.

Service Life and Net Salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of the service life and net salvage estimates from our studies of other natural gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for natural gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future, which included discussions of detailed upcoming project business cases and operational staff interviews. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The procedure for estimating net salvage consisted to a large extent on the approved net salvage parameters for PNG peers, interviews with PNG's Management and Operational groups, and on the experience and judgement of Concentric.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

PART II. DEVELOPMENT OF DEPRECIATIONS PARAMETERS

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Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, and obsolescence, changes in the art, changes in demand, and the requirements of public authorities. When considering the action of the elements, the average service life calculations have considered the large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, wind storms, large scale flooding, fires, intentional actions of third parties, and other natural forces of nature.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing natural gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight-line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves "...were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."[6] The Iowa curves are described as L-type (i.e. left moded), R-type (i.e. right moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age 0. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness of fit" criterion which is the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of "goodness of fit" is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows a widely used practice of fitting Iowa

[6] Statistical Analyses of Industrial Property Retirements, Robley Winfrey, Bulletin 125, Engineering Research Institute, Iowa State University, page 65

curves up to one percent of the maximum exposures. This practice standard is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix A of this report. An overview of the net salvage analysis is presented in Appendix B of this report.

Survivor Curve and Net Salvage Judgments

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of the service life and net salvage estimates from our studies of other natural gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for natural gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future, which included discussions of detailed upcoming project business cases and operational staff interviews. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The procedure for estimating net salvage consisted to a large extent on the approved net salvage parameters for PNG peers, interviews with PNG's Management and Operational groups, and on the experience and judgement of Concentric.

The following discussion, dealing with the Company's accounts by function, which comprise the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates.

Gathering Plant

Account 411.00 – Gathering - Land Rights – The investment in Gathering Land Rights is approximately $275 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. Concentric views that an Iowa 75-R4 is a reasonable expectation for the equipment in this account and is consistent with the other PNG Land Right accounts. Interviews with PNG's Operations and Management staff have indicated that the Iowa 75-R4 is reasonable for the equipment in this account. They also would not expect a significant change to the observed average service life characteristics based on an operational perspective. Based on the above the Iowa 75-R4 is recommended to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
75-R4	0%			$ 7
		75-R4		$ -
			0%	$ -
Total Recommended				$ 7

Account 412.00 – Gathering – Compressor Structures and Improvements – The investment in Gathering Compressor Structures and Improvements is approximately $34,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. A peer comparison of a similar Canadian gas utility similarly has a Transmission Compressor Structures Iowa 30-R4 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 30-R3 is reasonable for the equipment in this account. Concentric views that an Iowa 30-R3 is a reasonable expectation for the equipment in this account and is also consistent with the life of PNG's Transmission Compressor Structures account. Based on the above the Iowa 30-R3 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a Transmission Compressor Structures net salvage value of negative 3 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 3 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 3 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R3	0%			$	1,510
		30-R3		$	-
			-3%	$	131
Total Recommended				$	1,641

Account 413.00 – Gathering – Measuring and Regulating Structures – The investment in Gathering Measuring and Regulating Structures is approximately $75,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. A peer comparison of a similar Canadian gas utility similarly has a Transmission Measuring and Regulating Structures Iowa 38-S2 as its life parameter. Concentric views that an Iowa 30-R3 is a reasonable expectation for the equipment in this account and is consistent with the life of PNG's Transmission Measuring and Regulating Structures account. Interviews with PNG's Operations and Management staff have indicated that the Iowa 30-R3 is reasonable for the equipment in this account. Based on the above the Iowa 30-R3 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility

similarly has Transmission Measuring and Regulating Structures net salvage value of negative 15 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 15 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 15 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R3	0%			$	260
		30-R3		$	-
			-15%	$	3,115
Total Recommended				$	3,375

Account 417.00 – Gathering – Measuring and Regulating Equipment – The investment in Gathering Measuring and Regulating Structures is approximately $30,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 25-R2. A peer comparison of a similar Canadian gas utility similarly has Transmission Measuring and Regulating Equipment has an Iowa 36-S0.5 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the Iowa 25-R2 is reasonable for the equipment in this account. Concentric views that an Iowa 25-R2 is a reasonable expectation for the equipment in this account and is consistent with the life of PNG's Transmission Measuring and Regulating Equipment account. Based on the above the Iowa 25-R2 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has Transmission Measuring and Regulating Equipment net salvage value of negative 7 percent as its net salvage parameter. Interviews with PNG's Operations and

Management staff have indicated that negative 7 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 7 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
25-R2	0%			$	1,137
		25-R2		$	-
			-7%	$	176
Total Recommended				$	1,313

Account 418.00 – Gathering – Purification Equipment – The investment in Gathering Purification Equipment is approximately $3.7M representing approximately 0.9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 25-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $254,986 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-11 and V-12 of this report. A fit of the observed data indicated an excellent fit to the Iowa 31-S5 with a related Residual Measure of 2.06. This compares to the current Iowa 25-R2, with a related Residual Measure of 22.28, which does not fit the observed data as well as the Iowa 31-S5. A peer comparison of a similar Canadian gas utility similarly has Pre-Treatment Equipment has an Iowa 25-R3 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the Iowa 31-S5 is reasonable for the equipment in this account. Concentric views that an Iowa 31-S5 is a reasonable life expectation. Based on the above the Iowa 31-S5 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has Pre-Treatment Equipment net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 25 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 25 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
25-R3	0%			$ 72,940
		31-S5		$ (25,319)
			-25%	$ 118,455
Total Recommended				$ 166,076

Processing Plant

Account 449.00 – Processing – Other Local Storage Equipment – The investment in Processing – Other Local Storage Equipment is approximately $3,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 33-R3. Concentric views that an Iowa 33-R3 is a reasonable life expectation. Interviews with PNG's Operations and Management staff have indicated that the Iowa 33-R3 is reasonable for the equipment in this account. Based on the above the Iowa 33-R3 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. Concentric views that 0 percent is a reasonable net salvage for the equipment in this account. Interviews with PNG's Operations and Management staff also indicated agreement with a 0 percent net salvage. Based on the above

negative 0 percent is recommended to represent the net salvage expectations for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
33-R3	0%			$ 71
		33-R3		$ -
			0%	$ -
Total Recommended				$ 71

Transmission Plant

Account 461.00 – Transmission - Land Rights – The investment in Transmission Land Rights is approximately $1.7M representing 0.4 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. No retirements have been booked to this account. Interviews with the PNG's Operations and Management have indicated that an appropriate life for Distribution Land Rights should be at least equal to the longest distribution life account. Account 465.00 – Transmission Mains has a recommended Iowa 65-R4 which results in a maximum life of approximately 100 years. Concentric viewed that the comments from the Operational and Management personnel was a reasonable expectation for the equipment in this account. Concentric views that an Iowa 75-R4 is a reasonable expectation and is consistent with the Operations and Management comments as the maximum life is approximately 110 years. Based on the above the Iowa 75-R4 is recommended to continue to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
75-R4	0%			$	38,549
		75-R4		$	-
			0%	$	-
Total Recommended				$	38,549

Account 462.00 – Transmission – Compressor Structures – The investment in Transmission Compressor Structures is approximately $3.4M representing 0.9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R4. Minimal retirements have been booked to this account. A peer comparison of a similar Canadian gas utility similarly has a 30-R4 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 30-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 30-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 3 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 3 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 3 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
462.00	30-R4	0%			$ 73,476
			30-R4		$ -
				-3%	$ 25,571
	Total Recommended				$ 99,047

Account 463.00 – Transmission – Measuring and Regulating Station Structures – The investment in Transmission Measuring and Regulating Station Structures is approximately $1.5M representing 0.4 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $149,108 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-22 and V-23 of this report. A fit of the observed data indicated a reasonable fit up to age 31.5 to the Iowa 39-R4 with a related Residual Measure of 23.23. This compares to the current Iowa 30-R3, with a related Residual Measure of 48.67, which does not fit the observed data as well as the Iowa 39-R4. A peer comparison of similar Canadian gas utilities has a ranged from 38 to 55 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 39-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 39-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 15 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 15 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable

expectation for the equipment in this account. As such, a net salvage of negative 15 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R3	0%			$	25,971
		39-R4		$	(10,077)
			-15%	$	16,129
Total Recommended				$	32,023

Account 465.00 – Transmission – Mains – The investment in Transmission Mains is approximately $170.1M representing 42.5 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 60-R3. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $2,608,128 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-25 and V-26 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 65-R4 with a related Residual Measure of 1.85. This compares to the current Iowa 60-R3, with a related Residual Measure of 5.59, which does not fit the observed data as well as the Iowa 65-R4. A peer comparison of similar Canadian gas utilities has a range from 60 to 65 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 65-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility

similarly has a net salvage value of negative 20 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated negative 20 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 20 percent is recommended to represent the expectations for the equipment in this account.

The application of the previous study depreciation rates to PNG's 2016 balances results in an annual accrual of $2,143,628. The application of the previous study depreciation parameters (i.e. survivor curve and net salvage) to PNG's 2016 vintage balances results in a further annual accrual increase of $59,560 which is due to capitalization changes (i.e. additions, adjustments, and retirements) from the previous study. The application of the recommended life (i.e. $-207,549) and net salvage (i.e. $901,910) changes results in an additional net increase of $694,361 to the annual accrual. These changes are summarized as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
60-R3	0%			$ 2,203,188
		65-R4		$ (207,549)
			-20%	$ 901,910
Total Recommended				$ 2,897,549

Account 466.00 – Transmission – Compressor Equipment – The investment in Transmission Compressor Equipment is approximately $25.2M representing 6.3 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R2.5. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $1,257,686 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-28 and V-29 of this report. A fit of the observed data indicated a conservative reasonable fit to the Iowa 35-R3 with a related Residual Measure of 33.74. This compares to the current Iowa

30-R2.5, with a related Residual Measure of 44.36, which does not fit the observed data as well as the Iowa 35-R3. Interviews with PNG's Operations and Management staff have indicated that the Iowa 35-R3 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 35-R3 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 2 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 2 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 2 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R2.5	0%			$	446,978
		35-R3		$	(113,399)
			-2%	$	50,865
Total Recommended				$	384,444

Account 467.00 – Transmission – Measuring and Regulating Equipment – The investment in Transmission Measuring and Regulating Equipment is approximately $18.0M representing 4.5 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 25-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1967 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has

experienced $1,438,841 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-31 and V-32 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 35-S2.5 with a related Residual Measure of 19.33. This compares to the current Iowa 25-R2, with a related Residual Measure of 49.54, which does not fit the observed data as well as the Iowa 35-S2.5. A peer comparison of similar Canadian gas utilities has a range from 36 to 50 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 35-S2.5 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 35-S2.5 is recommended to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 7 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 7 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 7 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
25-R2	0%			$	577,844
		35-S2.5		$	(203,482)
			-7%	$	61,425
Total Recommended				$	435,787

Account 468.00 – Transmission – Communication Structures and Equipment – The investment in Transmission Communication Structures and Equipment is approximately $3.4M representing .9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 15-R2. Minimal retirements have been booked to this account. A peer comparison of a similar Canadian gas utility similarly has a 19-R3 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 15-R2 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 15-R2 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of 0 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that 0 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of 0 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
15-R2	0%			$	64,389
		15-R2		$	-
			0%	$	-
Total Recommended				$	64,389

Distribution Plant

Account 471.00 – Distribution – Land Rights – The investment in Distribution Land Rights is approximately $0.3M representing 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. No retirements have been booked to this account. Interviews with the PNG's Operations and Management have indicated that an appropriate life for Distribution Land Rights should be at least equal to the longest distribution life account. Account 475.00 – Distribution Mains has a recommended Iowa 65-R4 which results in a maximum life of approximately 100 years. Concentric viewed that the comments from the Operational and Management personnel was a reasonable expectation for the equipment in this account. Concentric views that an Iowa 75-R4 is a reasonable expectation and is consistent with the Operations and Management comments as the maximum life is approximately 110 years. Based on the above the Iowa 75-R4 is recommended to continue to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
75-R4	0%			$	4,968
		75-R4		$	-
			0%	$	-
Total Recommended				$	4,968

Account 472.00 – Distribution – Structures and Improvements – The investment in Distribution Structures and Improvements is approximately $2.7M representing .7 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1972 through 2015 and retirement experience over the period of 1972 through 2016. Over this 44-year period this account has experienced $184,833 of retirements as provided on pages V-40 and V-41 of this report. A fit of the observed data

indicated that the Iowa 30-R3 continues to be a reasonable fit. A peer comparison of similar Canadian gas utilities has a range from 35 to 55 years. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 30-R3 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 30-R3 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 10 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 10 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual	
	Parameters	Net Salvage	Life	Net Salvage	Accrual	
472.00	30-R3	0%			$	90,327
			30-R3		$	-
				-10%	$	18,125
	Total Recommended				$	108,452

Account 473.00 – Distribution – Services – The investment in Distribution Services is approximately $51.4M representing 12.9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 50-R2.5. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year

period this account has experienced $914,237 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-43 and V-44 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 50-R4 with a related Residual Measure of 4.92. This compares to the current Iowa 50-R2.5, with a related Residual Measure of 9.96, which does not fit the observed data as well as the Iowa 50-R4. A peer comparison of similar Canadian gas utilities has a range from 45 to 57 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 50-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 50-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 60 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 60 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 60 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
50-R2.5	0%			$ 846,828
		50-R4		$ 48,982
			-60%	$ 1,081,711
Total Recommended				$ 1,977,521

Account 474.00 – Distribution – House Regulators and Equipment – The investment in Distribution House Regulators and Equipment is approximately $10.3M representing 2.6 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R2. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $223,433 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-46 and V-47 of this report. A fit of the observed data indicated a conservative reasonable fit to the Iowa 40-R4 with a related Residual Measure of 10.53. This compares to the current Iowa 30-R2, with a related Residual Measure of 30.87, which does not fit the observed data as well as the Iowa 40-R4. A peer comparison of similar Canadian gas utilities has a range from 20 to 51 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 40-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 40-R4 is recommended to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 20 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 20 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 20 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
30-R2	0%			$ 279,718
		40-R4		$ (90,255)
			-20%	$ 122,876
Total Recommended				$ 312,339

Account 475.00 – Distribution – Mains – The investment in Distribution Mains is approximately $75.1M representing 18.8 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 60-R3. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $89,327 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-49 and V-50 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 65-R4 with a related Residual Measure of 3.24. This compares to the current Iowa 60-R3, with a related Residual Measure of 7.10, which does not fit the observed data as well as the Iowa 65-R4. A peer comparison of similar Canadian gas utilities has a range from 62 to 80 years. Interviews with PNG's Operations and Management staff have indicated that the Iowa 65-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 25 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 25 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable

expectation for the equipment in this account. As such, a net salvage of negative 25 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
60-R3	0%			$ 1,051,333
		65-R4		$ (94,361)
			-25%	$ 440,147
Total Recommended				$ 1,397,119

Account 477.00 – Distribution – Measuring and Regulating Equipment – The investment in Distribution Measuring and Regulating Equipment is approximately $2.3M representing .6 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 20-R3. Minimal retirements have been processed against this account. A peer comparison of similar Canadian gas utilities has a range from 15 to 50 years. Interviews with PNG's Operations and Management staff have indicated that the 35 year average service life recommended for their similar Transmission Measuring and Regulating Account 467.00 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 35-R4 is recommended represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 7 percent recommended for their similar Transmission Measuring and Regulating Account 467.00 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable

expectation for the equipment in this account. As such, a net salvage of negative 7 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
477.00	20-R3	0%			$ 52,884
			35-R4		$ (32,136)
				-7%	$ 10,304
	Total Recommended				$ 31,052

Account 478.00 – Distribution - Meters – The investment in Distribution Meters is approximately $6.4M representing 1.6 percent of the total depreciable plant studied. The majority of PNG's meters are residential with some commercial and industrial. The currently approved life parameter for this account is an Iowa 25-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1975 through 2016 and retirement experience over the period of 2010 through 2016. Over this 7-year period this account has experienced $2,695,955 of retirements as summarized on the observed life table as provided on pages V-54 and V-55 of this report. A fit of the observed data indicated a very good fit to the Iowa 28-R5 with a related Residual Measure of 4.93. This compares to the current Iowa 25-R2, with a related Residual Measure of 16.60, which does not fit the observed data as well as the Iowa 28-R5

Canadian Measurement Standards requires an initial seal period for regular-size residential meters of 10 years. At the end of the seal life, PNG tests a sample. If the sample passes, the existing meters stay in service. Most meters will pass the first test period. The second seal period is 8 years. PNG retires their meters after this 8 year extension thus resulting in a maximum residential meter life of 18 years. This account also includes commercial and industrial meters which are more expensive. PNG indicates a maximum life of commercial and industrial meters to be 25 years. Based on this Concentric views that a more appropriate life should be an Iowa 20-R4 curve. This recognizes the maximum 18 year

life of residential meters and an expected 25 year life for their commercial and industrial meters. As such, the Iowa 20-R4 curve is recommended for this account.

The previous depreciation study did not include an allowance for net salvage. The first year of recorded net salvage activity for this account is 2014. The net salvage for the years 2014 to 2016 has been 1 percent for each year with a cumulative 3 year value of 1 percent. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of 0 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that the historically indicated 1 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 1 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
478.00	25-R2	0%			$ 256,663
			20-R4		$ 429,518
				1%	$ (17,276)
	Total Recommended				$ 668,905

General Plant

Account 481.00 – General Plant – Land Rights – The investment in General Plant Land Rights is approximately $1,700 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. No retirements have been booked to this account. Interviews with the PNG's Operations and Management have indicated that an appropriate life for General Plant Land Rights should be at least equal to the longest General Plant account. Account 482.00 – General Plant Structures and Improvements has a recommended Iowa 30-R3 which results in a maximum life of approximately 50 years. Concentric viewed that the comments from the Operational

and Management personnel was a reasonable expectation for the equipment in this account. Concentric views that an Iowa 75-R4 is a reasonable expectation and is consistent with the PNG's other Land Rights accounts. Based on the above the Iowa 75-R4 is recommended to continue to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
75-R4	0%			$ 29
		75-R4		$ -
			0%	$ -
Total Recommended				$ 29

Account 482.00 – General Plant – Structures and Improvements – The investment in General Plant – Structures and Improvements is approximately $8.7M representing 2.2 percent of the total depreciable plant studied. The currently approved life parameter for this account is an Iowa 25-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $1,146,264 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-58 and V-59 of this report. A fit of the observed data indicated a conservative reasonable fit to the Iowa 30-R3 with a related Residual Measure of 29.07. This compares to the current Iowa 25-R2, with a related Residual Measure of 39.73, which does not fit the observed data as well as the Iowa 30-R3. A peer comparison of Canadian utilities produced a range from 20-75 years. Interviews with PNG's Operations and Management staff have indicated that the Iowa 30-R3 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, the peer comparison results, and on the professional judgement of

Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 30-R3 is recommended for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility has a net salvage range from 0 percent to negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 0 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of 0 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
25-R2	0%			$ 268,133
		30-R3		$ (55,995)
			0%	$ -
Total Recommended				$ 212,138

Account 484.00 – General Plant – Transportation Equipment – The equipment in General Plant – Transportation Equipment is approximately $3.7M representing .9 percent of the total depreciable plant studied. The currently approved life parameter for this account is an Iowa 7-L1.5. A peer comparison of Canadian utilities produced a range from 6-10 years. Concentric viewed that the most current experience of 7 years would best represent the historical indications for this account due to the relative short life of this equipment. The retirement rate analysis prepared in this study reviewed the plant installed over the period of 1995 through 2016 and retirement experience over the period of 2010 through 2016. Over this 7-year period this account has experienced $3,171,311 of retirements as summarized on the observed life table as provided on page V-61 of this report. A fit of the

observed data indicated an excellent fit to an Iowa 8-L3 curve with a related Residual Measure of 11.16. This compares to the current Iowa 7-L1.5 curve with a related Residual Measure of 17.98, which does not fit the observed data as well as the Iowa 8-L3 curve. Interviews with the PNG's Operations and Management have indicated that although PNG has a 7 year retirement policy, the timing of purchasing and disposition is more indicative of the historical 8 year observed life. Concentric viewed that the historical results combined with the peer comparison and the comments from the Operational and Management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 8-L3 curve is recommended for this account based on the fit to historic data and the indications from Management and Operations and on the professional judgment of Concentric.

The previous depreciation study included a net salvage of 20 percent. The first year of recorded net salvage activity for this account is 2010. For the period 2010 to 2016, the net salvage has ranged from 7 percent to the most current vintage of 22 percent with a cumulative value of 16 percent. A three-year moving average analysis from 2010 forward produced a range from 11 percent to 17 percent. The five-year average indicates 17 percent. Interviews with the PNG's Operations and Management have indicated that 15 percent is a more reasonable expectation for the equipment in this account. Based on historical indications and the comments from the Operations and Management personnel, Concentric views that the historical data indications of 15 percent is a reasonable net salvage expectation for the equipment in this account. As such, Concentric recommends 15 percent net salvage.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
484.00	7-L1.5	20%			$ 361,501
			8-L3		$ (124,261)
				15%	$ 142,540
	Total Recommended				$ 379,780

Account 485.00 – General Plant – Heavy Work Equipment – The equipment in General Plant – Heavy Work Equipment is approximately $5.7M representing 1.4 percent of the total depreciable plant studied. The currently approved life parameter for this account is an Iowa 15-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period of 1976 through 2016 and retirement experience over the period of 2010 through 2016. Over this 7-year period this account has experienced $658,037 of retirements as summarized on the observed life table as provided on page V-63 of this report. A fit of the observed data indicated a reasonable fit to an Iowa 18-R3 curve with a related Residual Measure of 34.54. This compares to the current Iowa 15-R2 curve with a related Residual Measure of 40.50, which does not fit the observed data as well as the Iowa 8-L3 curve. A peer comparison of Canadian utilities produced a range from 8-20 years. Interviews with the PNG's Operations and Management have indicated that the historical indications of an Iowa 18-R3 were reasonable expectations. Concentric viewed that the comments from the Operational and Management personnel was a reasonable expectation for the equipment in this account. As such, the Iowa 18-R3 curve is recommended for this account based on the indications from Management and Operations and on the professional judgment of Concentric.

The previous depreciation study included a net salvage of 15 percent. The first year of recorded net salvage activity for this account is 2012. For the period 2012 to 2016, the net salvage has ranged from 7 percent to 24 percent with a cumulative value of 10 percent. Interviews with the PNG's Operations and Management have indicated that the historically indicated value of 10 percent is a reasonable expectation for the equipment in this account. Based on historical indications and the comments from the Operations and Management personnel, Concentric views that 10 percent is a reasonable net salvage expectation for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
15-R2	15%			$ 195,227
		18-R3		$ 44,413
			10%	$ (55,646)
Total Recommended				$ 183,994

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART III. CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts. The accounts and their amortization periods are as follows:

ACCOUNT	TITLE	AMORTIZATION PERIOD YEARS
443.00	Processing Plant - Gas Holders – Storage	40
469.00	Transmission - Other	40
479.00	Distribution – Other	35
483.00	Office Furniture and Equipment	15
486.00	Tools and Work Equipment	20
487.00	Computer Equipment	5
488.00	Communication Structures and Equipment	14
489.00	Other General Equipment	20

For the purposes of calculating annual amortization amounts as of December 31, 2016, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual equal life group remaining lives in accordance with the following equation:

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve. In as much as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\text{Composite Remaining Life} = \frac{\text{Whole Life Future Accruals}}{\text{Whole Life Annual Accruals}}$$

Or

$$\text{Composite Remaining Life} = \frac{\text{Book Cost - Calc. Reserve}}{\text{Whole Life Annual Accrual}}.$$

PART IV. RESULTS OF STUDY

PART IV. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight-line method, using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other natural gas utilities. The results of the statistical analysis of service life are presented in Part V beginning on V-2 of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2016 are presented in account sequence starting on page VII-2 of the supporting documents. The following Tables 1 indicate the estimated average survivor

curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual. The following Tables 2 are the summaries of the service life and net salvage estimates and their effect of calculated annual accruals.

PACIFIC NORTHERN GAS LTD.
TOTAL SYSTEM
TABLE 1 SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	275	7	2.55	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	(3)	34,443	22,526	12,950	1,641	4.76	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	(15)	75,160	74,217	12,217	3,375	4.49	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	(7)	29,701	16,287	15,493	1,313	4.42	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	(25)	3,749,595	2,637,682	2,049,312	166,076	4.43	12.3
TOTAL GATHERING PLANT				**3,889,174**	**2,750,712**	**2,090,247**	**172,412**	4.43	
PROCESSING PLANT									
443.00	GAS HOLDERS - STORAGE	40-SQ	-	30,000	13,113	16,887	824	2.75	20.5
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	2,111	1,089	71	2.22	15.3
TOTAL PROCESSING PLANT				**33,200**	**15,224**	**17,976**	**895**	2.70	
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	1,696,046	93,821	1,602,225	38,549	2.27	41.6
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	3,365,788	2,657,623	809,139	99,047	2.94	8.2
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	1,491,198	1,127,683	587,196	32,023	2.15	18.3
465.00	MAINS	65-R4	(20)	170,129,175	81,294,078	122,860,932	2,897,549	1.70	42.4
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	25,201,337	19,841,105	5,864,259	384,444	1.53	15.3
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	17,966,528	7,947,174	11,277,011	435,787	2.43	25.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,403,490	2,911,318	492,172	64,389	1.89	7.6
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	505,344	8,227	497,116	12,775	2.53	38.9
TOTAL TRANSMISSION PLANT				**223,758,907**	**115,881,029**	**143,990,050**	**3,964,563**	1.77	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	257,861	21,861	236,000	4,968	1.93	47.5
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	2,705,198	938,004	2,037,714	108,452	4.01	18.8
473.00	SERVICES	50-R4	(60)	51,438,650	21,342,205	60,959,634	1,977,521	3.84	30.8
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	10,323,675	5,780,284	6,608,126	312,339	3.03	21.2
475.00	MAINS	65-R4	(25)	75,059,907	28,910,408	64,914,476	1,397,119	1.86	46.5
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	2,333,055	1,769,902	726,466	31,052	1.33	23.4
478.00	METERS	20-R4	1	6,426,221	2,424,780	3,937,179	668,905	10.41	5.9
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	50,131	33,925	16,206	1,009	2.01	16.1
TOTAL DISTRIBUTION PLANT				**148,594,698**	**61,221,369**	**139,435,801**	**4,501,365**	3.03	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,729	234	1,494	29	1.68	51.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	8,692,046	5,040,943	3,651,103	212,138	2.44	17.2
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	675,720	244,526	431,193	79,230	11.73	5.4
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	3,692,148	1,226,618	1,911,708	379,780	10.29	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	5,674,985	2,686,968	2,420,520	183,994	3.24	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	3,989,678	1,582,662	2,407,018	271,714	6.81	8.9
487.00	COMPUTER EQUIPMENT	5-SQ	-	607,385	296,122	311,264	147,007	24.20	2.1
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	481,777	244,967	236,809	41,226	8.56	5.7
489.00	OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	1,728	272	21	1.05	13.0
TOTAL GENERAL PLANT				**23,817,468**	**11,324,768**	**11,371,381**	**1,315,139**	5.52	
TOTAL GAS PLANT STUDIED				**400,093,446**	**191,193,102**	**296,905,455**	**9,954,374**	2.49	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			115,141	-				
470.00	LAND			47,943	-				
480.00	LAND			394,403	-				
490.00	COMPUTER SOFTWARE			1,438,184	1,162,785				
TOTAL PLANT NOT STUDIED				**1,998,761**	**1,162,785**				
				1,998,761					
TOTAL PLANT				**402,092,207**	**192,355,887**				

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 1A SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PROCESSING PLANT									
443.00	GAS HOLDERS - STORAGE	40-SQ	-	30,000	13,113	16,887	824	2.75	20.5
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	2,111	1,089	71	2.22	15.3
TOTAL PROCESSING PLANT				**33,200**	**15,224**	**17,976**	**895**	**2.70**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	1,236,760	35,215	1,201,545	32,881	2.66	36.5
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	2,900,743	2,392,601	595,165	81,730	2.82	7.3
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	1,281,843	1,050,295	423,825	25,904	2.02	16.4
465.00	MAINS	65-R4	(20)	155,681,495	75,931,928	110,885,866	2,662,306	1.71	41.7
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	25,196,925	19,837,962	5,862,902	384,331	1.53	15.3
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	9,809,396	5,010,680	5,485,374	218,781	2.23	25.1
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,248,146	2,781,162	466,984	62,635	1.93	7.5
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	486,894	1,210	485,683	12,327	2.53	39.4
TOTAL TRANSMISSION PLANT				**199,842,201**	**107,041,053**	**125,407,344**	**3,480,895**	**1.74**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	34,278	-	34,278	815	2.38	42.1
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	333,334	147,635	219,032	13,810	4.14	15.9
473.00	SERVICES	50-R4	(60)	25,828,532	14,737,981	26,587,670	1,007,709	3.90	26.4
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	4,296,732	2,625,008	2,531,070	133,221	3.10	19.0
475.00	MAINS	65-R4	(25)	31,534,898	15,808,798	23,609,824	600,209	1.90	39.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	276,550	271,335	24,573	1,977	0.71	12.4
478.00	METERS	20-R4	1	3,545,782	1,622,826	1,887,498	443,527	12.51	4.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	30,515	23,643	6,872	443	1.45	15.5
TOTAL DISTRIBUTION PLANT				**65,880,621**	**35,237,227**	**54,900,817**	**2,201,711**	**3.34**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	350	-	350	8	2.29	43.8
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	6,186,382	3,820,164	2,366,218	152,274	2.46	15.5
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	545,399	195,763	349,635	68,237	12.51	5.1
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	2,324,539	795,028	1,180,831	237,987	10.24	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	4,049,344	2,053,964	1,590,446	121,731	3.01	13.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	2,813,302	1,070,056	1,743,246	206,177	7.33	8.5
487.00	COMPUTER EQUIPMENT	5-SQ	-	564,461	288,274	276,187	136,505	24.18	2.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	387,810	219,902	167,908	32,704	8.43	5.1
489.00	OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	1,728	272	21	1.05	13.0
TOTAL GENERAL PLANT				**16,873,587**	**8,444,878**	**7,675,093**	**955,644**	**5.66**	
TOTAL GAS PLANT STUDIED				**282,629,608**	**150,738,382**	**188,001,230**	**6,639,145**	**2.35**	
PLANT NOT STUDIED									
410.00	LAND			-					
460.00	LAND			104,160					
470.00	LAND			552					
480.00	LAND			295,004					
490.00	COMPUTER SOFTWARE			1,190,803	930,852				
TOTAL PLANT NOT STUDIED				**1,590,519**	**930,852**				
TOTAL PLANT				**284,220,127**	**151,669,234**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 1B SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	284,620	58,606	226,014	3,181	1.12	71.1
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	265,022	213,974	17,317	3.72	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	83,484	50,113	45,893	2,408	2.88	19.1
465.00	MAINS	65-R4	(20)	6,878,819	2,964,857	5,289,726	98,195	1.43	53.9
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	5,365,795	2,313,113	3,428,288	135,432	2.52	25.3
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	20,124	-	20,124	1,383	6.87	14.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**13,097,887**	**5,651,711**	**9,224,019**	**257,916**	**1.97**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	156,677	21,861	134,816	2,459	1.57	54.8
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	1,158,054	399,713	874,147	45,404	3.92	19.3
473.00	SERVICES	50-R4	(60)	17,367,781	4,485,159	23,303,291	624,113	3.59	37.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	2,221,852	1,169,677	1,496,545	57,198	2.57	26.2
475.00	MAINS	65-R4	(25)	29,925,140	9,289,747	28,116,678	517,614	1.73	54.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,226,388	806,061	506,173	19,178	1.56	26.4
478.00	METERS	20-R4	1	1,886,965	543,598	1,324,497	128,093	6.79	10.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**53,962,473**	**16,726,099**	**55,765,481**	**1,394,625**	**2.58**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	948,924	661,048	287,876	21,044	2.22	13.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	29,513	7,188	22,325	1,920	6.51	11.6
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	543,958	166,059	296,305	58,782	10.81	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	299,518	161,923	107,643	8,897	2.97	12.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	479,331	223,111	256,221	27,617	5.76	9.3
487.00	COMPUTER EQUIPMENT	5-SQ	-	9,390	2,700	6,690	2,232	23.77	3.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	35,661	8,570	27,091	2,712	7.60	10.0
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**2,347,674**	**1,230,833**	**1,005,295**	**123,225**	**5.25**	
TOTAL GAS PLANT STUDIED				**69,408,034**	**23,608,644**	**65,994,795**	**1,775,766**	**2.56**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			6,395	-				
470.00	LAND			22,043	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			192,805	185,632				
TOTAL PLANT NOT STUDIED				**297,746**	**185,632**				
TOTAL PLANT				**69,705,780**	**23,794,276**				

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE 1C SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	174,666	-	174,666	2,487	1.42	70.2
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	125,872	27,275	117,478	3,711	2.95	31.7
465.00	MAINS	65-R4	(20)	5,827,847	1,334,951	5,658,464	103,202	1.77	54.8
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	2,362,606	546,000	1,981,988	68,820	2.91	28.8
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	129,794	129,794	-	-	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**8,639,235**	**2,045,038**	**7,944,029**	**178,668**	**2.07**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	64,895	-	64,895	1,646	2.54	39.4
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	873,028	301,637	658,694	35,677	4.09	18.5
473.00	SERVICES	50-R4	(60)	7,527,244	1,803,204	10,240,385	310,135	4.12	33.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	3,518,978	1,747,059	2,475,715	112,275	3.19	22.1
475.00	MAINS	65-R4	(25)	12,499,900	3,245,787	12,379,088	254,899	2.04	48.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	509,098	463,782	80,952	5,283	1.04	15.3
478.00	METERS	20-R4	1	791,912	181,476	602,517	83,978	10.60	7.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**25,785,055**	**7,742,946**	**26,502,246**	**803,893**	**3.12**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	1,154,428	159,777	994,651	37,645	3.26	26.4
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	76,782	32,130	44,652	7,038	9.17	6.3
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	783,574	251,791	414,247	78,621	10.03	5.3
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,208,623	387,512	700,249	51,789	4.28	13.5
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	613,799	260,018	353,782	33,488	5.46	10.6
487.00	COMPUTER EQUIPMENT	5-SQ	-	30,859	5,147	25,712	7,676	24.87	3.3
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	56,512	15,431	41,080	5,648	9.99	7.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**3,924,576**	**1,111,805**	**2,574,373**	**221,905**	**5.65**	
TOTAL GAS PLANT STUDIED				**38,348,866**	**10,899,789**	**37,020,648**	**1,204,466**	**3.14**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			4,586	-				
470.00	LAND			25,348	-				
480.00	LAND			-	-				
490.00	COMPUTER SOFTWARE			42,841	35,668				
TOTAL PLANT NOT STUDIED				**72,775**	**35,668**				
TOTAL PLANT				**38,421,641**	**10,935,457**				

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 1D SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	275	7	2.55	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	(3)	34,443	22,526	12,950	1,641	4.76	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	(15)	75,160	74,217	12,217	3,375	4.49	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	(7)	29,701	16,287	15,493	1,313	4.42	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	(25)	3,749,595	2,637,682	2,049,312	166,076	4.43	12.3
TOTAL GATHERING PLANT				**3,889,174**	**2,750,712**	**2,090,247**	**172,412**	**4.43**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS								
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS								
465.00	MAINS	65-R4	(20)	1,741,015	1,062,341	1,026,876	33,846	1.94	30.3
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	4,412	3,143	1,357	113	2.56	12.0
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	428,731	77,381	381,361	12,754	2.97	29.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	5,426	362	5,064	371	6.84	13.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**2,179,584**	**1,143,228**	**1,414,658**	**47,084**	**2.16**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	2,011	-	2,011	48	2.39	41.9
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	340,781	89,018	285,841	13,561	3.98	21.1
473.00	SERVICES	50-R4	(60)	715,093	315,861	828,288	35,564	4.97	23.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	286,113	238,540	104,796	9,645	3.37	10.9
475.00	MAINS	65-R4	(25)	1,099,969	566,075	808,886	24,397	2.22	33.2
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	321,020	228,723	114,768	4,614	1.44	24.9
478.00	METERS	20-R4	1	201,562	76,879	122,667	13,307	6.60	9.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**2,966,549**	**1,515,097**	**2,267,257**	**101,136**	**3.41**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R5	-	402,312	399,954	2,358	1,175	0.29	2.0
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	24,026	9,445	14,581	2,035	8.47	7.2
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	40,077	13,741	20,325	4,390	10.95	4.6
485.00	HEAVY WORK EQUIPMENT	18-R3	10	117,501	83,569	22,182	1,577	1.34	14.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	83,246	29,477	53,769	4,432	5.32	12.1
487.00	COMPUTER EQUIPMENT	5-SQ	-	2,675	-	2,675	594	22.21	4.5
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	1,795	1,065	730	162	9.03	4.5
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**671,631**	**537,251**	**116,620**	**14,365**	**2.14**	
TOTAL GAS PLANT STUDIED				**9,706,938**	**5,946,287**	**5,888,782**	**334,997**	**3.45**	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			-	-				
470.00	LAND			-	-				
480.00	LAND			22,896	-				
490.00	COMPUTER SOFTWARE			11,735	10,632				
TOTAL PLANT NOT STUDIED				**37,721**	**10,632**				
TOTAL PLANT				**9,744,659**	**5,956,919**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN AND DAWSON CREEK
TABLE 1E SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8)/(5)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	459,287	58,606	400,680	5,668	1.23	70.8
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	265,022	213,974	17,317	3.72	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	209,355	77,388	163,371	6,119	2.92	26.7
465.00	MAINS	65-R4	(20)	12,706,666	4,299,809	10,948,190	201,397	1.58	54.3
466.00	COMPRESSOR EQUIPMENT			-	-	-	-		
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	7,728,401	2,859,113	5,410,276	204,252	2.64	26.4
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	149,918	129,794	20,124	1,383	0.92	2.0
469.00	OTHER TRANSMISSION EQUIPMENT			18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**21,737,122**	**7,696,749**	**17,168,048**	**436,584**	**2.01**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	221,572	21,861	199,711	4,105	1.85	50.3
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	2,031,083	701,350	1,532,841	81,081	3.99	19.0
473.00	SERVICES	50-R4	(60)	24,895,025	6,288,363	33,543,676	934,248	3.75	36.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	5,740,830	2,916,736	3,972,260	169,473	2.95	23.7
475.00	MAINS	65-R4	(25)	42,425,040	12,535,535	40,495,766	772,513	1.82	52.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,735,485	1,269,843	587,125	24,461	1.41	23.1
478.00	METERS	20-R4	1	2,678,877	725,075	1,927,014	212,071	7.92	9.4
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**79,747,528**	**24,469,045**	**82,267,727**	**2,198,518**	**2.76**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	2,103,352	820,825	1,282,527	58,689	2.79	20.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	106,295	39,318	66,977	8,958	8.43	7.8
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	1,327,532	417,850	710,552	137,403	10.35	5.2
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,508,140	549,435	807,892	60,686	4.02	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	1,093,131	483,128	610,003	61,105	5.59	10.0
487.00	COMPUTER EQUIPMENT	5-SQ	-	40,249	7,848	32,402	9,908	24.62	3.2
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	92,173	24,001	68,171	8,360	9.07	8.3
489.00	OTHER GENERAL EQUIPMENT			-	-	-	-		
TOTAL GENERAL PLANT				**6,272,250**	**2,342,639**	**3,579,668**	**345,130**	**5.50**	
TOTAL GAS PLANT STUDIED				**107,756,900**	**34,508,433**	**103,015,443**	**2,980,232**	**2.77**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			10,981	-				
470.00	LAND			47,391	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			235,647	221,301				
TOTAL PLANT NOT STUDIED				**370,522**	**221,301**				
TOTAL PLANT				**108,127,422**	**34,729,733**				

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 1A-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT		DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PROCESSING PLANT										
443.00		GAS HOLDERS - STORAGE	40-SQ	-	30,000	13,113	16,887	824	2.75	20.5
449.00		OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	2,111	1,089	71	2.22	15.3
TOTAL PROCESSING PLANT					**33,200**	**15,224**	**17,976**	**895**	**2.70**	
TRANSMISSION PLANT										
461.00	461.00 4!	LAND RIGHTS	75-R4	-	1,236,760	35,215	1,201,545	32,881	2.66	36.5
462.00	462.00 4!	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	2,900,743	2,392,601	508,142	57,291	1.98	7.3
463.00	463.00 4!	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	1,281,843	1,050,295	231,548	11,113	0.87	16.4
465.00	465.00 4!	MAINS	65-R4	-	155,681,495	75,931,928	79,749,567	1,822,185	1.17	41.7
466.00	466.00 4!	COMPRESSOR EQUIPMENT	35-R3	-	25,196,925	19,837,962	5,358,963	333,473	1.32	15.3
467.00	467.00 4!	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	9,809,396	5,010,680	4,798,716	181,954	1.85	25.1
468.00	468.00 4!	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,248,146	2,781,162	466,984	62,635	1.93	7.5
469.00	469.00 4!	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	486,894	1,210	485,683	12,327	2.53	39.4
TOTAL TRANSMISSION PLANT					**199,842,201**	**107,041,053**	**92,801,148**	**2,513,859**	**1.26**	
DISTRIBUTION PLANT										
471.00	471.00 4!	LAND RIGHTS	75-R4	-	34,278	-	34,278	815	2.38	42.1
472.00	472.00 4!	STRUCTURES AND IMPROVEMENTS	30-R3	-	333,334	147,635	185,699	10,834	3.25	15.9
473.00	473.00 4!	SERVICES	50-R4	-	25,828,532	14,737,981	11,090,551	379,852	1.47	26.4
474.00	474.00 4!	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	4,296,732	2,625,008	1,671,724	76,484	1.78	19.0
475.00	475.00 4!	MAINS	65-R4	-	31,534,898	15,808,798	15,726,100	383,033	1.21	39.3
477.00	477.00 4!	MEASURING AND REGULATING EQUIPMENT	35-R4	-	276,550	271,335	5,214	236	0.09	12.4
478.00	478.00 4!	METERS	20-R4	1	3,545,782	1,622,826	1,887,498	443,527	12.51	4.3
479.00	479.00 4!	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	30,515	23,643	6,872	443	1.45	15.5
TOTAL DISTRIBUTION PLANT					**65,880,621**	**35,237,227**	**30,607,936**	**1,295,224**	**1.97**	
GENERAL PLANT										
481.00	481.00 4!	LAND RIGHTS	75-R4	-	350	-	350	8	2.29	43.8
482.00	482.00 4!	STRUCTURES AND EQUIPMENT	30-R3	-	6,186,382	3,820,164	2,366,218	152,274	2.46	15.5
483.00	483.00 4!	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	545,399	195,763	349,635	68,237	12.51	5.1
484.00	484.00 4!	TRANSPORTATION EQUIPMENT	8-L3	15	2,324,539	795,028	1,180,831	237,987	10.24	5.0
485.00	485.00 4!	HEAVY WORK EQUIPMENT	18-R3	10	4,049,344	2,053,964	1,590,446	121,731	3.01	13.1
486.00	486.00 4!	TOOLS AND WORK EQUIPMENT	20-SQ	-	2,813,302	1,070,056	1,743,246	206,177	7.33	8.5
487.00	487.00 4!	COMPUTER EQUIPMENT	5-SQ	-	564,461	288,274	276,187	136,505	24.18	2.0
488.00	488.00 4!	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	387,810	219,902	167,908	32,704	8.43	5.1
489.00		OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	1,728	272	21	1.05	13.0
TOTAL GENERAL PLANT					**16,873,587**	**8,444,878**	**7,675,093**	**955,644**	**5.66**	
TOTAL GAS PLANT STUDIED					**282,629,608**	**150,738,382**	**131,102,153**	**4,765,622**	**1.69**	
PLANT NOT STUDIED										
410.00		LAND			-					
460.00		LAND			104,160					
470.00		LAND			552					
480.00		LAND			295,004					
490.00		COMPUTER SOFTWARE			1,190,803	930,852				
TOTAL PLANT NOT STUDIED					**1,590,519**	**930,852**				
TOTAL PLANT					**284,220,127**	**151,669,234**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 1B-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	284,620	58,606	226,014	3,181	1.12	71.1
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	465,045	265,022	200,023	16,185	3.48	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	83,484	50,113	33,370	1,751	2.10	19.1
465.00	MAINS	65-R4	-	6,878,819	2,964,857	3,913,962	71,058	1.03	53.9
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	5,365,795	2,313,113	3,052,683	118,330	2.21	25.3
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	20,124	-	20,124	1,383	6.87	14.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**13,097,887**	**5,651,711**	**7,446,176**	**211,888**	**1.62**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	156,677	21,861	134,816	2,459	1.57	54.8
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	1,158,054	399,713	758,341	39,127	3.38	19.3
473.00	SERVICES	50-R4	-	17,367,781	4,485,159	12,882,623	339,029	1.95	37.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	2,221,852	1,169,677	1,052,174	38,783	1.75	26.2
475.00	MAINS	65-R4	-	29,925,140	9,289,747	20,635,393	375,288	1.25	54.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	1,226,388	806,061	420,326	15,439	1.26	26.4
478.00	METERS	20-R4	1	1,886,965	543,598	1,324,497	128,093	6.79	10.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**53,962,473**	**16,726,099**	**37,217,504**	**938,784**	**1.74**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	948,924	661,048	287,876	21,044	2.22	13.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	29,513	7,188	22,325	1,920	6.51	11.6
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	543,958	166,059	296,305	58,782	10.81	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	299,518	161,923	107,643	8,897	2.97	12.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	479,331	223,111	256,221	27,617	5.76	9.3
487.00	COMPUTER EQUIPMENT	5-SQ	-	9,390	2,700	6,690	2,232	23.77	3.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	35,661	8,570	27,091	2,712	7.60	10.0
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**2,347,674**	**1,230,833**	**1,005,295**	**123,225**	**5.25**	
TOTAL GAS PLANT STUDIED				**69,408,034**	**23,608,644**	**45,668,975**	**1,273,897**	**1.84**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			6,395	-				
470.00	LAND			22,043	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			192,805	185,632				
TOTAL PLANT NOT STUDIED				**297,746**	**185,632**				
TOTAL PLANT				**69,705,780**	**23,794,276**				

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE 1C SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	174,666	-	174,666	2,487	1.42	70.2
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	125,872	27,275	98,597	3,030	2.41	31.7
465.00	MAINS	65-R4	-	5,827,847	1,334,951	4,492,895	80,118	1.37	54.8
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	2,362,606	546,000	1,816,605	62,412	2.64	28.8
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	129,794	129,794	-	-	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**8,639,235**	**2,045,038**	**6,594,196**	**148,495**	**1.72**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	64,895	-	64,895	1,646	2.54	39.4
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	873,028	301,637	571,391	28,815	3.30	18.5
473.00	SERVICES	50-R4	-	7,527,244	1,803,204	5,724,039	161,374	2.14	33.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	3,518,978	1,747,059	1,771,920	71,107	2.02	22.1
475.00	MAINS	65-R4	-	12,499,900	3,245,787	9,254,113	182,891	1.46	48.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	509,098	463,782	45,316	1,820	0.36	15.3
478.00	METERS	20-R4	1	791,912	181,476	602,517	83,978	10.60	7.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**25,785,055**	**7,742,946**	**18,034,191**	**531,631**	**2.06**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	1,154,428	159,777	994,651	37,645	3.26	26.4
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	76,782	32,130	44,652	7,038	9.17	6.3
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	783,574	251,791	414,247	78,621	10.03	5.3
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,208,623	387,512	700,249	51,789	4.28	13.5
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	613,799	260,018	353,782	33,488	5.46	10.6
487.00	COMPUTER EQUIPMENT	5-SQ	-	30,859	5,147	25,712	7,676	24.87	3.3
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	56,512	15,431	41,080	5,648	9.99	7.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**3,924,576**	**1,111,805**	**2,574,373**	**221,905**	**5.65**	
TOTAL GAS PLANT STUDIED				**38,348,866**	**10,899,789**	**27,202,760**	**902,031**	**2.35**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			4,586	-				
470.00	LAND			25,348	-				
480.00	LAND			-	-				
490.00	COMPUTER SOFTWARE			42,841	35,668				
TOTAL PLANT NOT STUDIED				**72,775**	**35,668**				
TOTAL PLANT				**38,421,641**	**10,935,457**				

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 1D-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	LIFE NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	275	7	2.55	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	-	34,443	22,526	11,917	1,510	4.38	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	75,160	74,217	943	260	0.35	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	29,701	16,287	13,414	1,137	3.83	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	-	3,749,595	2,637,682	1,111,913	47,621	1.27	12.3
TOTAL GATHERING PLANT				**3,889,174**	**2,750,712**	**1,138,462**	**50,535**	**1.30**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS								
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS								
465.00	MAINS	65-R4	-	1,741,015	1,062,341	678,673	22,278	1.28	30.3
466.00	COMPRESSOR EQUIPMENT	35-R3	-	4,412	3,143	1,269	106	2.40	12.0
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	428,731	77,381	351,350	11,666	2.72	29.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	5,426	362	5,064	371	6.84	13.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**2,179,584**	**1,143,228**	**1,036,356**	**34,421**	**1.58**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	2,011	-	2,011	48	2.39	41.9
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	340,781	89,018	251,763	11,551	3.39	21.1
473.00	SERVICES	50-R4	-	715,093	315,861	399,232	15,555	2.18	23.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	286,113	238,540	47,573	3,089	1.08	10.9
475.00	MAINS	65-R4	-	1,099,969	566,075	533,894	15,760	1.43	33.2
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	321,020	228,723	92,296	3,253	1.01	24.9
478.00	METERS	20-R4	1	201,562	76,879	122,667	13,307	6.60	9.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**2,966,549**	**1,515,097**	**1,449,436**	**62,563**	**2.11**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R5	-	402,312	399,954	2,358	1,175	0.29	2.0
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	24,026	9,445	14,581	2,035	8.47	7.2
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	40,077	13,741	20,325	4,390	10.95	4.6
485.00	HEAVY WORK EQUIPMENT	18-R3	10	117,501	83,569	22,182	1,577	1.34	14.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	83,246	29,477	53,769	4,432	5.32	12.1
487.00	COMPUTER EQUIPMENT	5-SQ	-	2,675	-	2,675	594	22.21	4.5
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	1,795	1,065	730	162	9.03	4.5
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**671,631**	**537,251**	**116,620**	**14,365**	**2.14**	
TOTAL GAS PLANT STUDIED				**9,706,938**	**5,946,287**	**3,740,874**	**161,884**	**1.67**	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			-	-				
470.00	LAND			-	-				
480.00	LAND			22,896	-				
490.00	COMPUTER SOFTWARE			11,735	10,632				
TOTAL PLANT NOT STUDIED				**37,721**	**10,632**				
TOTAL PLANT				**9,744,659**	**5,956,919**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN & DAWSON CREEK
TABLE 1E-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8)/(5)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	459,287	58,606	400,680	5,668	1.23	70.8
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	465,045	265,022	200,023	16,185	3.48	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	209,355	77,388	131,967	4,781	2.28	26.7
465.00	MAINS	65-R4	-	12,706,666	4,299,809	8,406,857	151,176	1.19	54.3
466.00	COMPRESSOR EQUIPMENT			-	-	-	-		
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	7,728,401	2,859,113	4,869,288	180,742	2.34	26.4
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	149,918	129,794	20,124	1,383	0.92	2.0
469.00	OTHER TRANSMISSION EQUIPMENT			18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**21,737,122**	**7,696,749**	**14,040,372**	**360,383**	**1.66**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	221,572	21,861	199,711	4,105	1.85	50.3
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	2,031,083	701,350	1,329,732	67,942	3.35	19.0
473.00	SERVICES	50-R4	-	24,895,025	6,288,363	18,606,662	500,403	2.01	36.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	5,740,830	2,916,736	2,824,094	109,890	1.91	23.7
475.00	MAINS	65-R4	-	42,425,040	12,535,535	29,889,506	558,179	1.32	52.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	1,735,485	1,269,843	465,642	17,259	0.99	23.1
478.00	METERS	20-R4	1	2,678,877	725,075	1,927,014	212,071	7.92	9.4
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**79,747,528**	**24,469,045**	**55,251,695**	**1,470,415**	**1.84**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	2,103,352	820,825	1,282,527	58,689	2.79	20.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	106,295	39,318	66,977	8,958	8.43	7.8
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	1,327,532	417,850	710,552	137,403	10.35	5.2
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,508,140	549,435	807,892	60,686	4.02	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	1,093,131	483,128	610,003	61,105	5.59	10.0
487.00	COMPUTER EQUIPMENT	5-SQ	-	40,249	7,848	32,402	9,908	24.62	3.2
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	92,173	24,001	68,171	8,360	9.07	8.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**6,272,250**	**2,342,639**	**3,579,668**	**345,130**	**5.50**	
TOTAL GAS PLANT STUDIED				**107,756,900**	**34,508,433**	**72,871,735**	**2,175,928**	**2.02**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			10,981	-				
470.00	LAND			47,391	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			235,647	221,301				
TOTAL PLANT NOT STUDIED				**370,522**	**221,301**				
TOTAL PLANT				**108,127,422**	**34,729,733**				

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 1A-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PROCESSING PLANT									
443.00	GAS HOLDERS - STORAGE	40-SQ	-	30,000	-	-	-	-	20.5
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	-	-	-	-	15.3
TOTAL PROCESSING PLANT				**33,200**	**0**	**0**	**0**	**-**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	1,236,760	-	-	-	-	36.5
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	2,900,743	-	87,023	24,439	0.84	7.3
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	1,281,843	-	192,277	14,791	1.15	16.4
465.00	MAINS	65-R4	(20)	155,681,495	-	31,136,299	840,121	0.54	41.7
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	25,196,925	-	503,939	50,858	0.21	15.3
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	9,809,396	-	686,658	36,827	0.38	25.1
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,248,146	-	-	-	-	7.5
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	486,894	-	-	-	-	39.4
TOTAL TRANSMISSION PLANT				**199,842,201**	**0**	**32,606,196**	**967,036**	**0.48**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	34,278	-	-	-	-	42.1
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	333,334	-	33,333	2,976	0.89	15.9
473.00	SERVICES	50-R4	(60)	25,828,532	-	15,497,119	627,857	2.43	26.4
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	4,296,732	-	859,346	56,737	1.32	19.0
475.00	MAINS	65-R4	(25)	31,534,898	-	7,883,724	217,176	0.69	39.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	276,550	-	19,359	1,741	0.62	12.4
478.00	METERS	20-R4	-	3,545,782	-	-	-	-	4.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	30,515	-	-	-	-	15.5
TOTAL DISTRIBUTION PLANT				**65,880,621**	**0**	**24,292,881**	**906,487**	**1.38**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	350	-	-	-	-	43.8
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	6,186,382	-	-	-	-	15.5
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	545,399	-	-	-	-	5.1
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	2,324,539	-	-	-	-	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	-	4,049,344	-	-	-	-	13.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	2,813,302	-	-	-	-	8.5
487.00	COMPUTER EQUIPMENT	5-SQ	-	564,461	-	-	-	-	2.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	387,810	-	-	-	-	5.1
489.00	OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	-	-	-	-	13.0
TOTAL GENERAL PLANT				**16,873,587**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**282,629,608**	**0**	**56,899,077**	**1,873,523**	**0.66**	
PLANT NOT STUDIED									
410.00	LAND			-					
460.00	LAND			104,160					
470.00	LAND			552					
480.00	LAND			295,004					
490.00	COMPUTER SOFTWARE			1,190,803	-				
TOTAL PLANT NOT STUDIED				**1,590,519**	**-**				
TOTAL PLANT				**284,220,127**	**-**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 1B-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	284,620	-	-	-	-	71.1
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	-	13,951	1,132	0.24	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	83,484	-	12,523	657	0.78	19.1
465.00	MAINS	65-R4	(20)	6,878,819	-	1,375,764	27,137	0.40	53.9
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	5,365,795	-	375,605	17,102	0.31	25.3
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	20,124	-	-	-	-	14.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**13,097,887**	**0**	**1,777,843**	**46,028**	**0.35**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	156,677	-	-	-	-	54.8
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	1,158,054	-	115,806	6,277	0.54	19.3
473.00	SERVICES	50-R4	(60)	17,367,781	-	10,420,668	285,084	1.64	37.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	2,221,852	-	444,371	18,415	0.82	26.2
475.00	MAINS	65-R4	(25)	29,925,140	-	7,481,285	142,326	0.48	54.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,226,388	-	85,847	3,739	0.30	26.4
478.00	METERS	20-R4	-	1,886,965	-	-	-	-	10.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	-	-	-	-	16.5
TOTAL DISTRIBUTION PLANT				**53,962,473**	**0**	**18,547,977**	**455,841**	**0.84**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	-	-	-	-	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	948,924	-	-	-	-	13.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	29,513	-	-	-	-	11.6
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	543,958	-	-	-	-	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	-	299,518	-	-	-	-	12.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	479,331	-	-	-	-	9.3
487.00	COMPUTER EQUIPMENT	5-SQ	-	9,390	-	-	-	-	3.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	35,661	-	-	-	-	10.0
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**2,347,674**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**69,408,034**	**0**	**20,325,820**	**501,869**	**0.72**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			6,395	-				
470.00	LAND			22,043	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			192,805	185,632				
TOTAL PLANT NOT STUDIED				**297,746**	**185,632**				
TOTAL PLANT				**69,705,780**	**185,632**				

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE-1C COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	174,666	-	-	-	-	70.2
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	125,872	-	18,881	681	0.54	31.7
465.00	MAINS	65-R4	(20)	5,827,847	-	1,165,569	23,084	0.40	54.8
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	2,362,606	-	165,383	6,408	0.27	28.8
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	129,794	-	-	-	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	18,450	-	-	-	-	25.5
TOTAL TRANSMISSION PLANT				**8,639,235**	**0**	**1,349,833**	**30,173**	**0.35**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	64,895	-	-	-	-	39.4
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	873,028	-	87,303	6,862	0.79	18.5
473.00	SERVICES	50-R4	(60)	7,527,244	-	4,516,346	148,761	1.98	33.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	3,518,978	-	703,795	41,168	1.17	22.1
475.00	MAINS	65-R4	(25)	12,499,900	-	3,124,975	72,008	0.58	48.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	509,098	-	35,636	3,463	0.68	15.3
478.00	METERS	20-R4	-	791,912	-	-	-	-	7.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**25,785,055**	**0**	**8,468,055**	**272,262**	**1.06**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	1,154,428	-	-	-	-	26.4
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	76,782	-	-	-	-	6.3
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	783,574	-	-	-	-	5.3
485.00	HEAVY WORK EQUIPMENT	18-R3	-	1,208,623	-	-	-	-	13.5
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	613,799	-	-	-	-	10.6
487.00	COMPUTER EQUIPMENT	5-SQ	-	30,859	-	-	-	-	3.3
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	56,512	-	-	-	-	7.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**3,924,576**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**38,348,866**	**0**	**9,817,888**	**302,435**	**0.79**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			4,586	-				
470.00	LAND			25,348	-				
480.00	LAND			-	-				
490.00	COMPUTER SOFTWARE			42,841	35,668				
TOTAL PLANT NOT STUDIED				**72,775**	**35,668**				
TOTAL PLANT				**38,421,641**	**35,668**				

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 1D-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	-	-	-	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	(3)	34,443	-	1,033	131	0.38	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	(15)	75,160	-	11,274	3,115	4.14	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	(7)	29,701	-	2,079	176	0.59	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	(25)	3,749,595	-	937,399	118,455	3.16	12.3
TOTAL GATHERING PLANT				**3,889,174**	**0**	**951,785**	**121,877**	**3.13**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS								
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS								
465.00	MAINS	65-R4	(20)	1,741,015	-	348,203	11,568	0.66	30.3
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	4,412	-	88	7	0.16	12.0
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	428,731	-	30,011	1,088	0.25	29.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	5,426	-	-	-	-	13.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**2,179,584**	**0**	**378,302**	**12,663**	**0.58**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	2,011	-	-	-	-	41.9
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	340,781	-	34,078	2,010	0.59	21.1
473.00	SERVICES	50-R4	(60)	715,093	-	429,056	20,009	2.79	23.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	286,113	-	57,223	6,556	2.29	10.9
475.00	MAINS	65-R4	(25)	1,099,969	-	274,992	8,637	0.79	33.2
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	321,020	-	22,472	1,361	0	24.9
478.00	METERS	20-R4	-	201,562	-	-	-	-	9.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**2,966,549**	**0**	**817,821**	**38,573**	**1.30**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R5	-	402,312	-	-	-	-	2.0
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	24,026	-	-	-	-	7.2
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	40,077	-	-	-	-	4.6
485.00	HEAVY WORK EQUIPMENT	18-R3	-	117,501	-	-	-	-	14.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	83,246	-	-	-	-	12.1
487.00	COMPUTER EQUIPMENT	5-SQ	-	2,675	-	-	-	-	4.5
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	1,795	-	-	-	-	4.5
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**671,631**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**9,706,938**	**0**	**2,147,908**	**173,113**	**1.78**	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			-	-				
470.00	LAND			-	-				
480.00	LAND			22,896	-				
490.00	COMPUTER SOFTWARE			11,735	10,632				
TOTAL PLANT NOT STUDIED				**37,721**	**10,632**				
TOTAL PLANT				**9,744,659**	**10,632**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN & DAWSON CREEK
TABLE 1E-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8)/(5)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	459,287	-	-	-	-	70.8
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	-	13,951	1,132	0.24	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	209,355	-	31,404	1,338	0.64	26.7
465.00	MAINS	65-R4	(20)	12,706,666	-	2,541,333	50,221	0.40	54.3
466.00	COMPRESSOR EQUIPMENT			-	-	-	-		-
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	7,728,401	-	540,988	23,510	0.30	26.4
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	149,918	-	-	-	-	2.0
469.00	OTHER TRANSMISSION EQUIPMENT			18,450	-	-	-	-	25.5
TOTAL TRANSMISSION PLANT				**21,737,122**	**0**	**3,127,676**	**76,201**	**0.35**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	221,572	-	-	-	-	50.3
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	2,031,083	-	203,109	13,139	0.65	19.0
473.00	SERVICES	50-R4	(60)	24,895,025	-	14,937,014	433,845	1.74	36.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	5,740,830	-	1,148,166	59,583	1.04	23.7
475.00	MAINS	65-R4	(25)	42,425,040	-	10,606,260	214,334	0.51	52.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,735,485	-	121,483	7,202	0.41	23.1
478.00	METERS	20-R4	-	2,678,877	-	-	-	-	9.4
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	-	-	-	-	16.5
TOTAL DISTRIBUTION PLANT				**79,747,528**	**0**	**27,016,032**	**728,103**	**0.91**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	-	-	-	-	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	2,103,352	-	-	-	-	20.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	106,295	-	-	-	-	7.8
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	1,327,532	-	-	-	-	5.2
485.00	HEAVY WORK EQUIPMENT	18-R3	-	1,508,140	-	-	-	-	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	1,093,131	-	-	-	-	10.0
487.00	COMPUTER EQUIPMENT	5-SQ	-	40,249	-	-	-	-	3.2
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	92,173	-	-	-	-	8.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**6,272,250**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**107,756,900**	**0**	**30,143,708**	**804,304**	**0.75**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			10,981	-				
470.00	LAND			47,391	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			235,647	221,301				
TOTAL PLANT NOT STUDIED				**370,522**	**221,301**				
TOTAL PLANT				**108,127,422**	**221,301**				

PACIFIC NORTHERN GAS LTD.
TOTAL SYSTEM
TABLE 2 SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	ANNUAL ACCRUALS
	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
GATHERING PLANT										
411.00	LAND RIGHTS	75-R4	-	7	-	-	-	75-R4	-	7
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	-	1,510	-	131	131	30-R3	(3)	1,641
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	260	-	3,115	3,115	30-R3	(15)	3,375
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	1,137	-	176	176	25-R2	(7)	1,313
418.00	PURIFICATION EQUIPMENT	25-R3	-	72,940	(25,319)	118,455	93,136	31-S5	(25)	166,076
TOTAL GATHERING PLANT				**75,854**	**(25,319)**	**121,877**	**96,558**			**172,412**
PROCESSING PLANT										
443.00	GAS HOLDERS - STORAGE	40-SQ	-	824	-	-	-	40-SQ	-	824
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	71	-	-	-	33-R3	-	71
TOTAL PROCESSING PLANT				**895**	**-**	**-**	**-**			**895**
TRANSMISSION PLANT										
461.00	LAND RIGHTS	75-R4	-	38,549	-	-	-	75-R4	-	38,549
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	73,476	-	25,571	25,571	30-R4	(3)	99,047
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	25,971	(10,077)	16,129	6,052	39-R4	(15)	32,023
465.00	MAINS	60-R3	-	2,203,188	(207,549)	901,910	694,361	65-R4	(20)	2,897,549
466.00	COMPRESSOR EQUIPMENT	30-R2.5	-	446,978	(113,399)	50,865	(62,534)	35-R3	(2)	384,444
467.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	577,844	(203,482)	61,425	(142,057)	35-S2.5	(7)	435,787
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	64,389	-	-	-	15-R2	-	64,389
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	12,775	-	-	-	40-SQ	-	12,775
TOTAL TRANSMISSION PLANT				**3,443,170**	**(534,507)**	**1,055,900**	**521,393**			**3,964,563**
DISTRIBUTION PLANT										
471.00	LAND RIGHTS	75-R4	-	4,968	-	-	-	75-R4	-	4,968
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	90,327	-	18,125	18,125	30-R3	(10)	108,452
473.00	SERVICES	50-R2.5	-	846,828	48,982	1,081,711	1,130,693	50-R4	(60)	1,977,521
474.00	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	279,718	(90,255)	122,876	32,621	40-R4	(20)	312,339
475.00	MAINS	60-R3	-	1,051,333	(94,361)	440,147	345,786	65-R4	(25)	1,397,119
477.00	MEASURING AND REGULATING EQUIPMENT	20-R3	-	52,884	(32,136)	10,304	(21,832)	35-R4	(7)	31,052
478.00	METERS	25-R2	-	256,663	429,518	(17,276)	412,242	20-R4	1	668,905
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	1,009	-	-	-	35-SQ	-	1,009
TOTAL DISTRIBUTION PLANT				**2,583,730**	**261,748**	**1,655,887**	**1,917,635**			**4,501,365**
GENERAL PLANT										
481.00	LAND RIGHTS	75-R4	-	29	-	-	-	75-R4	-	29
482.00	STRUCTURES AND EQUIPMENT	25-R2	-	268,133	(55,995)	-	(55,995)	30-R3	-	212,138
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	79,230	-	-	-	15-SQ	-	79,230
484.00	TRANSPORTATION EQUIPMENT	7-L1.5	20	361,501	(124,261)	142,540	18,279	8-L3	15	379,780
485.00	HEAVY WORK EQUIPMENT	15-R2	15	195,227	(66,879)	55,646	(11,233)	18-R3	10	183,994
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	271,714	-	-	-	20-SQ	-	271,714
487.00	COMPUTER EQUIPMENT	5-SQ	-	147,007	-	-	-	5-SQ	-	147,007
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	41,226	-	-	-	14-SQ	-	41,226
489.00	OTHER GENERAL EQUIPMENT	20-SQ	-	22	(1)	-	(1)	20-R2.5	-	21
TOTAL GENERAL PLANT				**1,364,089**	**(247,136)**	**198,186**	**(48,950)**			**1,315,139**
TOTAL GAS PLANT STUDIED				**7,467,738**	**(545,214)**	**3,031,850**	**2,486,636**			**9,954,374**

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 2A SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT		DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	RECOMMENDED SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	RECOMMENDED ANNUAL ACCRUALS
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
PROCESSING PLANT											
443.00		GAS HOLDERS - STORAGE	40-SQ	-	824	-	-	-	40-SQ	-	824
449.00		OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	71	-	-	-	33-R3	-	71
TOTAL PROCESSING PLANT					**895**	**0**	**0**	**0**			**895**
TRANSMISSION PLANT											
461.00	461.00 4510	LAND RIGHTS	75-R4	-	32,881	-	-	-	75-R4	-	32,881
462.00	462.00 4510	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	57,291	-	24,439	24,439	30-R4	(3)	81,730
463.00	463.00 4510	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	18,845	(7,732)	14,791	7,059	39-R4	(15)	25,904
465.00	465.00 4510	MAINS	60-R3	-	2,013,497	(191,312)	840,121	648,809	65-R4	(20)	2,662,306
466.00	466.00 4510	COMPRESSOR EQUIPMENT	30-R2.5	-	446,836	(113,363)	50,858	(62,505)	35-R3	(2)	384,331
467.00	467.00 4510	MEASURING AND REGULATING EQUIPMENT	25-R2	-	284,123	(102,169)	36,827	(65,342)	35-S2.5	(7)	218,781
468.00	468.00 4510	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	62,635	-	-	-	15-R2	-	62,635
469.00	469.00 4510	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	12,327	-	-	-	40-SQ	-	12,327
TOTAL TRANSMISSION PLANT					**2,928,435**	**(414,576)**	**967,036**	**552,460**			**3,480,895**
DISTRIBUTION PLANT											
471.00	471.00 4510	LAND RIGHTS	75-R4	-	815	-	-	-	75-R4	-	815
472.00	472.00 4510	STRUCTURES AND IMPROVEMENTS	30-R3	-	10,834	-	2,976	2,976	30-R3	(10)	13,810
473.00	473.00 4510	SERVICES	50-R2.5	-	352,053	27,799	627,857	655,656	50-R4	(60)	1,007,709
474.00	474.00 4510	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	114,569	(38,085)	56,737	18,652	40-R4	(20)	133,221
475.00	475.00 4510	MAINS	60-R3	-	422,754	(39,721)	217,176	177,455	65-R4	(25)	600,209
477.00	477.00 4510	MEASURING AND REGULATING EQUIPMENT	20-R3	-	870	(634)	1,741	1,107	35-R4	(7)	1,977
478.00	478.00 4510	METERS	25-R2	-	140,749	315,558	(12,780)	302,778	20-R4	1	443,527
479.00	479.00 4510	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	443	-	-	-	35-SQ	-	443
TOTAL DISTRIBUTION PLANT					**1,043,087**	**264,917**	**893,707**	**1,158,624**			**2,201,711**
GENERAL PLANT											
481.00	481.00 4510	LAND RIGHTS	75-R4	-	8	-	-	-	75-R4	-	8
482.00	482.00 4510	STRUCTURES AND EQUIPMENT	25-R2	-	194,717	(42,443)	-	(42,443)	30-R3	-	152,274
483.00	483.00 4510	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	68,237	-	-	-	15-SQ	-	68,237
484.00	484.00 4510	TRANSPORTATION EQUIPMENT	7-L1.5	20	225,109	(80,498)	93,376	12,878	8-L3	15	237,987
485.00	485.00 4510	HEAVY WORK EQUIPMENT	15-R2	15	126,983	(45,881)	40,629	(5,252)	18-R3	10	121,731
486.00	486.00 4510	TOOLS AND WORK EQUIPMENT	20-SQ	-	206,177	-	-	-	20-SQ	-	206,177
487.00	487.00 4510	COMPUTER EQUIPMENT	5-SQ	-	136,505	-	-	-	5-SQ	-	136,505
488.00	488.00 4510	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	32,704	-	-	-	14-SQ	-	32,704
489.00		OTHER GENERAL EQUIPMENT	20-SQ	-	22	(1)	-	(1)	20-R2.5	-	21
TOTAL GENERAL PLANT					**990,462**	**(168,823)**	**134,005**	**(34,818)**			**955,644**
TOTAL GAS PLANT STUDIED					**4,962,879**	**(318,482)**	**1,994,748**	**1,676,266**			**6,639,145**

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 2B SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT		DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	RECOMMENDED SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	RECOMMENDED ANNUAL ACCRUALS
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
TRANSMISSION PLANT											
461.00	461.00 4513	LAND RIGHTS	75-R4	-	3,181	-	-	-	75-R4	-	3,181
462.00	462.00 4513	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	16,185	-	1,132	1,132	30-R4	(3)	17,317
463.00	463.00 4513	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	2,818	(1,067)	657	(410)	39-R4	(15)	2,408
465.00	465.00 4513	MAINS	60-R3	-	77,700	(6,642)	27,137	20,495	65-R4	(20)	98,195
466.00	466.00 4513	COMPRESSOR EQUIPMENT									
467.00	467.00 4513	MEASURING AND REGULATING EQUIPMENT	25-R2	-	182,692	(64,362)	17,102	(47,260)	35-S2.5	(7)	135,432
468.00	468.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	1,383	-	-	-	15-R2	-	1,383
469.00	469.00 4513	OTHER TRANSMISSION EQUIPMENT									
TOTAL TRANSMISSION PLANT					**283,959**	**(72,071)**	**46,028**	**(26,043)**			**257,916**
DISTRIBUTION PLANT											
471.00	471.00 4513	LAND RIGHTS	75-R4	-	2,459	-	-	-	75-R4	-	2,459
472.00	472.00 4513	STRUCTURES AND IMPROVEMENTS	30-R3	-	39,127	-	6,277	6,277	30-R3	(10)	45,404
473.00	473.00 4513	SERVICES	50-R2.5	-	329,090	9,939	285,084	295,023	50-R4	(60)	624,113
474.00	474.00 4513	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	55,349	(16,566)	18,415	1,849	40-R4	(20)	57,198
475.00	475.00 4513	MAINS	60-R3	-	410,553	(35,265)	142,326	107,061	65-R4	(25)	517,614
477.00	477.00 4513	MEASURING AND REGULATING EQUIPMENT	20-R3	-	35,703	(20,264)	3,739	(16,525)	35-R4	(7)	19,178
478.00	478.00 4513	METERS	25-R2	-	74,530	55,805	(2,242)	53,563	20-R4	1	128,093
479.00	479.00 4513	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	566	-	-	-	35-SQ	-	566
TOTAL DISTRIBUTION PLANT					**947,377**	**(6,351)**	**453,599**	**447,248**			**1,394,625**
GENERAL PLANT											
481.00	481.00 4513	LAND RIGHTS	75-R4	-	21	-	-	-	75-R4	-	21
482.00	482.00 4513	STRUCTURES AND EQUIPMENT	25-R2	-	26,702	(5,658)	-	(5,658)	30-R3	-	21,044
483.00	483.00 4513	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	1,920	-	-	-	15-SQ	-	1,920
484.00	484.00 4513	TRANSPORTATION EQUIPMENT	7-L1.5	20	57,636	(16,245)	17,391	1,146	8-L3	15	58,782
485.00	485.00 4513	HEAVY WORK EQUIPMENT	15-R2	15	9,121	(3,529)	3,305	(224)	18-R3	10	8,897
486.00	486.00 4513	TOOLS AND WORK EQUIPMENT	20-SQ	-	27,617	-	-	-	20-SQ	-	27,617
487.00	487.00 4513	COMPUTER EQUIPMENT	5-SQ	-	2,232	-	-	-	5-SQ	-	2,232
488.00	488.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	2,712	-	-	-	14-SQ	-	2,712
489.00		OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT					**127,961**	**(25,432)**	**20,696**	**(4,736)**			**123,225**
TOTAL GAS PLANT STUDIED					**1,359,297**	**(103,854)**	**520,323**	**416,469**			**1,775,766**

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE 2C SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	ANNUAL ACCRUALS
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
TRANSMISSION PLANT										
461.00	LAND RIGHTS	75-R4	-	2,487	-	-	-	75-R4	-	2,487
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS									
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	4,308	(1,278)	681	(597)	39-R4	(15)	3,711
465.00	MAINS	60-R3	-	87,534	(7,416)	23,084	15,668	65-R4	(20)	103,202
466.00	COMPRESSOR EQUIPMENT									
467.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	93,763	(31,351)	6,408	(24,943)	35-S2.5	(7)	68,820
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	-	-	-	-	15-R2	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	448	-	-	-	40-SQ	-	448
TOTAL TRANSMISSION PLANT				**188,540**	**(40,045)**	**30,173**	**(9,872)**			**178,668**
DISTRIBUTION PLANT										
471.00	LAND RIGHTS	75-R4	-	1,646	-	-	-	75-R4	-	1,646
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	28,815	-	6,862	6,862	30-R3	(10)	35,677
473.00	SERVICES	50-R2.5	-	151,968	9,406	148,761	158,167	50-R4	(60)	310,135
474.00	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	105,358	(34,251)	41,168	6,917	40-R4	(20)	112,275
475.00	MAINS	60-R3	-	200,730	(17,839)	72,008	54,169	65-R4	(25)	254,899
477.00	MEASURING AND REGULATING EQUIPMENT	20-R3	-	6,743	(4,923)	3,463	(1,460)	35-R4	(7)	5,283
478.00	METERS	25-R2	-	34,965	50,609	(1,596)	49,013	20-R4	1	83,978
479.00	OTHER DISTRIBUTION EQUIPMENT									
TOTAL DISTRIBUTION PLANT				**530,225**	**3,002**	**270,666**	**273,668**			**803,893**
GENERAL PLANT										
481.00	LAND RIGHTS									
482.00	STRUCTURES AND EQUIPMENT	25-R2	-	46,184	(8,539)	-	(8,539)	30-R3	-	37,645
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	7,038	-	-	-	15-SQ	-	7,038
484.00	TRANSPORTATION EQUIPMENT	7-L1.5	20	74,445	(26,299)	30,475	4,176	8-L3	15	78,621
485.00	HEAVY WORK EQUIPMENT	15-R2	15	57,782	(15,978)	9,985	(5,993)	18-R3	10	51,789
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	33,488	-	-	-	20-SQ	-	33,488
487.00	COMPUTER EQUIPMENT	5-SQ	-	7,676	-	-	-	5-SQ	-	7,676
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	5,648	-	-	-	14-SQ	-	5,648
489.00	OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT				**232,261**	**(50,816)**	**40,460**	**(10,356)**			**221,905**
TOTAL GAS PLANT STUDIED				**951,026**	**(87,859)**	**341,299**	**253,440**			**1,204,466**

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 2D SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

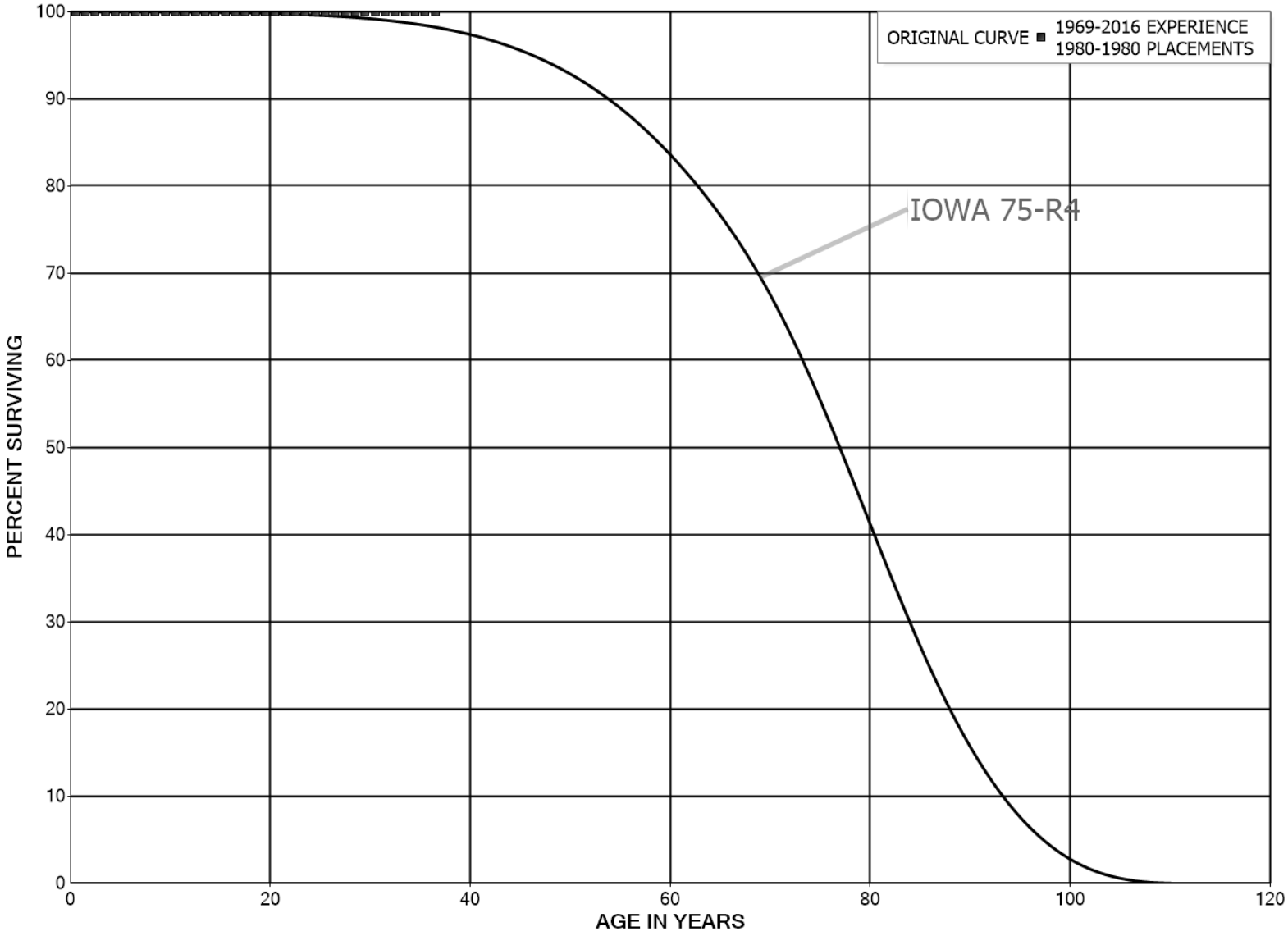
ACCOUNT	DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	ANNUAL ACCRUALS
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
GATHERING PLANT										
411.00	LAND RIGHTS	75-R4	-	7	-	-	-	75-R4	-	7
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	-	1,510	-	131	131	30-R3	(3)	1,641
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	260	-	3,115	3,115	30-R3	(15)	3,375
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	1,137	-	176	176	25-R2	(7)	1,313
418.00	PURIFICATION EQUIPMENT	25-R3	-	72,940	(25,319)	118,455	93,136	31-S5	(25)	166,076
TOTAL GATHERING PLANT				**75,854**	**(25,319)**	**121,877**	**96,558**			**172,412**
TRANSMISSION PLANT										
461.00	LAND RIGHTS									
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS									
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS									
465.00	MAINS	60-R3	-	24,457	(2,179)	11,568	9,389	65-R4	(20)	33,846
466.00	COMPRESSOR EQUIPMENT	30-R2.5	-	142	(36)	7	(29)	35-R3	(2)	113
467.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	17,266	(5,600)	1,088	(4,512)	35-S2.5	(7)	12,754
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	371	-	-	-	15-R2	-	371
469.00	OTHER TRANSMISSION EQUIPMENT									
TOTAL TRANSMISSION PLANT				**42,236**	**(7,815)**	**12,663**	**4,848**			**47,084**
DISTRIBUTION PLANT										
471.00	LAND RIGHTS	75-R4	-	48	-	-	-	75-R4	-	48
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	11,551	-	2,010	2,010	30-R3	(10)	13,561
473.00	SERVICES	50-R2.5	-	13,717	1,838	20,009	21,847	50-R4	(60)	35,564
474.00	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	4,442	(1,353)	6,556	5,203	40-R4	(20)	9,645
475.00	MAINS	60-R3	-	17,296	(1,536)	8,637	7,101	65-R4	(25)	24,397
477.00	MEASURING AND REGULATING EQUIPMENT	20-R3	-	9,568	(6,315)	1,361	(4,954)	35-R4	(7)	4,614
478.00	METERS	25-R2	-	6,419	7,546	(658)	6,888	20-R4	1	13,307
479.00	OTHER DISTRIBUTION EQUIPMENT									
TOTAL DISTRIBUTION PLANT				**63,041**	**180**	**37,915**	**38,095**			**101,136**
GENERAL PLANT										
481.00	LAND RIGHTS									
482.00	STRUCTURES AND EQUIPMENT	25-R2	-	530	645	-	645	30-R5	-	1,175
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	2,035	-	-	-	15-SQ	-	2,035
484.00	TRANSPORTATION EQUIPMENT	7-L1.5	20	4,311	(1,219)	1,298	79	8-L3	15	4,390
485.00	HEAVY WORK EQUIPMENT	15-R2	15	1,341	(1,491)	1,727	236	18-R3	10	1,577
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	4,432	-	-	-	20-SQ	-	4,432
487.00	COMPUTER EQUIPMENT	5-SQ	-	594	-	-	-	5-SQ	-	594
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	162	-	-	-	14-SQ	-	162
489.00	OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT				**13,405**	**(2,065)**	**3,025**	**960**			**14,365**
TOTAL GAS PLANT STUDIED				**194,536**	**(35,019)**	**175,480**	**140,461**			**334,997**

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN & DAWSON CREEK
TABLE 2E SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT		DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	RECOMMENDED SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	RECOMMENDED ANNUAL ACCRUALS
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
TRANSMISSION PLANT											
461.00	461.00 4513	LAND RIGHTS	75-R4	-	5,668	-	-	-	75-R4	-	5,668
462.00	462.00 4513	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	16,185	-	1,132	1,132	30-R4	(3)	17,317
463.00	463.00 4513	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	7,126	(2,345)	1,338	(1,007)	39-R4	(15)	6,119
465.00	465.00 4513	MAINS	60-R3	-	165,234	(14,058)	50,221	36,163	65-R4	(20)	201,397
466.00	466.00 4513	COMPRESSOR EQUIPMENT			-	-	-				-
467.00	467.00 4513	MEASURING AND REGULATING EQUIPMENT	25-R2	-	276,455	(95,713)	23,510	(72,203)	35-S2.5	(7)	204,252
468.00	468.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	1,383	-	-	-	15-R2	-	1,383
469.00	469.00 4513	OTHER TRANSMISSION EQUIPMENT	40-SQ		448	-	-	-	40-SQ	-	448
TOTAL TRANSMISSION PLANT					**472,499**	**(112,116)**	**76,201**	**(35,915)**			**436,584**
DISTRIBUTION PLANT											
471.00	471.00 4513	LAND RIGHTS	75-R4	-	4,105	-	-	-	75-R4	-	4,105
472.00	472.00 4513	STRUCTURES AND IMPROVEMENTS	30-R3	-	67,942	-	13,139	13,139	30-R3	(10)	81,081
473.00	473.00 4513	SERVICES	50-R2.5	-	481,058	19,345	433,845	453,190	50-R4	(60)	934,248
474.00	474.00 4513	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	160,707	(50,817)	59,583	8,766	40-R4	(20)	169,473
475.00	475.00 4513	MAINS	60-R3	-	611,283	(53,104)	214,334	161,230	65-R4	(25)	772,513
477.00	477.00 4513	MEASURING AND REGULATING EQUIPMENT	20-R3	-	42,446	(25,187)	7,202	(17,985)	35-R4	(7)	24,461
478.00	478.00 4513	METERS	25-R2	-	109,495	106,414	(3,838)	102,576	20-R4	1	212,071
479.00	479.00 4513	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	566	-	-	-	35-SQ	-	566
TOTAL DISTRIBUTION PLANT					**1,477,602**	**(3,349)**	**724,265**	**720,916**			**2,198,518**
GENERAL PLANT											
481.00	481.00 4513	LAND RIGHTS	75-R4	-	21	-	-	-	75-R4	-	21
482.00	482.00 4513	STRUCTURES AND EQUIPMENT	25-R2	-	72,886	(14,197)	-	(14,197)	30-R3	-	58,689
483.00	483.00 4513	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	8,958	-	-	-	15-SQ	-	8,958
484.00	484.00 4513	TRANSPORTATION EQUIPMENT	7-L1.5	20	132,081	(42,544)	47,866	5,322	8-L3	15	137,403
485.00	485.00 4513	HEAVY WORK EQUIPMENT	15-R2	15	66,903	(19,507)	13,290	(6,217)	18-R3	10	60,686
486.00	486.00 4513	TOOLS AND WORK EQUIPMENT	20-SQ	-	61,105	-	-	-	20-SQ	-	61,105
487.00	487.00 4513	COMPUTER EQUIPMENT	5-SQ	-	9,908	-	-	-	5-SQ	-	9,908
488.00	488.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	8,360	-	-	-	14-SQ	-	8,360
489.00		OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT					**360,222**	**(76,248)**	**61,156**	**(15,092)**			**345,130**
TOTAL GAS PLANT STUDIED					**2,310,323**	**(191,713)**	**861,622**	**669,909**			**2,980,232**

PART V. SERVICE LIFE STATISTICS

PACIFIC NORTHERN GAS LTD.
ACCOUNT 411.00 - GATHERING PLANT - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

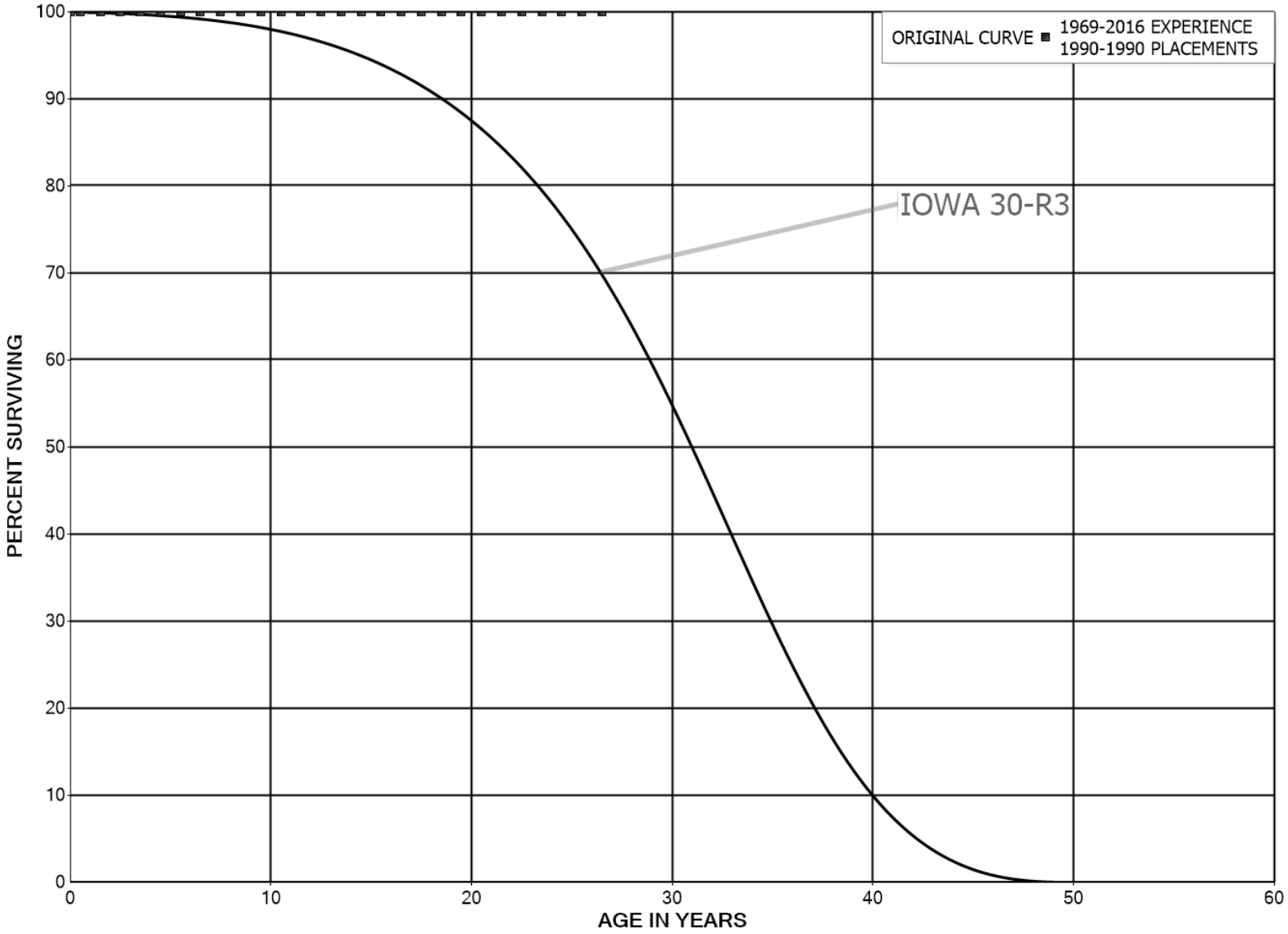
ACCOUNT 411.00 - GATHERING PLANT - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-1980 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	275		0.0000	1.0000	100.00
0.5	275		0.0000	1.0000	100.00
1.5	275		0.0000	1.0000	100.00
2.5	275		0.0000	1.0000	100.00
3.5	275		0.0000	1.0000	100.00
4.5	275		0.0000	1.0000	100.00
5.5	275		0.0000	1.0000	100.00
6.5	275		0.0000	1.0000	100.00
7.5	275		0.0000	1.0000	100.00
8.5	275		0.0000	1.0000	100.00
9.5	275		0.0000	1.0000	100.00
10.5	275		0.0000	1.0000	100.00
11.5	275		0.0000	1.0000	100.00
12.5	275		0.0000	1.0000	100.00
13.5	275		0.0000	1.0000	100.00
14.5	275		0.0000	1.0000	100.00
15.5	275		0.0000	1.0000	100.00
16.5	275		0.0000	1.0000	100.00
17.5	275		0.0000	1.0000	100.00
18.5	275		0.0000	1.0000	100.00
19.5	275		0.0000	1.0000	100.00
20.5	275		0.0000	1.0000	100.00
21.5	275		0.0000	1.0000	100.00
22.5	275		0.0000	1.0000	100.00
23.5	275		0.0000	1.0000	100.00
24.5	275		0.0000	1.0000	100.00
25.5	275		0.0000	1.0000	100.00
26.5	275		0.0000	1.0000	100.00
27.5	275		0.0000	1.0000	100.00
28.5	275		0.0000	1.0000	100.00
29.5	275		0.0000	1.0000	100.00
30.5	275		0.0000	1.0000	100.00
31.5	275		0.0000	1.0000	100.00
32.5	275		0.0000	1.0000	100.00
33.5	275		0.0000	1.0000	100.00
34.5	275		0.0000	1.0000	100.00
35.5	275		0.0000	1.0000	100.00
36.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 412.00 - GATHERING PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

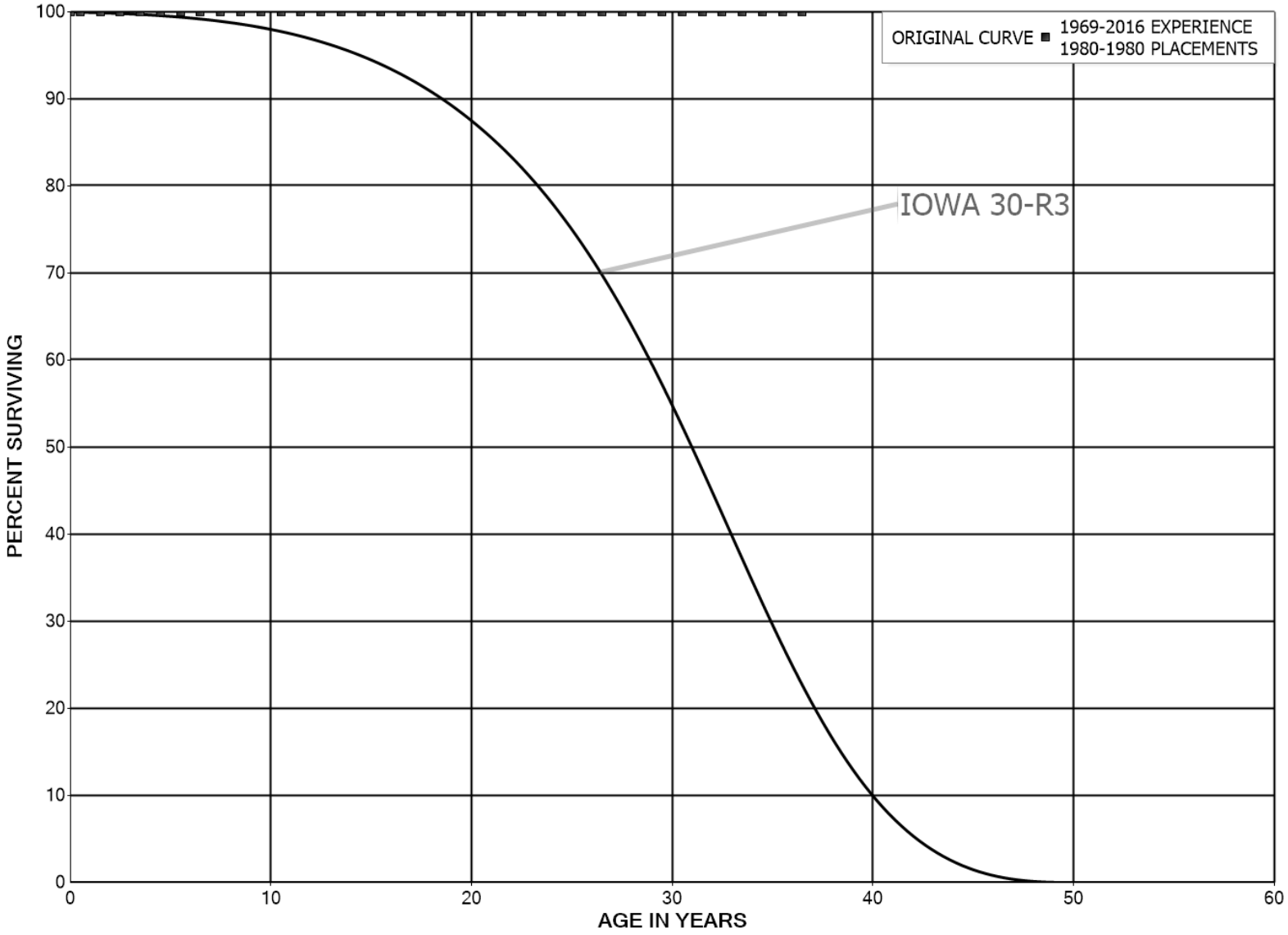
ACCOUNT 412.00 - GATHERING PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1990-1990 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	34,443		0.0000	1.0000	100.00
0.5	34,443		0.0000	1.0000	100.00
1.5	34,443		0.0000	1.0000	100.00
2.5	34,443		0.0000	1.0000	100.00
3.5	34,443		0.0000	1.0000	100.00
4.5	34,443		0.0000	1.0000	100.00
5.5	34,443		0.0000	1.0000	100.00
6.5	34,443		0.0000	1.0000	100.00
7.5	34,443		0.0000	1.0000	100.00
8.5	34,443		0.0000	1.0000	100.00
9.5	34,443		0.0000	1.0000	100.00
10.5	34,443		0.0000	1.0000	100.00
11.5	34,443		0.0000	1.0000	100.00
12.5	34,443		0.0000	1.0000	100.00
13.5	34,443		0.0000	1.0000	100.00
14.5	34,443		0.0000	1.0000	100.00
15.5	34,443		0.0000	1.0000	100.00
16.5	34,443		0.0000	1.0000	100.00
17.5	34,443		0.0000	1.0000	100.00
18.5	34,443		0.0000	1.0000	100.00
19.5	34,443		0.0000	1.0000	100.00
20.5	34,443		0.0000	1.0000	100.00
21.5	34,443		0.0000	1.0000	100.00
22.5	34,443		0.0000	1.0000	100.00
23.5	34,443		0.0000	1.0000	100.00
24.5	34,443		0.0000	1.0000	100.00
25.5	34,443		0.0000	1.0000	100.00
26.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 413.00 - GATHERING PLANT - MEASURING AND REGULATING STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

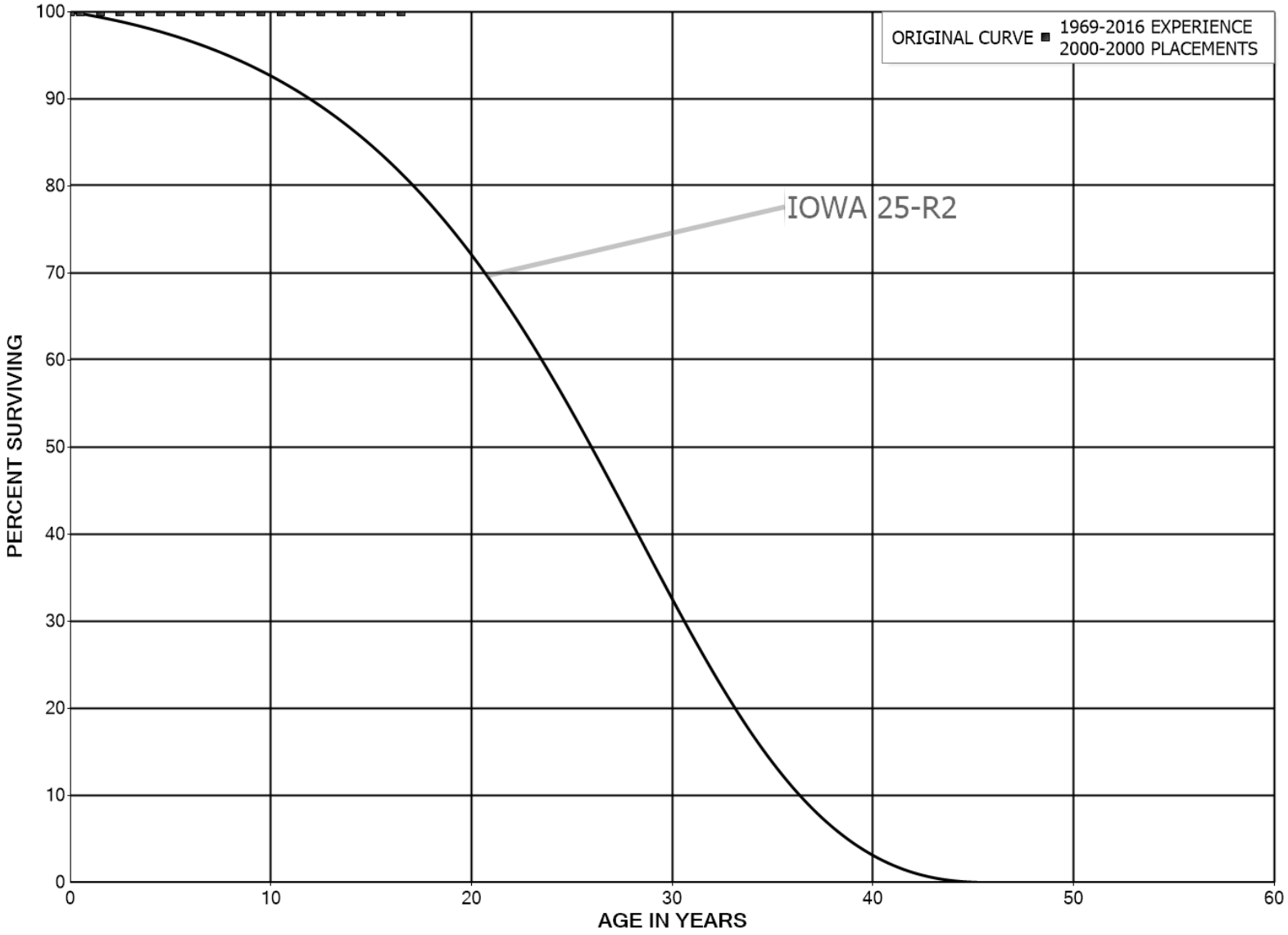
ACCOUNT 413.00 - GATHERING PLANT - MEASURING AND REGULATING STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-1980 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	75,160		0.0000	1.0000	100.00
0.5	75,160		0.0000	1.0000	100.00
1.5	75,160		0.0000	1.0000	100.00
2.5	75,160		0.0000	1.0000	100.00
3.5	75,160		0.0000	1.0000	100.00
4.5	75,160		0.0000	1.0000	100.00
5.5	75,160		0.0000	1.0000	100.00
6.5	75,160		0.0000	1.0000	100.00
7.5	75,160		0.0000	1.0000	100.00
8.5	75,160		0.0000	1.0000	100.00
9.5	75,160		0.0000	1.0000	100.00
10.5	75,160		0.0000	1.0000	100.00
11.5	75,160		0.0000	1.0000	100.00
12.5	75,160		0.0000	1.0000	100.00
13.5	75,160		0.0000	1.0000	100.00
14.5	75,160		0.0000	1.0000	100.00
15.5	75,160		0.0000	1.0000	100.00
16.5	75,160		0.0000	1.0000	100.00
17.5	75,160		0.0000	1.0000	100.00
18.5	75,160		0.0000	1.0000	100.00
19.5	75,160		0.0000	1.0000	100.00
20.5	75,160		0.0000	1.0000	100.00
21.5	75,160		0.0000	1.0000	100.00
22.5	75,160		0.0000	1.0000	100.00
23.5	75,160		0.0000	1.0000	100.00
24.5	75,160		0.0000	1.0000	100.00
25.5	75,160		0.0000	1.0000	100.00
26.5	75,160		0.0000	1.0000	100.00
27.5	75,160		0.0000	1.0000	100.00
28.5	75,160		0.0000	1.0000	100.00
29.5	75,160		0.0000	1.0000	100.00
30.5	75,160		0.0000	1.0000	100.00
31.5	75,160		0.0000	1.0000	100.00
32.5	75,160		0.0000	1.0000	100.00
33.5	75,160		0.0000	1.0000	100.00
34.5	75,160		0.0000	1.0000	100.00
35.5	75,160		0.0000	1.0000	100.00
36.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 417.00 - GATHERING PLANT - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

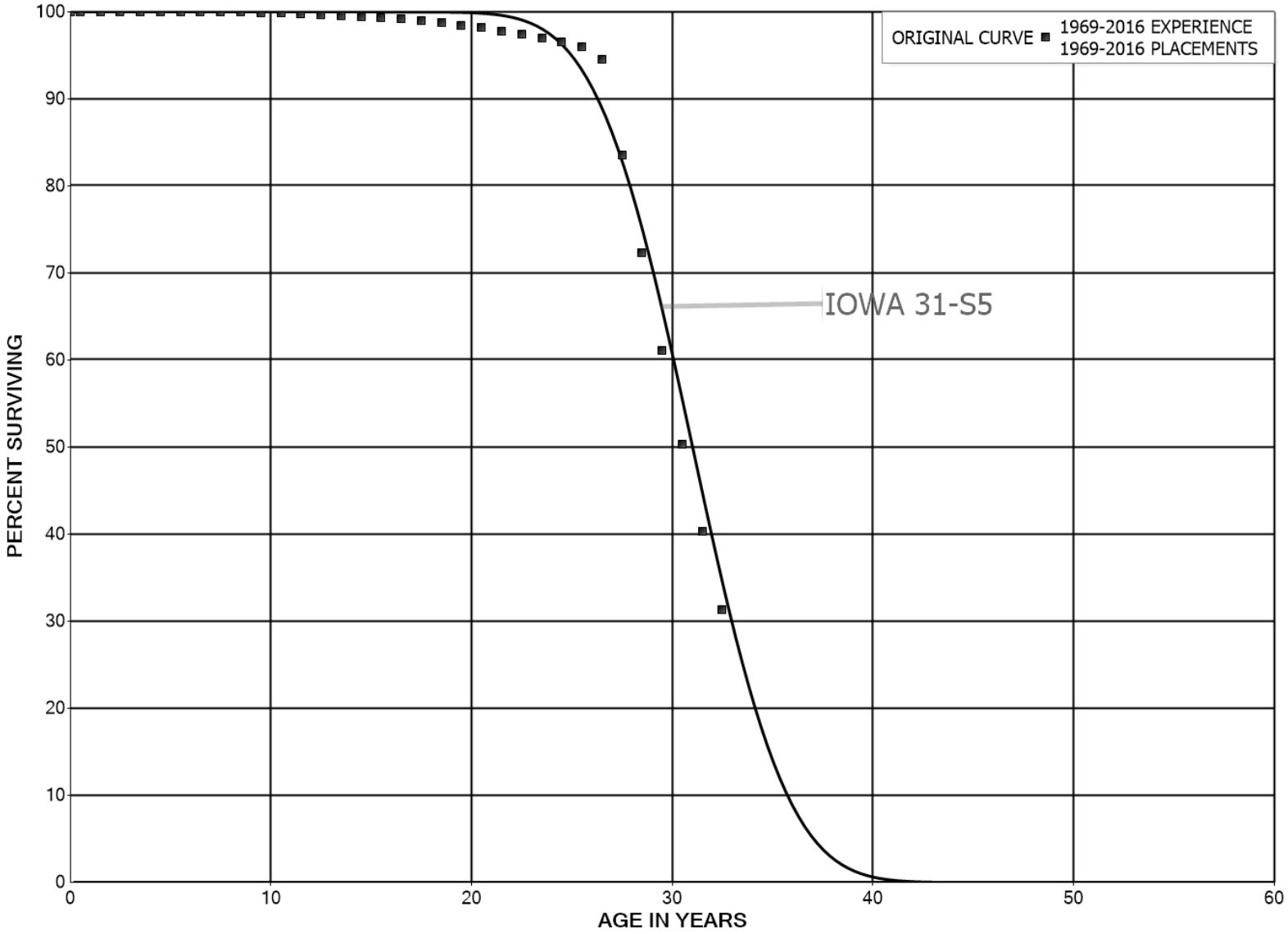
ACCOUNT 417.00 - GATHERING PLANT - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2000-2000 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	29,701		0.0000	1.0000	100.00
0.5	29,701		0.0000	1.0000	100.00
1.5	29,701		0.0000	1.0000	100.00
2.5	29,701		0.0000	1.0000	100.00
3.5	29,701		0.0000	1.0000	100.00
4.5	29,701		0.0000	1.0000	100.00
5.5	29,701		0.0000	1.0000	100.00
6.5	29,701		0.0000	1.0000	100.00
7.5	29,701		0.0000	1.0000	100.00
8.5	29,701		0.0000	1.0000	100.00
9.5	29,701		0.0000	1.0000	100.00
10.5	29,701		0.0000	1.0000	100.00
11.5	29,701		0.0000	1.0000	100.00
12.5	29,701		0.0000	1.0000	100.00
13.5	29,701		0.0000	1.0000	100.00
14.5	29,701		0.0000	1.0000	100.00
15.5	29,701		0.0000	1.0000	100.00
16.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 418.00 - GATHERING PLANT - PURIFICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 418.00 - GATHERING PLANT - PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,004,510		0.0000	1.0000	100.00
0.5	3,816,047	77	0.0000	1.0000	100.00
1.5	3,815,970	195	0.0001	0.9999	100.00
2.5	3,793,038	266	0.0001	0.9999	99.99
3.5	3,792,772	357	0.0001	0.9999	99.99
4.5	3,700,866	470	0.0001	0.9999	99.98
5.5	3,502,465	609	0.0002	0.9998	99.96
6.5	3,228,570	777	0.0002	0.9998	99.95
7.5	3,071,444	978	0.0003	0.9997	99.92
8.5	2,973,067	1,216	0.0004	0.9996	99.89
9.5	2,860,775	1,493	0.0005	0.9995	99.85
10.5	2,798,843	1,812	0.0006	0.9994	99.80
11.5	2,684,696	2,175	0.0008	0.9992	99.73
12.5	2,602,336	2,587	0.0010	0.9990	99.65
13.5	2,558,644	3,051	0.0012	0.9988	99.55
14.5	2,514,121	3,570	0.0014	0.9986	99.43
15.5	2,426,048	4,150	0.0017	0.9983	99.29
16.5	2,362,786	4,798	0.0020	0.9980	99.12
17.5	2,357,988	5,524	0.0023	0.9977	98.92
18.5	2,352,464	6,333	0.0027	0.9973	98.69
19.5	2,346,131	7,231	0.0031	0.9969	98.42
20.5	2,338,900	8,221	0.0035	0.9965	98.12
21.5	2,330,679	9,288	0.0040	0.9960	97.78
22.5	2,321,391	10,408	0.0045	0.9955	97.39
23.5	2,310,983	11,533	0.0050	0.9950	96.95
24.5	2,299,450	12,596	0.0055	0.9945	96.47
25.5	2,286,854	33,509	0.0147	0.9853	95.94
26.5	121,691	14,175	0.1165	0.8835	94.53
27.5	107,516	14,509	0.1349	0.8651	83.52
28.5	93,007	14,403	0.1549	0.8451	72.25
29.5	78,604	13,859	0.1763	0.8237	61.06
30.5	64,745	12,887	0.1990	0.8010	50.30
31.5	51,858	11,560	0.2229	0.7771	40.28
32.5	40,298	9,998	0.2481	0.7519	31.30
33.5	30,300	8,340	0.2752	0.7248	23.54
34.5	21,960	6,716	0.3058	0.6942	17.06
35.5	15,244	5,219	0.3424	0.6576	11.84
36.5	10,025	3,897	0.3887	0.6113	7.79
37.5	6,128	2,761	0.4506	0.5494	4.76
38.5	3,367	1,806	0.5364	0.4636	2.62

PACIFIC NORTHERN GAS LTD.

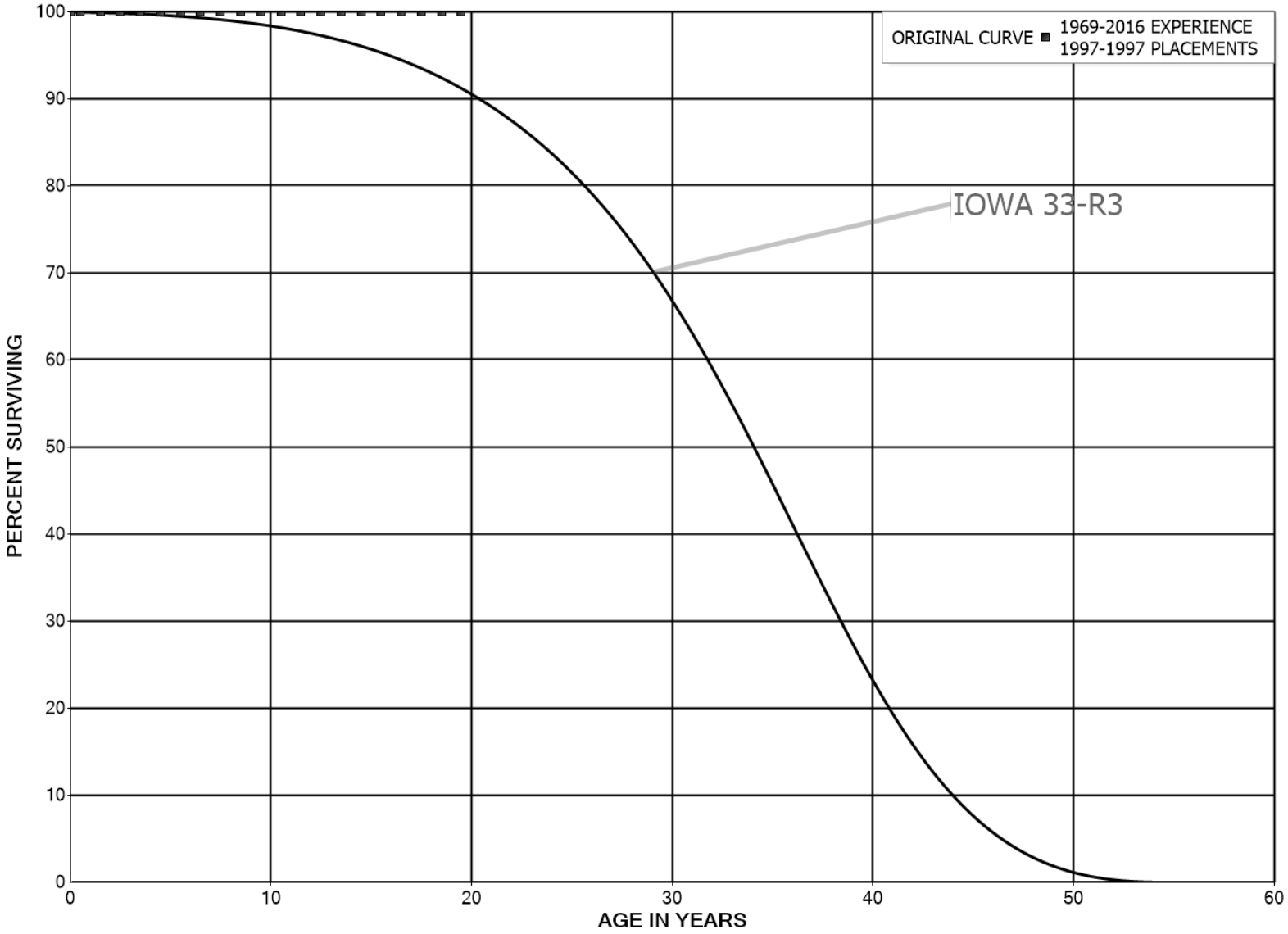
ACCOUNT 418.00 - GATHERING PLANT - PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,561	1,037	0.6643	0.3357	1.21
40.5	524	474	0.9046	0.0954	0.41
41.5					0.04

PACIFIC NORTHERN GAS LTD.
ACCOUNT 449.00 - PROCESSING PLANT - OTHER LOCAL STORAGE EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

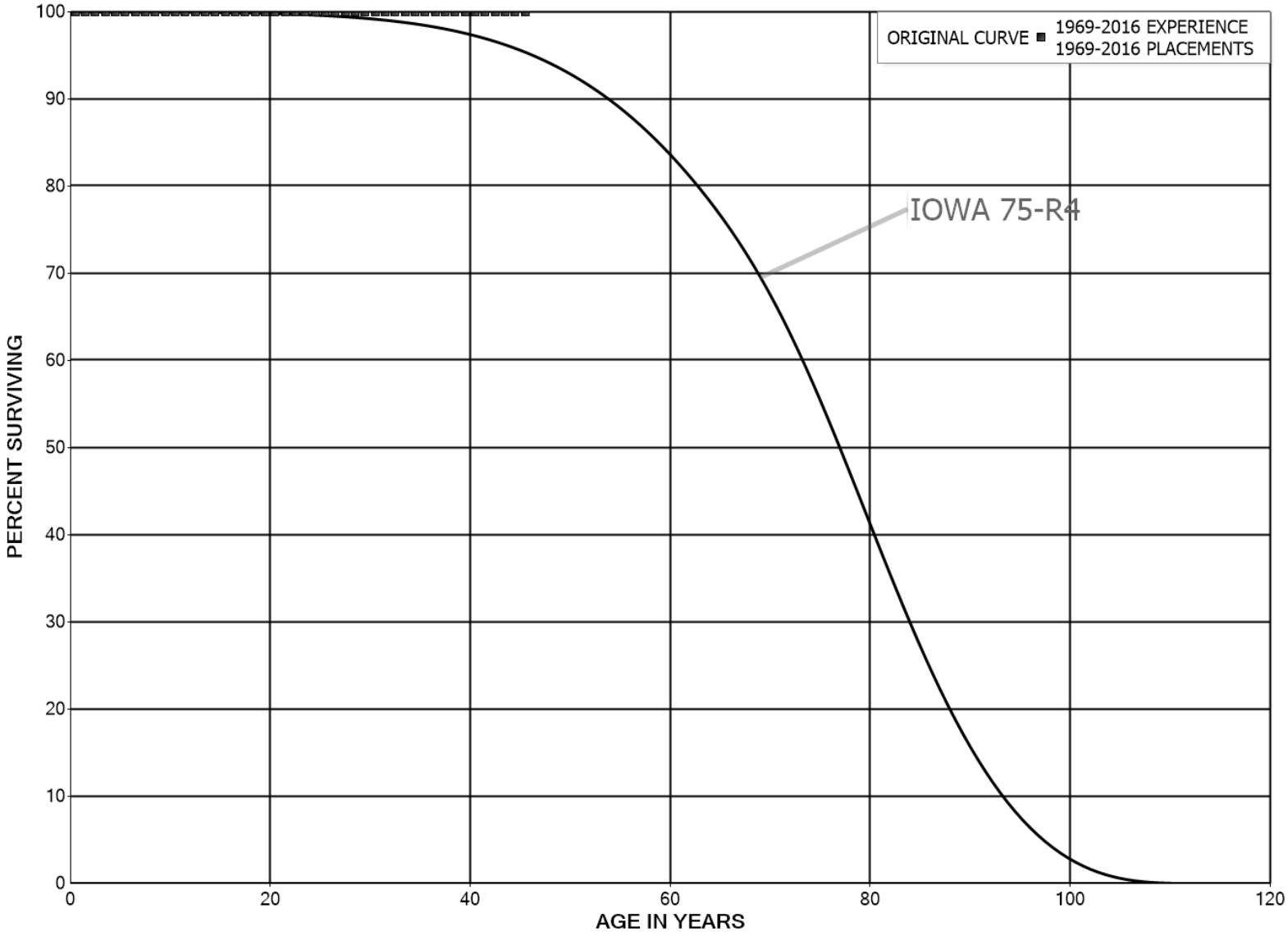
ACCOUNT 449.00 - PROCESSING PLANT - OTHER LOCAL STORAGE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1997-1997 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,200		0.0000	1.0000	100.00
0.5	3,200		0.0000	1.0000	100.00
1.5	3,200		0.0000	1.0000	100.00
2.5	3,200		0.0000	1.0000	100.00
3.5	3,200		0.0000	1.0000	100.00
4.5	3,200		0.0000	1.0000	100.00
5.5	3,200		0.0000	1.0000	100.00
6.5	3,200		0.0000	1.0000	100.00
7.5	3,200		0.0000	1.0000	100.00
8.5	3,200		0.0000	1.0000	100.00
9.5	3,200		0.0000	1.0000	100.00
10.5	3,200		0.0000	1.0000	100.00
11.5	3,200		0.0000	1.0000	100.00
12.5	3,200		0.0000	1.0000	100.00
13.5	3,200		0.0000	1.0000	100.00
14.5	3,200		0.0000	1.0000	100.00
15.5	3,200		0.0000	1.0000	100.00
16.5	3,200		0.0000	1.0000	100.00
17.5	3,200		0.0000	1.0000	100.00
18.5	3,200		0.0000	1.0000	100.00
19.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,399,087		0.0000	1.0000	100.00
0.5	1,372,010		0.0000	1.0000	100.00
1.5	1,157,865		0.0000	1.0000	100.00
2.5	1,099,978		0.0000	1.0000	100.00
3.5	1,021,243		0.0000	1.0000	100.00
4.5	1,021,243		0.0000	1.0000	100.00
5.5	1,021,243		0.0000	1.0000	100.00
6.5	1,021,243		0.0000	1.0000	100.00
7.5	1,021,243		0.0000	1.0000	100.00
8.5	1,021,243		0.0000	1.0000	100.00
9.5	1,021,243		0.0000	1.0000	100.00
10.5	1,021,243		0.0000	1.0000	100.00
11.5	1,021,243		0.0000	1.0000	100.00
12.5	1,021,243		0.0000	1.0000	100.00
13.5	1,021,243		0.0000	1.0000	100.00
14.5	1,021,243		0.0000	1.0000	100.00
15.5	1,021,243		0.0000	1.0000	100.00
16.5	1,021,243		0.0000	1.0000	100.00
17.5	1,021,243		0.0000	1.0000	100.00
18.5	1,021,243		0.0000	1.0000	100.00
19.5	1,021,243		0.0000	1.0000	100.00
20.5	950,768		0.0000	1.0000	100.00
21.5	950,768		0.0000	1.0000	100.00
22.5	905,452		0.0000	1.0000	100.00
23.5	892,225		0.0000	1.0000	100.00
24.5	891,784		0.0000	1.0000	100.00
25.5	886,544		0.0000	1.0000	100.00
26.5	822,027		0.0000	1.0000	100.00
27.5	771,957		0.0000	1.0000	100.00
28.5	759,347		0.0000	1.0000	100.00
29.5	729,656		0.0000	1.0000	100.00
30.5	689,706		0.0000	1.0000	100.00
31.5	678,966		0.0000	1.0000	100.00
32.5	666,487		0.0000	1.0000	100.00
33.5	564,965		0.0000	1.0000	100.00
34.5	515,235		0.0000	1.0000	100.00
35.5	207,207		0.0000	1.0000	100.00
36.5	207,087		0.0000	1.0000	100.00
37.5	207,087		0.0000	1.0000	100.00
38.5	205,608		0.0000	1.0000	100.00

PACIFIC NORTHERN GAS LTD.

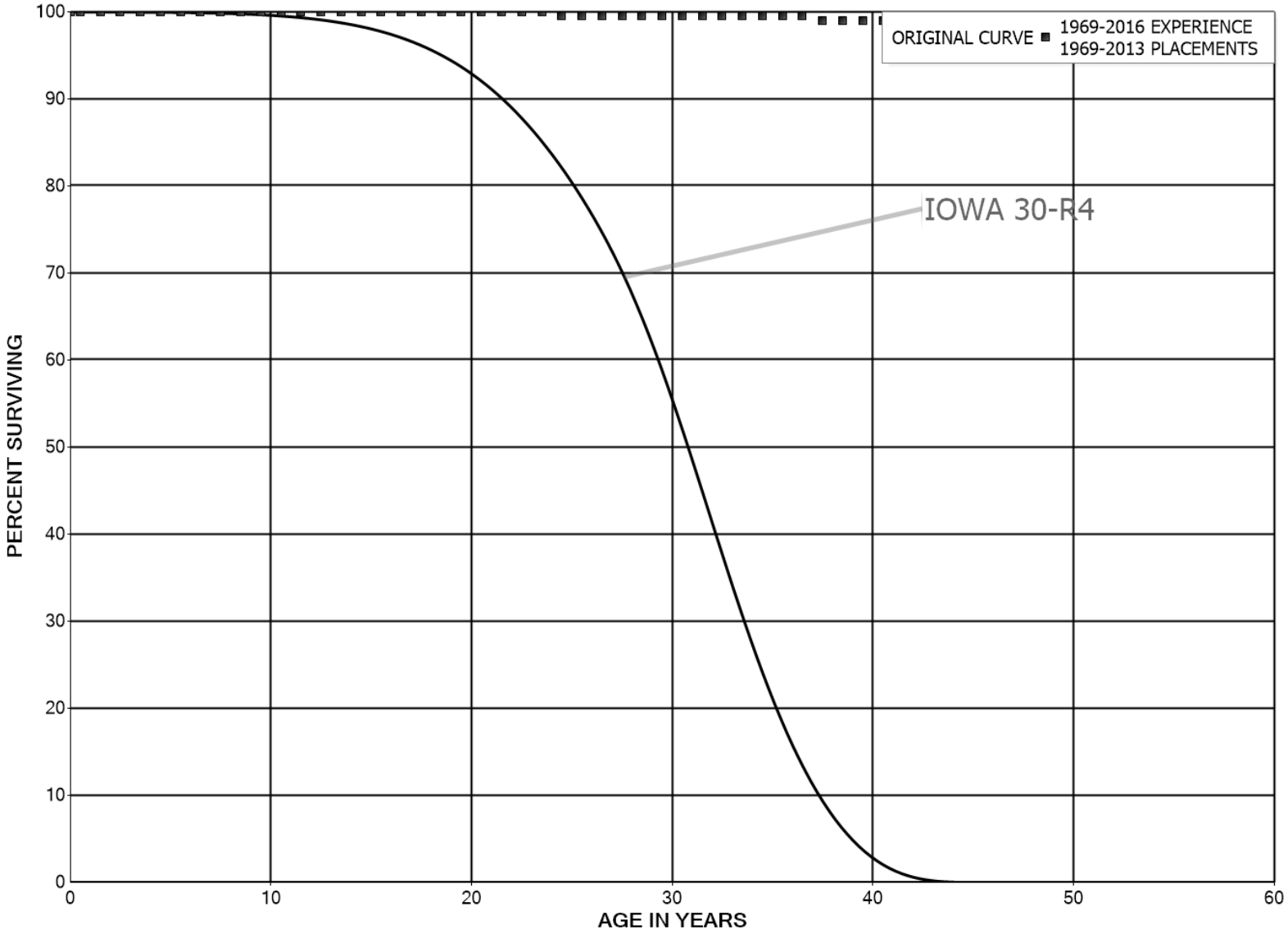
ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	204,214		0.0000	1.0000	100.00
40.5	194,516		0.0000	1.0000	100.00
41.5	194,196		0.0000	1.0000	100.00
42.5	193,910		0.0000	1.0000	100.00
43.5	188,023		0.0000	1.0000	100.00
44.5	158,275		0.0000	1.0000	100.00
45.5	92,595		0.0000	1.0000	100.00
46.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2013 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,377,046	2	0.0000	1.0000	100.00
0.5	3,377,044		0.0000	1.0000	100.00
1.5	3,377,044		0.0000	1.0000	100.00
2.5	3,377,044		0.0000	1.0000	100.00
3.5	3,317,982		0.0000	1.0000	100.00
4.5	3,317,982	41	0.0000	1.0000	100.00
5.5	3,299,053	19	0.0000	1.0000	100.00
6.5	3,299,034		0.0000	1.0000	100.00
7.5	3,293,219		0.0000	1.0000	100.00
8.5	3,288,318		0.0000	1.0000	100.00
9.5	3,273,030		0.0000	1.0000	100.00
10.5	3,173,848		0.0000	1.0000	100.00
11.5	3,092,080	53	0.0000	1.0000	100.00
12.5	3,081,249	35	0.0000	1.0000	100.00
13.5	3,075,826	13	0.0000	1.0000	100.00
14.5	3,075,813	65	0.0000	1.0000	99.99
15.5	3,075,748	46	0.0000	1.0000	99.99
16.5	3,055,965	212	0.0001	0.9999	99.99
17.5	2,846,659	265	0.0001	0.9999	99.98
18.5	2,428,836	117	0.0000	1.0000	99.98
19.5	2,365,085	817	0.0003	0.9997	99.97
20.5	2,337,169	194	0.0001	0.9999	99.94
21.5	2,248,217	453	0.0002	0.9998	99.93
22.5	2,156,495	301	0.0001	0.9999	99.91
23.5	2,019,989	6,777	0.0034	0.9966	99.89
24.5	1,954,673		0.0000	1.0000	99.56
25.5	1,813,068	1	0.0000	1.0000	99.56
26.5	1,788,033	16	0.0000	1.0000	99.56
27.5	1,786,454		0.0000	1.0000	99.56
28.5	1,767,506		0.0000	1.0000	99.56
29.5	1,745,355	5	0.0000	1.0000	99.56
30.5	1,734,196	6	0.0000	1.0000	99.56
31.5	1,719,426	2	0.0000	1.0000	99.56
32.5	1,604,436	27	0.0000	1.0000	99.56
33.5	1,589,399	6	0.0000	1.0000	99.55
34.5	316,822	9	0.0000	1.0000	99.55
35.5	316,813	35	0.0001	0.9999	99.55
36.5	313,047	1,741	0.0056	0.9944	99.54
37.5	311,306		0.0000	1.0000	98.99
38.5	311,306		0.0000	1.0000	98.99

PACIFIC NORTHERN GAS LTD.

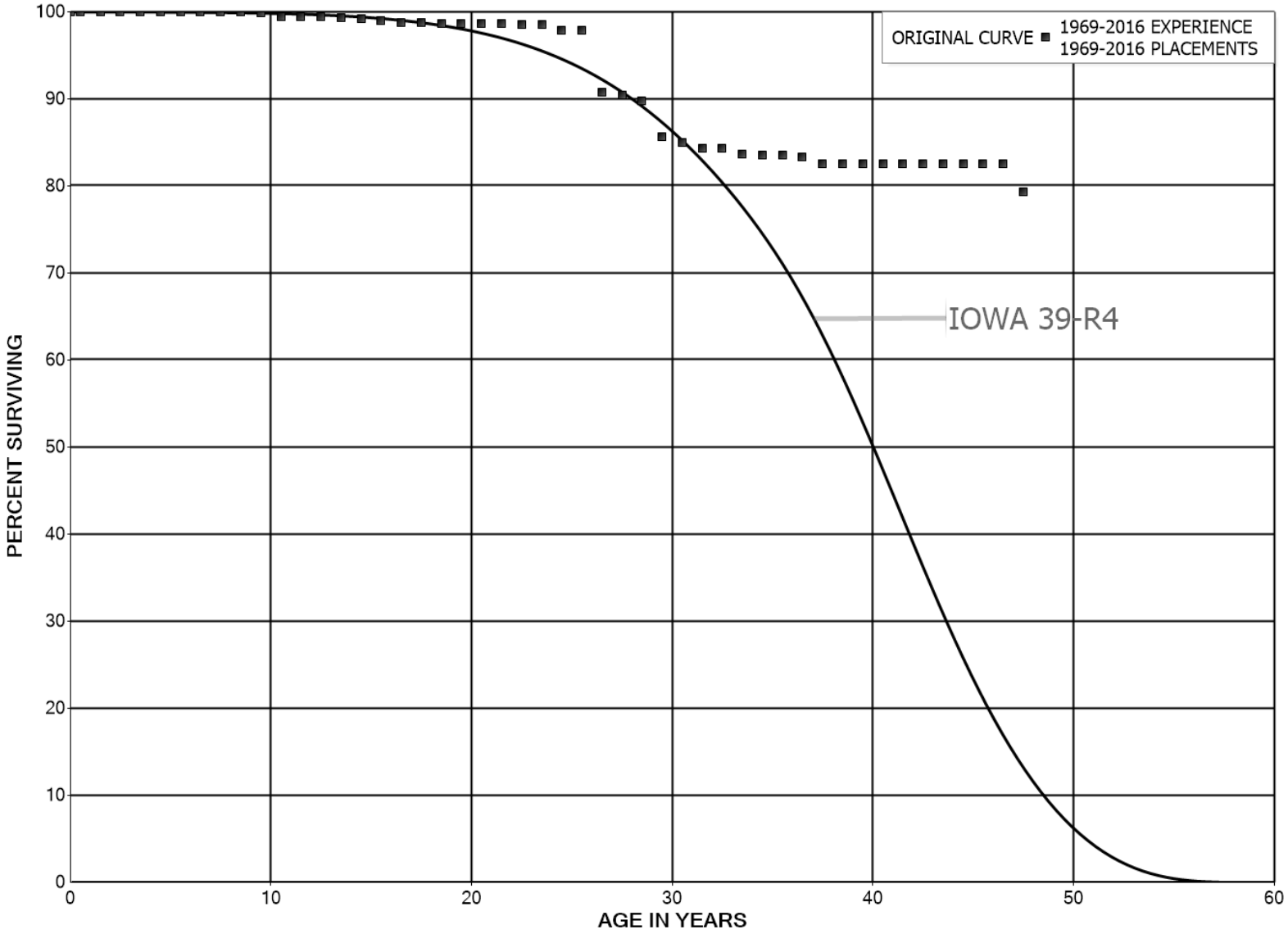
ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2013 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	310,712		0.0000	1.0000	98.99
40.5	307,576		0.0000	1.0000	98.99
41.5	306,849		0.0000	1.0000	98.99
42.5	306,265		0.0000	1.0000	98.99
43.5	304,447		0.0000	1.0000	98.99
44.5	302,527		0.0000	1.0000	98.99
45.5	302,527		0.0000	1.0000	98.99
46.5	299,496		0.0000	1.0000	98.99
47.5					98.99

PACIFIC NORTHERN GAS LTD.
ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,640,306	9	0.0000	1.0000	100.00
0.5	1,560,488	5	0.0000	1.0000	100.00
1.5	1,560,483	4	0.0000	1.0000	100.00
2.5	1,560,479	228	0.0001	0.9999	100.00
3.5	1,560,251	243	0.0002	0.9998	99.98
4.5	1,560,008	422	0.0003	0.9997	99.97
5.5	1,559,586	333	0.0002	0.9998	99.94
6.5	1,559,253	135	0.0001	0.9999	99.92
7.5	1,559,118	68	0.0000	1.0000	99.91
8.5	1,554,400	1,255	0.0008	0.9992	99.91
9.5	1,461,778	6,024	0.0041	0.9959	99.83
10.5	1,451,415	130	0.0001	0.9999	99.42
11.5	1,394,538	750	0.0005	0.9995	99.41
12.5	1,356,758	882	0.0007	0.9993	99.35
13.5	1,295,488	984	0.0008	0.9992	99.29
14.5	1,293,020	4,061	0.0031	0.9969	99.21
15.5	1,288,959	1,837	0.0014	0.9986	98.90
16.5	1,287,122	183	0.0001	0.9999	98.76
17.5	1,278,406	1,166	0.0009	0.9991	98.75
18.5	1,277,240	154	0.0001	0.9999	98.66
19.5	1,277,086	94	0.0001	0.9999	98.64
20.5	1,193,509	391	0.0003	0.9997	98.64
21.5	1,165,056	662	0.0006	0.9994	98.60
22.5	1,143,865	448	0.0004	0.9996	98.55
23.5	1,122,800	7,330	0.0065	0.9935	98.51
24.5	1,033,071	835	0.0008	0.9992	97.87
25.5	957,423	68,957	0.0720	0.9280	97.79
26.5	862,100	3,350	0.0039	0.9961	90.74
27.5	802,048	5,808	0.0072	0.9928	90.39
28.5	569,250	26,072	0.0458	0.9542	89.74
29.5	498,815	3,930	0.0079	0.9921	85.63
30.5	456,625	3,526	0.0077	0.9923	84.95
31.5	376,249	68	0.0002	0.9998	84.30
32.5	347,271	2,843	0.0082	0.9918	84.28
33.5	333,907	170	0.0005	0.9995	83.59
34.5	186,601	174	0.0009	0.9991	83.55
35.5	158,528	409	0.0026	0.9974	83.47
36.5	135,038	1,210	0.0090	0.9910	83.26
37.5	133,828		0.0000	1.0000	82.51
38.5	127,115		0.0000	1.0000	82.51

PACIFIC NORTHERN GAS LTD.

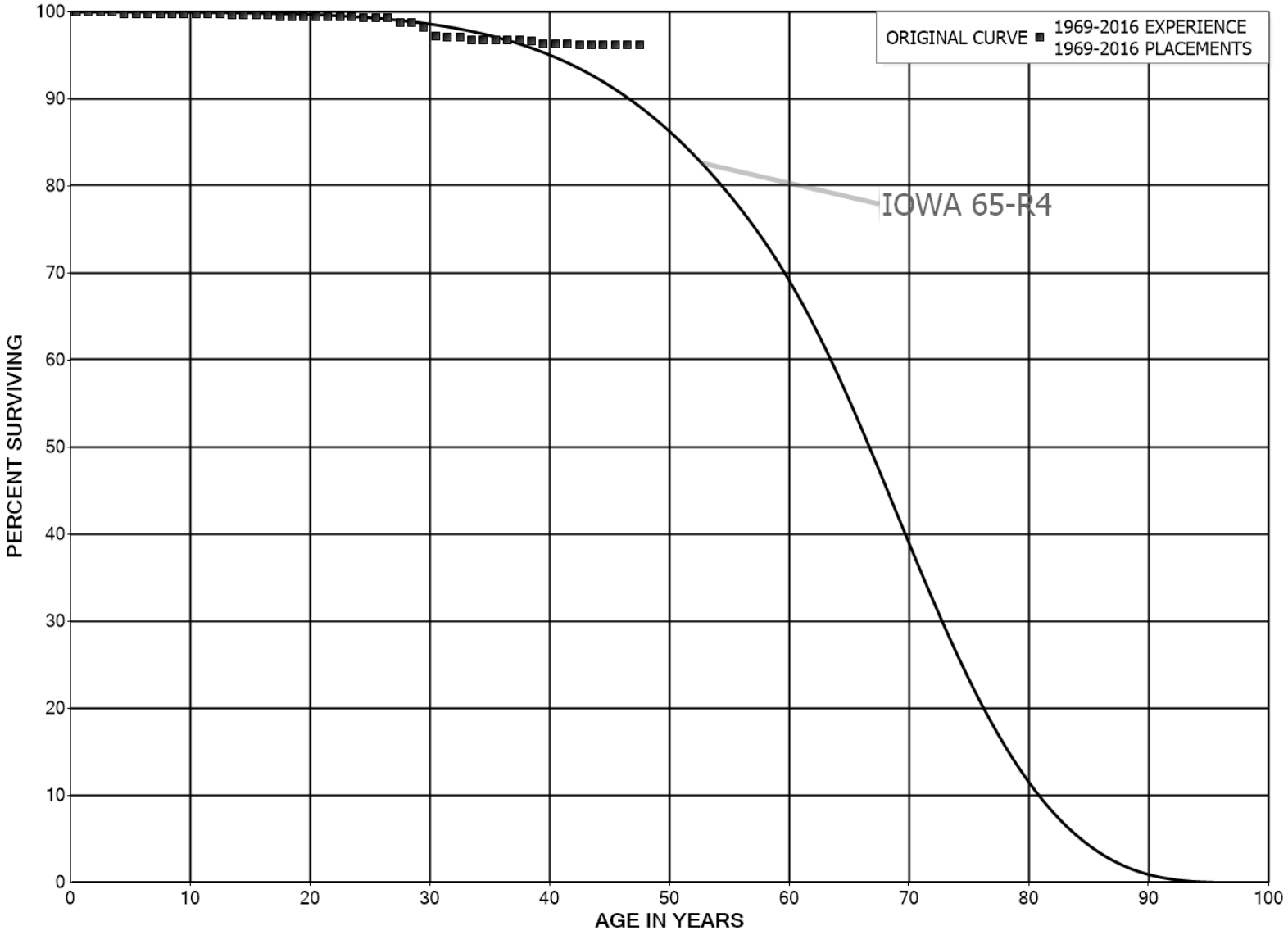
ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	124,277		0.0000	1.0000	82.51
40.5	120,835		0.0000	1.0000	82.51
41.5	118,541		0.0000	1.0000	82.51
42.5	118,541		0.0000	1.0000	82.51
43.5	117,733		0.0000	1.0000	82.51
44.5	115,843		0.0000	1.0000	82.51
45.5	110,417		0.0000	1.0000	82.51
46.5	102,412	3,958	0.0386	0.9614	82.51
47.5					79.32

PACIFIC NORTHERN GAS LTD.
ACCOUNT 465.00 - TRANSMISSION - MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	172,737,303	426	0.0000	1.0000	100.00
0.5	171,307,112	6,314	0.0000	1.0000	100.00
1.5	167,934,552	5,556	0.0000	1.0000	100.00
2.5	165,423,934	2,268	0.0000	1.0000	99.99
3.5	161,915,007	354,059	0.0022	0.9978	99.99
4.5	159,074,232	12,750	0.0001	0.9999	99.77
5.5	155,494,211	13,801	0.0001	0.9999	99.76
6.5	154,295,559	9,186	0.0001	0.9999	99.76
7.5	151,165,710	17,030	0.0001	0.9999	99.75
8.5	146,233,303	24,072	0.0002	0.9998	99.74
9.5	142,268,171	12,029	0.0001	0.9999	99.72
10.5	138,028,202	16,402	0.0001	0.9999	99.71
11.5	131,090,581	19,110	0.0001	0.9999	99.70
12.5	129,652,048	23,610	0.0002	0.9998	99.69
13.5	128,229,623	6,266	0.0000	1.0000	99.67
14.5	126,072,842	19,754	0.0002	0.9998	99.66
15.5	125,210,257	103,108	0.0008	0.9992	99.65
16.5	122,006,036	166,972	0.0014	0.9986	99.57
17.5	115,782,948	13,756	0.0001	0.9999	99.43
18.5	112,098,106	16,037	0.0001	0.9999	99.42
19.5	110,533,865	33,662	0.0003	0.9997	99.40
20.5	104,770,222	10,627	0.0001	0.9999	99.37
21.5	95,779,468	4,013	0.0000	1.0000	99.36
22.5	86,423,998	7,517	0.0001	0.9999	99.36
23.5	80,118,038	24,055	0.0003	0.9997	99.35
24.5	76,844,554	35,278	0.0005	0.9995	99.32
25.5	74,802,277	9,725	0.0001	0.9999	99.28
26.5	64,960,755	332,704	0.0051	0.9949	99.26
27.5	63,599,006	31,885	0.0005	0.9995	98.75
28.5	59,321,808	308,643	0.0052	0.9948	98.71
29.5	58,115,801	605,662	0.0104	0.9896	98.19
30.5	52,134,307	32,485	0.0006	0.9994	97.17
31.5	51,939,769	20,524	0.0004	0.9996	97.11
32.5	51,111,473	170,464	0.0033	0.9967	97.07
33.5	49,972,944	13,692	0.0003	0.9997	96.75
34.5	25,263,153	4,609	0.0002	0.9998	96.72
35.5	24,648,976	46	0.0000	1.0000	96.70
36.5	22,063,307	4,639	0.0002	0.9998	96.70
37.5	21,006,839	4,905	0.0002	0.9998	96.68
38.5	20,980,067	69,824	0.0033	0.9967	96.66

PACIFIC NORTHERN GAS LTD.

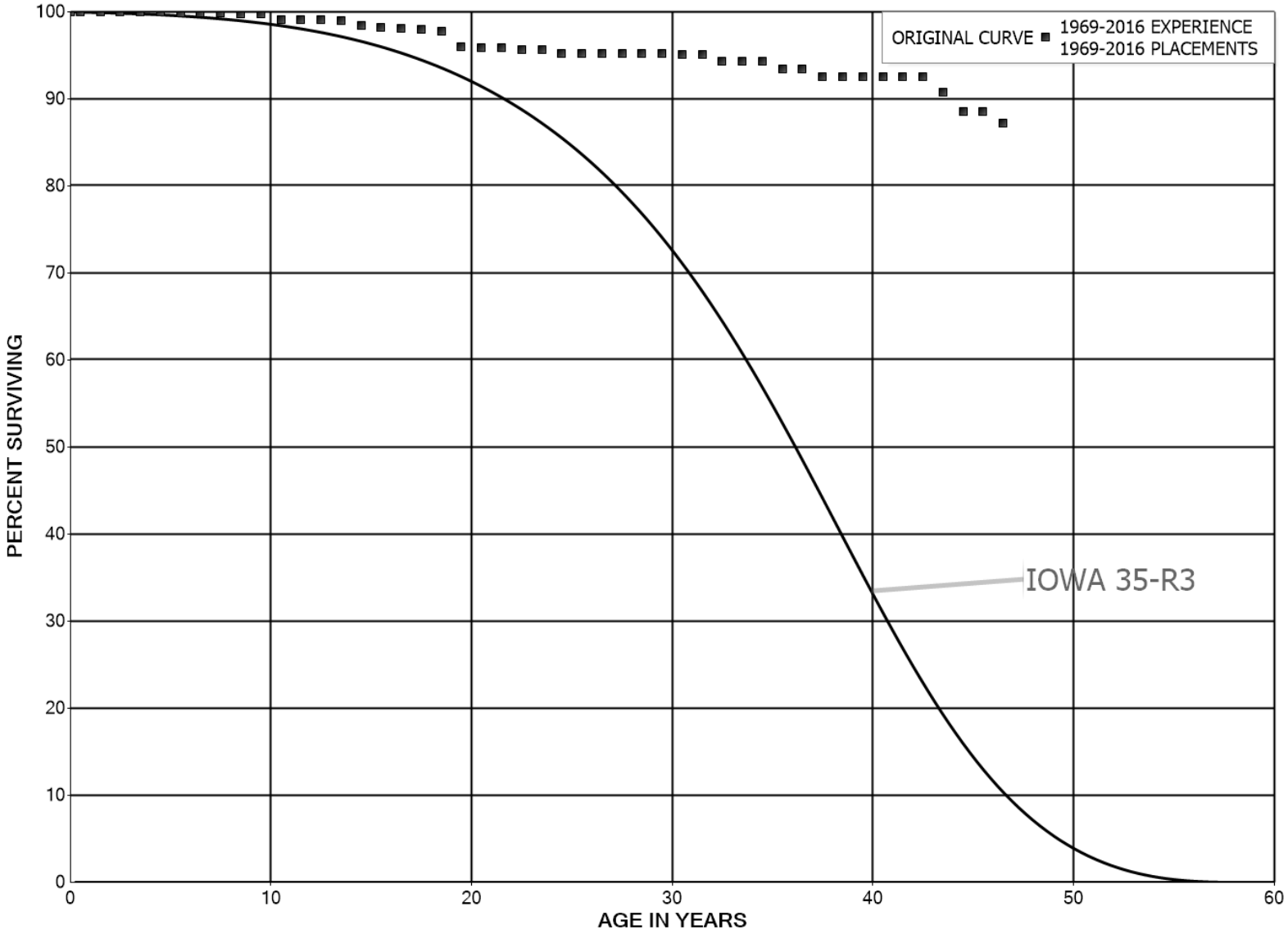
ACCOUNT 465.00 - TRANSMISSION - MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,842,011		0.0000	1.0000	96.34
40.5	20,727,192	19,176	0.0009	0.9991	96.34
41.5	20,425,117	9,783	0.0005	0.9995	96.25
42.5	18,440,399	821	0.0000	1.0000	96.20
43.5	18,394,773	10,154	0.0006	0.9994	96.20
44.5	17,865,251		0.0000	1.0000	96.14
45.5	17,812,106	729	0.0000	1.0000	96.14
46.5	17,380,047		0.0000	1.0000	96.14
47.5					96.14

PACIFIC NORTHERN GAS LTD.
ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	26,459,022	4,237	0.0002	0.9998	100.00
0.5	26,264,996	1,804	0.0001	0.9999	99.98
1.5	25,753,085	1,860	0.0001	0.9999	99.98
2.5	25,349,357	5,963	0.0002	0.9998	99.97
3.5	24,988,945	10,933	0.0004	0.9996	99.95
4.5	24,816,607	6,929	0.0003	0.9997	99.90
5.5	24,779,046	3,887	0.0002	0.9998	99.87
6.5	24,740,300	18,279	0.0007	0.9993	99.86
7.5	24,705,457	4,856	0.0002	0.9998	99.79
8.5	24,687,776	2,225	0.0001	0.9999	99.77
9.5	24,614,706	157,409	0.0064	0.9936	99.76
10.5	24,429,536	6,644	0.0003	0.9997	99.12
11.5	24,189,594	19,493	0.0008	0.9992	99.09
12.5	23,651,050	22,594	0.0010	0.9990	99.01
13.5	23,362,870	115,370	0.0049	0.9951	98.92
14.5	22,822,784	66,758	0.0029	0.9971	98.43
15.5	22,330,895	16,517	0.0007	0.9993	98.14
16.5	22,064,375	34,103	0.0015	0.9985	98.07
17.5	21,698,439	31,429	0.0014	0.9986	97.92
18.5	21,610,342	406,318	0.0188	0.9812	97.78
19.5	20,523,841	17,709	0.0009	0.9991	95.94
20.5	19,715,411	5,482	0.0003	0.9997	95.85
21.5	19,259,581	47,287	0.0025	0.9975	95.83
22.5	18,699,036	4,066	0.0002	0.9998	95.59
23.5	18,416,770	80,410	0.0044	0.9956	95.57
24.5	18,248,219	2,105	0.0001	0.9999	95.15
25.5	17,612,171	397	0.0000	1.0000	95.14
26.5	17,586,668	911	0.0001	0.9999	95.14
27.5	16,388,324	2,242	0.0001	0.9999	95.14
28.5	16,341,975	348	0.0000	1.0000	95.12
29.5	16,227,715	524	0.0000	1.0000	95.12
30.5	13,226,262	11,149	0.0008	0.9992	95.12
31.5	11,247,727	82,670	0.0073	0.9927	95.04
32.5	10,066,297	182	0.0000	1.0000	94.34
33.5	9,578,193	2,705	0.0003	0.9997	94.34
34.5	827,630	8,234	0.0099	0.9901	94.31
35.5	819,396	169	0.0002	0.9998	93.37
36.5	819,227	7,455	0.0091	0.9909	93.35
37.5	811,772		0.0000	1.0000	92.50
38.5	811,772		0.0000	1.0000	92.50

PACIFIC NORTHERN GAS LTD.

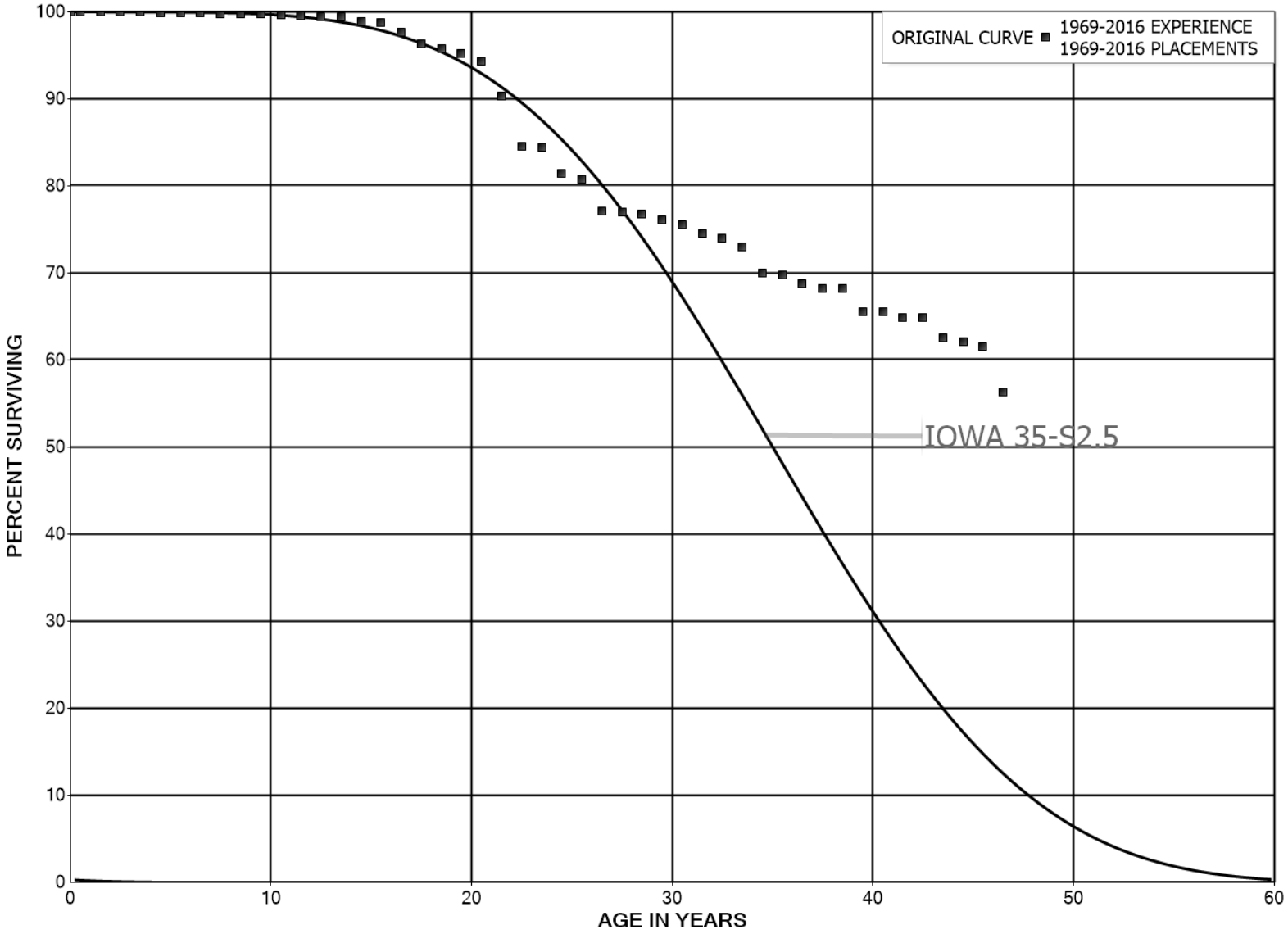
ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	811,772		0.0000	1.0000	92.50
40.5	811,772		0.0000	1.0000	92.50
41.5	805,218		0.0000	1.0000	92.50
42.5	802,301	15,000	0.0187	0.9813	92.50
43.5	782,283	19,900	0.0254	0.9746	90.77
44.5	754,468		0.0000	1.0000	88.46
45.5	746,350	11,133	0.0149	0.9851	88.46
46.5	717,052		0.0000	1.0000	87.15
47.5					87.15

PACIFIC NORTHERN GAS LTD.
ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,405,370	409	0.0000	1.0000	100.00
0.5	18,279,774	5,790	0.0003	0.9997	100.00
1.5	17,677,652	3,504	0.0002	0.9998	99.97
2.5	15,497,262	2,317	0.0001	0.9999	99.95
3.5	14,236,543	7,547	0.0005	0.9995	99.93
4.5	13,217,546	7,227	0.0005	0.9995	99.88
5.5	12,568,681	4,577	0.0004	0.9996	99.82
6.5	12,069,786	2,634	0.0002	0.9998	99.79
7.5	10,783,041	5,953	0.0006	0.9994	99.77
8.5	10,321,293	3,104	0.0003	0.9997	99.71
9.5	9,668,531	6,024	0.0006	0.9994	99.68
10.5	9,505,317	16,135	0.0017	0.9983	99.62
11.5	9,271,863	4,537	0.0005	0.9995	99.45
12.5	8,788,564	4,818	0.0005	0.9995	99.40
13.5	8,641,606	41,625	0.0048	0.9952	99.35
14.5	8,563,612	15,335	0.0018	0.9982	98.87
15.5	8,364,175	93,183	0.0111	0.9889	98.69
16.5	8,143,255	112,728	0.0138	0.9862	97.59
17.5	7,561,985	42,589	0.0056	0.9944	96.24
18.5	7,097,829	39,739	0.0056	0.9944	95.70
19.5	6,653,605	58,518	0.0088	0.9912	95.16
20.5	4,595,931	197,063	0.0429	0.9571	94.33
21.5	4,204,097	270,188	0.0643	0.9357	90.28
22.5	3,567,035	6,347	0.0018	0.9982	84.48
23.5	3,274,527	114,373	0.0349	0.9651	84.33
24.5	2,529,619	22,677	0.0090	0.9910	81.38
25.5	2,406,198	110,259	0.0458	0.9542	80.65
26.5	2,118,710	3,541	0.0017	0.9983	76.96
27.5	2,084,961	3,909	0.0019	0.9981	76.83
28.5	1,407,631	13,126	0.0093	0.9907	76.69
29.5	1,229,417	9,853	0.0080	0.9920	75.97
30.5	1,129,534	14,674	0.0130	0.9870	75.36
31.5	1,021,738	8,208	0.0080	0.9920	74.38
32.5	888,293	12,118	0.0136	0.9864	73.78
33.5	868,112	35,569	0.0410	0.9590	72.78
34.5	791,532	3,046	0.0038	0.9962	69.80
35.5	564,904	8,689	0.0154	0.9846	69.53
36.5	503,150	3,562	0.0071	0.9929	68.46
37.5	497,662	496	0.0010	0.9990	67.97
38.5	484,063	19,341	0.0400	0.9600	67.91

PACIFIC NORTHERN GAS LTD.

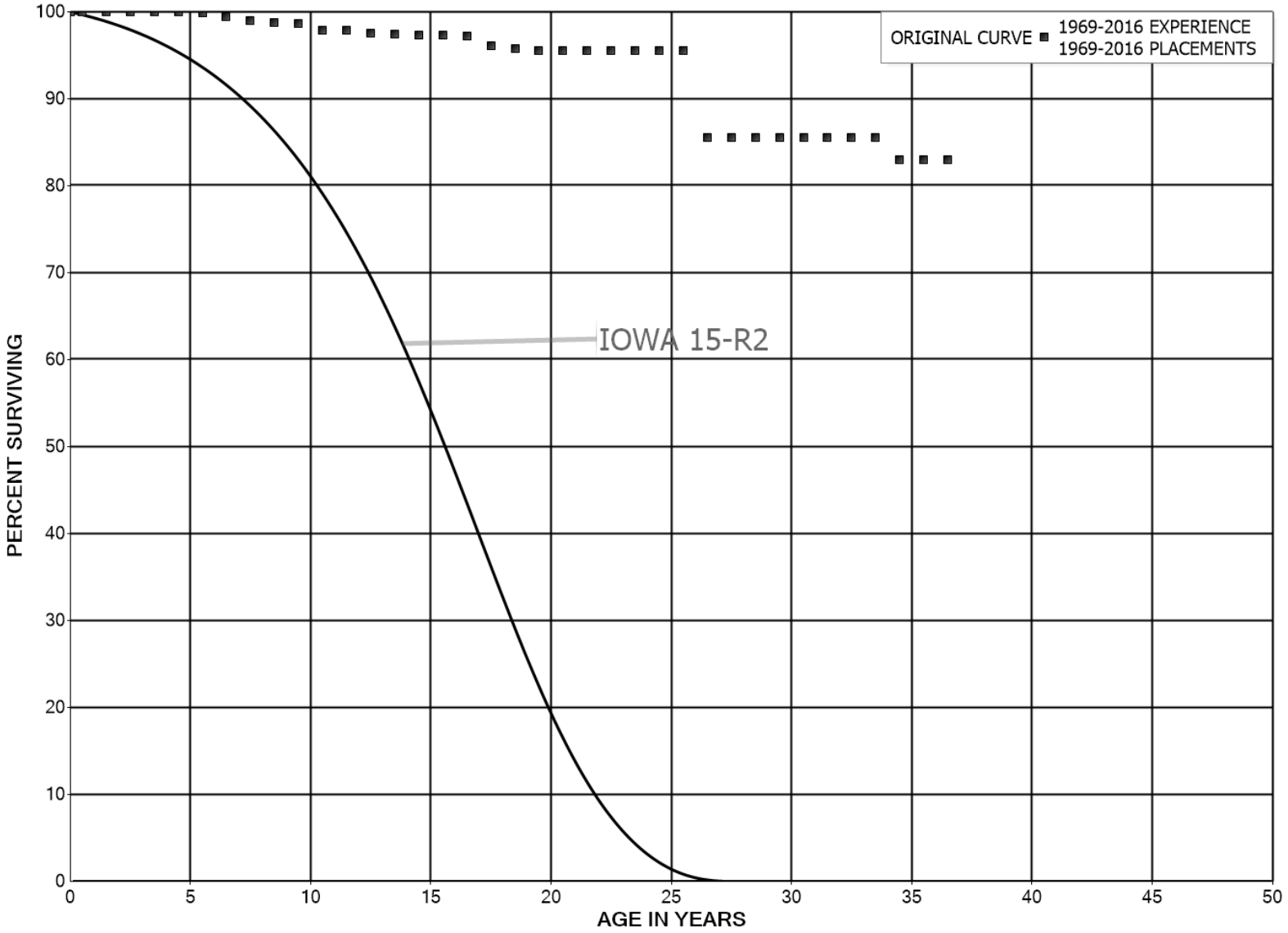
ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	462,677		0.0000	1.0000	65.19
40.5	461,869	5,460	0.0118	0.9882	65.19
41.5	433,444		0.0000	1.0000	64.42
42.5	425,286	15,427	0.0363	0.9637	64.42
43.5	380,995	2,951	0.0077	0.9923	62.08
44.5	338,235	3,033	0.0090	0.9910	61.60
45.5	323,351	28,818	0.0891	0.9109	61.05
46.5	202,901	47,820	0.2357	0.7643	55.61
47.5					42.50

PACIFIC NORTHERN GAS LTD.
ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,630,911		0.0000	1.0000	100.00
0.5	3,596,166		0.0000	1.0000	100.00
1.5	3,590,740	311	0.0001	0.9999	100.00
2.5	3,254,430	1,263	0.0004	0.9996	99.99
3.5	3,251,589	278	0.0001	0.9999	99.95
4.5	3,225,063	3,456	0.0011	0.9989	99.94
5.5	3,221,607	14,044	0.0044	0.9956	99.84
6.5	3,207,563	14,399	0.0045	0.9955	99.40
7.5	3,193,164	7,719	0.0024	0.9976	98.96
8.5	3,180,658	3,194	0.0010	0.9990	98.72
9.5	3,173,285	25,657	0.0081	0.9919	98.62
10.5	3,147,628	645	0.0002	0.9998	97.82
11.5	3,060,978	8,447	0.0028	0.9972	97.80
12.5	2,951,807	4,806	0.0016	0.9984	97.53
13.5	2,898,677	1,167	0.0004	0.9996	97.37
14.5	2,814,860	2,126	0.0008	0.9992	97.33
15.5	2,597,107	2,154	0.0008	0.9992	97.26
16.5	2,480,342	29,739	0.0120	0.9880	97.18
17.5	2,185,136	6,949	0.0032	0.9968	96.01
18.5	2,177,225	5,390	0.0025	0.9975	95.71
19.5	1,251,800		0.0000	1.0000	95.47
20.5	1,211,686		0.0000	1.0000	95.47
21.5	1,197,485		0.0000	1.0000	95.47
22.5	1,135,248		0.0000	1.0000	95.47
23.5	1,135,248		0.0000	1.0000	95.47
24.5	1,109,445		0.0000	1.0000	95.47
25.5	797,103	83,656	0.1050	0.8950	95.47
26.5	555,716		0.0000	1.0000	85.45
27.5	489,919		0.0000	1.0000	85.45
28.5	459,827		0.0000	1.0000	85.45
29.5	445,140		0.0000	1.0000	85.45
30.5	445,140		0.0000	1.0000	85.45
31.5	445,140		0.0000	1.0000	85.45
32.5	433,905		0.0000	1.0000	85.45
33.5	418,930	12,021	0.0287	0.9713	85.45
34.5	64,211		0.0000	1.0000	83.00
35.5	62,621		0.0000	1.0000	83.00
36.5	23,463		0.0000	1.0000	83.00
37.5	23,463		0.0000	1.0000	83.00
38.5	23,463		0.0000	1.0000	83.00

PACIFIC NORTHERN GAS LTD.

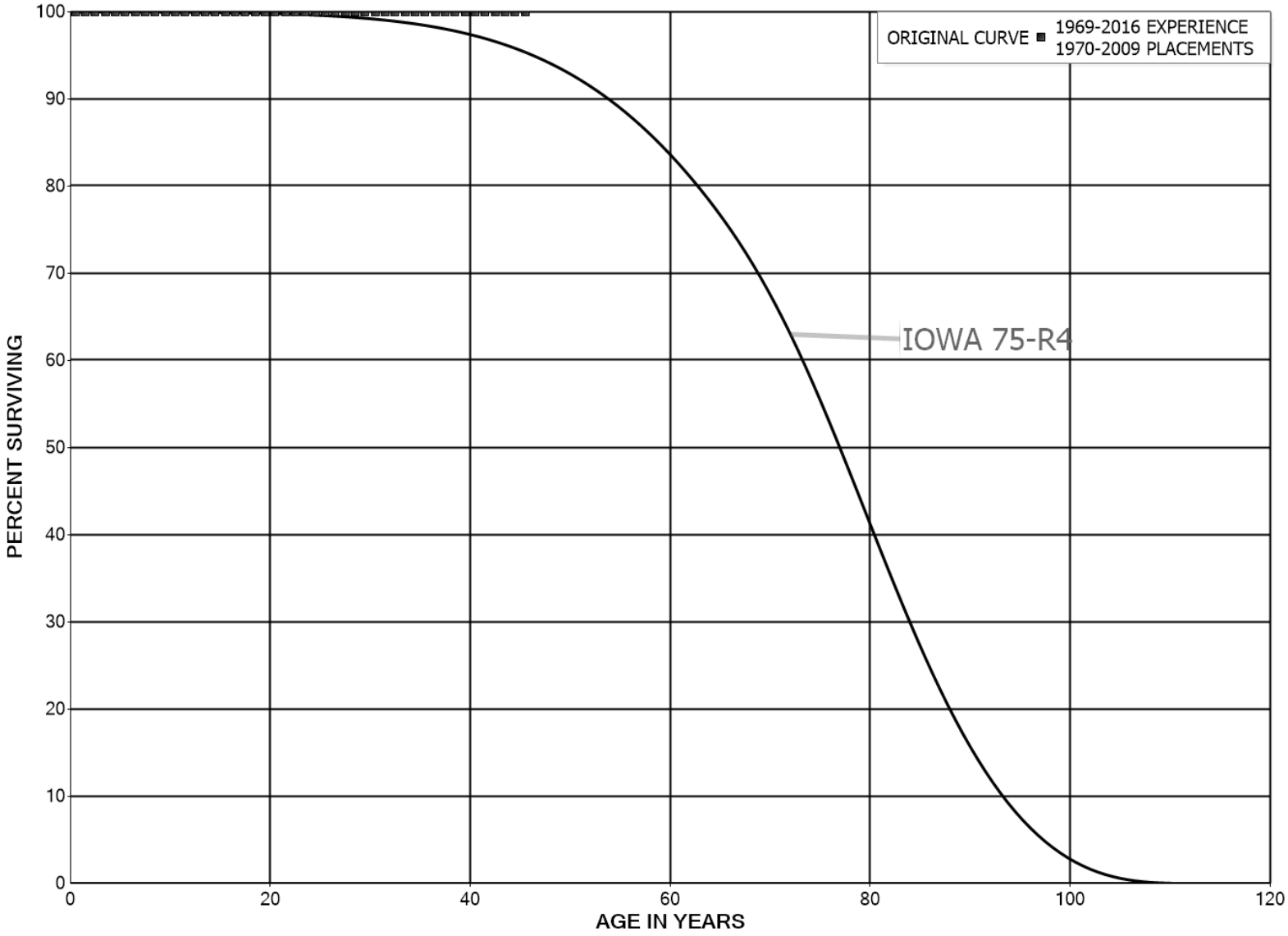
ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,463		0.0000	1.0000	83.00
40.5	23,463		0.0000	1.0000	83.00
41.5	23,463		0.0000	1.0000	83.00
42.5	23,463		0.0000	1.0000	83.00
43.5	9,782		0.0000	1.0000	83.00
44.5	9,782		0.0000	1.0000	83.00
45.5	9,782		0.0000	1.0000	83.00
46.5	2,373		0.0000	1.0000	83.00
47.5					83.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2009 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	257,861		0.0000	1.0000	100.00
0.5	257,861		0.0000	1.0000	100.00
1.5	257,861		0.0000	1.0000	100.00
2.5	257,861		0.0000	1.0000	100.00
3.5	257,861		0.0000	1.0000	100.00
4.5	257,861		0.0000	1.0000	100.00
5.5	257,861		0.0000	1.0000	100.00
6.5	257,861		0.0000	1.0000	100.00
7.5	255,917		0.0000	1.0000	100.00
8.5	255,917		0.0000	1.0000	100.00
9.5	255,917		0.0000	1.0000	100.00
10.5	255,917		0.0000	1.0000	100.00
11.5	255,917		0.0000	1.0000	100.00
12.5	255,917		0.0000	1.0000	100.00
13.5	255,917		0.0000	1.0000	100.00
14.5	255,917		0.0000	1.0000	100.00
15.5	255,917		0.0000	1.0000	100.00
16.5	255,917		0.0000	1.0000	100.00
17.5	255,917		0.0000	1.0000	100.00
18.5	240,794		0.0000	1.0000	100.00
19.5	238,789		0.0000	1.0000	100.00
20.5	99,240		0.0000	1.0000	100.00
21.5	99,240		0.0000	1.0000	100.00
22.5	99,240		0.0000	1.0000	100.00
23.5	99,240		0.0000	1.0000	100.00
24.5	99,240		0.0000	1.0000	100.00
25.5	97,928		0.0000	1.0000	100.00
26.5	92,658		0.0000	1.0000	100.00
27.5	91,057		0.0000	1.0000	100.00
28.5	90,222		0.0000	1.0000	100.00
29.5	85,696		0.0000	1.0000	100.00
30.5	85,427		0.0000	1.0000	100.00
31.5	84,088		0.0000	1.0000	100.00
32.5	82,533		0.0000	1.0000	100.00
33.5	73,346		0.0000	1.0000	100.00
34.5	71,822		0.0000	1.0000	100.00
35.5	71,395		0.0000	1.0000	100.00
36.5	9,309		0.0000	1.0000	100.00
37.5	9,309		0.0000	1.0000	100.00
38.5	7,446		0.0000	1.0000	100.00

PACIFIC NORTHERN GAS LTD.

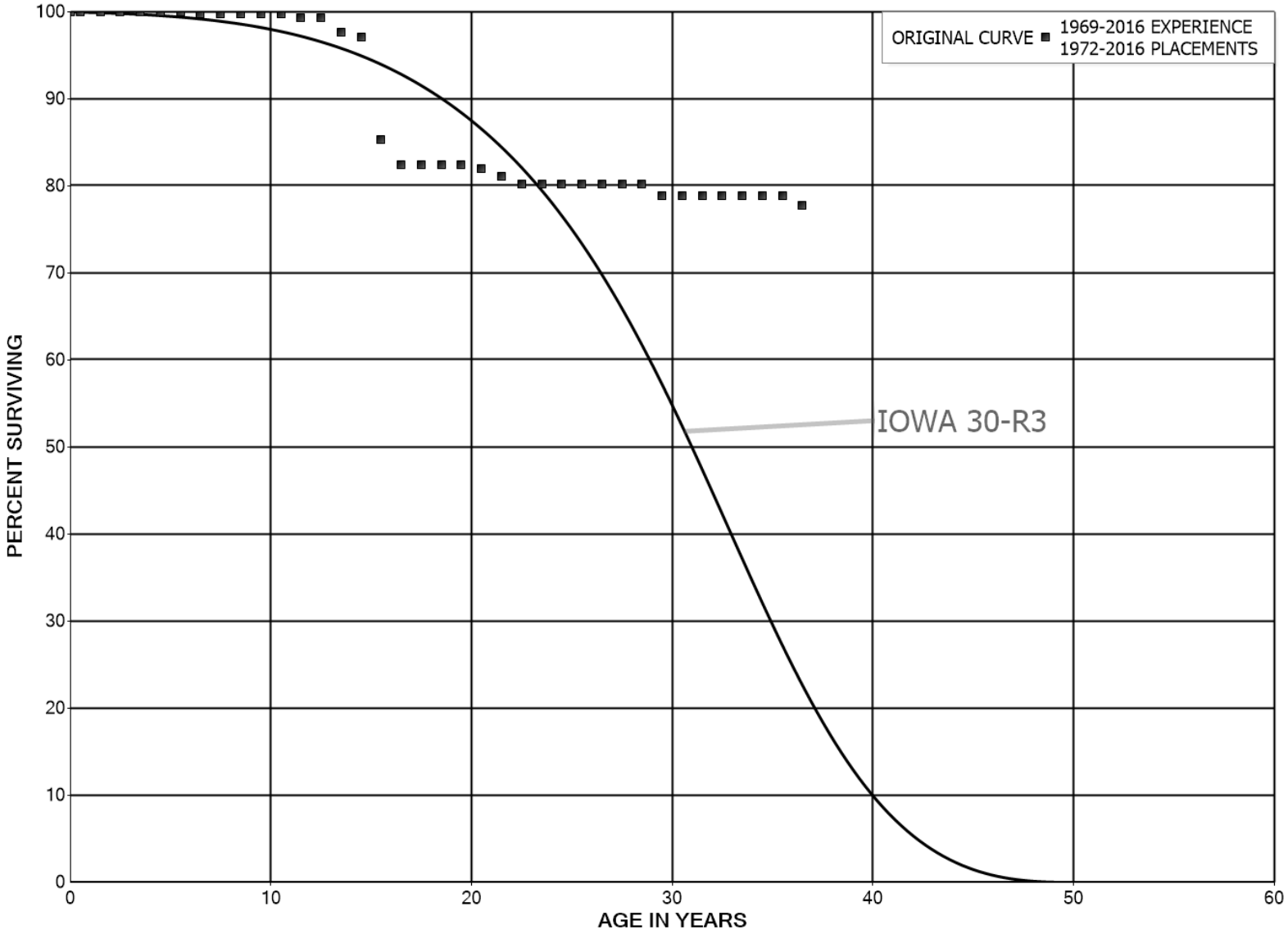
ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2009 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,145		0.0000	1.0000	100.00
40.5	7,145		0.0000	1.0000	100.00
41.5	7,145		0.0000	1.0000	100.00
42.5	4,371		0.0000	1.0000	100.00
43.5	2,667		0.0000	1.0000	100.00
44.5	2,667		0.0000	1.0000	100.00
45.5	2,547		0.0000	1.0000	100.00
46.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,890,030		0.0000	1.0000	100.00
0.5	2,729,276		0.0000	1.0000	100.00
1.5	2,650,119	22	0.0000	1.0000	100.00
2.5	2,586,874	2	0.0000	1.0000	100.00
3.5	2,506,002		0.0000	1.0000	100.00
4.5	2,355,669		0.0000	1.0000	100.00
5.5	2,195,975	6,972	0.0032	0.9968	100.00
6.5	2,009,870		0.0000	1.0000	99.68
7.5	1,818,050		0.0000	1.0000	99.68
8.5	1,631,740		0.0000	1.0000	99.68
9.5	1,529,202		0.0000	1.0000	99.68
10.5	1,463,405	5,287	0.0036	0.9964	99.68
11.5	1,366,605		0.0000	1.0000	99.32
12.5	1,255,596	21,846	0.0174	0.9826	99.32
13.5	1,070,735	6,356	0.0059	0.9941	97.59
14.5	897,674	108,234	0.1206	0.8794	97.01
15.5	688,804	23,458	0.0341	0.9659	85.32
16.5	338,933		0.0000	1.0000	82.41
17.5	338,933		0.0000	1.0000	82.41
18.5	333,982		0.0000	1.0000	82.41
19.5	322,467	2,000	0.0062	0.9938	82.41
20.5	262,521	2,800	0.0107	0.9893	81.90
21.5	259,721	2,856	0.0110	0.9890	81.03
22.5	256,865		0.0000	1.0000	80.14
23.5	251,871		0.0000	1.0000	80.14
24.5	251,871		0.0000	1.0000	80.14
25.5	245,803		0.0000	1.0000	80.14
26.5	204,464		0.0000	1.0000	80.14
27.5	204,464		0.0000	1.0000	80.14
28.5	183,475	3,000	0.0164	0.9836	80.14
29.5	180,475		0.0000	1.0000	78.83
30.5	158,597		0.0000	1.0000	78.83
31.5	147,809		0.0000	1.0000	78.83
32.5	147,809		0.0000	1.0000	78.83
33.5	147,809		0.0000	1.0000	78.83
34.5	144,781		0.0000	1.0000	78.83
35.5	144,781	2,000	0.0138	0.9862	78.83
36.5	14,715		0.0000	1.0000	77.74
37.5	14,299		0.0000	1.0000	77.74
38.5	14,299		0.0000	1.0000	77.74

PACIFIC NORTHERN GAS LTD.

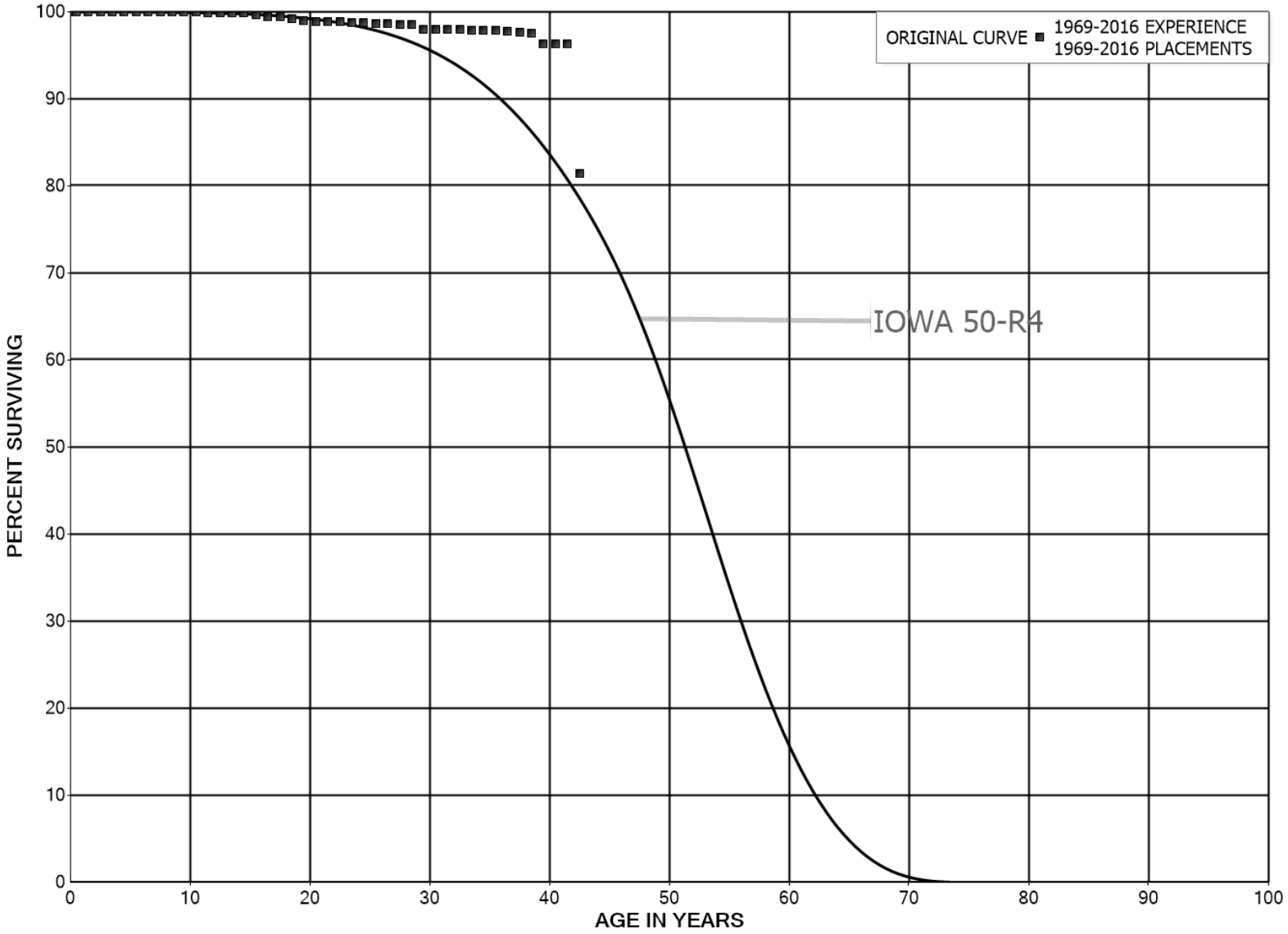
ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1972-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,949		0.0000	1.0000	77.74
40.5	7,074		0.0000	1.0000	77.74
41.5	7,074		0.0000	1.0000	77.74
42.5	908		0.0000	1.0000	77.74
43.5	908		0.0000	1.0000	77.74
44.5					77.74

PACIFIC NORTHERN GAS LTD.
ACCOUNT 473.00 - DISTRIBUTION - SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	52,360,679		0.0000	1.0000	100.00
0.5	51,123,791	1,299	0.0000	1.0000	100.00
1.5	49,445,039	3,779	0.0001	0.9999	100.00
2.5	47,780,747	4,475	0.0001	0.9999	99.99
3.5	46,133,155	6,466	0.0001	0.9999	99.98
4.5	44,613,309	7,586	0.0002	0.9998	99.97
5.5	43,412,314	10,052	0.0002	0.9998	99.95
6.5	41,467,987	8,222	0.0002	0.9998	99.93
7.5	40,280,190	1,206	0.0000	1.0000	99.91
8.5	38,720,995	1,320	0.0000	1.0000	99.90
9.5	37,470,383	1,823	0.0000	1.0000	99.90
10.5	36,425,339	2,859	0.0001	0.9999	99.90
11.5	35,531,067	4,543	0.0001	0.9999	99.89
12.5	34,607,235	6,726	0.0002	0.9998	99.87
13.5	33,750,254	8,689	0.0003	0.9997	99.86
14.5	32,944,948	52,833	0.0016	0.9984	99.83
15.5	32,115,086	72,488	0.0023	0.9977	99.67
16.5	31,187,640	7,540	0.0002	0.9998	99.44
17.5	30,252,112	64,504	0.0021	0.9979	99.42
18.5	28,440,781	64,553	0.0023	0.9977	99.21
19.5	26,434,496	35,135	0.0013	0.9987	98.98
20.5	19,298,435	6,363	0.0003	0.9997	98.85
21.5	18,448,919	7,064	0.0004	0.9996	98.82
22.5	17,264,391	7,334	0.0004	0.9996	98.78
23.5	15,896,544	7,427	0.0005	0.9995	98.74
24.5	14,456,063	7,109	0.0005	0.9995	98.69
25.5	13,278,800	9,413	0.0007	0.9993	98.64
26.5	10,929,159	5,360	0.0005	0.9995	98.57
27.5	10,079,457	4,683	0.0005	0.9995	98.53
28.5	9,272,763	44,674	0.0048	0.9952	98.48
29.5	8,591,163	3,027	0.0004	0.9996	98.01
30.5	8,036,066	2,958	0.0004	0.9996	97.97
31.5	7,170,778	2,581	0.0004	0.9996	97.94
32.5	6,447,565	2,319	0.0004	0.9996	97.90
33.5	5,556,057	2,226	0.0004	0.9996	97.87
34.5	4,797,146	2,067	0.0004	0.9996	97.83
35.5	4,115,051	2,537	0.0006	0.9994	97.78
36.5	2,358,624	2,053	0.0009	0.9991	97.72
37.5	1,876,000	1,737	0.0009	0.9991	97.64
38.5	1,572,426	20,965	0.0133	0.9867	97.55

PACIFIC NORTHERN GAS LTD.

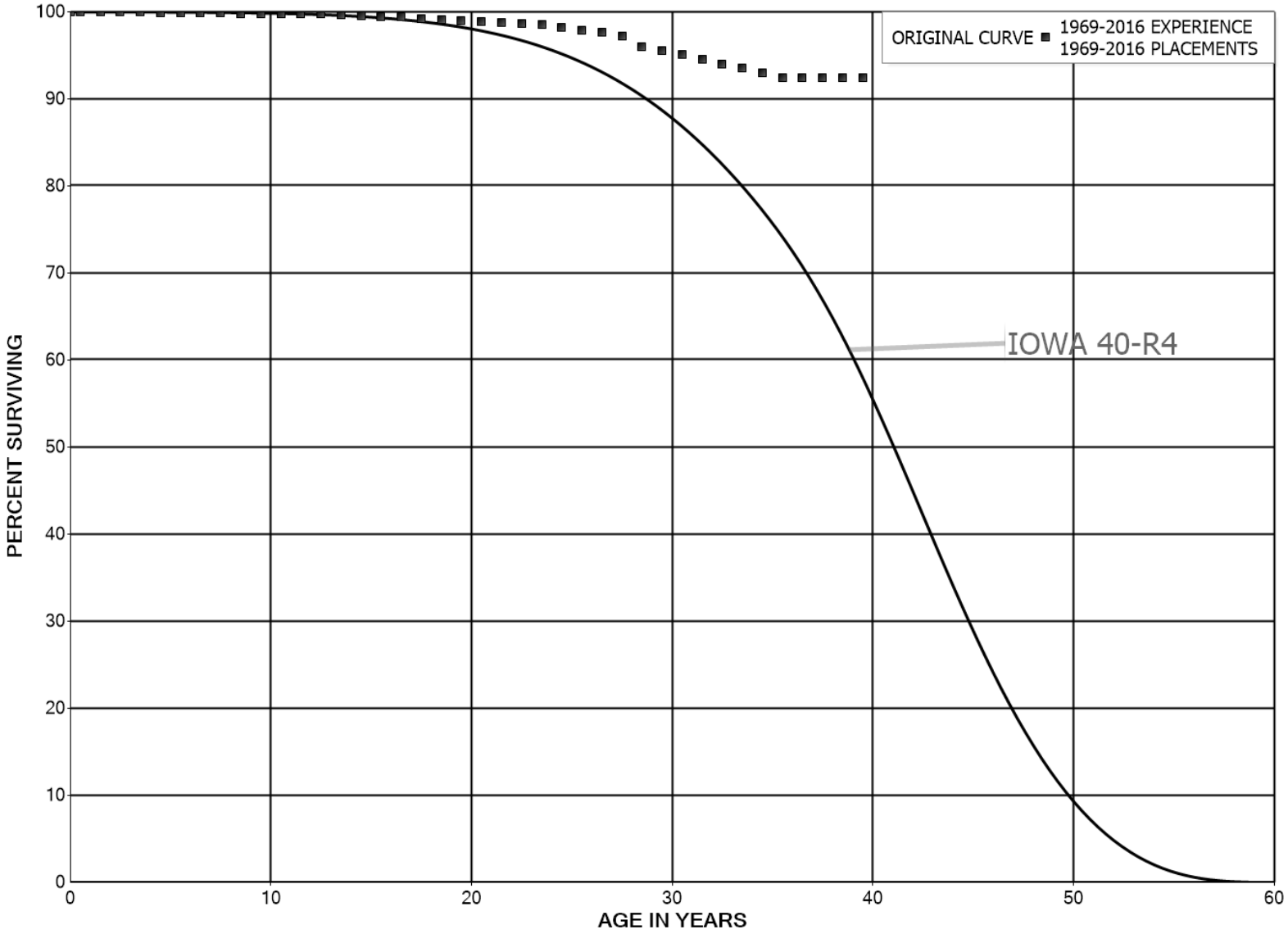
ACCOUNT 473.00 - DISTRIBUTION - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,270,234		0.0000	1.0000	96.25
40.5	1,026,286		0.0000	1.0000	96.25
41.5	863,100	133,000	0.1541	0.8459	96.25
42.5	532,370	223,848	0.4205	0.5795	81.42
43.5	259,141	7,824	0.0302	0.9698	47.18
44.5	251,317	21,527	0.0857	0.9143	45.76
45.5	229,789	20,043	0.0872	0.9128	41.84
46.5					38.19

PACIFIC NORTHERN GAS LTD.
ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,554,232		0.0000	1.0000	100.00
0.5	10,307,986	481	0.0000	1.0000	100.00
1.5	10,052,785	1,197	0.0001	0.9999	100.00
2.5	9,818,684	1,621	0.0002	0.9998	99.98
3.5	9,636,184	8,726	0.0009	0.9991	99.97
4.5	9,436,461	5,183	0.0005	0.9995	99.88
5.5	9,289,481	2,898	0.0003	0.9997	99.82
6.5	9,036,739	521	0.0001	0.9999	99.79
7.5	8,875,626	447	0.0001	0.9999	99.78
8.5	8,634,988	454	0.0001	0.9999	99.78
9.5	8,503,181	450	0.0001	0.9999	99.77
10.5	8,307,457	2,698	0.0003	0.9997	99.77
11.5	8,184,428	4,338	0.0005	0.9995	99.74
12.5	7,769,996	4,097	0.0005	0.9995	99.68
13.5	7,347,085	5,516	0.0008	0.9992	99.63
14.5	6,926,420	7,911	0.0011	0.9989	99.56
15.5	6,474,752	6,308	0.0010	0.9990	99.44
16.5	6,196,561	7,507	0.0012	0.9988	99.35
17.5	6,030,659	7,875	0.0013	0.9987	99.23
18.5	5,752,934	6,493	0.0011	0.9989	99.10
19.5	5,308,548	6,795	0.0013	0.9987	98.98
20.5	4,136,263	5,501	0.0013	0.9987	98.86
21.5	4,005,877	6,505	0.0016	0.9984	98.73
22.5	3,843,945	3,579	0.0009	0.9991	98.57
23.5	3,662,318	11,000	0.0030	0.9970	98.47
24.5	3,530,613	10,600	0.0030	0.9970	98.18
25.5	3,347,092	8,914	0.0027	0.9973	97.88
26.5	2,222,669	9,426	0.0042	0.9958	97.62
27.5	2,107,287	26,928	0.0128	0.9872	97.21
28.5	1,935,310	9,898	0.0051	0.9949	95.97
29.5	1,783,766	7,419	0.0042	0.9958	95.48
30.5	1,674,068	9,484	0.0057	0.9943	95.08
31.5	1,530,456	10,128	0.0066	0.9934	94.54
32.5	1,444,262	6,642	0.0046	0.9954	93.91
33.5	1,364,269	7,124	0.0052	0.9948	93.48
34.5	1,291,005	8,769	0.0068	0.9932	92.99
35.5	1,193,818		0.0000	1.0000	92.36
36.5	559,574		0.0000	1.0000	92.36
37.5	488,282		0.0000	1.0000	92.36
38.5	182,470		0.0000	1.0000	92.36

PACIFIC NORTHERN GAS LTD.

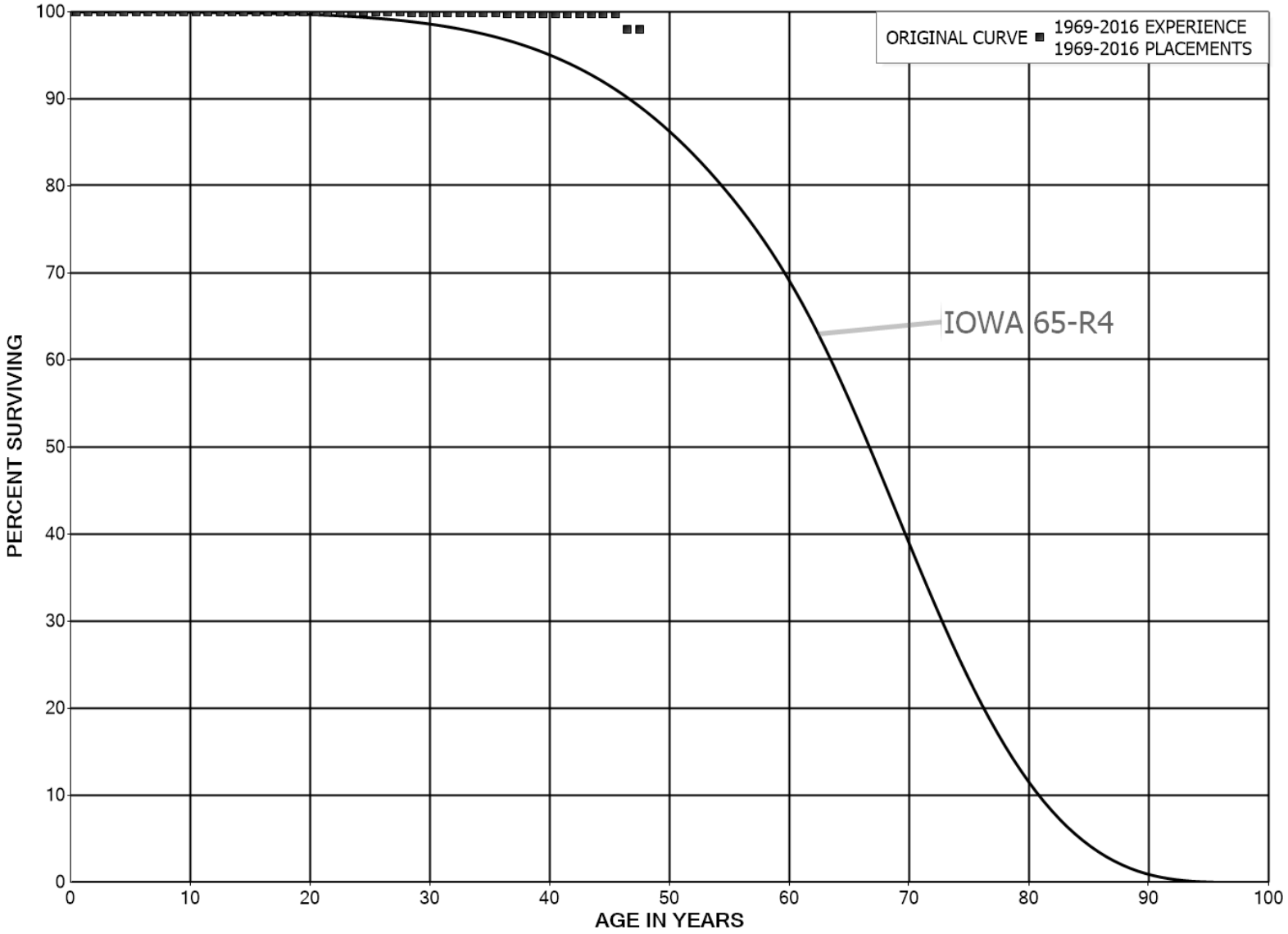
ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	114,233		0.0000	1.0000	92.36
40.5	67,424		0.0000	1.0000	92.36
41.5	26,653		0.0000	1.0000	92.36
42.5	7,200		0.0000	1.0000	92.36
43.5					92.36

PACIFIC NORTHERN GAS LTD.
ACCOUNT 475.00 - DISTRIBUTION - MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 475.00 - DISTRIBUTION - MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	74,584,969	30	0.0000	1.0000	100.00
0.5	71,005,565	56	0.0000	1.0000	100.00
1.5	67,991,169	51	0.0000	1.0000	100.00
2.5	65,156,837	399	0.0000	1.0000	100.00
3.5	62,721,539	2,002	0.0000	1.0000	100.00
4.5	60,604,335	792	0.0000	1.0000	100.00
5.5	59,040,782	1,074	0.0000	1.0000	99.99
6.5	56,451,938	781	0.0000	1.0000	99.99
7.5	53,179,368	764	0.0000	1.0000	99.99
8.5	50,751,813	628	0.0000	1.0000	99.99
9.5	49,607,570	459	0.0000	1.0000	99.99
10.5	48,915,352	1,058	0.0000	1.0000	99.99
11.5	47,664,881	912	0.0000	1.0000	99.99
12.5	46,152,252	593	0.0000	1.0000	99.98
13.5	45,184,606	472	0.0000	1.0000	99.98
14.5	44,468,828	3,619	0.0001	0.9999	99.98
15.5	43,511,278	3,829	0.0001	0.9999	99.97
16.5	42,460,310	1,809	0.0000	1.0000	99.96
17.5	41,369,710	12,071	0.0003	0.9997	99.96
18.5	38,733,276	762	0.0000	1.0000	99.93
19.5	36,156,604	109	0.0000	1.0000	99.93
20.5	24,978,478	246	0.0000	1.0000	99.93
21.5	23,695,748	219	0.0000	1.0000	99.93
22.5	23,412,010	2,810	0.0001	0.9999	99.93
23.5	22,830,913	650	0.0000	1.0000	99.91
24.5	21,643,765	1,102	0.0001	0.9999	99.91
25.5	20,685,724	384	0.0000	1.0000	99.91
26.5	17,548,126	514	0.0000	1.0000	99.91
27.5	16,481,053	5,678	0.0003	0.9997	99.90
28.5	16,021,682	7,025	0.0004	0.9996	99.87
29.5	15,511,515	1,480	0.0001	0.9999	99.82
30.5	14,857,801	254	0.0000	1.0000	99.81
31.5	14,463,835	38	0.0000	1.0000	99.81
32.5	13,538,831	155	0.0000	1.0000	99.81
33.5	12,779,186	39	0.0000	1.0000	99.81
34.5	9,885,377	1,381	0.0001	0.9999	99.81
35.5	8,960,967	3,535	0.0004	0.9996	99.80
36.5	5,278,230	570	0.0001	0.9999	99.76
37.5	4,597,818	873	0.0002	0.9998	99.75
38.5	4,233,462		0.0000	1.0000	99.73

PACIFIC NORTHERN GAS LTD.

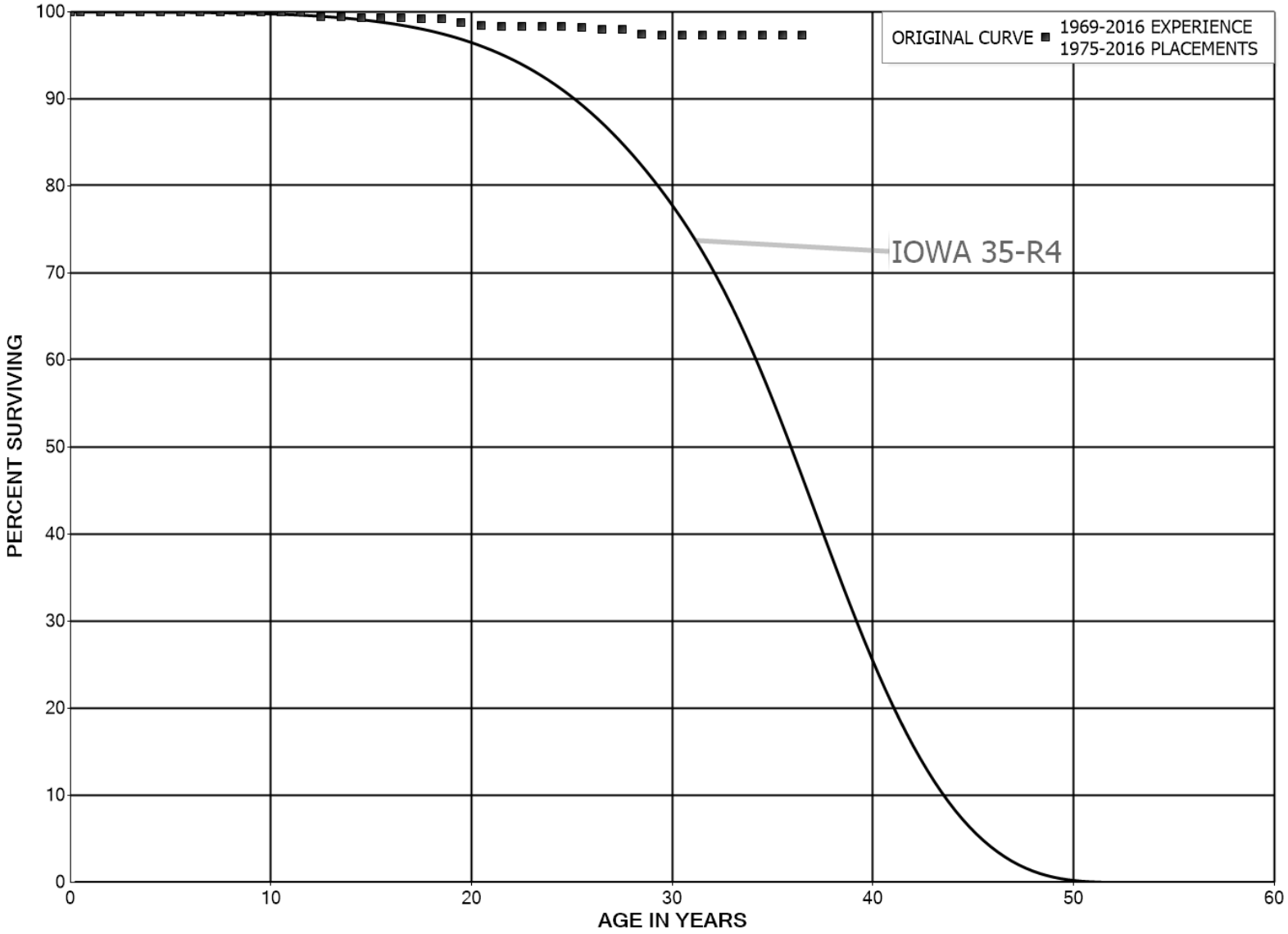
ACCOUNT 475.00 - DISTRIBUTION - MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,671,182		0.0000	1.0000	99.73
40.5	3,375,560		0.0000	1.0000	99.73
41.5	3,093,660		0.0000	1.0000	99.73
42.5	2,833,262		0.0000	1.0000	99.73
43.5	2,437,770		0.0000	1.0000	99.73
44.5	2,014,111		0.0000	1.0000	99.73
45.5	1,743,129	30,104	0.0173	0.9827	99.73
46.5	1,256,817		0.0000	1.0000	98.01
47.5					98.01

PACIFIC NORTHERN GAS LTD.
ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

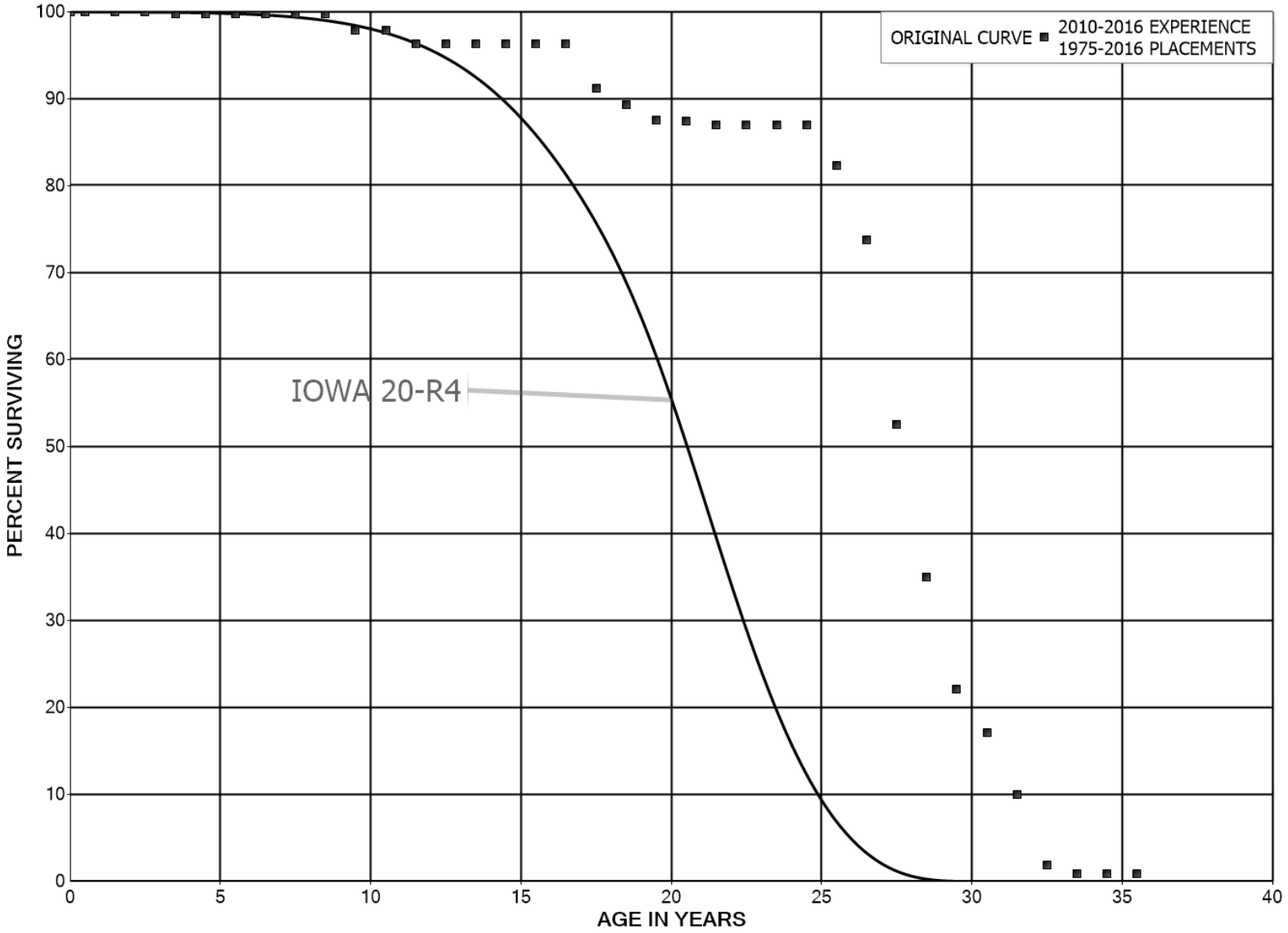
ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,362,396		0.0000	1.0000	100.00
0.5	2,209,066	3	0.0000	1.0000	100.00
1.5	2,209,063	2	0.0000	1.0000	100.00
2.5	2,209,061		0.0000	1.0000	100.00
3.5	2,209,061	12	0.0000	1.0000	100.00
4.5	2,124,992	6	0.0000	1.0000	100.00
5.5	2,082,978		0.0000	1.0000	100.00
6.5	1,924,842		0.0000	1.0000	100.00
7.5	1,878,262		0.0000	1.0000	100.00
8.5	1,878,262		0.0000	1.0000	100.00
9.5	1,838,158		0.0000	1.0000	100.00
10.5	1,792,249	76	0.0000	1.0000	100.00
11.5	1,789,775	10,833	0.0061	0.9939	99.99
12.5	1,710,547	67	0.0000	1.0000	99.39
13.5	1,681,629	1,314	0.0008	0.9992	99.39
14.5	1,019,956	346	0.0003	0.9997	99.31
15.5	947,326	166	0.0002	0.9998	99.27
16.5	897,072	565	0.0006	0.9994	99.26
17.5	896,507	120	0.0001	0.9999	99.19
18.5	896,387	3,839	0.0043	0.9957	99.18
19.5	892,548	3,394	0.0038	0.9962	98.76
20.5	889,154	492	0.0006	0.9994	98.38
21.5	888,115		0.0000	1.0000	98.33
22.5	883,292		0.0000	1.0000	98.33
23.5	883,292	85	0.0001	0.9999	98.33
24.5	878,922	1,107	0.0013	0.9987	98.32
25.5	807,687	1,684	0.0021	0.9979	98.19
26.5	728,359	187	0.0003	0.9997	97.99
27.5	721,700	3,787	0.0052	0.9948	97.96
28.5	667,447	1,178	0.0018	0.9982	97.45
29.5	666,269	78	0.0001	0.9999	97.28
30.5	611,788		0.0000	1.0000	97.27
31.5	567,906		0.0000	1.0000	97.27
32.5	567,906		0.0000	1.0000	97.27
33.5	567,906		0.0000	1.0000	97.27
34.5	567,906		0.0000	1.0000	97.27
35.5	566,852		0.0000	1.0000	97.27
36.5	20,626		0.0000	1.0000	97.27
37.5	20,626		0.0000	1.0000	97.27
38.5					97.27

PACIFIC NORTHERN GAS LTD.
ACCOUNT 478.00 - DISTRIBUTION - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

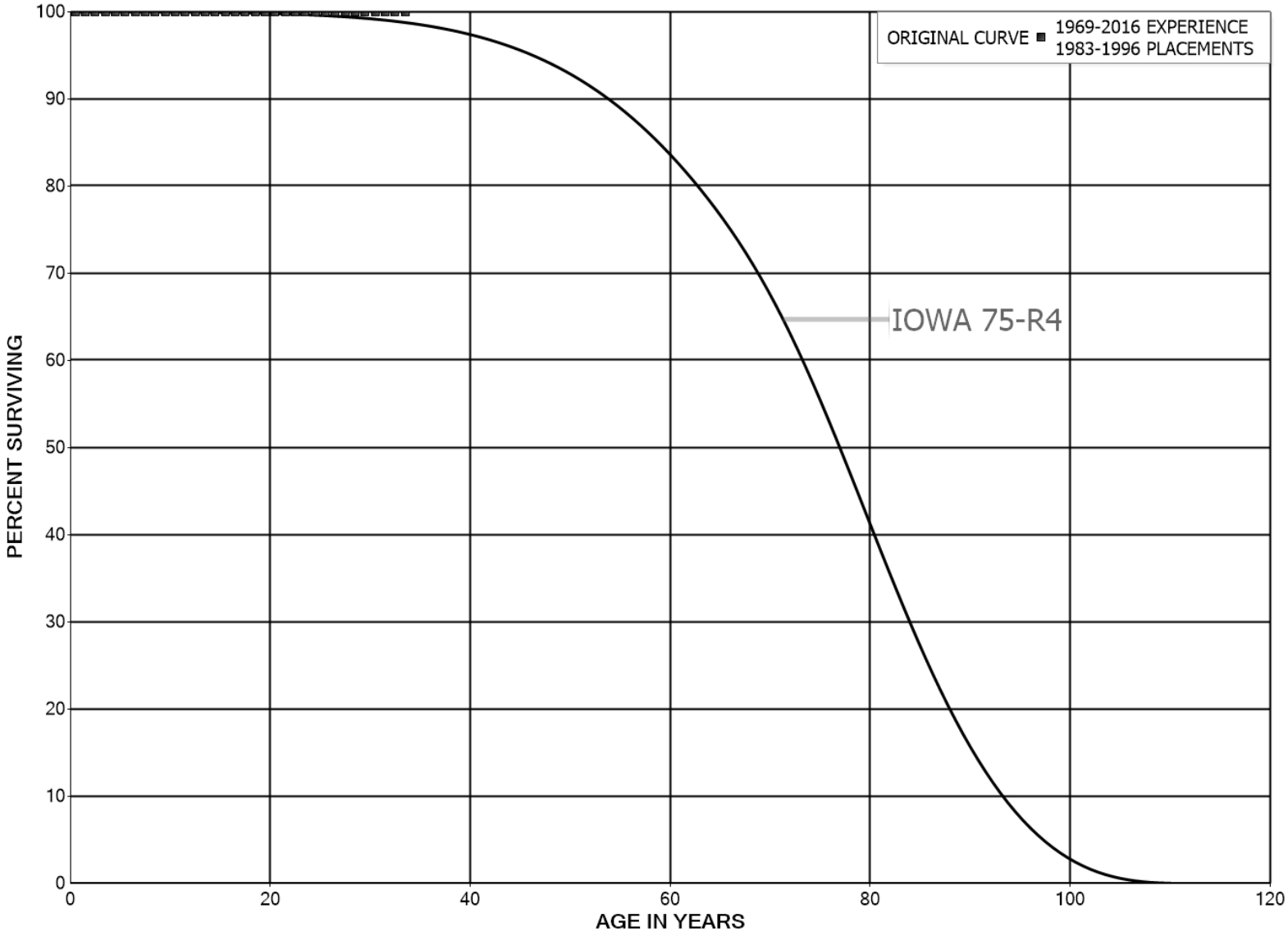
ACCOUNT 478.00 - DISTRIBUTION - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2016 EXPERIENCE BAND 2010-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,604,543		0.0000	1.0000	100.00
0.5	2,417,581	876	0.0004	0.9996	100.00
1.5	2,236,112	1,172	0.0005	0.9995	99.96
2.5	1,992,669	2,711	0.0014	0.9986	99.91
3.5	1,700,050	792	0.0005	0.9995	99.78
4.5	1,348,425		0.0000	1.0000	99.73
5.5	1,164,617		0.0000	1.0000	99.73
6.5	1,147,793		0.0000	1.0000	99.73
7.5	984,674		0.0000	1.0000	99.73
8.5	765,051	14,190	0.0185	0.9815	99.73
9.5	609,753		0.0000	1.0000	97.88
10.5	1,054,819	17,674	0.0168	0.9832	97.88
11.5	1,055,993		0.0000	1.0000	96.24
12.5	1,299,057		0.0000	1.0000	96.24
13.5	1,328,544		0.0000	1.0000	96.24
14.5	1,342,039		0.0000	1.0000	96.24
15.5	1,515,749		0.0000	1.0000	96.24
16.5	1,775,086	94,040	0.0530	0.9470	96.24
17.5	1,504,608	31,413	0.0209	0.9791	91.14
18.5	1,661,267	31,239	0.0188	0.9812	89.24
19.5	1,831,911	3,362	0.0018	0.9982	87.56
20.5	1,816,737	10,085	0.0056	0.9944	87.40
21.5	1,937,515		0.0000	1.0000	86.91
22.5	1,808,923		0.0000	1.0000	86.91
23.5	1,727,804		0.0000	1.0000	86.91
24.5	1,663,272	87,632	0.0527	0.9473	86.91
25.5	1,446,467	151,167	0.1045	0.8955	82.33
26.5	1,106,866	319,254	0.2884	0.7116	73.73
27.5	999,208	333,363	0.3336	0.6664	52.46
28.5	935,246	346,405	0.3704	0.6296	34.96
29.5	1,066,320	240,454	0.2255	0.7745	22.01
30.5	1,000,260	418,040	0.4179	0.5821	17.05
31.5	642,159	521,787	0.8126	0.1874	9.92
32.5	126,723	67,725	0.5344	0.4656	1.86
33.5	59,099		0.0000	1.0000	0.87
34.5	59,157	621	0.0105	0.9895	0.87
35.5	58,537	1,953	0.0334	0.9666	0.86
36.5					0.83

PACIFIC NORTHERN GAS LTD.
ACCOUNT 481.00 - GENERAL - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

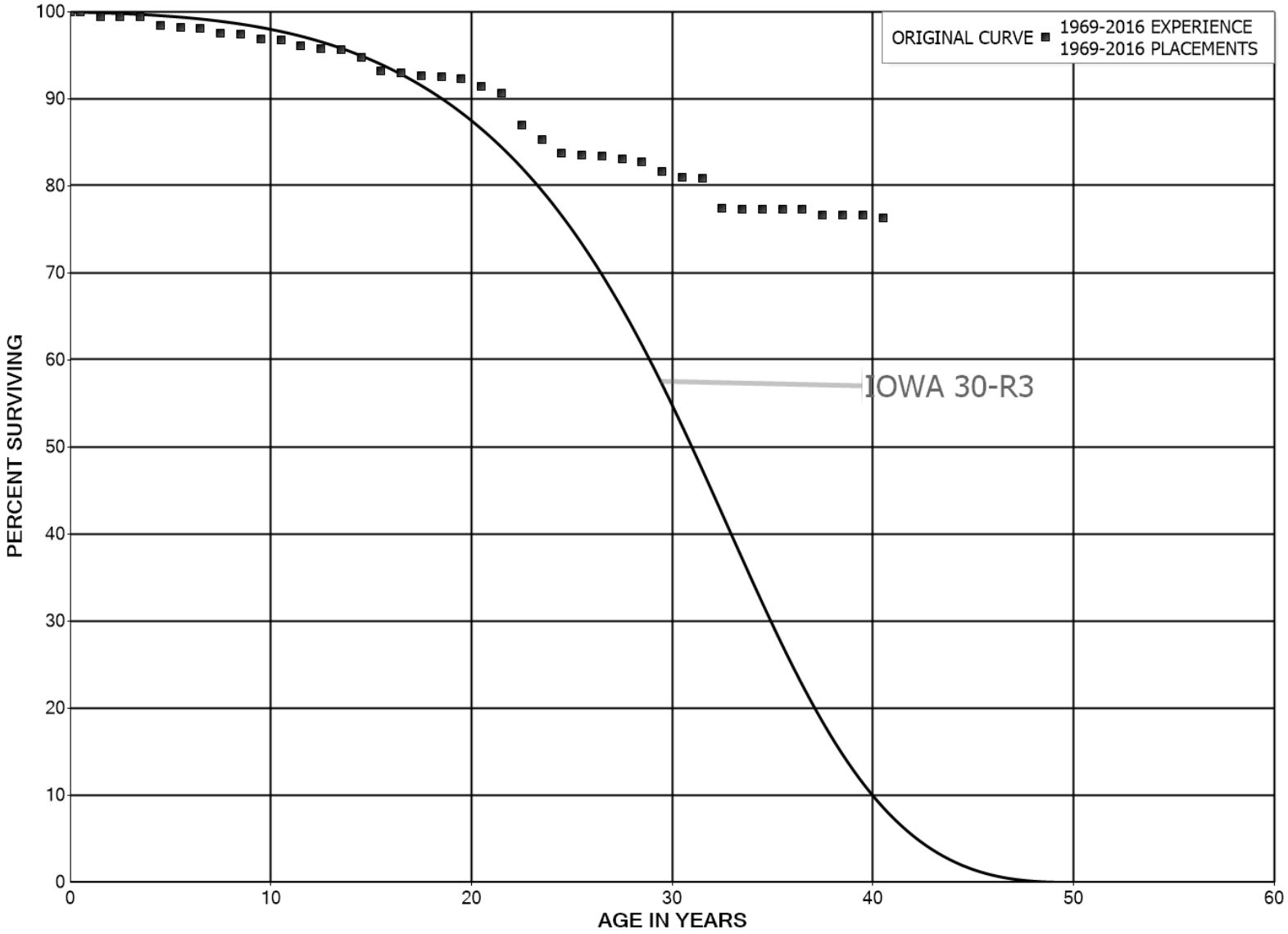
ACCOUNT 481.00 - GENERAL - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-1996 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,729		0.0000	1.0000	100.00
0.5	1,729		0.0000	1.0000	100.00
1.5	1,729		0.0000	1.0000	100.00
2.5	1,729		0.0000	1.0000	100.00
3.5	1,729		0.0000	1.0000	100.00
4.5	1,729		0.0000	1.0000	100.00
5.5	1,729		0.0000	1.0000	100.00
6.5	1,729		0.0000	1.0000	100.00
7.5	1,729		0.0000	1.0000	100.00
8.5	1,729		0.0000	1.0000	100.00
9.5	1,729		0.0000	1.0000	100.00
10.5	1,729		0.0000	1.0000	100.00
11.5	1,729		0.0000	1.0000	100.00
12.5	1,729		0.0000	1.0000	100.00
13.5	1,729		0.0000	1.0000	100.00
14.5	1,729		0.0000	1.0000	100.00
15.5	1,729		0.0000	1.0000	100.00
16.5	1,729		0.0000	1.0000	100.00
17.5	1,729		0.0000	1.0000	100.00
18.5	1,729		0.0000	1.0000	100.00
19.5	1,729		0.0000	1.0000	100.00
20.5	350		0.0000	1.0000	100.00
21.5	350		0.0000	1.0000	100.00
22.5	350		0.0000	1.0000	100.00
23.5	350		0.0000	1.0000	100.00
24.5	350		0.0000	1.0000	100.00
25.5	350		0.0000	1.0000	100.00
26.5	350		0.0000	1.0000	100.00
27.5	350		0.0000	1.0000	100.00
28.5	350		0.0000	1.0000	100.00
29.5	350		0.0000	1.0000	100.00
30.5	350		0.0000	1.0000	100.00
31.5	50		0.0000	1.0000	100.00
32.5	50		0.0000	1.0000	100.00
33.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,833,107	199	0.0000	1.0000	100.00
0.5	9,343,285	53,280	0.0057	0.9943	100.00
1.5	9,083,047	1,452	0.0002	0.9998	99.43
2.5	8,991,785	5,404	0.0006	0.9994	99.41
3.5	7,998,133	79,948	0.0100	0.9900	99.35
4.5	7,798,573	17,362	0.0022	0.9978	98.36
5.5	7,728,701	4,036	0.0005	0.9995	98.14
6.5	7,534,093	48,203	0.0064	0.9936	98.09
7.5	7,286,639	3,562	0.0005	0.9995	97.46
8.5	7,070,226	42,496	0.0060	0.9940	97.41
9.5	7,005,804	9,977	0.0014	0.9986	96.83
10.5	6,941,426	45,578	0.0066	0.9934	96.69
11.5	6,792,588	24,191	0.0036	0.9964	96.06
12.5	6,594,080	8,877	0.0013	0.9987	95.71
13.5	6,538,757	55,264	0.0085	0.9915	95.58
14.5	6,469,660	106,973	0.0165	0.9835	94.78
15.5	6,316,999	17,512	0.0028	0.9972	93.21
16.5	6,225,456	20,216	0.0032	0.9968	92.95
17.5	6,172,530	10,750	0.0017	0.9983	92.65
18.5	6,017,190	10,992	0.0018	0.9982	92.49
19.5	5,125,026	53,111	0.0104	0.9896	92.32
20.5	4,510,870	37,011	0.0082	0.9918	91.36
21.5	3,442,027	137,075	0.0398	0.9602	90.61
22.5	2,660,706	51,356	0.0193	0.9807	87.00
23.5	2,609,350	49,801	0.0191	0.9809	85.32
24.5	2,550,821	6,308	0.0025	0.9975	83.70
25.5	2,527,556	2,356	0.0009	0.9991	83.49
26.5	2,498,063	9,836	0.0039	0.9961	83.41
27.5	2,472,498	11,237	0.0045	0.9955	83.08
28.5	2,174,541	28,476	0.0131	0.9869	82.71
29.5	2,088,225	16,460	0.0079	0.9921	81.62
30.5	1,795,465	2,833	0.0016	0.9984	80.98
31.5	1,729,040	73,556	0.0425	0.9575	80.85
32.5	1,613,429	1,654	0.0010	0.9990	77.41
33.5	1,492,887	143	0.0001	0.9999	77.33
34.5	1,123,141	476	0.0004	0.9996	77.32
35.5	1,109,452	6	0.0000	1.0000	77.29
36.5	694,858	6,470	0.0093	0.9907	77.29
37.5	688,388	10	0.0000	1.0000	76.57
38.5	687,731	38	0.0001	0.9999	76.57

PACIFIC NORTHERN GAS LTD.

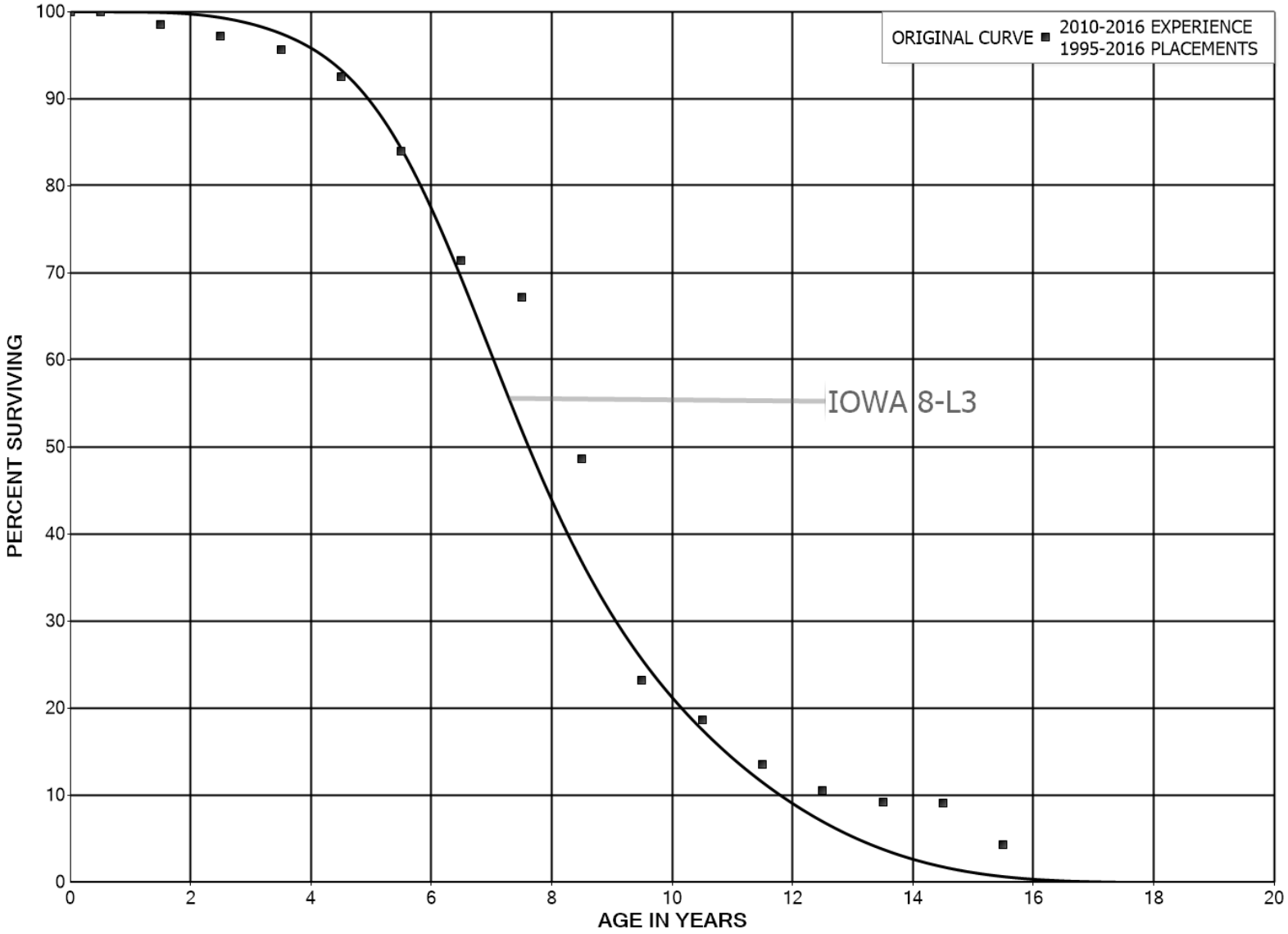
ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	684,936	2,149	0.0031	0.9969	76.57
40.5	630,810		0.0000	1.0000	76.33
41.5	151,679	89,630	0.5909	0.4091	76.33
42.5	67,291		0.0000	1.0000	31.22
43.5	6,065		0.0000	1.0000	31.22
44.5	6,065		0.0000	1.0000	31.22
45.5					31.22

PACIFIC NORTHERN GAS LTD.
ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

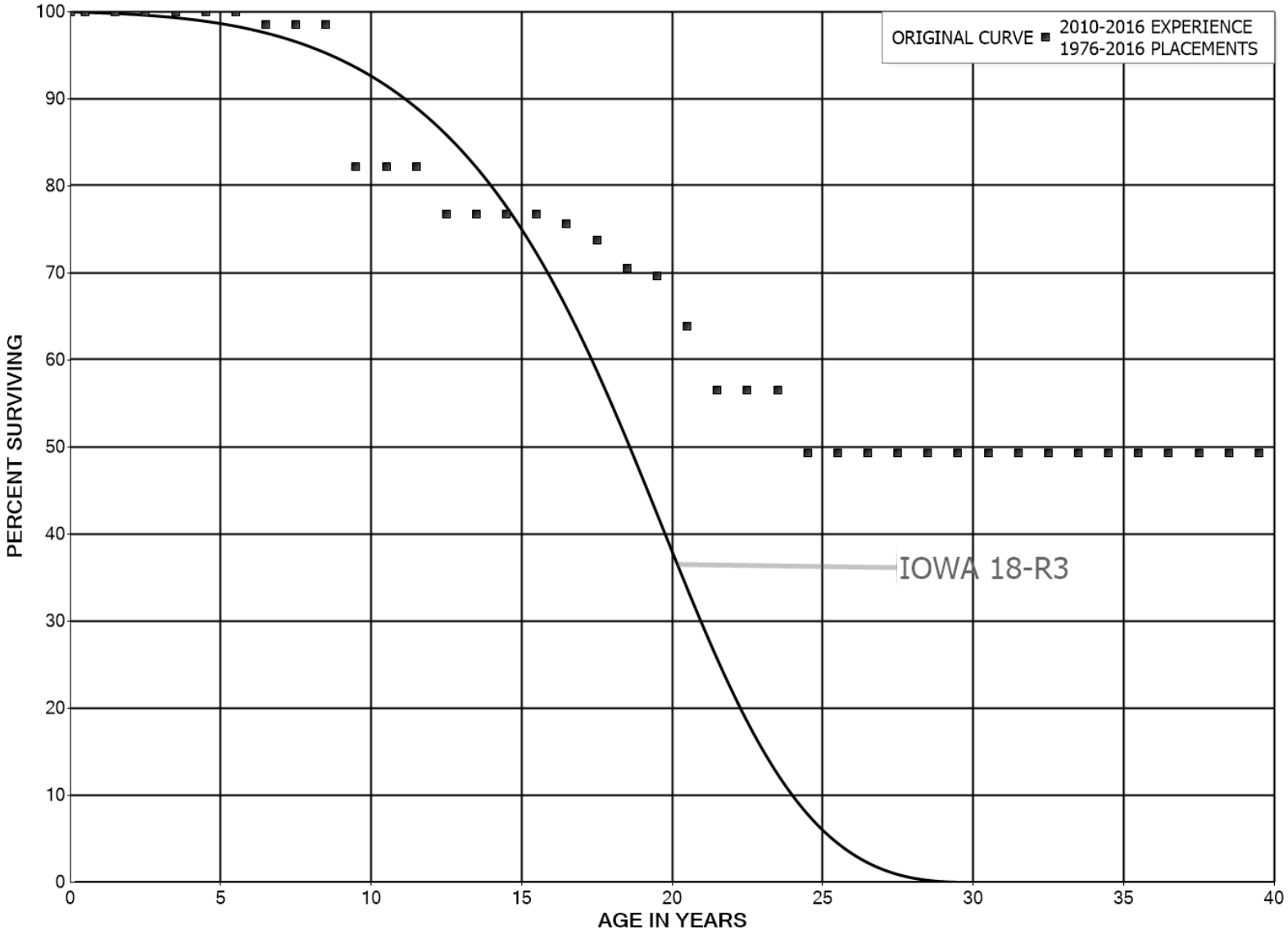
ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2016 EXPERIENCE BAND 2010-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,556,910		0.0000	1.0000	100.00
0.5	3,067,272	45,921	0.0150	0.9850	100.00
1.5	2,755,226	37,813	0.0137	0.9863	98.50
2.5	2,634,826	40,566	0.0154	0.9846	97.15
3.5	2,729,887	91,268	0.0334	0.9666	95.66
4.5	2,593,041	238,457	0.0920	0.9080	92.46
5.5	2,463,168	368,568	0.1496	0.8504	83.95
6.5	2,166,016	128,220	0.0592	0.9408	71.39
7.5	2,278,915	628,835	0.2759	0.7241	67.17
8.5	1,822,092	952,658	0.5228	0.4772	48.63
9.5	951,503	188,065	0.1977	0.8023	23.21
10.5	491,610	134,705	0.2740	0.7260	18.62
11.5	366,323	82,285	0.2246	0.7754	13.52
12.5	350,957	45,479	0.1296	0.8704	10.48
13.5	275,325	1,884	0.0068	0.9932	9.12
14.5	222,478	116,359	0.5230	0.4770	9.06
15.5	70,228	70,228	1.0000		4.32
16.5					

PACIFIC NORTHERN GAS LTD.
ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1976-2016 EXPERIENCE BAND 2010-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,179,827		0.0000	1.0000	100.00
0.5	2,098,291		0.0000	1.0000	100.00
1.5	2,063,860		0.0000	1.0000	100.00
2.5	2,419,295		0.0000	1.0000	100.00
3.5	2,759,725		0.0000	1.0000	100.00
4.5	2,836,066		0.0000	1.0000	100.00
5.5	2,880,635	42,906	0.0149	0.9851	100.00
6.5	2,924,531		0.0000	1.0000	98.51
7.5	2,402,031		0.0000	1.0000	98.51
8.5	2,146,591	355,912	0.1658	0.8342	98.51
9.5	1,174,757		0.0000	1.0000	82.18
10.5	880,772		0.0000	1.0000	82.18
11.5	730,223	48,108	0.0659	0.9341	82.18
12.5	579,257		0.0000	1.0000	76.76
13.5	505,044		0.0000	1.0000	76.76
14.5	568,104		0.0000	1.0000	76.76
15.5	467,216	7,089	0.0152	0.9848	76.76
16.5	422,200	10,350	0.0245	0.9755	75.60
17.5	571,767	25,311	0.0443	0.9557	73.75
18.5	598,231	7,667	0.0128	0.9872	70.48
19.5	615,461	50,492	0.0820	0.9180	69.58
20.5	587,833	67,779	0.1153	0.8847	63.87
21.5	332,438		0.0000	1.0000	56.51
22.5	333,620		0.0000	1.0000	56.51
23.5	333,620	42,423	0.1272	0.8728	56.51
24.5	81,831		0.0000	1.0000	49.32
25.5	85,942		0.0000	1.0000	49.32
26.5	50,242		0.0000	1.0000	49.32
27.5	46,327		0.0000	1.0000	49.32
28.5	47,930		0.0000	1.0000	49.32
29.5	34,107		0.0000	1.0000	49.32
30.5	34,107		0.0000	1.0000	49.32
31.5	25,238		0.0000	1.0000	49.32
32.5	24,761		0.0000	1.0000	49.32
33.5	33,055		0.0000	1.0000	49.32
34.5	18,266		0.0000	1.0000	49.32
35.5	16,663		0.0000	1.0000	49.32
36.5	13,750		0.0000	1.0000	49.32
37.5	13,750		0.0000	1.0000	49.32
38.5	13,750		0.0000	1.0000	49.32
39.5	10,117		0.0000	1.0000	49.32
40.5					49.32

PART VI. NET SALVAGE STATISTICS

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	129,561	169,667	131	0		0		169,667-	131-
2015	126,630	172,774	136	0		0		172,774-	136-
2016	124,004	119,679	97	0		0		119,679-	97-
TOTAL	380,195	462,120	122	0		0		462,120-	122-
THREE-YEAR MOVING AVERAGES									
14-16	126,732	154,040	122	0		0		154,040-	122-

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	458,975		0		0	4,089	1	4,089	1
2015	432,374		0		0	3,827	1	3,827	1
2016	469,288		0		0	2,544	1	2,544	1
TOTAL	1,360,637		0		0	10,460	1	10,460	1
THREE-YEAR MOVING AVERAGES									
14-16	453,546		0		0	3,487	1	3,487	1

PACIFIC NORTHERN GAS LTD.

ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	361,872		0		0	51,050	14	51,050	14
2011	77,034		0		0	10,490	14	10,490	14
2012	240,863		0		0	16,285	7	16,285	7
2013	426,036		0		0	87,413	21	87,413	21
2014	590,698		0		0	75,487	13	75,487	13
2015	456,360		0		0	54,169	12	54,169	12
2016	1,018,448		0		0	227,240	22	227,240	22
TOTAL	3,171,311		0		0	522,133	16	522,133	16
THREE-YEAR MOVING AVERAGES									
10-12	226,589		0		0	25,942	11	25,942	11
11-13	247,978		0		0	38,063	15	38,063	15
12-14	419,199		0		0	59,728	14	59,728	14
13-15	491,031		0		0	72,356	15	72,356	15
14-16	688,502		0		0	118,965	17	118,965	17
FIVE-YEAR AVERAGE									
12-16	546,481		0		0	92,119	17	92,119	17

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2012	54,771		0		0	13,353	24	13,353	24
2013									
2014	200,248		0		0	15,000	7	15,000	7
2015									
2016	342,450		0		0	28,604	8	28,604	8
TOTAL	597,470		0		0	56,957	10	56,957	10
THREE-YEAR MOVING AVERAGES									
12-14	85,006		0		0	9,451	11	9,451	11
13-15	66,749		0		0	5,000	7	5,000	7
14-16	180,900		0		0	14,535	8	14,535	8
FIVE-YEAR AVERAGE									
12-16	119,494		0		0	11,391	10	11,391	10

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	3,893		0		0	125	3	125	3
2011	8,404		0		0		0		0
2012	15,633		0		0	5,125	33	5,125	33
2013	161,332		0		0		0		0
2014	2,500		0		0		0		0
2015	4,500		0		0		0		0
2016	35,749		0		0		0		0
TOTAL	232,012		0		0	5,250	2	5,250	2
THREE-YEAR MOVING AVERAGES									
10-12	9,310		0		0	1,750	19	1,750	19
11-13	61,790		0		0	1,708	3	1,708	3
12-14	59,822		0		0	1,708	3	1,708	3
13-15	56,111		0		0		0		0
14-16	14,250		0		0		0		0
FIVE-YEAR AVERAGE									
12-16	43,943		0		0	1,025	2	1,025	2

PART VII. DETAILED DEPRECIATION CALCULATIONS

PACIFIC NORTHERN GAS LTD.

ACCOUNT 411.00 - GATHERING PLANT - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1980	275.00	131		275	39.32	7
	275.00	131		275		7

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.3 2.55

PACIFIC NORTHERN GAS LTD.

ACCOUNT 412.00 - GATHERING PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -3						
1990	34,442.84	26,146	22,526	12,950	7.89	1,641
	34,442.84	26,146	22,526	12,950		1,641

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.9 4.76

PACIFIC NORTHERN GAS LTD.

ACCOUNT 413.00 - GATHERING PLANT - MEASURING AND REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -15						
1980	75,159.71	76,004	74,217	12,217	3.62	3,375
	75,159.71	76,004	74,217	12,217		3,375

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.6 4.49

PACIFIC NORTHERN GAS LTD.

ACCOUNT 417.00 - GATHERING PLANT - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. -7						
2000	29,701.25	16,780	16,287	15,493	11.80	1,313
	29,701.25	16,780	16,287	15,493		1,313

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.8 4.42

PACIFIC NORTHERN GAS LTD.

ACCOUNT 418.00- GATHERING PLANT - PURIFICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 31-S5						
NET SALVAGE PERCENT.. -25						
1990	2,131,654.03	2,210,738	2,136,728	527,840	5.28	99,970
2000	59,112.21	39,329	38,012	35,878	14.50	2,474
2001	84,502.30	52,814	51,046	54,582	15.50	3,521
2002	41,472.49	24,248	23,436	28,405	16.50	1,722
2003	41,105.45	22,376	21,627	29,755	17.50	1,700
2004	80,184.24	40,416	39,063	61,167	18.50	3,306
2005	112,335.11	52,091	50,347	90,072	19.50	4,619
2006	60,438.84	25,589	24,732	50,817	20.50	2,479
2007	111,076.30	42,549	41,125	97,720	21.50	4,545
2008	97,399.41	33,382	32,264	89,485	22.50	3,977
2009	156,349.01	47,284	45,701	149,735	23.50	6,372
2010	273,285.67	71,628	69,230	272,377	24.50	11,117
2011	197,930.65	43,896	42,427	204,986	25.50	8,039
2012	91,549.12	16,612	16,056	98,380	26.50	3,712
2014	22,737.18	2,292	2,215	26,206	28.50	920
2016	188,463.07	3,800	3,673	231,906	30.50	7,603
	3,749,595.08	2,729,044	2,637,682	2,049,312		166,076

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.3 4.43

PACIFIC NORTHERN GAS LTD.

ACCOUNT 443.00 - PROCESSING PLANT - GAS HOLDERS - STORAGE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	30,000.00	14,625	13,113	16,887	20.50	824
	30,000.00	14,625	13,113	16,887		824

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.5 2.75

PACIFIC NORTHERN GAS LTD.

ACCOUNT 449.00 - PROCESSING PLANT - OTHER LOCAL STORAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-R3						
NET SALVAGE PERCENT.. 0						
1997	3,200.00	1,713	2,111	1,089	15.33	71
	3,200.00	1,713	2,111	1,089		71

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.3 2.22

PACIFIC NORTHERN GAS LTD.

ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1968	296,958.82	182,728	10,527	286,432	28.85	9,928
1970	92,594.85	54,927	3,164	89,430	30.51	2,931
1971	65,680.01	38,226	2,202	63,478	31.35	2,025
1972	29,748.57	16,972	978	28,771	32.21	893
1973	5,886.96	3,291	190	5,697	33.07	172
1974	285.13	156	9	276	33.94	8
1975	320.54	172	10	311	34.81	9
1976	9,698.29	5,082	293	9,406	35.70	263
1977	1,394.00	714	41	1,353	36.59	37
1978	1,478.45	739	43	1,436	37.49	38
1980	120.05	57	3	117	39.32	3
1981	308,028.30	142,762	8,225	299,804	40.24	7,450
1982	49,730.05	22,438	1,293	48,437	41.16	1,177
1983	101,521.35	44,534	2,566	98,956	42.10	2,350
1984	12,479.08	5,318	306	12,173	43.04	283
1985	10,740.05	4,442	256	10,484	43.98	238
1986	39,950.77	16,017	923	39,028	44.93	869
1987	29,691.01	11,528	664	29,027	45.88	633
1988	12,609.72	4,735	273	12,337	46.84	263
1989	50,070.09	18,159	1,046	49,024	47.80	1,026
1990	53,549.00	18,728	1,079	52,470	48.77	1,076
1991	5,240.82	1,766	102	5,139	49.73	103
1992	440.39	143	8	432	50.71	9
1993	13,227.28	4,113	237	12,990	51.68	251
1994	45,315.96	13,498	778	44,538	52.66	846
	1,236,759.54	611,245	35,215	1,201,545		32,881
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1996	70,475.07	19,150	47,894	22,581	54.62	413
2015	214,145.24	4,283	10,712	203,433	73.50	2,768
	284,620.31	23,433	58,606	226,014		3,181

PACIFIC NORTHERN GAS LTD.

ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1990	10,967.40	3,836		10,967	48.77	225
2013	78,734.45	3,675		78,734	71.50	1,101
2014	57,887.01	1,929		57,887	72.50	798
2016	27,077.40	181		27,077	74.50	363
	174,666.26	9,621		174,666		2,487
	1,696,046.11	644,299	93,821	1,602,225		38,549

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.6 2.27

PACIFIC NORTHERN GAS LTD.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -3						
1969	299,496.05	298,199	304,359	4,122	1.00	4,122
1970	3,030.96	3,018	3,080	42	1.00	42
1972	1,920.04	1,912	1,951	26	1.00	26
1973	1,817.75	1,810	1,847	25	1.00	25
1974	584.10	582	594	8	1.00	8
1975	726.71	724	739	10	1.00	10
1976	3,136.84	3,108	3,172	59	1.14	52
1977	593.43	583	595	16	1.38	12
1980	3,731.57	3,567	3,641	203	2.16	94
1982	1,272,570.06	1,191,469	1,216,081	94,666	2.73	34,676
1983	15,010.29	13,894	14,181	1,280	3.04	421
1984	114,988.38	105,094	107,265	11,173	3.38	3,306
1985	14,763.72	13,306	13,581	1,626	3.75	434
1986	11,153.66	9,895	10,099	1,389	4.16	334
1987	22,151.27	19,295	19,694	3,122	4.63	674
1988	18,948.43	16,166	16,500	3,017	5.15	586
1989	1,562.63	1,303	1,330	280	5.72	49
1990	25,033.92	20,336	20,756	5,029	6.34	793
1991	141,605.25	111,821	114,131	31,723	7.00	4,532
1992	58,539.28	44,860	45,787	14,509	7.68	1,889
1993	136,204.87	101,056	103,144	37,147	8.39	4,428
1994	91,268.58	65,429	66,781	27,226	9.12	2,985
1995	88,758.62	61,344	62,611	28,810	9.87	2,919
1996	11,746.00	7,803	7,964	4,134	10.65	388
1997	63,633.55	40,505	41,342	24,201	11.46	2,112
1998	35,029.88	21,300	21,740	14,341	12.29	1,167
1999	141,930.30	82,158	83,855	62,333	13.14	4,744
2000	19,737.06	10,835	11,059	9,270	14.01	662
2003	5,387.92	2,451	2,502	3,048	16.75	182
2004	10,778.31	4,555	4,649	6,453	17.69	365
2005	81,767.39	31,892	32,551	51,670	18.64	2,772
2006	99,182.23	35,415	36,147	66,011	19.60	3,368
2007	15,288.00	4,950	5,052	10,694	20.57	520
2008	4,901.11	1,422	1,451	3,597	21.55	167
2009	5,814.84	1,489	1,520	4,470	22.54	198
2011	18,888.43	3,554	3,627	15,828	24.52	646
2013	59,061.55	7,077	7,223	53,610	26.51	2,022
	2,900,742.98	2,344,177	2,392,601	595,165		81,730

PACIFIC NORTHERN GAS LTD.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -3						
1996	15,352.66	10,200	9,597	6,216	10.65	584
1998	382,528.81	232,593	218,845	175,160	12.29	14,252
1999	67,163.42	38,878	36,580	32,598	13.14	2,481
	465,044.89	281,671	265,022	213,974		17,317
	3,365,787.87	2,625,848	2,657,623	809,139		99,047
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.2	2.94

PACIFIC NORTHERN GAS LTD.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 39-R4						
NET SALVAGE PERCENT.. -15						
1969	98,454.43	105,094	113,223			
1970	8,004.87	8,481	9,206			
1971	5,425.16	5,701	6,239			
1972	1,890.17	1,970	2,174			
1973	808.52	835	930			
1975	2,294.22	2,323	2,597	41	4.66	9
1976	3,441.50	3,445	3,851	106	5.05	21
1977	2,838.12	2,805	3,136	128	5.48	23
1978	3,144.89	3,065	3,426	190	5.95	32
1980	23,080.67	21,779	24,347	2,196	7.00	314
1981	27,899.44	25,840	28,887	3,197	7.59	421
1982	147,135.53	133,586	149,338	19,868	8.21	2,420
1983	10,521.06	9,347	10,449	1,650	8.87	186
1984	28,910.06	25,114	28,075	5,171	9.54	542
1985	76,850.03	65,195	72,883	15,495	10.23	1,515
1986	38,259.47	31,656	35,389	8,610	10.94	787
1987	44,362.94	35,751	39,967	11,051	11.67	947
1988	226,989.59	177,908	198,887	62,151	12.42	5,004
1989	56,701.91	43,170	48,261	16,947	13.18	1,286
1990	25,453.68	18,786	21,001	8,271	13.97	592
1991	74,813.14	53,452	59,755	26,280	14.77	1,779
1992	82,398.99	56,855	63,559	31,200	15.60	2,000
1993	20,616.79	13,715	15,332	8,377	16.44	510
1994	20,528.84	13,136	14,685	8,923	17.30	516
1995	28,062.08	17,236	19,268	13,003	18.17	716
1999	8,533.14	4,323	4,833	4,980	21.82	228
2002	1,484.00	627	701	1,006	24.66	41
2003	30,321.43	11,954	13,364	21,506	25.63	839
2004	8,838.20	3,232	3,613	6,551	26.60	246
2005	56,747.66	19,109	21,362	43,898	27.58	1,592
2006	4,339.50	1,336	1,494	3,497	28.56	122
2007	91,366.87	25,486	28,491	76,581	29.54	2,592
2008	4,650.00	1,161	1,298	4,050	30.53	133
2016	16,676.08	246	275	18,902	38.50	491
	1,281,842.98	943,719	1,050,295	423,825		25,904

PACIFIC NORTHERN GAS LTD.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 39-R4						
NET SALVAGE PERCENT.. -15						
1996	83,483.54	49,086	50,113	45,893	19.06	2,408
	83,483.54	49,086	50,113	45,893		2,408
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 39-R4						
NET SALVAGE PERCENT.. -15						
1978	3,568.45	3,478	3,482	622	5.95	105
1990	912.88	674	675	375	13.97	27
2003	30,066.02	11,853	11,866	22,710	25.63	886
2004	28,191.47	10,308	10,320	22,101	26.60	831
2016	63,132.87	931	932	71,671	38.50	1,862
	125,871.69	27,244	27,275	117,478		3,711
	1,491,198.21	1,020,049	1,127,683	587,196		32,023

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.3 2.15

PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1969	17,380,047.36	14,217,365	15,607,290	5,248,767	20.69	253,686
1970	420,941.37	338,361	371,440	133,690	21.46	6,230
1971	53,145.06	41,963	46,065	17,709	22.23	797
1972	519,367.77	402,520	441,871	181,370	23.02	7,879
1973	44,805.00	34,071	37,402	16,364	23.81	687
1974	1,974,935.05	1,472,267	1,616,199	753,723	24.62	30,614
1975	282,899.30	206,614	226,813	112,666	25.44	4,429
1976	114,818.79	82,098	90,124	47,658	26.27	1,814
1977	68,231.88	47,716	52,381	29,497	27.12	1,088
1978	21,867.79	14,949	16,410	9,831	27.97	351
1979	1,051,828.43	702,361	771,026	491,169	28.83	17,037
1980	325,587.76	212,184	232,928	157,778	29.70	5,312
1981	609,567.99	387,349	425,217	306,264	30.58	10,015
1982	24,696,098.92	15,287,379	16,781,911	12,853,407	31.47	408,434
1983	968,064.71	583,162	640,173	521,504	32.37	16,111
1984	807,771.32	473,031	519,276	450,050	33.28	13,523
1985	162,053.53	92,147	101,156	93,309	34.20	2,728
1986	5,375,832.37	2,965,460	3,255,371	3,195,628	35.12	90,992
1987	897,363.88	479,602	526,489	550,348	36.05	15,266
1988	4,245,313.62	2,195,269	2,409,884	2,684,492	36.99	72,573
1989	1,029,044.30	514,267	564,543	670,310	37.93	17,672
1990	8,743,215.53	4,216,153	4,628,335	5,863,524	38.88	150,811
1991	2,006,999.34	932,604	1,023,778	1,384,622	39.83	34,763
1992	3,249,428.77	1,452,339	1,594,323	2,304,991	40.79	56,509
1993	6,298,443.63	2,703,468	2,967,766	4,590,367	41.75	109,949
1994	9,351,457.01	3,846,479	4,222,520	6,999,228	42.72	163,840
1995	8,980,127.01	3,532,962	3,878,353	6,897,799	43.69	157,880
1996	2,381,432.99	894,238	981,661	1,876,059	44.66	42,008
1997	1,442,443.88	515,558	565,960	1,164,972	45.64	25,525
1998	3,178,422.65	1,078,515	1,183,953	2,630,154	46.62	56,417
1999	5,946,251.83	1,910,103	2,096,839	5,038,663	47.60	105,854
2000	3,011,149.35	912,812	1,002,051	2,611,328	48.58	53,753
2001	731,933.38	208,496	228,879	649,441	49.57	13,101
2002	2,150,515.18	573,284	629,330	1,951,289	50.56	38,594
2003	1,372,877.27	340,891	374,217	1,273,235	51.55	24,699
2004	1,359,069.81	312,624	343,187	1,287,697	52.54	24,509
2005	6,921,218.43	1,465,582	1,608,861	6,696,601	53.53	125,100
2006	4,205,571.88	812,920	892,393	4,154,293	54.53	76,184
2007	3,853,629.31	674,462	740,399	3,883,956	55.52	69,956
2008	4,850,373.18	759,336	833,571	4,986,877	56.52	88,232
2009	2,923,042.50	404,187	443,701	3,063,950	57.51	53,277
2010	1,121,505.83	134,379	147,516	1,198,291	58.51	20,480

PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
2011	3,520,212.85	356,781	391,661	3,832,595	59.51	64,403
2012	2,150,153.82	178,239	195,664	2,384,520	60.51	39,407
2013	2,115,297.24	136,691	150,054	2,388,302	61.50	38,834
2014	480,152.44	22,160	24,326	551,857	62.50	8,830
2015	1,257,455.33	34,826	38,231	1,470,716	63.50	23,161
2016	1,029,528.51	9,500	10,429	1,225,005	64.50	18,992
	155,681,495.15	69,169,724	75,931,928	110,885,866		2,662,306
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1996	3,348,547.95	1,257,393	2,268,070	1,750,187	44.66	39,189
1997	105,760.40	37,801	68,185	58,727	45.64	1,287
1998	492,662.93	167,172	301,543	289,653	46.62	6,213
1999	109,864.44	35,292	63,659	68,178	47.60	1,432
2000	78,580.79	23,821	42,968	51,329	48.58	1,057
2003	3,553.94	882	1,591	2,674	51.55	52
2006	22,367.96	4,324	7,800	19,042	54.53	349
2007	87,430.90	15,302	27,602	77,316	55.52	1,393
2008	65,003.79	10,176	18,355	59,649	56.52	1,055
2009	83,763.81	11,583	20,893	79,623	57.51	1,385
2010	4,003.06	480	866	3,938	58.51	67
2011	22,179.04	2,248	4,055	22,560	59.51	379
2012	213,214.77	17,675	31,882	223,976	60.51	3,701
2015	2,103,466.59	58,258	105,085	2,419,075	63.50	38,096
2016	138,418.78	1,277	2,303	163,799	64.50	2,540
	6,878,819.15	1,643,684	2,964,857	5,289,726		98,195
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1970	10,388.55	8,351	9,537	2,929	21.46	136
1980	589,185.56	383,970	438,513	268,509	29.70	9,041
1990	1,043,295.67	503,098	574,564	677,391	38.88	17,423
2000	11,382.63	3,451	3,941	9,718	48.58	200
2001	110,897.25	31,590	36,077	96,999	49.57	1,957
2003	22,383.42	5,558	6,348	20,513	51.55	398

PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
2004	60,353.98	13,883	15,855	56,570	52.54	1,077
2009	113,856.77	15,744	17,980	118,648	57.51	2,063
2010	59,342.01	7,110	8,120	63,090	58.51	1,078
2012	123,347.96	10,225	11,677	136,340	60.51	2,253
2013	1,391,361.92	89,910	102,682	1,566,952	61.50	25,479
2014	2,024,908.91	93,454	106,729	2,323,161	62.50	37,171
2015	5,324.61	147	168	6,222	63.50	98
2016	261,817.27	2,416	2,759	311,422	64.50	4,828
	5,827,846.51	1,168,907	1,334,951	5,658,464		103,202
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1980	1,670,849.65	1,088,886	1,039,095	965,924	29.70	32,523
1990	45,285.77	21,838	20,839	33,503	38.88	862
2011	24,879.22	2,522	2,407	27,448	59.51	461
	1,741,014.64	1,113,246	1,062,341	1,026,876		33,846
	170,129,175.45	73,095,561	81,294,078	122,860,932		2,897,549
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					42.4	1.70

PACIFIC NORTHERN GAS LTD.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -2						
1969	717,052.22	671,002	731,393			
1970	18,164.36	16,860	18,528			
1971	8,118.03	7,474	8,280			
1972	7,914.94	7,224	8,073			
1973	5,018.51	4,541	5,119			
1974	2,916.92	2,615	2,975			
1975	6,553.50	5,816	6,685			
1982	8,747,857.95	7,061,784	8,351,055	571,760	7.30	78,323
1983	487,922.62	386,768	457,380	40,301	7.80	5,167
1984	1,098,759.23	854,325	1,010,299	110,435	8.32	13,273
1985	1,967,386.33	1,498,167	1,771,688	235,047	8.87	26,499
1986	3,000,929.07	2,234,492	2,642,443	418,504	9.45	44,286
1987	113,912.00	82,827	97,949	18,242	10.05	1,815
1988	44,106.75	31,261	36,968	8,021	10.68	751
1989	1,197,433.48	826,351	977,218	244,164	11.32	21,569
1990	20,693.95	13,877	16,411	4,697	11.99	392
1991	633,943.04	412,357	487,641	158,981	12.68	12,538
1992	88,140.63	55,509	65,643	24,260	13.39	1,812
1993	278,199.63	169,285	200,191	83,572	14.12	5,919
1994	513,257.99	301,251	356,250	167,273	14.86	11,257
1995	450,348.51	254,221	300,634	158,721	15.63	10,155
1996	790,721.05	428,617	506,870	299,666	16.40	18,272
1997	680,182.80	352,839	417,257	276,530	17.20	16,077
1998	56,668.02	28,075	33,201	24,601	18.00	1,367
1999	331,832.97	156,373	184,922	153,548	18.83	8,154
2000	250,003.56	111,766	132,171	122,832	19.66	6,248
2001	425,130.49	179,524	212,300	221,333	20.51	10,791
2002	424,716.18	168,580	199,358	233,853	21.38	10,938
2003	265,586.55	98,686	116,703	154,195	22.25	6,930
2004	519,050.53	179,403	212,157	317,275	23.14	13,711
2005	233,298.34	74,516	88,120	149,844	24.04	6,233
2006	27,761.57	8,131	9,615	18,701	24.95	750
2007	70,844.71	18,850	22,291	49,970	25.87	1,932
2008	12,824.62	3,065	3,625	9,457	26.80	353
2009	16,564.94	3,505	4,145	12,751	27.74	460
2010	34,858.50	6,410	7,580	27,975	28.69	975
2011	30,632.27	4,776	5,648	25,597	29.65	863
2012	161,404.64	20,650	24,420	140,213	30.61	4,581
2013	354,448.63	35,326	41,775	319,762	31.58	10,125

PACIFIC NORTHERN GAS LTD.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -2						
2014	401,868.36	28,693	33,931	375,974	32.55	11,551
2015	510,106.70	21,853	25,843	494,466	33.53	14,747
2016	189,789.77	2,710	3,205	190,381	34.51	5,517
	25,196,924.86	16,830,355	19,837,962	5,862,902		384,331
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -2						
1990	4,412.00	2,959	3,143	1,357	11.99	113
	4,412.00	2,959	3,143	1,357		113
	25,201,336.86	16,833,314	19,841,105	5,864,259		384,444
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.3	1.53

PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1969	155,081.23	145,598	165,937			
1970	91,632.28	85,385	98,047			
1971	11,851.07	10,960	12,681			
1972	39,808.64	36,522	42,595			
1973	28,863.99	26,261	30,884			
1974	8,158.30	7,355	8,729			
1975	22,965.44	20,515	24,573			
1976	808.11	715	865			
1977	2,043.79	1,789	2,187			
1978	504.17	437	539			
1979	1,925.57	1,648	2,060			
1980	10,510.57	8,888	11,246			
1981	223,582.51	186,533	236,070	3,163	7.71	410
1982	41,009.75	33,738	42,698	1,183	8.09	146
1983	8,062.96	6,537	8,273	354	8.48	42
1984	125,237.19	99,928	126,465	7,538	8.90	847
1985	93,121.81	73,050	92,450	7,191	9.34	770
1986	90,029.92	69,331	87,743	8,589	9.81	876
1987	165,087.16	124,659	157,764	18,879	10.30	1,833
1988	673,421.32	498,008	630,262	90,299	10.81	8,353
1989	30,208.49	21,841	27,641	4,682	11.35	413
1990	75,723.67	53,430	67,619	13,405	11.92	1,125
1991	100,743.77	69,266	87,661	20,135	12.51	1,610
1992	630,534.91	421,576	533,532	141,140	13.13	10,749
1993	286,160.57	185,641	234,941	71,251	13.78	5,171
1994	366,874.23	230,375	291,555	101,001	14.46	6,985
1995	194,770.74	118,076	149,433	58,972	15.17	3,887
1996	91,190.75	53,220	67,353	30,221	15.91	1,899
1997	403,330.97	226,014	286,036	145,528	16.67	8,730
1998	421,566.36	226,052	286,084	164,992	17.46	9,450
1999	121,614.16	62,163	78,671	51,456	18.28	2,815
2000	107,510.11	52,193	66,054	48,982	19.12	2,562
2001	29,746.24	13,650	17,275	14,553	19.99	728
2003	110,906.84	44,823	56,726	61,944	21.78	2,844
2004	418,681.21	157,307	199,082	248,906	22.71	10,960
2005	177,509.74	61,594	77,951	111,984	23.65	4,735
2006	92,219.92	29,320	37,106	61,569	24.60	2,503
2007	284,198.13	81,932	103,690	200,402	25.57	7,837
2008	58,116.41	15,031	19,023	43,162	26.54	1,626
2009	781,968.45	178,578	226,002	610,704	27.53	22,183
2010	62,728.27	12,446	15,751	51,368	28.51	1,802
2011	365,132.57	61,284	77,559	313,133	29.51	10,611

PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
2012	350,291.35	48,190	60,988	313,824	30.50	10,289
2013	10,989.37	1,176	1,488	10,270	31.50	326
2014	1,306,426.82	99,850	126,367	1,271,510	32.50	39,123
2015	285,038.90	13,072	16,543	288,448	33.50	8,610
2016	851,507.01	13,020	16,478	894,635	34.50	25,931
	9,809,395.74	3,988,977	5,010,680	5,485,374		218,781
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1996	1,907,965.78	1,113,508	1,440,621	600,902	15.91	37,769
1997	1,153.80	647	837	397	16.67	24
1999	346,928.58	177,332	229,426	141,787	18.28	7,756
2000	8,534.51	4,143	5,360	3,772	19.12	197
2005	39,809.13	13,813	17,871	24,725	23.65	1,045
2006	12,764.60	4,058	5,250	8,408	24.60	342
2007	242,299.56	69,853	90,374	168,887	25.57	6,605
2008	377,229.76	97,563	126,224	277,412	26.54	10,453
2009	219,910.21	50,221	64,974	170,330	27.53	6,187
2010	261,480.52	51,880	67,121	212,663	28.51	7,459
2011	251,586.82	42,226	54,631	214,567	29.51	7,271
2012	607,391.34	83,559	108,106	541,803	30.50	17,764
2013	466,191.38	49,882	64,536	434,289	31.50	13,787
2014	189,207.21	14,461	18,709	183,743	32.50	5,654
2015	265,500.25	12,176	15,753	268,332	33.50	8,010
2016	167,841.73	2,566	3,320	176,271	34.50	5,109
	5,365,795.18	1,787,888	2,313,113	3,428,288		135,432
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1978	12,599.45	10,912	12,358	1,123	6.67	168
1980	42,554.34	35,984	40,753	4,780	7.34	651
1990	74,099.39	52,284	59,214	20,073	11.92	1,684
2000	11,691.73	5,676	6,428	6,082	19.12	318
2001	129,333.66	59,349	67,215	71,172	19.99	3,560
2002	36,369.01	15,699	17,780	21,135	20.88	1,012

PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
2003	26,449.89	10,690	12,107	16,195	21.78	744
2004	52,991.12	19,910	22,549	34,152	22.71	1,504
2006	52,205.03	16,598	18,798	37,062	24.60	1,507
2007	123,160.53	35,506	40,212	91,570	25.57	3,581
2009	282,232.67	64,454	72,996	228,992	27.53	8,318
2010	170,109.83	33,752	38,225	143,792	28.51	5,044
2011	24,918.14	4,182	4,736	21,926	29.51	743
2012	53,767.49	7,397	8,377	49,154	30.50	1,612
2013	615,250.76	65,832	74,557	583,761	31.50	18,532
2014	536,680.64	41,019	46,456	527,793	32.50	16,240
2015	34,447.17	1,580	1,789	35,069	33.50	1,047
2016	83,744.73	1,280	1,450	88,157	34.50	2,555
	2,362,605.58	482,104	546,000	1,981,988		68,820
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1990	27,405.79	19,337	21,263	8,061	11.92	676
2001	25,021.93	11,482	12,626	14,148	19.99	708
2003	4,783.52	1,933	2,126	2,993	21.78	137
2004	7,090.20	2,664	2,929	4,657	22.71	205
2008	20,448.59	5,289	5,816	16,064	26.54	605
2013	165,970.26	17,759	19,528	158,060	31.50	5,018
2014	144,571.25	11,050	12,151	142,541	32.50	4,386
2015	11,346.15	520	572	11,569	33.50	345
2016	22,093.67	338	372	23,269	34.50	674
	428,731.36	70,372	77,381	381,361		12,754
	17,966,527.86	6,329,341	7,947,174	11,277,011		435,787
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					25.9	2.43

PACIFIC NORTHERN GAS LTD.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
1969	2,373.06	2,215	2,373			
1970	7,408.99	6,915	7,409			
1973	13,680.72	12,769	13,681			
1980	39,158.21	36,548	39,158			
1981	1,590.51	1,484	1,591			
1982	342,697.47	319,850	342,697			
1983	14,974.60	13,976	14,975			
1984	11,235.20	10,486	11,235			
1987	14,687.37	13,708	14,687			
1988	30,091.84	28,086	30,092			
1989	65,796.51	61,410	65,797			
1990	157,731.52	147,216	157,732			
1991	182,547.48	170,377	182,547			
1992	25,803.87	24,084	25,804			
1994	62,237.04	56,096	62,237			
1995	14,201.00	12,525	14,201			
1996	40,113.57	34,578	40,114			
1997	920,035.48	774,053	905,033	15,003	2.38	6,304
1998	961.44	787	920	41	2.72	15
1999	265,467.55	210,959	246,656	18,812	3.08	6,108
2000	114,610.46	88,021	102,915	11,695	3.48	3,361
2001	215,627.83	159,278	186,230	29,398	3.92	7,499
2002	82,649.82	58,461	68,353	14,296	4.39	3,256
2003	48,323.41	32,506	38,006	10,317	4.91	2,101
2004	100,724.08	64,061	74,901	25,823	5.46	4,729
2005	86,004.94	51,317	60,001	26,004	6.05	4,298
2007	4,179.42	2,132	2,493	1,687	7.35	230
2008	4,786.76	2,221	2,597	2,190	8.04	272
2012	26,248.09	6,807	7,959	18,289	11.11	1,646
2013	1,578.25	322	376	1,202	11.94	101
2014	335,998.55	49,503	57,880	278,119	12.79	21,745
2016	14,620.83	439	513	14,108	14.55	970
	3,248,145.87	2,453,190	2,781,162	466,984		62,635

PACIFIC NORTHERN GAS LTD.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
2016	20,124.11	604		20,124	14.55	1,383
	20,124.11	604		20,124		1,383
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
1991	129,794.00	121,141	129,794			
	129,794.00	121,141	129,794			
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
2015	5,426.25	485	362	5,064	13.66	371
	5,426.25	485	362	5,064		371
	3,403,490.23	2,575,420	2,911,318	492,172		64,389
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.6	1.89

PACIFIC NORTHERN GAS LTD.

ACCOUNT 469.00 - TRANSMISSION - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	1,943.15	802	141	1,802	23.50	77
2016	484,950.35	6,062	1,069	483,881	39.50	12,250
	486,893.50	6,864	1,210	485,683		12,327
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	18,450.46	6,688	7,017	11,433	25.50	448
	18,450.46	6,688	7,017	11,433		448
	505,343.96	13,552	8,227	497,116		12,775

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.9 2.53

PACIFIC NORTHERN GAS LTD.

ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1970	364.03	216		364	30.51	12
1971	120.60	70		121	31.35	4
1973	1,703.45	952		1,703	33.07	51
1974	2,774.26	1,519		2,774	33.94	82
1977	301.25	154		301	36.59	8
1978	1,862.98	932		1,863	37.49	50
1980	2,332.91	1,110		2,333	39.32	59
1981	427.00	198		427	40.24	11
1982	1,523.96	688		1,524	41.16	37
1983	9,186.62	4,030		9,187	42.10	218
1984	1,555.47	663		1,555	43.04	36
1985	1,338.52	554		1,339	43.98	30
1986	269.50	108		270	44.93	6
1987	4,525.67	1,757		4,526	45.88	99
1988	835.02	314		835	46.84	18
1989	1,600.92	581		1,601	47.80	33
1990	300.00	105		300	48.77	6
1991	1,312.50	442		1,312	49.73	26
2009	1,943.83	194		1,944	67.51	29
	34,278.49	14,587		34,278		815
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1996	139,548.29	37,919	19,666	119,882	54.62	2,195
1997	2,005.35	519	269	1,736	55.60	31
1998	15,123.04	3,712	1,925	13,198	56.59	233
	156,676.68	42,150	21,861	134,816		2,459
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1970	2,182.78	1,295		2,183	30.51	72
1980	58,392.52	27,779		58,393	39.32	1,485
1990	4,319.64	1,511		4,320	48.77	89
	64,894.94	30,585		64,895		1,646

PACIFIC NORTHERN GAS LTD.

ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1980	1,360.63	647		1,361	39.32	35
1990	650.00	227		650	48.77	13
	2,010.63	874		2,011		48
	257,860.74	88,196	21,861	236,000		4,968
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					47.5	1.93

PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1972	908.33	949	876	124	1.50	83
1974	6,165.87	6,326	5,836	946	2.02	468
1976	3,875.21	3,903	3,601	662	2.53	262
1979	416.64	407	375	83	3.33	25
1980	203.82	197	182	42	3.62	12
1982	3,028.03	2,859	2,638	693	4.25	163
1985	10,787.68	9,738	8,984	2,882	5.38	536
1986	21,878.74	19,398	17,896	6,170	5.82	1,060
1988	20,988.08	17,862	16,479	6,608	6.79	973
1991	6,067.59	4,788	4,417	2,257	8.48	266
1993	4,993.94	3,708	3,421	2,072	9.75	213
2000	131,919.83	72,991	67,340	77,772	14.91	5,216
2002	3,168.10	1,562	1,441	2,044	16.55	124
2005	5,947.34	2,368	2,185	4,357	19.14	228
2009	6,081.94	1,610	1,485	5,205	22.78	228
2012	44,686.90	7,177	6,621	42,534	25.62	1,660
2014	23,021.17	2,068	1,908	23,415	27.55	850
2015	39,194.48	2,113	1,949	41,165	28.53	1,443
	333,333.69	160,024	147,635	219,032		13,810
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1996	57,946.45	38,584	34,315	29,426	11.84	2,485
1997	11,514.75	7,355	6,541	6,125	12.58	487
1998	4,951.41	3,025	2,690	2,756	13.34	207
2000	171,817.09	95,066	84,548	104,451	14.91	7,005
2001	93,565.06	48,957	43,541	59,381	15.73	3,775
2002	84,330.77	41,589	36,988	55,776	16.55	3,370
2003	104,898.99	48,463	43,101	72,288	17.40	4,154
2004	65,607.36	28,242	25,117	47,051	18.26	2,577
2005	42,405.46	16,886	15,018	31,628	19.14	1,652
2006	34,107.32	12,468	11,089	26,429	20.03	1,319
2007	42,084.73	13,996	12,448	33,846	20.93	1,617
2008	43,856.84	13,106	11,656	36,587	21.85	1,674
2009	124,470.27	32,952	29,306	107,611	22.78	4,724
2010	100,683.11	23,221	20,652	90,100	23.71	3,800
2011	78,414.76	15,354	13,655	72,601	24.66	2,944
2012	24,891.66	3,998	3,556	23,825	25.62	930

PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
2013	39,880.35	5,001	4,448	39,421	26.58	1,483
2015	16,356.46	882	784	17,208	28.53	603
2016	16,271.50	292	260	17,639	29.51	598
	1,158,054.34	449,437	399,713	874,147		45,404
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1977	3,349.30	3,342	3,060	624	2.79	224
1980	105,346.88	101,898	93,308	22,574	3.62	6,236
1990	41,339.75	33,514	30,689	14,785	7.89	1,874
2000	22,675.72	12,546	11,488	13,455	14.91	902
2001	532.72	279	255	331	15.73	21
2002	79,207.03	39,062	35,769	51,359	16.55	3,103
2003	51,480.36	23,784	21,779	34,849	17.40	2,003
2004	45,401.39	19,544	17,896	32,045	18.26	1,755
2005	28,730.41	11,440	10,476	21,128	19.14	1,104
2006	31,690.30	11,585	10,608	24,251	20.03	1,211
2007	40,017.58	13,308	12,186	31,833	20.93	1,521
2008	15,473.94	4,624	4,234	12,787	21.85	585
2009	41,405.22	10,961	10,037	35,509	22.78	1,559
2010	66,648.28	15,372	14,076	59,237	23.71	2,498
2011	51,889.62	10,160	9,303	47,775	24.66	1,937
2012	48,378.98	7,770	7,115	46,102	25.62	1,799
2013	40,989.33	5,140	4,707	40,382	26.58	1,519
2014	31,041.67	2,789	2,554	31,592	27.55	1,147
2016	127,429.84	2,289	2,096	138,077	29.51	4,679
	873,028.32	329,407	301,637	658,694		35,677
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1980	22,514.94	21,778	19,369	5,397	3.62	1,491
2001	6,537.72	3,421	3,043	4,149	15.73	264
2003	6,635.51	3,066	2,727	4,572	17.40	263
2005	14,429.58	5,746	5,110	10,762	19.14	562
2007	20,434.77	6,796	6,044	16,434	20.93	785

PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
2008	126,979.80	37,946	33,749	105,929	21.85	4,848
2009	19,862.00	5,258	4,676	17,172	22.78	754
2010	11,801.66	2,722	2,421	10,561	23.71	445
2011	29,389.97	5,755	5,118	27,211	24.66	1,103
2012	32,375.90	5,200	4,625	30,989	25.62	1,210
2014	9,159.89	823	732	9,344	27.55	339
2015	23,606.33	1,272	1,131	24,836	28.53	871
2016	17,053.13	306	272	18,486	29.51	626
	340,781.20	100,089	89,018	285,841		13,561
	2,705,197.55	1,038,957	938,004	2,037,714		108,452

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.8 4.01

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1973	49,381.72	61,628	48,456	30,555	11.00	2,778
1974	189,938.66	232,971	183,178	120,724	11.67	10,345
1975	163,185.66	196,606	154,585	106,512	12.35	8,624
1976	243,947.91	288,522	226,856	163,461	13.04	12,535
1977	281,227.00	326,313	256,570	193,394	13.74	14,075
1978	301,837.34	343,274	269,905	213,034	14.46	14,733
1979	480,571.00	535,164	420,783	348,131	15.20	22,903
1980	432,449.24	471,197	370,487	321,432	15.95	20,152
1981	680,027.58	724,420	569,589	518,456	16.71	31,027
1982	756,685.41	787,195	618,947	591,750	17.49	33,834
1983	889,188.14	902,277	709,432	713,269	18.29	38,998
1984	720,631.94	712,561	560,264	592,747	19.10	31,034
1985	862,330.71	830,045	652,638	727,091	19.92	36,501
1986	552,069.25	516,560	406,155	477,156	20.76	22,984
1987	636,926.20	578,635	454,962	564,120	21.61	26,105
1988	802,011.44	706,283	555,328	727,890	22.48	32,379
1989	844,341.59	719,784	565,943	785,003	23.36	33,605
1990	1,238,272.16	1,020,336	802,258	1,178,978	24.25	48,618
1991	1,170,154.63	930,507	731,628	1,140,619	25.15	45,353
1992	1,433,053.66	1,097,834	863,192	1,429,694	26.06	54,862
1993	1,360,512.70	1,002,208	788,004	1,388,816	26.98	51,476
1994	1,177,463.99	832,326	654,432	1,229,511	27.91	44,053
1995	843,152.95	570,646	448,681	900,364	28.85	31,208
1996	2,108,160.91	1,363,390	1,071,990	2,301,067	29.79	77,243
1997	1,419,276.04	874,274	687,414	1,583,428	30.75	51,494
1998	886,825.80	519,041	408,106	1,010,816	31.71	31,877
1999	420,298.81	233,081	183,264	489,214	32.67	14,974
2000	378,972.31	198,400	155,996	450,360	33.64	13,388
2001	267,999.03	131,898	103,707	325,091	34.62	9,390
2002	245,109.81	112,947	88,807	303,369	35.60	8,522
2003	345,497.47	148,370	116,659	436,137	36.58	11,923
2004	255,919.51	101,876	80,102	329,369	37.56	8,769
2005	216,249.06	79,234	62,299	283,699	38.55	7,359
2006	281,244.12	94,138	74,018	375,973	39.54	9,509
2007	252,297.35	76,456	60,115	343,561	40.53	8,477
2008	475,950.71	129,154	101,550	659,971	41.52	15,895
2009	225,707.72	54,025	42,478	318,654	42.52	7,494
2010	463,676.54	96,296	75,714	666,168	43.51	15,311
2011	248,663.50	43,685	34,348	363,513	44.51	8,167
2012	249,375.17	35,830	28,172	370,828	45.51	8,148
2013	222,812.25	24,955	19,621	336,878	46.50	7,245

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
2014	325,362.46	26,029	20,466	500,114	47.50	10,529
2015	217,662.20	10,448	8,215	340,045	48.50	7,011
2016	212,110.35	3,394	2,669	336,708	49.50	6,802
	25,828,532.00	18,744,213	14,737,981	26,587,670		1,007,709
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1996	4,992,764.60	3,228,921	2,149,583	5,838,841	29.79	196,000
1997	522,456.43	321,833	214,253	621,677	30.75	20,217
1998	860,001.48	503,342	335,089	1,040,914	31.71	32,826
1999	507,688.90	281,544	187,432	624,871	32.67	19,127
2000	402,534.69	210,735	140,292	503,763	33.64	14,975
2001	362,194.16	178,257	118,671	460,840	34.62	13,311
2002	432,124.84	199,123	132,562	558,838	35.60	15,698
2003	410,451.58	176,264	117,344	539,379	36.58	14,745
2004	486,854.60	193,807	129,023	649,945	37.56	17,304
2005	485,495.49	177,886	118,424	658,369	38.55	17,078
2006	501,312.99	167,799	111,708	690,392	39.54	17,461
2007	700,248.02	212,203	141,269	979,127	40.53	24,158
2008	734,110.23	199,208	132,618	1,041,958	41.52	25,095
2009	422,851.07	101,214	67,381	609,181	42.52	14,327
2010	651,739.34	135,353	90,108	952,675	43.51	21,896
2011	630,890.03	110,835	73,786	935,638	44.51	21,021
2012	761,126.92	109,359	72,803	1,145,000	45.51	25,159
2013	938,826.36	105,149	70,001	1,432,122	46.50	30,798
2014	851,215.27	68,097	45,334	1,316,610	47.50	27,718
2015	902,839.98	43,336	28,850	1,415,694	48.50	29,190
2016	810,054.43	12,961	8,628	1,287,459	49.50	26,009
	17,367,781.41	6,737,226	4,485,159	23,303,291		624,113
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1970	209,746.85	274,248	152,344	183,251	9.14	20,049
1980	923,036.27	1,005,740	558,684	918,174	15.95	57,566
1990	1,058,173.40	871,935	484,356	1,208,721	24.25	49,844

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
2000	73,450.42	38,453	21,360	96,160	33.64	2,859
2001	146,496.77	72,100	40,051	194,344	34.62	5,614
2002	115,052.73	53,016	29,450	154,634	35.60	4,344
2003	78,203.94	33,584	18,656	106,471	36.58	2,911
2004	114,965.36	45,765	25,422	158,522	37.56	4,221
2005	182,058.33	66,706	37,055	254,238	38.55	6,595
2006	240,701.96	80,568	44,755	340,368	39.54	8,608
2007	283,035.34	85,771	47,645	405,211	40.53	9,998
2008	344,537.18	93,494	51,936	499,324	41.52	12,026
2009	522,958.51	125,175	69,534	767,199	42.52	18,043
2010	805,853.05	167,360	92,968	1,196,397	43.51	27,497
2011	259,804.74	45,642	25,354	390,334	44.51	8,770
2012	476,255.65	68,428	38,011	723,998	45.51	15,909
2013	445,724.87	49,921	27,731	685,429	46.50	14,740
2014	475,514.17	38,041	21,132	739,691	47.50	15,572
2015	556,950.84	26,734	14,851	876,271	48.50	18,067
2016	214,723.23	3,436	1,909	341,648	49.50	6,902
	7,527,243.61	3,246,117	1,803,204	10,240,385		310,135
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1980	398,405.06	434,102	253,481	383,967	15.95	24,073
1990	43,782.09	36,076	21,066	48,986	24.25	2,020
2001	338.72	167	98	444	34.62	13
2002	4,329.17	1,995	1,165	5,762	35.60	162
2003	16,102.55	6,915	4,038	21,726	36.58	594
2004	61,549.72	24,502	14,307	84,172	37.56	2,241
2005	7,610.15	2,788	1,628	10,548	38.55	274
2006	19,961.91	6,682	3,902	28,037	39.54	709
2007	13,711.21	4,155	2,426	19,512	40.53	481
2008	3,390.45	920	537	4,888	41.52	118
2009	8,058.37	1,929	1,126	11,767	42.52	277
2010	13,005.09	2,701	1,577	19,231	43.51	442
2011	54,051.23	9,496	5,545	80,937	44.51	1,818

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
2012	26,622.70	3,825	2,233	40,363	45.51	887
2013	35,753.14	4,004	2,338	54,867	46.50	1,180
2014	8,421.36	674	394	13,081	47.50	275
	715,092.92	540,931	315,861	828,288		35,564
	51,438,649.94	29,268,487	21,342,205	60,959,634		1,977,521
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					30.8	3.84

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1973	7,200.41	7,681	7,526	1,115	4.44	251
1974	19,452.21	20,536	20,120	3,222	4.81	670
1975	40,771.14	42,565	41,703	7,222	5.20	1,389
1976	46,809.47	48,265	47,288	8,883	5.63	1,578
1977	68,236.47	69,417	68,012	13,872	6.09	2,278
1978	68,021.42	68,157	66,777	14,848	6.60	2,250
1979	71,291.62	70,279	68,856	16,694	7.14	2,338
1980	101,960.40	98,708	96,710	25,643	7.73	3,317
1981	88,418.12	83,953	82,253	23,848	8.35	2,856
1982	59,015.61	54,885	53,774	17,045	9.00	1,894
1983	73,351.16	66,742	65,391	22,630	9.67	2,340
1984	76,066.04	67,638	66,269	25,010	10.36	2,414
1985	134,127.72	116,409	114,052	46,901	11.07	4,237
1986	102,279.33	86,559	84,807	37,928	11.79	3,217
1987	141,646.06	116,731	114,368	55,607	12.53	4,438
1988	145,048.30	116,227	113,874	60,184	13.29	4,529
1989	105,956.54	82,424	80,755	46,392	14.07	3,297
1990	224,029.18	168,896	165,477	103,358	14.87	6,951
1991	172,921.66	126,112	123,559	83,947	15.69	5,350
1992	120,705.26	85,025	83,304	61,543	16.52	3,725
1993	178,047.82	120,823	118,377	95,280	17.38	5,482
1994	155,426.87	101,463	99,409	87,103	18.24	4,775
1995	124,885.09	78,191	76,608	73,254	19.13	3,829
1996	221,649.85	132,790	130,102	135,878	20.03	6,784
1997	282,840.31	161,728	158,454	180,954	20.94	8,642
1998	184,510.95	100,411	98,378	123,035	21.86	5,628
1999	120,326.21	62,088	60,831	83,560	22.80	3,665
2000	92,279.16	45,014	44,103	66,632	23.74	2,807
2001	114,488.01	52,584	51,520	85,866	24.69	3,478
2002	176,497.24	75,982	74,444	137,353	25.65	5,355
2003	111,070.94	44,584	43,681	89,604	26.62	3,366
2004	43,132.26	16,045	15,720	36,039	27.60	1,306
2005	22,035.90	7,556	7,403	19,040	28.57	666
2006	69,116.33	21,647	21,209	61,731	29.56	2,088
2007	9,106.01	2,584	2,532	8,396	30.54	275
2008	50,428.37	12,814	12,555	47,959	31.53	1,521
2009	39,190.85	8,794	8,616	38,413	32.52	1,181
2010	63,416.62	12,328	12,078	64,022	33.52	1,910
2011	33,929.27	5,588	5,475	35,240	34.51	1,021
2012	50,496.43	6,802	6,664	53,931	35.51	1,519
2013	31,075.53	3,254	3,188	34,103	36.51	934

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
2014	41,597.80	3,120	3,057	46,861	37.50	1,250
2015	87,957.09	3,958	3,878	101,671	38.50	2,641
2016	125,919.09	1,889	1,851	149,252	39.50	3,779
	4,296,732.12	2,679,246	2,625,008	2,531,070		133,221
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1996	943,840.01	565,455	687,483	445,125	20.03	22,223
1997	155,053.05	88,659	107,792	78,272	20.94	3,738
1998	85,338.88	46,441	56,463	45,943	21.86	2,102
1999	38,068.61	19,643	23,882	21,800	22.80	956
2000	33,757.81	16,467	20,021	20,489	23.74	863
2001	44,161.11	20,283	24,660	28,333	24.69	1,148
2002	71,139.86	30,626	37,235	48,133	25.65	1,877
2003	33,315.56	13,373	16,259	23,720	26.62	891
2004	53,855.47	20,034	24,357	40,269	27.60	1,459
2005	51,684.21	17,723	21,548	40,473	28.57	1,417
2006	63,303.95	19,827	24,106	51,859	29.56	1,754
2007	79,573.50	22,583	27,457	68,032	30.54	2,228
2008	98,986.96	25,153	30,581	88,203	31.53	2,797
2009	64,598.57	14,496	17,624	59,894	32.52	1,842
2010	69,532.77	13,517	16,434	67,005	33.52	1,999
2011	39,914.22	6,574	7,993	39,904	34.51	1,156
2012	56,666.32	7,633	9,280	58,719	35.51	1,654
2013	52,167.15	5,462	6,641	55,960	36.51	1,533
2014	55,505.68	4,163	5,061	61,545	37.50	1,641
2015	65,881.41	2,965	3,605	75,453	38.50	1,960
2016	65,506.75	983	1,195	77,413	39.50	1,960
	2,221,851.85	962,060	1,169,677	1,496,545		57,198
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1978	237,790.83	238,266	226,971	58,378	6.60	8,845
1980	293,040.64	283,693	270,245	81,404	7.73	10,531
1990	880,509.47	663,816	632,348	424,263	14.87	28,531

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
2000	145,825.92	71,134	67,762	107,229	23.74	4,517
2001	285,108.25	130,950	124,742	217,388	24.69	8,805
2002	166,944.19	71,869	68,462	131,871	25.65	5,141
2003	274,427.91	110,155	104,933	224,380	26.62	8,429
2004	308,918.16	114,918	109,470	261,231	27.60	9,465
2005	45,593.32	15,634	14,893	39,819	28.57	1,394
2006	60,754.62	19,028	18,126	54,780	29.56	1,853
2007	42,050.04	11,934	11,368	39,092	30.54	1,280
2008	87,274.22	22,176	21,125	83,604	31.53	2,652
2009	55,835.03	12,529	11,935	55,067	32.52	1,693
2010	114,602.74	22,279	21,223	116,300	33.52	3,470
2011	64,781.39	10,669	10,163	67,574	34.51	1,958
2012	74,288.67	10,007	9,533	79,614	35.51	2,242
2013	89,730.71	9,395	8,950	98,727	36.51	2,704
2014	135,800.44	10,185	9,702	153,258	37.50	4,087
2015	100,881.53	4,540	4,325	116,733	38.50	3,032
2016	54,820.19	822	783	65,001	39.50	1,646
	3,518,978.27	1,833,999	1,747,059	2,475,715		112,275
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1980	239,243.74	231,612	223,619	63,473	7.73	8,211
1990	10,969.58	8,270	7,985	5,179	14.87	348
2000	19.64	10	10	14	23.74	1
2002	567.56	244	236	445	25.65	17
2004	4,188.12	1,558	1,504	3,522	27.60	128
2005	1,017.77	349	337	884	28.57	31
2006	2,098.20	657	634	1,884	29.56	64
2007	624.11	177	171	578	30.54	19
2008	3,500.78	890	859	3,342	31.53	106
2009	967.66	217	210	952	32.52	29
2010	2,292.15	446	431	2,320	33.52	69

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
2011	3,172.08	522	504	3,303	34.51	96
2012	9,545.50	1,286	1,242	10,213	35.51	288
2013	7,905.98	828	799	8,688	36.51	238
	286,112.87	247,066	238,540	104,796		9,645
	10,323,675.11	5,722,371	5,780,284	6,608,126		312,339
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.2	3.03

PACIFIC NORTHERN GAS LTD.

ACCOUNT 475.00 - DISTRIBUTION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1969	1,256,817.29	1,070,950	1,084,874	486,147	20.69	23,497
1970	441,367.81	369,563	374,368	177,342	21.46	8,264
1971	270,981.38	222,882	225,780	112,947	22.23	5,081
1972	423,659.77	342,026	346,473	183,102	23.02	7,954
1973	395,492.06	313,274	317,347	177,018	23.81	7,435
1974	260,397.44	202,208	204,837	120,660	24.62	4,901
1975	281,900.64	214,463	217,251	135,124	25.44	5,311
1976	295,621.59	220,183	223,046	146,481	26.27	5,576
1977	562,279.55	409,600	414,926	287,924	27.12	10,617
1978	363,483.33	258,841	262,206	192,148	27.97	6,870
1979	679,842.46	472,881	479,029	370,774	28.83	12,861
1980	834,170.74	566,277	573,640	469,074	29.70	15,794
1981	923,029.78	610,976	618,920	534,867	30.58	17,491
1982	2,893,769.43	1,865,939	1,890,200	1,727,012	31.47	54,878
1983	759,489.87	476,580	482,776	466,586	32.37	14,414
1984	924,966.01	564,229	571,565	584,643	33.28	17,567
1985	393,712.24	233,201	236,233	255,907	34.20	7,483
1986	652,234.33	374,782	379,655	435,638	35.12	12,404
1987	503,141.52	280,111	283,753	345,174	36.05	9,575
1988	453,692.88	244,382	247,559	319,557	36.99	8,639
1989	1,066,559.78	555,224	562,443	770,757	37.93	20,321
1990	1,415,180.20	710,863	720,106	1,048,870	38.88	26,977
1991	956,938.67	463,194	469,216	726,957	39.83	18,251
1992	1,186,498.08	552,404	559,586	923,536	40.79	22,641
1993	578,287.29	258,559	261,921	460,938	41.75	11,040
1994	283,518.38	121,477	123,056	231,342	42.72	5,415
1995	1,282,484.91	525,578	532,411	1,070,695	43.69	24,507
1996	2,353,292.94	920,491	932,459	2,009,157	44.66	44,988
1997	1,790,152.38	666,496	675,162	1,562,529	45.64	34,236
1998	1,696,640.76	599,699	607,496	1,513,305	46.62	32,460
1999	436,832.16	146,170	148,070	397,970	47.60	8,361
2000	484,218.99	152,904	154,892	450,382	48.58	9,271
2001	163,402.86	48,486	49,116	155,137	49.57	3,130
2002	61,786.77	17,157	17,380	59,853	50.56	1,184
2003	250,221.05	64,720	65,561	247,215	51.55	4,796
2004	352,788.98	84,533	85,632	355,354	52.54	6,763
2005	288,298.01	63,591	64,418	295,955	53.53	5,529
2006	168,254.20	33,878	34,318	175,999	54.53	3,228
2007	415,340.71	75,722	76,707	442,469	55.52	7,970
2008	77,302.74	12,606	12,770	83,859	56.52	1,484
2009	362,358.89	52,193	52,872	400,077	57.51	6,957
2010	576,098.00	71,904	72,839	647,284	58.51	11,063

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ACCOUNT 475.00 - DISTRIBUTION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
2011	132,438.16	13,982	14,164	151,384	59.51	2,544
2012	382,377.10	33,018	33,447	444,524	60.51	7,346
2013	330,078.86	22,218	22,507	390,092	61.50	6,343
2014	95,516.55	4,592	4,652	114,744	62.50	1,836
2015	696,935.67	20,107	20,368	850,801	63.50	13,398
2016	81,044.85	779	789	100,517	64.50	1,558
	31,534,898.06	15,605,893	15,808,798	23,609,824		600,209
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1996	8,824,723.88	3,451,791	4,919,005	6,111,900	44.66	136,854
1997	785,757.66	292,547	416,897	565,300	45.64	12,386
1998	927,722.17	327,915	467,298	692,355	46.62	14,851
1999	651,958.48	218,153	310,881	504,067	47.60	10,590
2000	553,870.40	174,898	249,240	443,098	48.58	9,121
2001	679,840.92	201,726	287,471	562,330	49.57	11,344
2002	572,743.38	159,044	226,647	489,282	50.56	9,677
2003	556,088.45	143,832	204,969	490,142	51.55	9,508
2004	1,042,854.27	249,881	356,095	947,473	52.54	18,033
2005	788,200.67	173,857	247,756	737,494	53.53	13,777
2006	408,131.73	82,177	117,107	393,058	54.53	7,208
2007	558,669.74	101,852	145,145	553,192	55.52	9,964
2008	1,403,017.66	228,797	326,049	1,427,723	56.52	25,260
2009	826,776.27	119,087	169,706	863,764	57.51	15,019
2010	929,320.32	115,991	165,294	996,356	58.51	17,029
2011	1,002,210.99	105,808	150,783	1,101,981	59.51	18,518
2012	1,300,823.86	112,326	160,071	1,465,959	60.51	24,227
2013	1,222,065.31	82,260	117,225	1,410,356	61.50	22,933
2014	1,946,970.00	93,601	133,387	2,300,326	62.50	36,805
2015	1,860,448.66	53,674	76,489	2,249,072	63.50	35,418
2016	3,082,945.03	29,635	42,232	3,811,450	64.50	59,092
	29,925,139.85	6,518,852	9,289,747	28,116,678		517,614

PACIFIC NORTHERN GAS LTD.

ACCOUNT 475.00 - DISTRIBUTION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1961	564,265.19	542,562	476,740	228,591	15.00	15,239
1970	14,840.19	12,426	10,919	7,632	21.46	356
1980	1,901,479.30	1,290,819	1,134,221	1,242,628	29.70	41,839
1990	1,706,038.69	856,965	753,001	1,379,548	38.88	35,482
2000	9,049.87	2,858	2,511	8,801	48.58	181
2001	110,687.48	32,844	28,859	109,500	49.57	2,209
2002	80,775.72	22,430	19,709	81,261	50.56	1,607
2003	160,743.56	41,576	36,532	164,397	51.55	3,189
2004	116,073.10	27,813	24,439	120,653	52.54	2,296
2005	172,914.55	38,141	33,514	182,629	53.53	3,412
2006	115,372.73	23,230	20,412	123,804	54.53	2,270
2007	144,854.01	26,409	23,205	157,862	55.52	2,843
2008	946,470.57	154,346	135,621	1,047,467	56.52	18,533
2009	2,082,654.40	299,980	263,587	2,339,731	57.51	40,684
2010	1,082,351.42	135,091	118,702	1,234,237	58.51	21,094
2011	357,690.29	37,763	33,182	413,931	59.51	6,956
2012	418,826.57	36,166	31,778	491,755	60.51	8,127
2013	850,677.76	57,261	50,314	1,013,033	61.50	16,472
2014	791,794.76	38,066	33,448	956,295	62.50	15,301
2015	456,956.00	13,183	11,584	559,611	63.50	8,813
2016	415,384.12	3,993	3,509	515,722	64.50	7,996
	12,499,900.28	3,693,922	3,245,787	12,379,088		254,899
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1980	943,551.11	640,530	546,224	633,214	29.70	21,320
1990	15,994.88	8,034	6,851	13,142	38.88	338
2007	24,750.46	4,512	3,848	27,090	55.52	488
2011	70,422.07	7,435	6,340	81,687	59.51	1,373
2012	13,174.10	1,138	970	15,497	60.51	256
2013	32,076.62	2,159	1,841	38,255	61.50	622
	1,099,969.24	663,808	566,075	808,886		24,397
	75,059,907.43	26,482,475	28,910,408	64,914,476		1,397,119
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					46.5	1.86

PACIFIC NORTHERN GAS LTD.

ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1980	25,840.15	24,118	27,649			
1981	1,054.45	970	1,128			
1985	43,881.62	37,522	46,953			
1986	54,403.27	45,455	57,429	782	7.67	102
1988	50,466.00	40,083	50,642	3,356	9.02	372
1989	6,472.14	5,000	6,317	608	9.73	62
1990	3,209.19	2,409	3,044	390	10.45	37
1991	70,127.24	51,025	64,467	10,569	11.20	944
1992	4,285.21	3,017	3,812	773	11.97	65
1994	4,822.89	3,160	3,992	1,168	13.57	86
1995	547.62	345	436	150	14.41	10
2004	11,440.00	4,326	5,466	6,775	22.63	299
	276,549.78	217,430	271,335	24,573		1,977
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
2000	50,087.84	24,745	47,794	5,800	18.84	308
2001	72,283.62	33,655	65,003	12,341	19.77	624
2002	656,175.77	286,664	553,676	148,432	20.71	7,167
2003	28,851.23	11,757	22,708	8,163	21.67	377
2004	24,731.74	9,353	18,065	8,398	22.63	371
2005	2,397.93	836	1,615	951	23.60	40
2006	34,423.37	10,976	21,200	15,633	24.57	636
2007	23,007.99	6,647	12,838	11,780	25.55	461
2009	28,652.01	6,543	12,637	18,020	27.53	655
2010	26,381.50	5,226	10,094	18,134	28.52	636
2011	42,007.30	7,051	13,619	31,329	29.51	1,062
2012	84,057.57	11,539	22,287	67,655	30.51	2,217
2016	153,329.85	2,344	4,527	159,536	34.50	4,624
	1,226,387.72	417,336	806,061	506,173		19,178
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1978	20,626.07	19,712	22,070			
1980	332,360.78	310,209	349,689	5,937	4.47	1,328

PACIFIC NORTHERN GAS LTD.

ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1990	74,435.15	55,866	62,976	16,670	10.45	1,595
2002	4,183.56	1,828	2,061	2,416	20.71	117
2004	32,222.95	12,186	13,737	20,742	22.63	917
2006	5,719.36	1,824	2,056	4,064	24.57	165
2007	17,095.83	4,939	5,568	12,725	25.55	498
2009	17,928.10	4,094	4,615	14,568	27.53	529
2010	4,525.73	897	1,011	3,831	28.52	134
	509,097.53	411,555	463,782	80,952		5,283
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1980	188,024.57	175,493	198,184	3,002	4.47	672
2006	5,766.32	1,839	2,077	4,093	24.57	167
2010	127,228.83	25,204	28,463	107,672	28.52	3,775
	321,019.72	202,536	228,723	114,768		4,614
	2,333,054.75	1,248,857	1,769,902	726,466		31,052

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.4 1.33

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1990	238,470.97	224,282	169,129	66,957	1.00	66,957
1991	280,384.96	261,898	197,495	80,086	1.13	70,873
1992	254,596.89	234,407	176,765	75,286	1.40	53,776
1993	254,230.11	230,672	173,948	77,740	1.67	46,551
1994	233,800.10	208,663	157,351	74,111	1.97	37,620
1995	82,941.68	72,628	54,768	27,344	2.31	11,837
1996	152,261.81	130,389	98,325	52,414	2.70	19,413
1997	242,746.59	202,229	152,499	87,820	3.17	27,703
1998	95,789.01	77,193	58,211	36,620	3.72	9,844
1999	84,630.50	65,603	49,471	34,313	4.34	7,906
2001	47,216.49	33,399	25,186	21,558	5.71	3,775
2002	36,651.25	24,565	18,524	17,760	6.46	2,749
2003	45,398.50	28,675	21,624	23,321	7.24	3,221
2004	45,155.03	26,710	20,142	24,562	8.05	3,051
2005	50,940.55	27,989	21,106	29,325	8.90	3,295
2006	23,549.20	11,902	8,975	14,338	9.79	1,465
2007	41,870.61	19,275	14,535	26,917	10.70	2,516
2008	197,662.95	81,895	61,756	133,930	11.63	11,516
2009	137,262.29	50,347	37,966	97,923	12.59	7,778
2010	57,930.57	18,496	13,948	43,404	13.55	3,203
2011	94,458.03	25,576	19,287	74,227	14.53	5,109
2012	156,230.96	34,646	26,126	128,542	15.52	8,282
2013	138,622.96	23,948	18,059	119,178	16.51	7,219
2014	120,413.75	14,901	11,237	107,973	17.50	6,170
2015	222,860.24	16,547	12,478	208,154	18.50	11,252
2016	209,705.92	5,190	3,914	203,695	19.50	10,446
	3,545,781.92	2,152,025	1,622,826	1,887,498		443,527
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1997	118,518.44	98,736	72,140	45,193	3.17	14,256
1999	354,428.73	274,743	200,738	150,146	4.34	34,596
2002	41,309.65	27,687	20,229	20,667	6.46	3,199
2003	53,070.21	33,520	24,491	28,048	7.24	3,874
2004	65,646.66	38,832	28,372	36,618	8.05	4,549
2005	15,658.38	8,603	6,286	9,216	8.90	1,036
2006	51,220.91	25,887	18,914	31,795	9.79	3,248
2007	63,735.57	29,341	21,438	41,661	10.70	3,894

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
2008	64,311.24	26,645	19,468	44,200	11.63	3,801
2009	72,599.32	26,629	19,456	52,417	12.59	4,163
2010	84,674.26	27,034	19,752	64,075	13.55	4,729
2011	97,584.83	26,423	19,306	77,303	14.53	5,320
2012	173,813.71	38,545	28,163	143,913	15.52	9,273
2013	138,651.99	23,953	17,501	119,764	16.51	7,254
2014	173,055.08	21,416	15,647	155,677	17.50	8,896
2015	164,070.79	12,182	8,901	153,529	18.50	8,299
2016	154,614.83	3,827	2,796	150,273	19.50	7,706
	1,886,964.60	744,003	543,598	1,324,497		128,093
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1990	106,388.50	100,058	62,332	42,993	1.00	42,993
2001	20,373.73	14,411	8,977	11,193	5.71	1,960
2002	1,081.80	725	452	619	6.46	96
2003	63,801.45	40,298	25,104	38,059	7.24	5,257
2004	7,399.72	4,377	2,727	4,599	8.05	571
2005	10,342.16	5,682	3,540	6,699	8.90	753
2006	14,920.89	7,541	4,698	10,074	9.79	1,029
2007	38,374.96	17,666	11,005	26,986	10.70	2,522
2008	26,569.20	11,008	6,858	19,446	11.63	1,672
2009	32,681.59	11,987	7,467	24,887	12.59	1,977
2010	31,133.09	9,940	6,192	24,630	13.55	1,818
2011	85,400.02	23,123	14,405	70,141	14.53	4,827
2012	65,578.55	14,543	9,060	55,863	15.52	3,599
2013	80,457.74	13,899	8,658	70,995	16.51	4,300
2014	80,440.13	9,954	6,201	73,435	17.50	4,196
2015	59,783.93	4,439	2,765	56,421	18.50	3,050
2016	67,184.63	1,663	1,036	65,477	19.50	3,358
	791,912.09	291,314	181,476	602,517		83,978

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1980	56,583.41	53,217	50,000	6,018	1.00	6,018
2009	1,925.16	706	663	1,243	12.59	99
2010	5,356.69	1,710	1,607	3,697	13.55	273
2011	37,710.00	10,211	9,594	27,739	14.53	1,909
2012	32,151.19	7,130	6,699	25,131	15.52	1,619
2013	32,418.52	5,600	5,261	26,833	16.51	1,625
2014	12,572.98	1,556	1,462	10,985	17.50	628
2015	22,844.28	1,696	1,593	21,022	18.50	1,136
	201,562.23	81,826	76,879	122,667		13,307
	6,426,220.84	3,269,168	2,424,780	3,937,179		668,905

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.9 10.41

PACIFIC NORTHERN GAS LTD.

ACCOUNT 479.00 - OTHER DISTRIBUTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 35-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	30,514.62	17,001	23,643	6,872	15.50	443
	30,514.62	17,001	23,643	6,872		443
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 35-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	5.31	3	3	2	14.50	
1998	19,611.39	10,366	10,279	9,332	16.50	566
	19,616.70	10,369	10,282	9,334		566
	50,131.32	27,370	33,925	16,206		1,009

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.1 2.01

PACIFIC NORTHERN GAS LTD.

ACCOUNT 481.00 - GENERAL - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1983	50.00	22		50	42.10	1
1985	300.00	124		300	43.98	7
	350.00	146		350		8
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1996	1,378.59	375	234	1,144	54.62	21
	1,378.59	375	234	1,144		21
	1,728.59	521	234	1,494		29

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.5 1.68

PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1971	6,064.80	5,812	6,065			
1973	61,226.06	57,634	61,226			
1975	479,130.81	442,875	479,131			
1976	51,977.61	47,594	51,978			
1977	2,718.84	2,466	2,703	15	2.79	5
1978	647.05	581	637	10	3.06	3
1981	13,212.81	11,486	12,592	621	3.92	158
1982	369,603.15	317,241	347,790	21,813	4.25	5,132
1983	118,887.54	100,659	110,352	8,535	4.60	1,855
1984	42,055.39	35,074	38,451	3,604	4.98	724
1985	63,591.77	52,188	57,214	6,378	5.38	1,186
1986	276,300.53	222,698	244,143	32,158	5.82	5,525
1987	57,840.41	45,713	50,115	7,725	6.29	1,228
1988	286,719.03	221,826	243,187	43,532	6.79	6,411
1989	15,729.69	11,886	13,031	2,699	7.33	368
1990	8,303.94	6,120	6,709	1,595	7.89	202
1991	16,956.98	12,164	13,335	3,622	8.48	427
1992	8,728.30	6,081	6,667	2,062	9.10	227
1994	644,245.65	420,261	460,731	183,515	10.43	17,595
1995	1,031,832.67	649,363	711,894	319,939	11.12	28,771
1996	144,101.52	87,229	95,629	48,473	11.84	4,094
1997	497,134.46	288,671	316,469	180,666	12.58	14,361
1998	95,233.53	52,886	57,979	37,255	13.34	2,793
1999	32,710.54	17,315	18,982	13,728	14.12	972
2000	44,346.64	22,306	24,454	19,893	14.91	1,334
2001	45,687.93	21,732	23,825	21,863	15.73	1,390
2002	13,832.66	6,202	6,799	7,033	16.55	425
2003	46,445.99	19,507	21,385	25,061	17.40	1,440
2004	174,316.77	68,215	74,784	99,533	18.26	5,451
2005	103,260.25	37,380	40,980	62,281	19.14	3,254
2006	48,230.75	16,029	17,573	30,658	20.03	1,531
2007	21,926.74	6,629	7,267	14,659	20.93	700
2008	191,684.66	52,075	57,090	134,595	21.85	6,160
2009	194,526.47	46,817	51,325	143,201	22.78	6,286
2010	190,572.08	39,957	43,805	146,767	23.71	6,190
2011	35,104.03	6,249	6,851	28,253	24.66	1,146
2012	88,357.61	12,900	14,142	74,215	25.62	2,897
2013	7,696.19	877	961	6,735	26.58	253

PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
2014	63,345.99	5,173	5,671	57,675	27.55	2,093
2015	157,558.45	7,720	8,463	149,095	28.53	5,226
2016	434,535.58	7,096	7,779	426,756	29.51	14,461
	6,186,381.87	3,492,687	3,820,164	2,366,218		152,274
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1996	416,942.42	252,388	315,230	101,713	11.84	8,591
1997	384,037.68	222,999	278,523	105,515	12.58	8,388
1998	49,356.50	27,409	34,234	15,123	13.34	1,134
2000	23,187.89	11,664	14,568	8,620	14.91	578
2006	6,170.00	2,050	2,560	3,610	20.03	180
2008	21,166.02	5,750	7,182	13,984	21.85	640
2011	17,406.60	3,098	3,869	13,537	24.66	549
2012	21,848.50	3,190	3,984	17,864	25.62	697
2014	8,808.61	719	898	7,911	27.55	287
	948,924.22	529,267	661,048	287,876		21,044
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1980	22,485.44	19,772	21,281	1,205	3.62	333
1990	8,623.16	6,355	6,840	1,783	7.89	226
2000	6,495.66	3,267	3,516	2,979	14.91	200
2009	4,724.21	1,137	1,224	3,500	22.78	154
2012	9,405.57	1,373	1,478	7,928	25.62	309
2013	980,551.57	111,783	120,312	860,240	26.58	32,364
2014	17,655.00	1,442	1,552	16,103	27.55	585
2015	49,400.00	2,421	2,606	46,794	28.53	1,640
2016	55,087.01	900	969	54,118	29.51	1,834
	1,154,427.62	148,450	159,777	994,651		37,645

PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 30-R5						
NET SALVAGE PERCENT.. 0						
1980	392,102.75	377,724	391,117	986	1.10	896
1990	10,209.53	8,535	8,838	1,372	4.92	279
	402,312.28	386,259	399,954	2,358		1,175
	8,692,045.99	4,556,663	5,040,943	3,651,103		212,138
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					17.2	2.44

PACIFIC NORTHERN GAS LTD.

ACCOUNT 483.00 - GENERAL - OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	62,866.54	58,675	42,537	20,330	1.00	20,330
2003	24,104.74	21,694	15,727	8,378	1.50	5,585
2004	40,762.66	33,969	24,626	16,137	2.50	6,455
2005	53,536.69	41,045	29,756	23,781	3.50	6,795
2006	46,009.70	32,207	23,349	22,661	4.50	5,036
2008	47,521.51	26,929	19,522	27,999	6.50	4,308
2009	51,100.65	25,550	18,523	32,578	7.50	4,344
2010	11,287.55	4,891	3,546	7,742	8.50	911
2011	1,389.69	510	370	1,020	9.50	107
2012	29,113.14	8,734	6,332	22,781	10.50	2,170
2013	34,588.58	8,071	5,851	28,737	11.50	2,499
2014	10,524.90	1,754	1,272	9,253	12.50	740
2015	23,823.64	2,382	1,727	22,097	13.50	1,637
2016	108,768.81	3,625	2,628	106,141	14.50	7,320
	545,398.80	270,036	195,763	349,635		68,237
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	1,841.86	1,289	1,364	478	4.50	106
2008	1,640.28	929	983	657	6.50	101
2013	9,761.75	2,278	2,411	7,351	11.50	639
2014	10,033.79	1,672	1,769	8,264	12.50	661
2015	6,235.02	624	660	5,575	13.50	413
	29,512.70	6,792	7,188	22,325		1,920
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	3,695.86	3,449	2,901	795	1.00	795
2003	3,493.36	3,144	2,645	849	1.50	566
2004	6,025.48	5,021	4,224	1,802	2.50	721
2005	5,851.44	4,486	3,774	2,078	3.50	594
2006	6,523.58	4,567	3,842	2,682	4.50	596
2007	3,242.08	2,053	1,727	1,515	5.50	275
2008	8,812.69	4,994	4,201	4,612	6.50	710
2009	5,615.59	2,808	2,362	3,254	7.50	434

PACIFIC NORTHERN GAS LTD.

ACCOUNT 483.00 - GENERAL - OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	3,012.40	1,305	1,098	1,915	8.50	225
2011	1,676.00	615	517	1,159	9.50	122
2012	3,273.26	982	826	2,447	10.50	233
2013	7,681.61	1,792	1,507	6,174	11.50	537
2014	17,878.66	2,980	2,507	15,372	12.50	1,230
	76,782.01	38,196	32,130	44,652		7,038
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	2,311.20	2,080	1,790	521	1.50	347
2004	1,814.53	1,512	1,301	514	2.50	206
2005	716.47	549	472	244	3.50	70
2006	2,872.10	2,010	1,730	1,143	4.50	254
2010	6,811.03	2,951	2,539	4,272	8.50	503
2013	4,366.00	1,019	877	3,489	11.50	303
2014	5,134.84	856	737	4,398	12.50	352
	24,026.17	10,977	9,445	14,581		2,035
	675,719.68	326,001	244,526	431,193		79,230

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4 11.73

PACIFIC NORTHERN GAS LTD.

ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2002	63,463.37	47,201	48,706	5,238	1.00	5,238
2003	33,131.13	24,148	24,918	3,244	1.14	2,846
2006	277,043.13	179,853	185,587	49,900	1.89	26,402
2008	21,876.62	13,203	13,624	4,971	2.32	2,143
2009	5,981.30	3,502	3,614	1,470	2.49	590
2010	5,245.49	2,932	3,025	1,433	2.74	523
2011	92,237.86	47,335	48,844	29,558	3.17	9,324
2012	297,484.35	132,120	136,332	116,530	3.82	30,505
2013	464,308.10	166,251	171,551	223,111	4.63	48,188
2014	252,820.18	66,081	68,188	146,709	5.54	26,482
2015	421,244.98	67,136	69,276	288,782	6.50	44,428
2016	389,702.36	20,703	21,363	309,884	7.50	41,318
	2,324,538.87	770,465	795,028	1,180,831		237,987
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2011	100,111.42	51,376	50,132	34,962	3.17	11,029
2012	55,666.75	24,723	24,125	23,192	3.82	6,071
2013	117,281.42	41,994	40,977	58,712	4.63	12,681
2014	152,524.75	39,866	38,901	90,745	5.54	16,380
2015	55,818.97	8,896	8,681	38,765	6.50	5,964
2016	62,554.51	3,323	3,243	49,929	7.50	6,657
	543,957.82	170,178	166,059	296,305		58,782
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2001	35,890.70	26,694	28,077	2,430	1.00	2,430
2006	49,030.29	31,830	33,479	8,197	1.89	4,337
2008	8,600.00	5,190	5,459	1,851	2.32	798
2010	30,182.50	16,868	17,742	7,913	2.74	2,888
2011	104,377.58	53,565	56,340	32,381	3.17	10,215
2012	40,123.82	17,820	18,743	15,362	3.82	4,021
2013	91,179.58	32,648	34,339	43,163	4.63	9,322

PACIFIC NORTHERN GAS LTD.

ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2014	101,476.60	26,523	27,897	58,358	5.54	10,534
2015	104,540.04	16,661	17,524	71,335	6.50	10,975
2016	218,173.26	11,590	12,190	173,257	7.50	23,101
	783,574.37	239,389	251,791	414,247		78,621
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2013	40,077.00	14,350	13,741	20,325	4.63	4,390
	40,077.00	14,350	13,741	20,325		4,390
	3,692,148.06	1,194,382	1,226,618	1,911,708		379,780
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.0	10.29

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
1976	10,116.69	8,599	9,105			
1977	3,633.26	3,088	3,270			
1980	2,913.04	2,476	2,622			
1981	1,602.92	1,362	1,443			
1982	14,789.11	12,571	13,310			
1984	4,110.85	3,494	3,700			
1985	7,185.15	6,107	6,467			
1987	16,735.50	14,225	15,062			
1989	18,704.10	15,898	16,834			
1990	6,424.15	5,461	5,782			
1992	217,818.85	180,027	196,037			
1994	15,553.52	12,443	13,998			
1995	187,616.42	147,373	168,855			
1996	5,012.54	3,855	4,511			
1997	12,626.00	9,476	11,363			
1998	4,467.72	3,261	4,021			
1999	77,172.98	54,523	69,456			
2000	37,927.60	25,791	34,135			
2001	113,586.81	74,002	102,228			
2002	30,145.95	18,705	26,225	906	5.59	162
2003	113,176.28	66,434	93,144	8,715	6.26	1,392
2004	53,208.60	29,371	41,180	6,708	6.96	964
2005	180,327.56	92,868	130,206	32,089	7.70	4,167
2006	296,813.92	141,431	198,293	68,839	8.47	8,127
2007	653,989.75	285,467	400,239	188,352	9.27	20,318
2008	260,120.49	102,748	144,058	90,051	10.10	8,916
2009	279,630.62	98,430	138,004	113,664	10.96	10,371
2010	32,765.61	10,092	14,149	15,340	11.84	1,296
2011	3,295.00	867	1,216	1,750	12.74	137
2012	217,720.64	47,137	66,088	129,860	13.67	9,500
2013	15,696.90	2,661	3,731	10,396	14.61	712
2014	374,699.00	45,715	64,095	273,134	15.56	17,554
2015	354,475.21	26,055	36,530	282,497	16.53	17,090
2016	425,281.60	10,419	14,608	368,145	17.51	21,025
	4,049,344.34	1,562,432	2,053,964	1,590,446		121,731

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
1985	1,683.68	1,431	1,515			
1990	15,549.14	13,217	13,994			
1996	3,835.00	2,949	3,452			
1999	18,713.38	13,221	16,842			
2002	8,000.00	4,964	6,788	412	5.59	74
2004	50,703.52	27,988	38,274	7,359	6.96	1,057
2006	81,822.65	38,988	53,317	20,324	8.47	2,400
2007	6,948.38	3,033	4,148	2,106	9.27	227
2009	18,591.70	6,544	8,949	7,784	10.96	710
2012	5,855.32	1,268	1,734	3,536	13.67	259
2014	68,159.00	8,316	11,372	49,971	15.56	3,212
2015	13,123.55	965	1,320	10,492	16.53	635
2016	6,532.35	160	219	5,660	17.51	323
	299,517.67	123,044	161,923	107,643		8,897
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
1983	1,822.30	1,549	1,640			
1990	15,549.14	13,217	13,994			
1992	415.58	343	374			
1999	4,854.17	3,429	4,353	15	3.87	4
2001	2,854.17	1,859	2,360	209	4.97	42
2002	10,102.01	6,268	7,958	1,134	5.59	203
2003	20,376.14	11,961	15,185	3,153	6.26	504
2004	11,572.05	6,388	8,110	2,305	6.96	331
2006	26,439.59	12,598	15,994	7,802	8.47	921
2008	153,705.35	60,714	77,081	61,254	10.10	6,065
2009	355,029.61	124,970	158,658	160,869	10.96	14,678
2010	8,842.48	2,723	3,457	4,501	11.84	380
2011	107,328.71	28,227	35,836	60,760	12.74	4,769
2012	49,902.69	10,804	13,716	31,196	13.67	2,282
2013	48,948.62	8,297	10,534	33,520	14.61	2,294
2015	98,098.50	7,211	9,155	79,134	16.53	4,787
2016	292,781.67	7,173	9,107	254,397	17.51	14,529
	1,208,622.78	307,731	387,512	700,249		51,789

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
2002	82,503.75	51,193	73,931	323	5.59	58
2010	5,143.21	1,584	2,288	2,341	11.84	198
2011	12,540.90	3,298	4,763	6,524	12.74	512
2012	7,121.00	1,542	2,227	4,182	13.67	306
2016	10,191.75	250	361	8,812	17.51	503
	117,500.61	57,867	83,569	22,182		1,577
	5,674,985.40	2,051,074	2,686,968	2,420,520		183,994
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					13.2	3.24

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	78,942.60	74,995	61,252	17,690	1.00	17,690
1998	124,786.07	115,427	94,275	30,511	1.50	20,341
1999	198,545.26	173,727	141,892	56,653	2.50	22,661
2000	131,778.11	108,717	88,795	42,983	3.50	12,281
2001	103,936.01	80,550	65,789	38,147	4.50	8,477
2002	180,593.19	130,930	106,937	73,656	5.50	13,392
2003	91,983.23	62,089	50,711	41,272	6.50	6,350
2004	130,906.42	81,817	66,824	64,082	7.50	8,544
2005	100,110.93	57,564	47,016	53,095	8.50	6,246
2006	215,843.12	113,318	92,553	123,290	9.50	12,978
2007	170,594.05	81,032	66,183	104,411	10.50	9,944
2008	110,299.76	46,877	38,287	72,013	11.50	6,262
2009	85,020.84	31,883	26,041	58,980	12.50	4,718
2010	124,331.19	40,408	33,003	91,328	13.50	6,765
2011	89,966.97	24,741	20,207	69,760	14.50	4,811
2012	124,295.34	27,966	22,841	101,454	15.50	6,545
2013	77,927.96	13,637	11,138	66,790	16.50	4,048
2014	233,823.83	29,228	23,872	209,952	17.50	11,997
2015	84,766.95	6,358	5,193	79,574	18.50	4,301
2016	354,850.06	8,871	7,245	347,605	19.50	17,826
	2,813,301.89	1,310,135	1,070,056	1,743,246		206,177
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	8,116.29	7,710	7,263	854	1.00	854
1998	31,401.13	29,046	27,361	4,040	1.50	2,693
1999	29,340.27	25,673	24,183	5,157	2.50	2,063
2000	43,537.58	35,919	33,835	9,703	3.50	2,772
2002	19,813.60	14,365	13,532	6,282	5.50	1,142
2003	27,669.37	18,677	17,593	10,076	6.50	1,550
2004	20,725.31	12,953	12,201	8,524	7.50	1,137
2005	24,991.41	14,370	13,536	11,455	8.50	1,348
2006	29,127.87	15,292	14,405	14,723	9.50	1,550
2007	17,802.98	8,456	7,965	9,838	10.50	937
2008	15,866.70	6,743	6,352	9,515	11.50	827
2009	45,471.30	17,052	16,063	29,409	12.50	2,353
2010	42,614.13	13,850	13,046	29,568	13.50	2,190
2012	30,387.47	6,837	6,440	23,947	15.50	1,545

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	33,998.45	5,950	5,605	28,394	16.50	1,721
2014	10,105.90	1,263	1,190	8,916	17.50	509
2015	29,764.36	2,232	2,102	27,662	18.50	1,495
2016	18,597.22	465	438	18,159	19.50	931
	479,331.34	236,853	223,111	256,221		27,617
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	33,744.46	27,839	25,987	7,758	3.50	2,217
2001	54,152.26	41,968	39,175	14,977	4.50	3,328
2002	32,346.57	23,451	21,891	10,456	5.50	1,901
2003	41,311.94	27,886	26,030	15,282	6.50	2,351
2004	78,642.21	49,151	45,880	32,762	7.50	4,368
2005	29,869.04	17,175	16,032	13,837	8.50	1,628
2006	54,115.66	28,411	26,520	27,595	9.50	2,905
2007	22,872.15	10,864	10,141	12,731	10.50	1,212
2008	20,472.51	8,701	8,122	12,350	11.50	1,074
2009	15,886.01	5,957	5,561	10,325	12.50	826
2010	28,294.09	9,196	8,584	19,710	13.50	1,460
2011	24,081.22	6,622	6,181	17,900	14.50	1,234
2012	9,377.85	2,110	1,970	7,408	15.50	478
2013	68,245.90	11,943	11,148	57,098	16.50	3,460
2014	35,597.00	4,450	4,154	31,443	17.50	1,797
2015	24,192.97	1,814	1,693	22,500	18.50	1,216
2016	40,597.37	1,015	947	39,650	19.50	2,033
	613,799.21	278,553	260,018	353,782		33,488
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	268.47	221	204	65	3.50	19
2001	3,550.80	2,752	2,538	1,013	4.50	225
2002	248.62	180	166	83	5.50	15
2003	3,168.74	2,139	1,972	1,196	6.50	184
2004	2,774.67	1,734	1,599	1,176	7.50	157
2005	5,598.10	3,219	2,968	2,630	8.50	309

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	9,241.00	4,852	4,474	4,767	9.50	502
2008	14,980.00	6,366	5,870	9,110	11.50	792
2009	4,193.30	1,572	1,450	2,744	12.50	220
2010	4,472.68	1,454	1,341	3,132	13.50	232
2011	14,968.43	4,116	3,796	11,173	14.50	771
2012	11,678.27	2,628	2,423	9,255	15.50	597
2014	2,507.35	313	289	2,219	17.50	127
2015	5,595.37	420	387	5,208	18.50	282
	83,245.80	31,966	29,477	53,769		4,432
	3,989,678.24	1,857,507	1,582,662	2,407,018		271,714

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.9 6.81

PACIFIC NORTHERN GAS LTD.

ACCOUNT 487.00 - GENERAL - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	290,071.50	232,057	211,889	78,183	1.00	78,183
2013	53,939.54	37,758	34,476	19,463	1.50	12,975
2014	39,275.46	19,638	17,931	21,344	2.50	8,538
2015	40,714.48	12,214	11,152	29,562	3.50	8,446
2016	140,460.21	14,046	12,825	127,635	4.50	28,363
	564,461.19	315,713	288,274	276,187		136,505
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,997.80	2,999	2,225	3,773	2.50	1,509
2015	1,506.76	452	335	1,171	3.50	335
2016	1,885.48	189	140	1,745	4.50	388
	9,390.04	3,640	2,700	6,690		2,232
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	1,942.30	1,554	995	947	1.00	947
2013	3,334.49	2,334	1,494	1,840	1.50	1,227
2015	7,963.60	2,389	1,530	6,434	3.50	1,838
2016	17,618.46	1,762	1,128	16,490	4.50	3,664
	30,858.85	8,039	5,147	25,712		7,676
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	2,675.00	268		2,675	4.50	594
	2,675.00	268		2,675		594
	607,385.08	327,660	296,122	311,264		147,007

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.1 24.20

PACIFIC NORTHERN GAS LTD.

ACCOUNT 488.00 - GENERAL - COMMUNICATION STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	176,126.87	163,546	158,975	17,152	1.00	17,152
2005	23,066.11	18,947	18,417	4,649	2.50	1,860
2006	20,037.74	15,028	14,608	5,430	3.50	1,551
2010	49,469.34	22,968	22,326	27,143	7.50	3,619
2011	4,151.08	1,631	1,585	2,566	8.50	302
2016	114,958.55	4,105	3,990	110,968	13.50	8,220
	387,809.69	226,225	219,902	167,908		32,704
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	19,995.39	9,284	8,083	11,912	7.50	1,588
2016	15,665.78	559	487	15,179	13.50	1,124
	35,661.17	9,843	8,570	27,091		2,712
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	10,845.74	10,071	8,572	2,274	1.00	2,274
2013	30,000.00	7,500	6,384	23,616	10.50	2,249
2016	15,665.78	559	476	15,190	13.50	1,125
	56,511.52	18,130	15,431	41,080		5,648
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	1,794.63	1,218	1,065	730	4.50	162
	1,794.63	1,218	1,065	730		162
	481,777.01	255,416	244,967	236,809		41,226

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.7 8.56

PACIFIC NORTHERN GAS LTD.

ACCOUNT 489.00 - OTHER GENERAL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
2009	2,000.00	675	1,728	272	13.25	21
	2,000.00	675	1,728	272		21

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0 1.05

APPENDIX A – ESTIMATION OF SURVIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

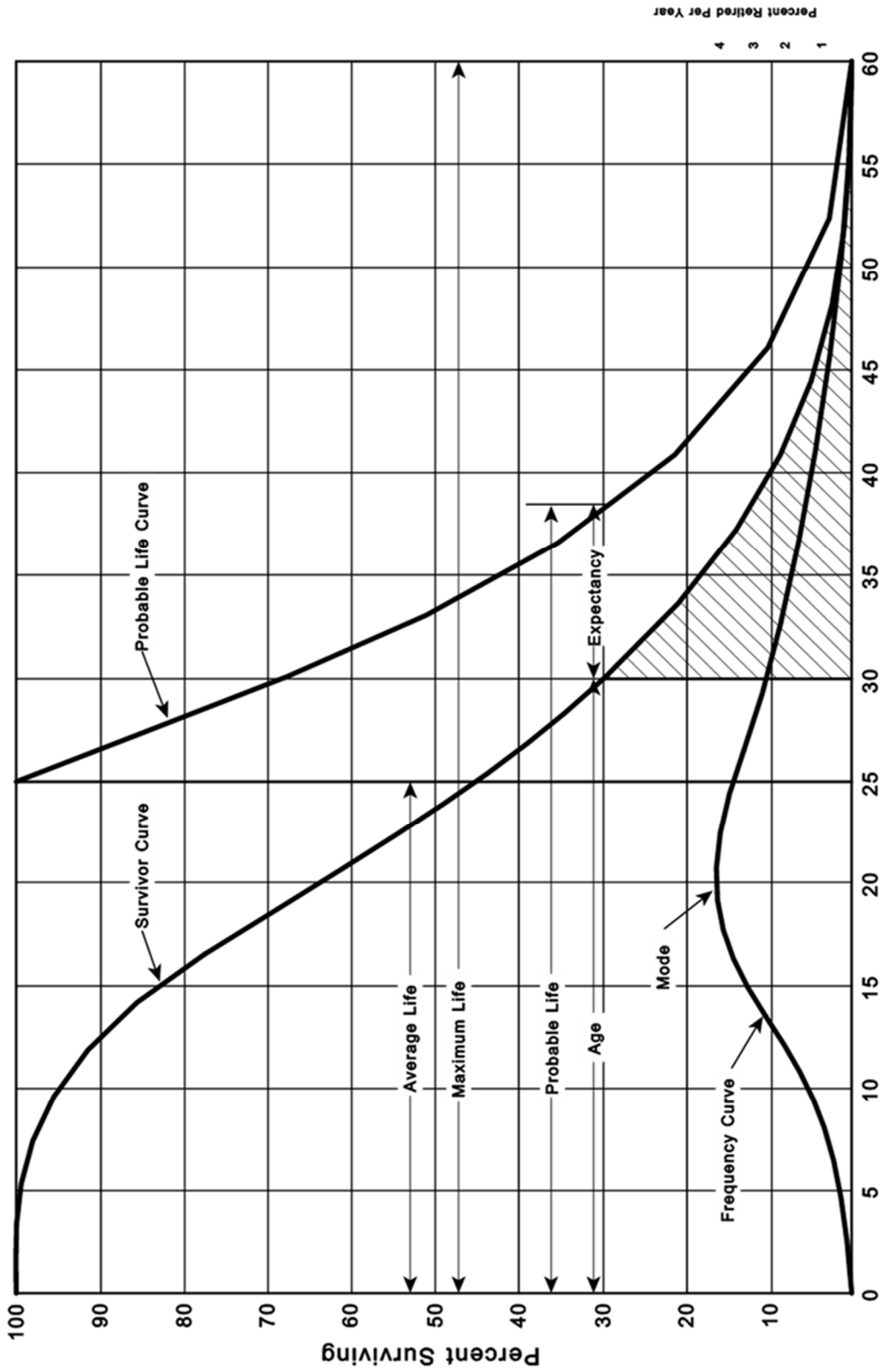


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

[1] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.
[2] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[3] Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

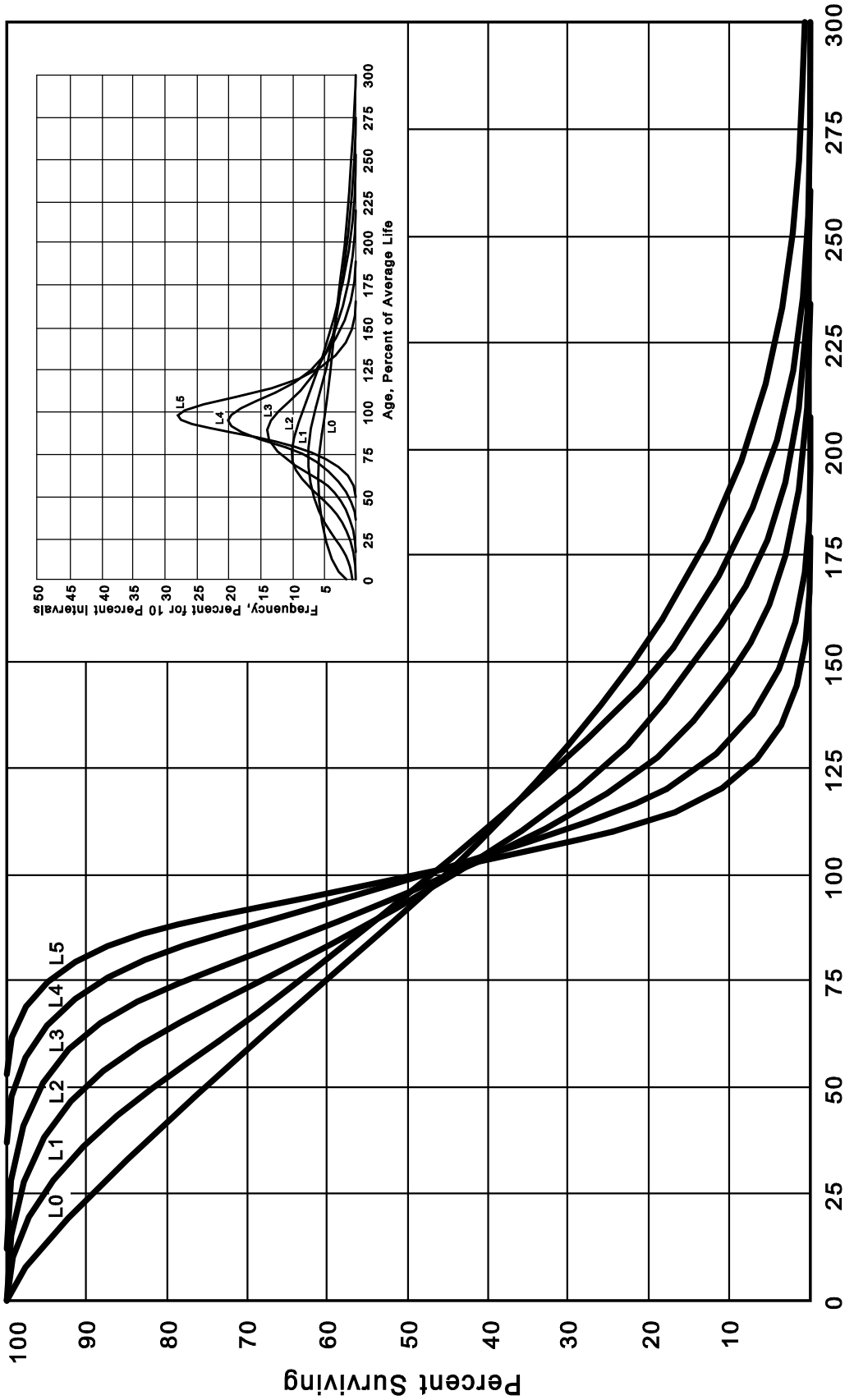


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

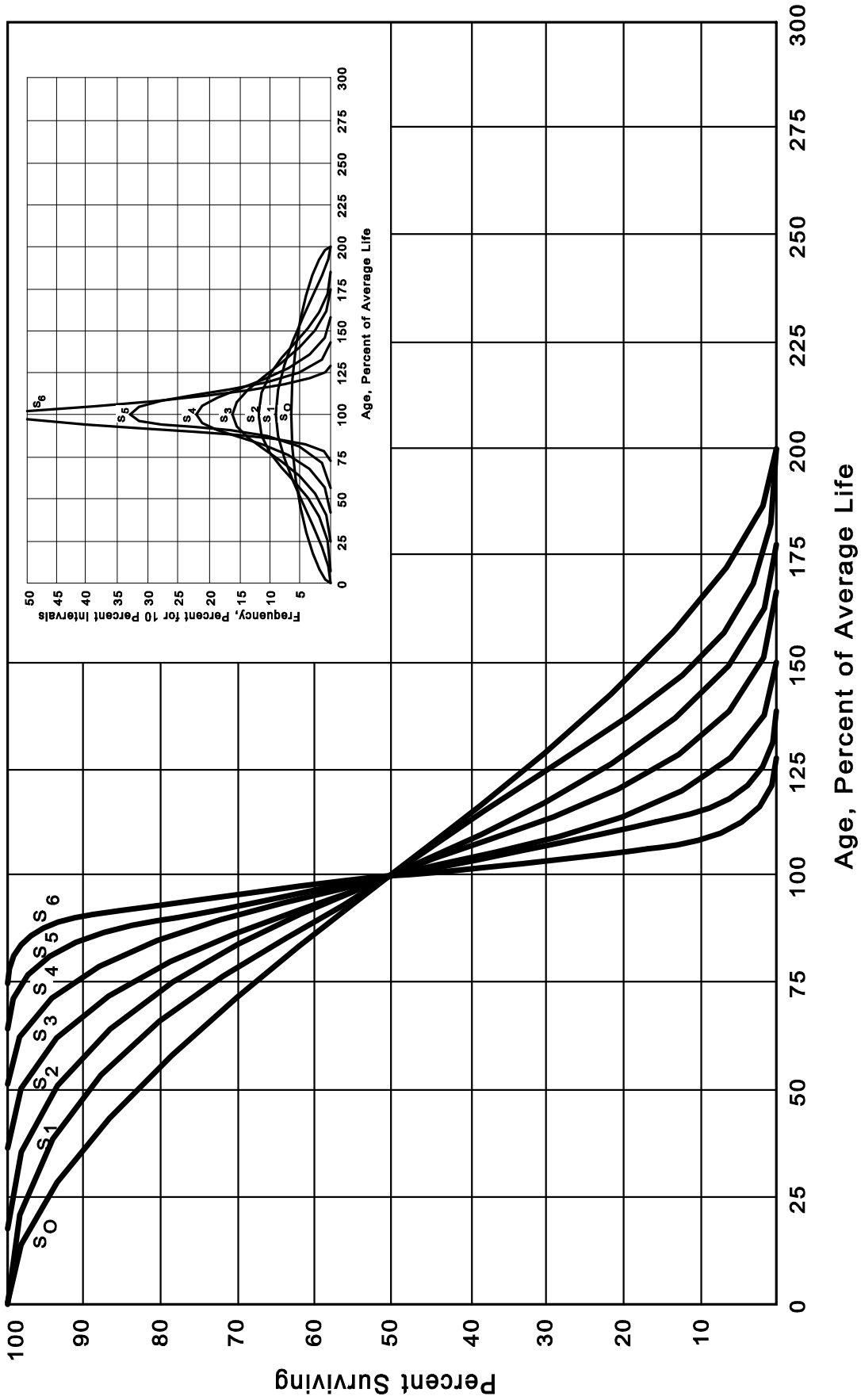


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

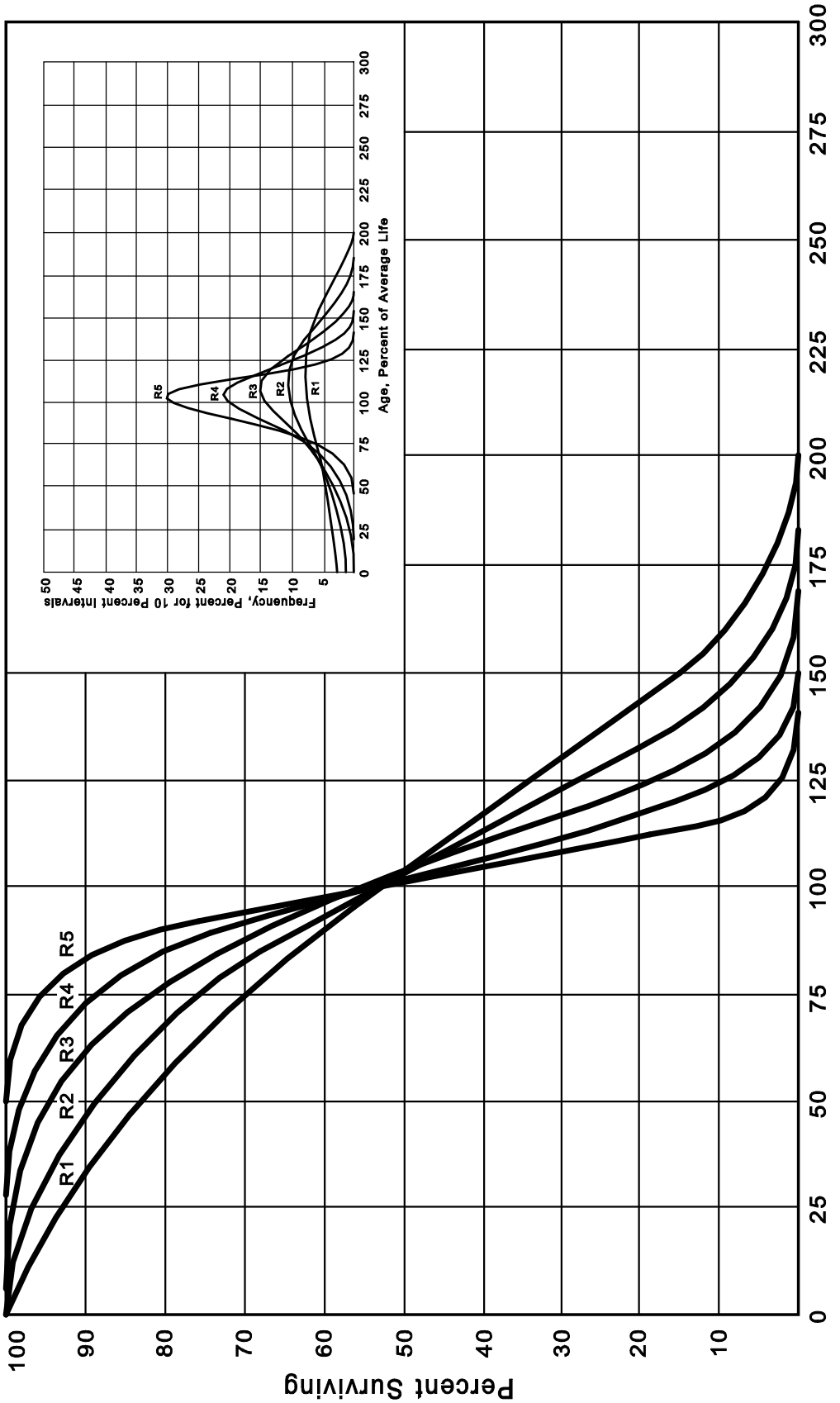


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

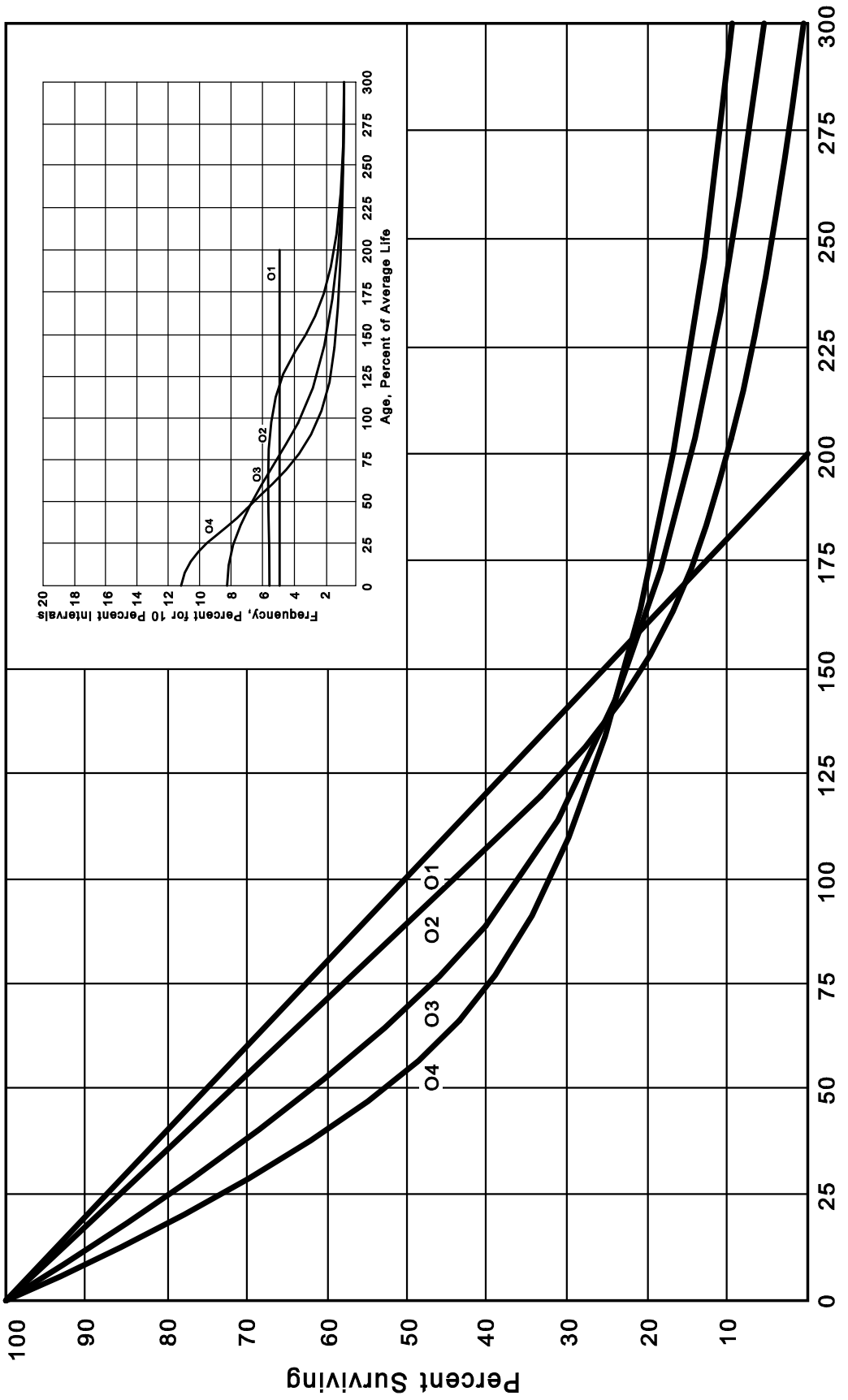


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2007-2016 during which there were placements during the years 2007-2016. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2002 were

[4] Winfrey, Robley, Supra Note 1.
[5] Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[6] Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2002-2016

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2003	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2004	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2005	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2006	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2007	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2008		5	11	12	13	14	15	16	18	20	113	7½-8½
2009			6	12	13	15	16	17	19	19	124	6½-7½
2010				6	13	15	16	17	19	19	131	5½-6½
2011					7	14	16	17	19	20	143	4½-5½
2012						8	18	20	22	23	146	3½-4½
2013							9	20	22	25	150	2½-3½
2014								11	23	25	151	1½-2½
2015									11	24	153	½-1½
2016										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2007-2016

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2003	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2004	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2005	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2006	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2007	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2008		-	-	-	-	-	-	-	-	-	-	7½-8½
2009			-	-	-	-	-	-	-	-	-	6½-7½
2010				-	-	-	-	(12)[b]	-	-	-	5½-6½
2011					-	-	-	-	22[a]	-	-	4½-5½
2012						-	-	(19)[b]	-	-	10	3½-4½
2013							-	-	-	-	-	2½-3½
2014								-	-	(102)[c]	(121)	1½-2½
2015									-	-	-	½-1½
2016												0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

retired in 2007. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2007 retirements of 2002 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on the following page. The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2002-2016

Year Placed	Exposures, Thousands of Dollars, Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2003	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2004	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2005	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2006	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2007	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2008		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2009			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2010				580[a]	574	561	546	530	501	482	3,057	5½-6½
2011					660[a]	653	639	623	628	609	3,789	4½-5½
2012						750[a]	742	724	685	663	4,332	3½-4½
2013							850[a]	841	821	799	4,955	2½-3½
2014								960[a]	949	923	5,719	1½-2½
2015									1,080[a]	1,069	6,579	½-1½
2016										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2006-2015, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on the following page, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the

retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2007-2016 Placement Band 2002-2016

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning o Age Interva (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	3,789,000		
Retirements from age 4½ to 5½	=	143,000		
Retirement Ratio	=	143,000 ÷ 3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year

average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

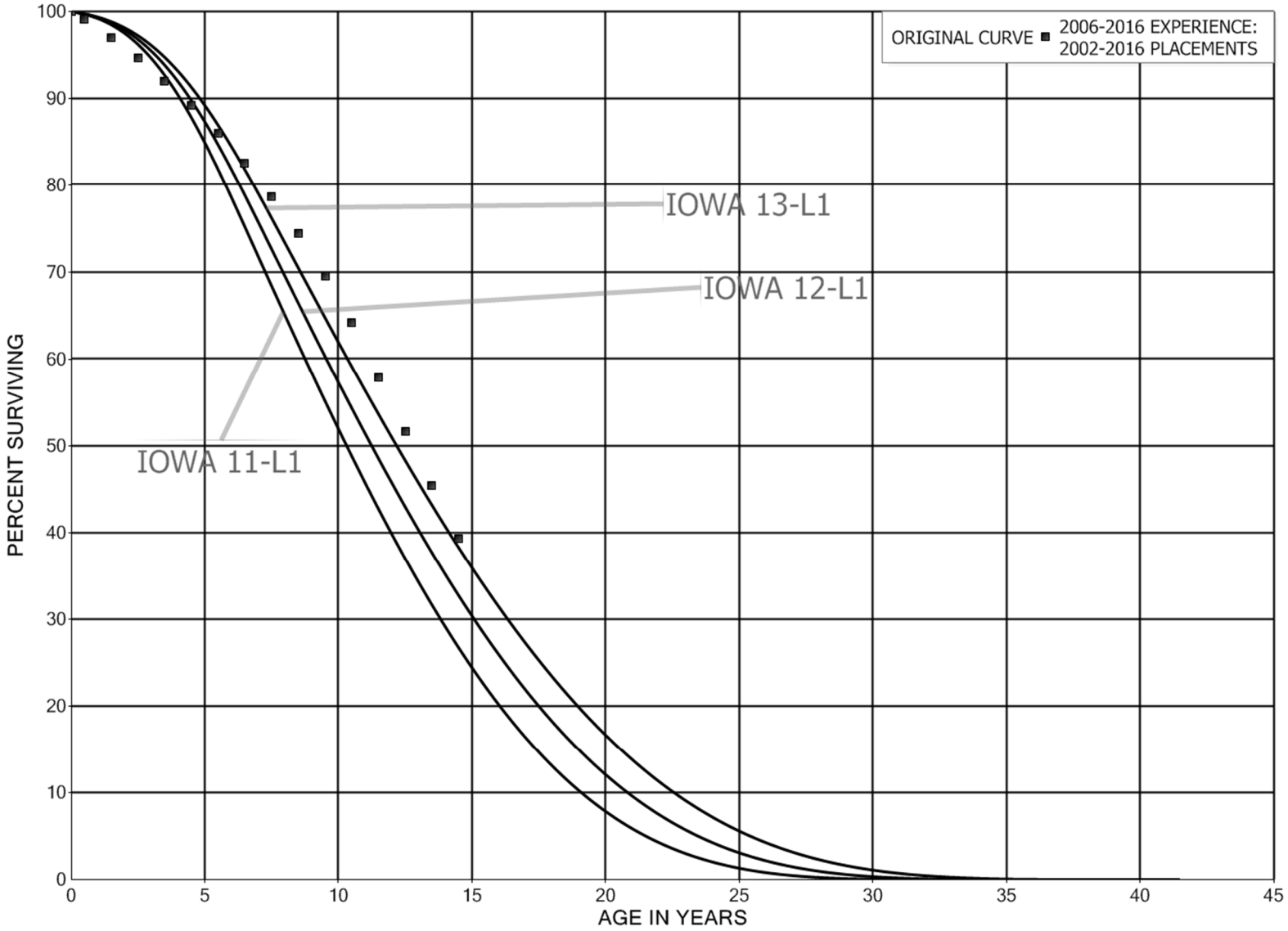


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

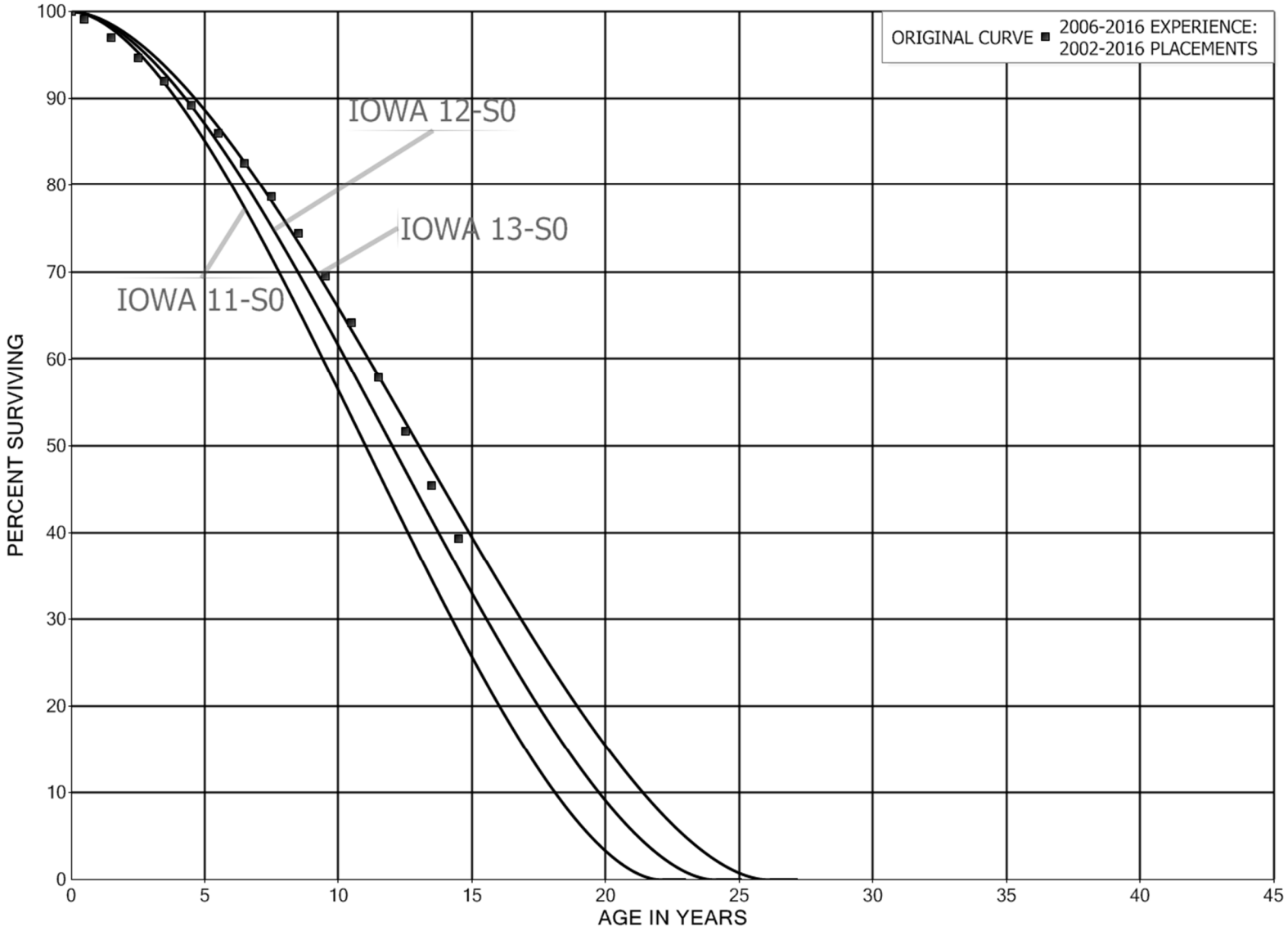


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

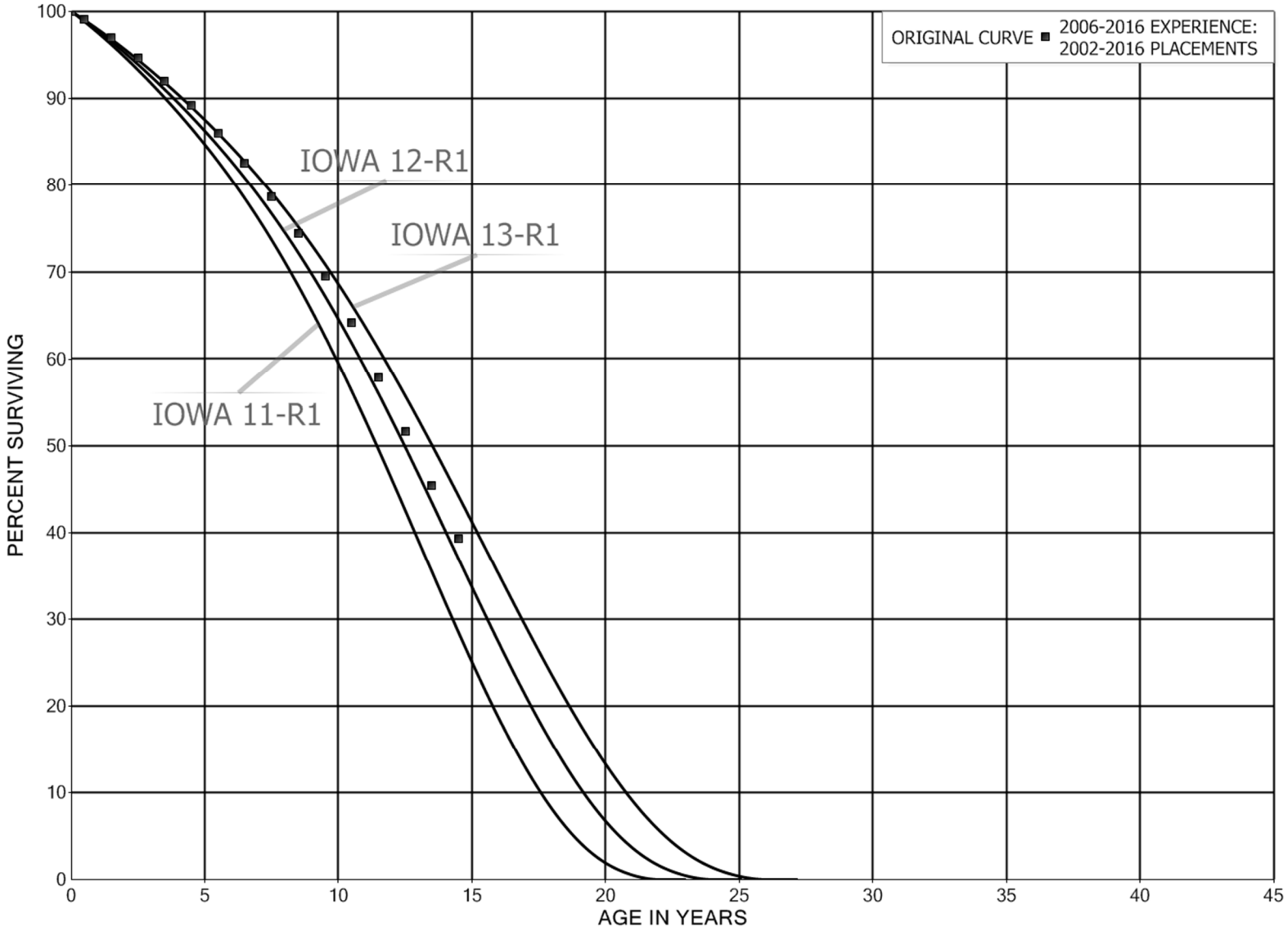
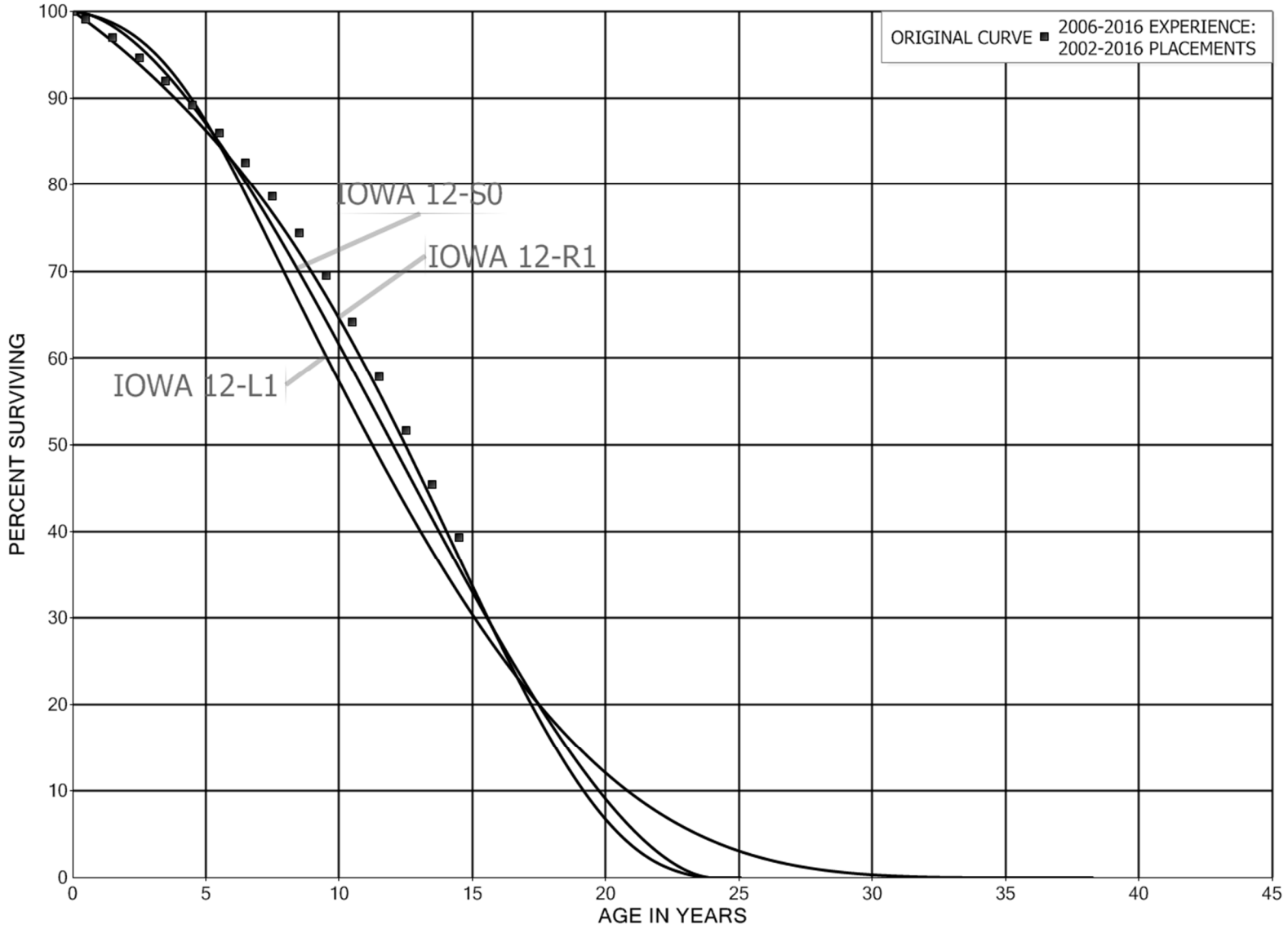


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



APPENDIX B – ESTIMATION OF NET SALVAGE

ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric Advisors, in part on historical data for the years 2010 through 2016, and in part through a comparison to peer gas utility companies. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on both annual and five-year moving average bases.The net salvage percentages estimated in this study have been determined using the "Traditional Approach" for net salvage estimation. The estimates of net salvage were based in part on the database of historic transactions encompassing the period from 2010 through 2016.

When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used a salvage proceed (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the accounts original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage percentage results.

The estimation of the net salvage percentages developed using the traditional approach, included the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period January 1, 2010 through December 31, 2016 were extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) was calculated for each historic year. Additionally, a net salvage amount was also calculated for each historic five-year.
3. The net salvage amount determined above was compared to the original booked costs retired for each period in the manner described, which resulted in a net salvage percentage of original costs retired for each year, in addition to five-year rolling bands.

4. The annual and five-year rolling average net salvage percentages were analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage was based purely upon statistical analysis.
5. Each account was then analyzed based on the statistical analyses, were compared to a group of peer gas utilities, and with the professional judgment of Concentric Advisors. Based on this analysis, a net salvage percentage for each account was determined.
6. The net salvage percentage was then used in the depreciation rate calculations in the depreciation study.

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APPENDIX D – Econolink Extract – January 2018

CANADIAN FORECASTS - 2018

Annual percent change, seasonally adjusted
(except where noted)

2018 FORECAST

	Royal Bank	CIBC	Bank of Montreal	Scotia Bank	TD Bank	FORECAST RANGE	2018 FORECAST AVERAGE
ECONOMIC ACTIVITY							
Real GDP*	1.9	2.1	2.2	2.3	2.4	1.9 - 2.4	2.2
Unemployment Rate	5.9	5.7	5.6	5.9	6.0	5.6 - 6.0	5.8
Consumer Price Index	2.1	2.1	2.0	1.9	1.8	1.8 - 2.1	2.0
THE CONSUMER							
Real Consumer Spending*	2.1	2.4	2.5	2.8	2.9	2.1 - 2.9	2.5
Motor Vehicle Sales *(%chg)*	-5.3	na	-5.8	-2.0	na	-5.8 - -2.0	-4.4
Housing Starts *(million units)*	0.197	0.195	0.205	0.206	0.198	0.195 - 0.206	0.200
% chg	-6.3	-11.8	-7.2	-6.8	-10.4	-11.8 - -6.3	-8.5
BUSINESS							
Business Non-Residential Invst*	3.6	2.9	2.9	3.6	4.1	2.9 - 4.1	3.4
Corporate Profits *(before tax)*	0.2	na	3.1	5.0	4.9	0.2 - 5.0	3.3
Imports*	2.2	2.4	1.7	2.4	1.9	1.7 - 2.4	2.1
Exports*	1.7	2.2	0.8	2.3	1.8	0.8 - 2.3	1.8
FINANCIAL							
Canada-Overnite Rate(%)	1.44	1.50	1.38	1.50	1.38	1.25 - 2.00	1.51
Prime Rate (%)	na	na	na	3.70	na	3.70 - 3.70	na
Exchange Rate *(cents U.S.- annual avg)*	na	na	0.79	na	na	0.79 - 0.79	0.79
(cents U.S.- end of period)	0.81	0.76	na	0.80	0.81	0.76 - 0.81	0.79
90 day T-bills *(annual average)*	2.05	1.21	1.35	1.55	1.44	1.21 - 2.05	1.52
10 yr Gov't Bonds *(annual average)*	2.95	2.19	2.35	2.39	2.35	2.19 - 2.95	2.45

* *indicates chain weighted $2007 dollars, change after subtracting inflation.*

CANADIAN FORECASTS - 2019

Annual percent change, seasonally adjusted
(except where noted)

2019 FORECAST

	Royal Bank	CIBC	Bank of Montreal	Scotia Bank	TD Bank	FORECAST RANGE	2019 FORECAST AVERAGE
ECONOMIC ACTIVITY							
Real GDP*	1.6	1.6	1.8	1.7	1.8	1.6 - 1.8	1.7
Unemployment Rate	5.9	5.6	5.4	5.9	6.0	5.4 - 6.0	5.8
Consumer Price Index	2.0	2.1	2.0	2.1	2.0	2.0 - 2.1	2.0
THE CONSUMER							
Real Consumer Spending*	1.4	1.3	1.8	1.9	1.7	1.3 - 1.9	1.6
Motor Vehicle Sales *(%chg)*	-2.0	na	-2.6	-2.5	na	-2.6 - -2.0	-2.4
Housing Starts *(million units)*	0.193	0.178	0.195	0.196	0.193	0.178 - 0.196	0.191
% chg	-2.0	-8.7	-4.9	-4.9	-2.5	-8.7 - -2.0	-4.6
BUSINESS							
Business Non-Residential Invst*	2.1	2.6	2.4	2.6	3.4	2.1 - 3.4	2.6
Corporate Profits *(before tax)*	-0.7	na	9.6	1.0	5.7	-0.7 - 9.6	3.9
Imports*	2.0	2.5	2.0	2.7	2.8	2.0 - 2.8	2.4
Exports*	2.5	3.7	2.3	3.2	3.1	2.3 - 3.7	3.0
FINANCIAL							
Canada-Overnite Rate(%)	2.3	1.6	2.31	2.25	1.88	1.63 - 2.31	2.06
Prime Rate (%)	na	na	na	4.45	na	4.45 - 4.45	na
Exchange Rate *(cents U.S.- annual avg)*	na	na	0.81	na	na	0.81 - 0.81	0.81
(cents U.S.- end of period)	0.79	0.78	na	0.80	0.80	0.78 - 0.80	0.79
90 day T-bills *(annual average)*	2.15	1.60	2.20	2.29	1.94	1.60 - 2.29	2.04
10 yr Gov't Bonds *(annual average)*	2.80	2.32	2.85	2.74	2.73	2.32 - 2.85	2.69

* *indicates chain weighted $2007 dollars, change after subtracting inflation.*

APPENDIX E – 2017 Pipeline Risk Mitigation Report

(filed confidentially)

APPENDIX F – Business Risk Assessment – 2018 Update

Background

In the Commission's Decision on the 2012 Generic Cost of Capital (2012 GCOC) Proceeding Stage 2, as per Order G-77-13, Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E). Ltd. (collectively, PNG) were directed as follows:

> *"… the Commission Panel directs PNG utilities to include an updated business risk assessment in all future revenue requirements applications."*[1]

The direction given by the Commission was to acknowledge that the PNG utilities face a unique set of circumstances with respect to the level of business risk. Further, the direction given acknowledged that the determinations made in the 2012 GCOC proceeding were based on an assessment of the business risks as they existed at the time of the proceeding with little weight placed on the potential for change to these risks in the future. The example was given that, should the various LNG initiatives contemplated in the region become a reality, the business risk would shift accordingly. Potential developments in the mining industry were also cited as an example.

The Commission's primary interest in this directive was to ensure that PNG's business risk assessment remains contemporary, and that PNG's cost of capital is aligned with the assessment.

In response to this direction, PNG provides the following business risk assessment update at the consolidated entity level as risks of all individual regulated divisions (PNG-West and PNG(NE), consisting of Fort St. John and Dawson Creek (FSJ/DC) and Tumbler Ridge (TR)) are considered somewhat similar.

[1] Section 3.3.7 Commission Cost of Capital Determination, BCUC Decision on the 2012 Generic Cost of Capital Proceeding Stage 2, p. 114

Overview

PNG's business risk profile has been trending higher since the last risk assessment was provided with the 2016-2017 Revenue Requirements Application due to certain events that have arisen since 2016. None of the potential LNG initiatives have proceeded at this time and developments in the mining and other industrial sectors in PNG's service territory have not yet materialized. Other factors that have arisen that have a potential negative effect on PNG include: the impact of the Federal and Provincial governments' climate change initiatives, the trend towards electrification and reduced use of fossil fuels, and the potential changes in access to supply of natural gas for PNG.

PNG reported on seven key risk areas in 2016 and during Stage 2 of the 2012 GCOC. This current business risk analysis uses the same risk categorization to facilitate the Commission's review of how PNG's risks have evolved since the last report. The overall assessment of risk can be summarized as follows:

- For the majority of the risk categories identified, the risk assessment has remained stable or has increased slightly.
- The Western system will continue to be significantly under-utilized keeping pressure on delivery rates and the competitive position of natural gas.
- PNG's filing of two-year revenue requirements applications commencing with the 2016 and 2017 period has resulted in higher regulatory lag and has increased forecasting risk.
- Climate change initiatives may negatively impact the demand for natural gas.

Taking the above into account, PNG entities' overall business risk has been assessed as slightly higher than 2012 and 2016 when this assessment was last updated, with increasing cautionary items of note.

Assessment of Business Risks

Aboriginal Rights

PNG's territory spans virtually the entire Province on an east to west basis, and thus traverses many areas that are currently within existing First Nation territories or within disputed First Nation areas. The PNG-West service area includes 17 different First Nations and PNG-West facilities are located in the traditional territory of "non-treaty" which serves to increase uncertainty. PNG(NE)'s system lies primarily in the "group of eight" First Nations which have a treaty in place with senior governments.

Given PNG's smaller size and resources, the numerous requirements for dealing with various aspects of Aboriginal Rights represent a much more resource intensive effort. The assessment of this risk continues to remain consistent with that made in 2016 and in 2012, but with an increasing trend given recent court cases.

Competitive Position of Natural Gas

This risk relates to the natural gas commodity price risk and price competitiveness of natural gas compared to other energy sources.

Commodity prices continue to be lower than in 2016 and 2012, and market prices have shown less volatility in recent years. In terms of competitiveness, natural gas continues to be a cost effective alternative to electricity for space and water heating but the upfront installation costs are higher and increases in the carbon tax rate have been enacted. PNG notes that the competitive position of natural gas has not improved, therefore this risk continues to be similar to 2012.

Customer Growth

Customer growth is a very significant factor in the operation of a transmission/distribution utility. The safe, reliable and efficient operation of PNG's pipeline infrastructure requires ongoing operating and maintenance costs which need to be covered by its customer base. A slow-down in the customer growth combined with a continuing decline in usage per customer, primarily as a result of more efficient homes and appliances, translates into increasing delivery rates.

PNG-West's customer base suffered a decline during the 2003 to 2012 period and has remained flat over the 2013 to 2017 period. The PNG(NE) Fort St. John/Dawson Creek (FSJ/DC) service area has experienced an average customer growth rate of approximately 2%

per year, though that trend has recently slowed significantly reflecting the effect that the very low commodity prices in the natural gas production sector have had on the economy of the area. The PNG(NE) Tumbler Ridge (TR) service area had experienced small growth of less than 1% over the 2003-2012 period, however the 2013 to 2017 period has seen a slight decrease in the customer base. As a result, this risk continues to be similar to 2012 with a declining trend.

The future for customer growth has become more uncertain under the climate change policies of both the Provincial and Federal Governments. As a fuel which produces carbon dioxide emissions when combusted, natural gas is subject to potential prescriptive policies which favour electrification and which would negatively influence natural gas demand regardless of its price competitiveness.

However, PNG is evaluating various initiatives to add customer growth that entail connecting off-grid customers and also providing renewable natural gas to customers.

Market Demand and Throughput

This risk considers the various elements that influence PNG's ability to attract new customers and retain its existing customer base and throughput.

Due to the loss of several very significant customers, PNG-West saw its total system throughput decline by 87% during the 2003 to 2012 period. There has been some recovery of this loss during the period 2013 to 2016, with throughput increasing by 12%. In the 2016/17 Application, PNG had initially shared that it was in the process of negotiating the final terms for a customer to contract for PNG-West's spare transmission capacity (Douglas Channel LNG). Unfortunately this project was cancelled subsequently and no similar projects to make use of the excess capacity have advanced. Consequently, the PNG-West system continues to be significantly under-utilized.

With respect to other industrial demand, the modernization of the Rio-Tinto Alcan smelter located in Kitimat that was completed in 2015 has helped to stabilize throughput on the PNG-West system, however in the absence of attracting other large industrial customers to the system there is a continued dependency on this customer to maintain throughput volumes.

For the remainder of the PNG-West service area, in terms of the "more stable" residential and small commercial customer counts, PNG continues to experience declines in Usage per Account (UPA) in both the residential and small commercial customers.

For PNG(NE) FSJ/DC, overall throughput has decreased over the 2013 to 2016 period with a declining trend in residential UPA but a relatively stable UPA for its small commercial customers. Demand in the oil and gas sector, representing the vast majority of industrial demand in this area, has generally been falling in response to depressed oil and gas prices.

Due to its smaller size, the PNG(NE) TR service area faces a significantly greater level of volatility, both in terms of customer count and overall throughput. During the 2013 to 2017 period, PNG(NE) TR has experienced significant volatility in demand by CNRL for its natural gas field facilities, due both to operational and market-related pressures on CNRL's service requirements. Further, an anticipated increase in demand from coal mining in the area has not materialized due to very depressed coal prices. In fact, the shut in of some mining operations has further reduced economic activity in the area. In terms of UPA, both the residential and small commercial customers have shown a declining trend since 2012.

Accordingly, given PNG has faced some significant challenges and experienced continued volatility, and given the fact that the Douglas Channel LNG project was cancelled, this risk is assessed to have increased since 2012, but is consistent with the 2016 assessment.

Regulatory Risk

Regulatory risk is the risk that the allowed return does not accord with the Fair Return Standard and that rates are set at a level that does not provide PNG with an opportunity to earn a fair return or that requested capital investments are not approved.

In the 2012 risk assessment, PNG had identified a number of areas where it had either received treatment or decisions that had been inconsistent, or the impact to PNG was much greater due to its small size. Further to the 2012 risk assessment, the implementation of two-year revenue requirements applications commencing the 2016-2017 period has created further regulatory lag and has increased PNG's forecasting risk. In spite of this added forecasting uncertainty, PNG considers this risk to have remained largely consistent during the period from the initial assessment in 2012 to the present date.

Supply Risk

PNG reiterates that this risk continues to be high as PNG only has one access point for all of its gas supply. Compared to 2012, the natural gas transportation infrastructure in PNG's service territory has remained relatively unchanged. However, Enbridge (formerly Spectra) has recently indicated that it may reallocate capacity that was previously designated to

Summit Lake down to Huntingdon. This would potentially hinder economic growth in PNG's service areas as new customers would not be able to access transportation capacity.

Other Risks

Other risks include Operating Risk, Size Specific Risk and Competition Risk. For the Operating Risk, there has been no change to the service areas in which PNG operates, which are characterized by northern, mountainous and generally harsher climate, factors that increase the cost of operating and maintaining a safe, reliable and efficient pipeline system. PNG continues to carry a $2 million deductible on its insurance program in relation to pipeline breaks.

PNG's aging infrastructure requires additional maintenance and refurbishment costs to maintain system reliability and pipeline integrity as PNG faces risks associated with corrosion, geotechnical instability, and obsolete equipment. In addition, pipeline codes, standards, and regulations are becoming more stringent in the face of heightened stakeholder expectations arising from pipeline incidents across North America. The combination of an aging infrastructure, heightened regulations, and low customer growth translates to incremental pressure to maintain service levels while managing customer rates.

For the Size Specific Risk and the Competition Risk, PNG considers both of these risks similar to 2012 and 2016 as no changes have taken place in the environment in which PNG operates.

Conclusion

PNG submits that the business risks for each of its entities have been trending higher since 2012. However, PNG does not propose any changes to its cost of capital to compensate it for these increasing risks as the change has not been overly substantive at this time.

Tab Schedules

1 Utility Income & Return

2 Utility Rate Base

3 Income Taxes

4 Common Equity

5 Return on Capital

6 Rates

Tab 1

Utility Income & Return

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

UTILITY INCOME & RETURN

SCHEDULE 1
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Energy sales (TJ)	4 057	4 029	4 043	3 909	3 333	3,492	3,805	3 496	Tab 6, page 11 & 31
2	Average rate per GJ	$6.12	$5.58	$6.35	$6.05	$5.73	$6.98	$7.57	$6.55	
3										
4	Transportation service (TJ)	1 691	1 618	1 473	604	501	867	1,072	935	Tab 6, page 11 & 31
5	Average rate per GJ	$0.79	$0.75	$0.73	$1.87	$1.62	$1.82	$2.05	$1.44	
6										
7	Total deliveries (TJ)	5 747	5 647	5 516	4 513	3 834	4 359	4 877	4 431	Tab 6, page 11 & 31
8										
9	Utility revenue									
10	Energy sales	$24,050	$21,730	$24,635	$23,634	$19,104	$24,374	$28,785	$22,896	Tab 6, page 9 & 29
11	Interim rates - sales	789	766	1,031	0	0	0	0	0	Tab 6, page 8 & 28
12	Transportation service	1,274	1,167	1,013	1,131	809	1,578	2,200	1,350	Tab 6, page 9 & 29
13	Interim rates - transportation	54	50	59	0	0	0	0	0	Tab 6, page 8 & 28
14										
15	Total Utility Revenue	26,166	23,713	26,737	24,765	19,913	25,952	30,985	24,246	
16	Cost of sales	8,399	6,972	10,509	8,663	5,132	11,716	16,890	11,300	Tab 6, page 9 & 15, 29 & 35
17										
18	Gross margin	17,768	16,741	16,228	16,102	14,781	14,236	14,094	12,946	
19										
20	Operating expenses	5,929	5,842	5,560	5,638	5,192	5,481	5,142	4,992	Tab 1, page 2, line 6
21	Maintenance expenses	429	421	392	282	365	337	420	385	Tab 1, page 2, line 10
22	Admin. & general expenses	2,551	2,631	2,480	2,490	2,532	2,530	2,146	2,271	Tab 1, page 2, line 16
23	Property taxes	1,371	1,305	1,373	1,373	1,350	1,205	1,202	1,227	Tab 1, page 7, line 4
24	Depreciation	2,032	1,856	2,023	1,982	1,836	1,763	1,587	1,416	Tab 2, page 9 & 10, line 49
25	Amortization on gross deferrals	229	240	221	220	26	(514)	80	(310)	Tab 2, page 14 & 15, line 39 less line 26
26	Investment income, other revenue	(274)	(274)	(267)	(227)	(249)	(256)	(309)	(244)	Tab 1, page 8, line 7
29	2018/19 rate smoothing deferral	172	(165)							Tab 2, page 14 & 15, line 26
30	Interim to permanent rate adjustment	0	0	0	0	0	0	0	0	
31										
32		12,439	11,856	11,782	11,758	11,052	10,545	10,268	9,737	
33										
34	Earned return before income taxes	5,329	4,885	4,444	4,343	3,729	3,691	3,826	3,209	
35	Future Income taxes on deferrals	(34)	(20)	(31)	(31)	9	144	46	103	Tab 2, page 14 & 15, line 40
36	Income taxes	498	456	499	502	311	182	409	204	Tab 3, page 1, line 10
37										
38	Earned return	$4,865	$4,449	$3,976	3,873	3,408	$3,364	$3,370	$2,902	
39										
40	Utility rate base	$77,075	$71,128	$69,005	$67,384	$63,383	$59,450	$55,122	$48,231	Tab 2, page 1, line 23
41										
42	Return on rate base	6.31%	6.25%	5.76%	5.75%	5.38%	5.66%	6.11%	6.02%	Tab 5, page 1, line 18

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SUMMARY OF OPERATING, MAINTENANCE
& ADMINISTRATIVE & GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	OPERATING EXPENSES								
2	- wages	$2,329	$2,280	$2,192	$2,680	$2,304	$2,090	$1,874	$1,871
3	- gas	176	141	189	192	145	240	245	206
4	- transferred to capital	(284)	(230)	(181)	(192)	(196)	(174)	(146)	(138)
5	- other	3,708	3,651	3,360	2,958	2,939	3,324	3,169	3,052
6	Total Operating	5,929	5,842	5,560	5,638	5,192	5,481	5,142	4,992
7	MAINTENANCE EXPENSES								
8	- wages	132	129	126	86	105	93	144	166
9	- other	297	292	266	195	260	244	277	219
10	Total Maintenance	429	421	392	282	365	337	420	385
11	ADMINISTRATIVE AND GENERAL EXPENSES								
12	- wages	0	0	0	0	0	0	0	0
13	- benefits	769	774	781	745	756	773	710	877
14	- transferred to capital	(406)	(274)	(491)	(495)	(357)	(320)	(301)	(370)
15	- other	2,188	2,131	2,190	2,240	2,132	2,076	1,737	1,764
16	Total Admin & General	2,551	2,631	2,480	2,490	2,532	2,530	2,146	2,271
17	TOTAL EXPENSES	$8,909	$8,894	$8,431	$8,409	$8,089	$8,348	$7,708	$7,648

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

OPERATING EXPENSES

(000's)

Line No.	Account	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	664	Communications	$8	$8	$8	$3	$3	$15	$10	$11
2	665	Pipelines	248	244	195	198	153	300	264	153
3		Pipelines - Gas	176	141	189	192	145	240	245	206
4	667	Regulating stations	140	138	127	106	80	142	128	137
5		Regulating stations - Gas	0	0	0	0	0	0	0	0
6		Total transmission	572	530	518	499	381	697	647	508
7	670	Supervision	476	467	456	428	462	479	428	431
8	673	Removing & resetting meters	342	335	328	376	470	439	314	315
9	674	Service on customer premises	45	44	43	36	37	50	21	26
10	675	Mains and services	518	508	523	486	440	440	467	437
11	677	Regulating stations	16	16	15	16	16	31	22	17
12	679	Other	0	0	0	0	0	0	0	0
13		Total distribution	1,397	1,370	1,365	1,342	1,425	1,440	1,250	1,226
14	684	Communications	2	2	2	3	2	2	2	2
15	685	General systems operations	1,009	991	705	854	642	559	601	663
16		Shared Services from Parent	789	777	701	701	704	649	586	593
17	688	Other general operations	673	660	659	675	533	632	601	554
18	689	Transferred to capital	(284)	(230)	(181)	(192)	(196)	(174)	(146)	(138)
19		Total general	2,190	2,200	1,886	2,042	1,685	1,668	1,644	1,675
20	700	Sales supervision	16	15	15	11	24	12	18	18
21	701	Advertising	9	9	9	3	5	6	7	4
22	702	Demonstration and selling	2	2	2	0	0	0	0	0
23	709	Other	2	2	2	0	0	0	0	0
24		Total sales	29	29	28	14	29	17	26	22
25	711	Customer contracts	0	0	0	0	0	0	0	0
26		Shared Services from Parent	292	289	287	287	277	281	288	314
27	712	Meter reading	260	255	249	233	263	213	245	256
28	713	Customer billing	612	598	633	563	547	564	542	493
29		Shared Services from Parent	478	470	504	504	503	479	461	453
30	714	Credit and collections	16	16	16	8	16	59	9	8
31		Shared Services from Parent	29	29	37	37	32	36	29	38
32	718	Uncollectible accounts	52	56	36	111	36	26	0	0
33		Total customer accounting	1,740	1,713	1,762	1,741	1,672	1,659	1,574	1,562
34		Total operating	5,929	5,842	$5,560	$5,638	$5,192	$5,481	$5,142	$4,992

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

MAINTENANCE EXPENSES

(000's)

Line No.		Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	864	Communications	$0	$0	$0	$0	$0	($1)	$0	$1
2	865	Pipe lines	96	95	93	41	29	28	82	104
3	866	Compressors	0	0	0	0	0	0	0	0
4	867	Regulating stations	70	69	47	53	32	76	70	56
5		Total transmission	166	163	140	95	61	104	152	161
6	872	Structures	13	13	13	1	0	0	2	0
7	875	Mains and services	168	165	161	93	151	85	187	153
8	877	Regulating stations	8	8	8	1	2	3	2	4
9	878	Meters	73	72	71	92	150	145	77	68
10	879	Other	0	0	0	0	0	0	0	0
11		Total distribution	263	258	252	187	303	234	268	225
12	884	Communications	0	0	0	0	0	0	0	0
13	885	General	0	0	0	0	0	(0)	0	0
14		Total general	0	0	0	0	0	(0)	0	0
15		Total maintenance	$429	$421	$392	$282	$365	$337	$420	$385

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

ADMINISTRATIVE AND GENERAL EXPENSES
NET OF COST ADJUSTMENTS
(000's)

Line No.	Account	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	721	Administration	$24	$23	$42	$39	$36	$57	($18)	$45
2		Shared Services from Parent	1,566	1,525	1,596	1,596	1,519	1,443	1,249	1,197
3	722	Audit, legal & consulting fees	89	87	95	143	120	135	90	143
4	723	Insurance	97	94	63	71	72	77	76	76
5	724	Reserve for damages	0	0	0	0	0	0	0	0
6	725	Employee benefits	769	774	781	742	756	773	710	877
7	728	Shared Services from Parent	336	327	319	319	312	294	280	247
8		Regulation	74	72	73	71	70	67	57	49
9		Donations	3	2	2	3	1	2	2	1
10		Other	0	0	0	0	2	1	1	7
11	729	Transferred to capital	(406)	(274)	(491)	(495)	(357)	(320)	(301)	(370)
12		Subtotal general and administrative	$2,551	$2,631	$2,480	$2,490	$2,532	$2,530	$2,146	$2,271

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

ADMINISTRATIVE AND GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	721 Administration	$24	$23	$42	$39	$36	$57	($18)	$45
2	Shared Services from Parent	1,566	1,525	1,596	1,596	1,519	1,443	1,249	1,197
3	722 Audit, legal & consulting fees	89	87	95	143	120	135	90	143
4	723 Insurance	97	94	63	71	72	77	76	76
5	724 Reserve for damages	0	0	0	0	0	0	0	0
6	725 Employee benefits	771	776	783	745	756	773	710	877
7	728 Shared Services from Parent	336	327	319	319	312	294	280	247
8	Regulation	74	72	73	71	70	67	57	49
9	Donations	5	5	5	7	1	2	2	1
10	Other	0	0	0	0	2	1	1	7
11	729 Transferred to capital	(406)	(274)	(491)	(495)	(357)	(320)	(301)	(370)
12	Subtotal general and administrative	2,556	2,635	2,484	2,495	2,532	2,530	2,146	2,271
13	Cost adjustments								
14	728 - 50% of donations	(3)	(2)	(2)	(3)	0	0	0	0
15	725 - 1% portion of employee savings plan	(2)	(2)	(2)	(2)	0	0	0	0
16	Subtotal cost adjustments	(5)	(5)	(5)	(5)	0	0	0	0
17	Total general and administrative	$2,551	$2,631	$2,480	$2,490	$2,532	$2,530	$2,146	$2,271

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

TAXES OTHER THAN INCOME TAXES

(000's)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**PROPERTY TAXES**								
2	Regular	$1,200	$1,177	$1,168	$1,168	$1,145	$1,045	$1,043	$1,039
3	1% in lieu	171	129	205	205	205	160	158	188
4	TOTAL	$1,371	$1,305	$1,373	$1,373	$1,350	$1,205	$1,202	$1,227

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

MISCELLANEOUS OPERATING REVENUE

(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Penalty charges	$90	$90	$85	$74	$70	$84	$86	$83
2	Connection Fees	138	138	138	134	125	127	140	138
3	Rents	0	0	0	0	0	0	0	0
4	Overheads recovered	44	44	26	18	47	40	40	13
5	Automotive surcharges	0	0	0	0	0	0	0	0
6	Other	2	2	18	0	6	5	43	10
7		$274	$274	$267	$227	$249	$256	$309	$244

Tab 2

Utility Rate Base

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

UTILITY RATE BASE

SCHEDULE 2
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Plant in service beginning of year	$121,002	$112,286	$111,998	$109,675	$103,942	$96,945	$89,370	$82,233	Tab 2, page 4 & 5, line 46
2	Additions	6,858	8,780	4,748	4,253	6,670	7,198	7,914	7,731	Tab 2, page 4 & 5, line 46
3	Disposals	(177)	(64)	(49)	(1,642)	(937)	(201)	(340)	(594)	Tab 2, page 4 & 5, line 46
4										
5	Plant in service end of year	127,683	121,002	116,697	112,286	109,675	103,942	96,945	89,370	
6	Accumulated depreciation	41,420	39,235	39,161	37,116	36,277	34,766	32,789	(31,126)	Tab 2, page 9 & 10 line 43
7										
8	Net plant in service end of year	86,263	81,767	77,536	75,170	73,398	69,176	64,155	120,496	
9										
10	Net plant beginning of year	81,767	75,170	75,177	73,398	69,176	64,155	58,243	52,394	Tab 2, pages 6 & 11, net of lines 1 & 1
11										
12	Net plant in service midyear	84,015	78,468	76,356	74,284	71,287	66,666	61,199	55,319	
13	Contributions for construction	(10,110)	(10,189)	(10,316)	(10,192)	(10,308)	(9,932)	(9,315)	(9,017)	Tab 2, page 30, line 13
14	Tomslake net plant disallowance	(50)	(50)	(51)	(51)	(52)	(52)	(53)	(54)	Tab 2, page 31, line 7
15	Unamortized deferred charges	465	540	493	588	538	406	263	75	Tab 2, page 14 & 15, line 11
16	Deferred income taxes	0	0	0	0	0	0	0	(415)	Tab 2, page 34, line 9
17	Reserve for damages	0	0	0	0	0	0	0	0	
18	Pension funding in excess of expense	1,096	1,024	831	970	1,059	1,137	1,005	739	Tab 2, page 32, line 14
19	Non-pension post retirement	0	0	0	0	0	0	0	0	Tab 2, page 33, line 20
20	Cash working capital	841	825	854	1,164	427	335	639	918	Tab 2, page 16 & 23, line 10
21	Other working capital	818	510	838	622	432	890	1,385	667	Tab 2, page 22 & 29, line 15
22										
23	Utility rate base, midyear	$77,075	$71,128	$69,005	$67,384	$63,383	$59,450	$55,122	$48,231	

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE
ACTUAL 2016

(000s)

Line No.	Description	Jan/16 Beginning Balance	Actual Additions	Allocations	Transfers	Retirements	Dec/16 Ending Balance
1	Transmission plant						
2	460 Land	11					11
3	461 Land rights	432	27				459
4	462 Compressor structures	465					465
5	463 Regulating structures	146	63				209
6	465 Mains	12,306	400				12,707
7	466 Compressor equipment						
8	467 Regulating equipment	7,502	252			(25)	7,728
9	468 Communications	130	20				150
10	469 Other	18					18
11		21,011	762			(25)	21,748
12	Distribution plant						
13	470 Land	47					47
14	471 Land rights	222					222
15	472 Structures	1,889	144			(2)	2,031
16	473 Services	23,919	1,025			(49)	24,895
17	474 House installations	5,621	120				5,741
18	475 Mains	38,927	3,498				42,425
19	476 Compressor equipment						
20	477 Regulating equipment	1,582	153				1,735
21	478 Meters	2,572	222			(115)	2,679
22	479 Other	20					20
23		74,798	5,162			(166)	79,795
24	General plant						
25	480 Land	77					77
26	481 Land rights	1					1
27	482 Structures	2,048	55				2,103
28	483 Office equipment	346					346
29	484 Transportation equipment	1,540	281			(494)	1,328
30	485 Heavy work equipment	1,453	299			(244)	1,508
31	486 Tools	1,373	59			(9)	1,424
32	487 Computer equipment	945	20				965
33	488 Communications	349	31				380
38	489 Other						
39		8,133	745			(746)	8,132
40	Construction overheads						
41							
42	System operations transfers						
43	Administrative transfers						
44	Depreciation						
45							
46							
47		$103,942	$6,670	$0	$0	($937)	$109,675

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE
ACTUAL 2017

(000s)

Line No.	Description	Jan/17 Beginning Balance	Actual Additions	Allocations	Transfers	Retirements	Dec/17 Ending Balance
1	Transmission plant						
2	460 Land	11					11
3	461 Land rights	459					459
4	462 Compressor structures	465					465
5	463 Regulating structures	209					209
6	465 Mains	12,707	14				12,721
7	466 Compressor equipment						
8	467 Regulating equipment	7,728	22				7,751
9	468 Communications	150					150
10	469 Other	18					18
11		21,748	37				21,785
12	Distribution plant						
13	470 Land	47					47
14	471 Land rights	222					222
15	472 Structures	2,031	50				2,081
16	473 Services	24,895	809			(38)	25,666
17	474 House installations	5,741	85				5,826
18	475 Mains	42,425	2,864			(49)	45,240
19	476 Compressor equipment						
20	477 Regulating equipment	1,735					1,735
21	478 Meters	2,679	182			(87)	2,774
22	479 Other	20					20
23		79,795	3,990			(174)	83,611
24	General plant						
25	480 Land	77					77
26	481 Land rights	1					1
27	482 Structures	2,103					2,103
28	483 Office equipment	346				(190)	156
29	484 Transportation equipment	1,328	172			(71)	1,429
30	485 Heavy work equipment	1,508				(93)	1,415
31	486 Tools	1,424	40			(318)	1,146
32	487 Computer equipment	965				(685)	279
33	488 Communications	380	14			(110)	284
38	489 Other						
39		8,132	226			(1,468)	6,890
40	Construction overheads						
41							
42	System operations transfers						
43	Administrative transfers						
44	Depreciation						
45							
46							
47		$109,675	$4,253	$0	$0	($1,642)	$112,286

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE
TEST YEAR 2018

(000s)

Line No.	Description	Jan/18 Beginning Balance	Decision				Dec/18 Ending Balance
			Additions	Allocations	Transfers	Retirements	
1	Transmission plant						
2	460 Land	11					11
3	461 Land rights	459	46				506
4	462 Compressor structures	465					465
5	463 Regulating structures	209					209
6	465 Mains	12,721	3,060	32			15,813
7	466 Compressor equipment						
8	467 Regulating equipment	7,751	1,550	150			9,451
9	468 Communications	150					150
10	469 Other	18					18
11		21,785	4,656	182			26,623
12	Distribution plant						
13	470 Land	47					47
14	471 Land rights	222					222
15	472 Structures	2,081					2,081
16	473 Services	25,666	849	95			26,610
17	474 House installations	5,826	124	14			5,963
18	475 Mains	45,240	2,047	220			47,508
19	476 Compressor equipment						
20	477 Regulating equipment	1,735					1,735
21	478 Meters	2,774	187	21			2,982
22	479 Other	20					20
23		83,611	3,207	351			87,168
24	General plant						
25	480 Land	77					77
26	481 Land rights	1					1
27	482 Structures	2,103	35				2,138
28	483 Office equipment	156					156
29	484 Transportation equipment	1,429	128			(64)	1,493
30	485 Heavy work equipment	1,415	77				1,491
31	486 Tools	1,146	123				1,269
32	487 Computer equipment	279	22				302
33	488 Communications	284					284
38	489 Other						
39		6,890	385			(64)	7,211
40	Construction overheads						
41							
42	System operations transfers		230	(230)			
43	Administrative transfers		274	(274)			
44	Depreciation		61	(61)			
45	Less: Overheads allocated to WIP		(33)	33			
46			533	(533)			
47		$112,286	$8,780	$0	$0	($64)	$121,002

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

GAS PLANT IN SERVICE
TEST YEAR 2019

(000s)

Line No.	Description	Jan/19 Beginning Balance	Decision Additions	Decision Allocations	Decision Retirements	Dec/19 Ending Balance
1	Transmission plant					
2	460 Land	11				11
3	461 Land rights	506				506
4	462 Compressor structures	465				465
5	463 Regulating structures	209				209
6	465 Mains	15,813	1,908	209		17,929
7	466 Compressor equipment					
8	467 Regulating equipment	9,451	163	29		9,643
9	468 Communications	150				150
10	469 Other	18				18
11		26,623	2,071	238		28,932
12	Distribution plant					
13	470 Land	47				47
14	471 Land rights	222				222
15	472 Structures	2,081				2,081
16	473 Services	26,610	1,023	148		27,781
17	474 House installations	5,963	129	19		6,111
18	475 Mains	47,508	2,198	308		50,014
19	476 Compressor equipment					
20	477 Regulating equipment	1,735				1,735
21	478 Meters	2,982	194	26		3,202
22	479 Other	20				20
23		87,168	3,544	501		91,213
24	General plant					
25	480 Land	77				77
26	481 Land rights	1				1
27	482 Structures	2,138	96			2,234
28	483 Office equipment	156				156
29	484 Transportation equipment	1,493	355		(177)	1,671
30	485 Heavy work equipment	1,491	27			1,518
31	486 Tools	1,269	27			1,296
32	487 Computer equipment	302				302
33	488 Communications	284				284
38	489 Other					
39		7,211	504		(177)	7,538
40	Construction overheads					
41						
42	System operations transfers		284	(284)		
43	Administrative transfers		406	(406)		
	Depreciation		65	(65)		
44	Less: Overheads allocated to WIP		(16)	16		
45			739	(739)		
46		$121,002	$6,858	$0	($177)	$127,683

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE - CONTINUITY OF PLANT COST

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016
1	Balance, Beginning of Year	121,002	112,286	109,675	103,942
2	CIAC Balance, Beginning of Year	(17,259)	(17,073)	(16,720)	(16,739)
3	Plant Cost, net of CIAC, Beginning of Year	103,743	95,213	92,954	87,203
4	Additions during year:				
5	Plant Cost	6,120	8,248	4,253	6,670
6	Allocation of overheads	755	566		
7	Total Plant Additions	6,875	8,813	4,253	6,670
8	Contributions in Aid of Construction	(186)	(186)	(353)	19
9	Total Additions	6,689	8,627	3,901	6,688
10	Plant Retirements:				
11	Normal Course	(177)	(64)	(1,642)	(937)
12	Deactivated Assets	-	-		
13	CIAC Retirements				
14	Total Retirements	(177)	(64)	(1,642)	(937)
15	Balance, End of Year	110,255	103,776	95,213	92,954
16	Closing balance consists of:				
17	Plant Cost	127,699	121,035	112,286	109,675
18	CIAC	(17,445)	(17,259)	(17,073)	(16,720)
19	Balance, End of Year	$110,255	$103,776	$95,213	$92,954

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

CONTINUITY OF
ACCUMULATED DEPRECIATION

ACTUAL 2016

(000s)

Line No.	Description	Jan/16 Beginning Balance	Actual Provision	Transfers	Retirements	Recoveries	Depreciation Adjustment	Dec/16 Ending Balance
1	Gathering Plant							
2	Franchises & Consents							
3	Gas Holders - Manufacturing	()						()
4	Gas Holders - Storage							
5								
6		()						()
7	Transmission plant							
8	461 Land rights	(59)						(59)
9	462 Compressor structures	(249)	(16)					(265)
10	463 Regulating structures	(72)	(5)					(77)
11	465 Mains	(4,144)	(156)					(4,300)
12	466 Compressor equipment							
13	467 Regulating equipment	(2,609)	(270)		20			(2,859)
14	468 Communications	(130)						(130)
15	469 Other	(7)	()					(7)
16								
17		(7,270)	(447)		20			(7,697)
18	Distribution plant							
19	471 Land Rights	(22)						(22)
20	472 Structures	(639)	(63)		15			(688)
21	473 Services	(5,856)	(460)		14			(6,302)
22	474 House installations	(2,753)	(164)					(2,917)
23	475 Mains	(12,000)	(536)					(12,536)
24	476 Compressor equipment							
25	477 Regulating equipment	(1,228)	(42)		11			(1,259)
26	478 Meters	(672)	(118)		55			(736)
27	479 Other	(10)	(1)					(10)
28								
29		(23,180)	(1,384)		95			(24,469)
30								
31	General plant							
32	481 Land Rights	()						()
33	482 Structures	(748)	(73)					(821)
34	483 Office equipment	(272)	(7)					(279)
35	484 Transportation equipment	(697)	(123)		401			(419)
36	485 Heavy work equipment	(619)	(94)		165			(549)
37	486 Tools	(767)	(53)		7			(814)
38	487 Computer equipment	(908)	(10)					(918)
39	488 Communications	(305)	(6)					(312)
40	489 Other							
41		(4,316)	(367)		572			(4,111)
42								
43		($34,766)	($2,198)	$0	$687	$0	$0	($36,277)
44								
45	Amortization of CIAC		286					
46								
47	Depreciation capitalized		76					
48								
49	Net Depreciation Expense		($1,836)					

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

CONTINUITY OF
ACCUMULATED DEPRECIATION

ACTUAL 2017

(000s)

Line No.	Description	Jan/17 Beginning Balance	Actual					Dec/17 Ending Balance
			Provision	Transfers	Retirements	Recoveries	Depreciation Adjustment	
1	Gathering Plant							
2	Franchises & Consents							
3	Gas Holders - Manufacturing	()						()
4	Gas Holders - Storage							
5								
6		()						()
7	Transmission plant							
8	461 Land rights	(59)						(59)
9	462 Compressor structures	(265)	(16)					(281)
10	463 Regulating structures	(77)	(7)					(84)
11	465 Mains	(4,300)	(163)					(4,463)
12	466 Compressor equipment							
13	467 Regulating equipment	(2,859)	(279)					(3,139)
14	468 Communications	(130)	(1)					(131)
15	469 Other	(7)	()					(7)
16								
17		(7,697)	(467)					(8,163)
18	Distribution plant							
19	471 Land Rights	(22)						(22)
20	472 Structures	(701)	(65)		9			(758)
21	473 Services	(6,288)	(479)		(13)			(6,780)
22	474 House installations	(2,917)	(168)		7			(3,077)
23	475 Mains	(12,536)	(594)		(11)			(13,141)
24	476 Compressor equipment							
25	477 Regulating equipment	(1,270)	(50)		10			(1,309)
26	478 Meters	(725)	(120)		(45)			(890)
27	479 Other	(10)	(1)					(11)
28								
29		(24,469)	(1,477)		(42)			(25,989)
30								
31	General plant							
32	481 Land Rights	()						()
33	482 Structures	(821)	(75)					(896)
34	483 Office equipment	(279)	(7)		(111)			(397)
35	484 Transportation equipment	(418)	(146)		(4)			(567)
36	485 Heavy work equipment	(549)	(100)		(48)			(697)
37	486 Tools	(814)	(55)		(167)			(1,036)
38	487 Computer equipment	(918)	(13)		(600)			(1,531)
39	488 Communications	(312)	(7)		80			(239)
40	489 Other							
41		(4,111)	(402)		(851)			(5,364)
42								
43		($36,277)	($2,346)	$0	($893)	$0	$0	($39,516)
44								
45	Amortization of CIAC		280					
46								
47	Depreciation capitalized		84					
48								
49	Net Depreciation Expense		($1,982)					

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

CONTINUITY OF
ACCUMULATED DEPRECIATION

TEST YEAR 2018

(000s)

Line No.	Description	Jan/18 Beginning Balance	Decision					Dec/18 Ending Balance
			Provision	Transfers	Retirements	Recoveries	Depreciation Adjustment	
1	Gathering Plant							
2	Franchises & Consents							
3	Gas Holders - Manufacturing	()						()
4	Gas Holders - Storage							
5								
6		()						()
7	Transmission plant							
8	461 Land rights	(59)						(59)
9	462 Compressor structures	(281)	(16)					(297)
10	463 Regulating structures	(84)	(5)					(89)
11	465 Mains	(4,463)	(150)					(4,613)
12	466 Compressor equipment							
13	467 Regulating equipment	(3,139)	(175)					(3,313)
14	468 Communications	(131)	(1)					(133)
15	469 Other	(7)	()					(8)
16								
17		(8,163)	(347)					(8,511)
18	Distribution plant							
19	471 Land Rights	(22)						(22)
20	472 Structures	(767)	(67)					(833)
21	473 Services	(6,746)	(516)					(7,262)
22	474 House installations	(3,085)	(108)					(3,192)
23	475 Mains	(13,112)	(591)					(13,703)
24	476 Compressor equipment							
25	477 Regulating equipment	(1,319)	(16)					(1,335)
26	478 Meters	(790)	(184)					(974)
27	479 Other	(11)	(1)					(11)
28								
29		(25,851)	(1,481)					(27,332)
30								
31	General plant							
32	481 Land Rights	()						()
33	482 Structures	(896)	(57)		24			(929)
34	483 Office equipment	(96)	(8)					(104)
35	484 Transportation equipment	(512)	(141)		40			(613)
36	485 Heavy work equipment	(581)	(66)					(647)
37	486 Tools	(552)	(62)					(614)
38	487 Computer equipment	(246)	(14)					(259)
39	488 Communications	(219)	(6)					(225)
40	489 Other							
41		(3,101)	(355)		64			(3,392)
42								
43		($37,116)	($2,183)	$0	$64	$0	$0	($39,235)
44								
45	Amortization of CIAC		265					
46								
47	Depreciation capitalized		61					
48								
49	Net Depreciation Expense		($1,856)					

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF
ACCUMULATED DEPRECIATION

TEST YEAR 2019

(000s)

Line No.	Description	Jan/19 Beginning Balance	Decision			Dec/19 Ending Balance
			Provision	Retirements	Recoveries	
1	Gathering Plant					
2	Franchises & Consents					
3	Gas Holders - Manufacturing	()				()
4	Gas Holders - Storage					
5						
6		()				()
7	Transmission plant					
8	461 Land rights	(59)				(59)
9	462 Compressor structures	(297)	(16)			(313)
10	463 Regulating structures	(89)	(5)			(94)
11	465 Mains	(4,613)	(198)			(4,811)
12	466 Compressor equipment					
13	467 Regulating equipment	(3,313)	(223)			(3,536)
14	468 Communications	(133)	(1)			(134)
15	469 Other	(8)	()			(8)
16						
17		(8,511)	(444)			(8,954)
18	Distribution plant					
19	471 Land Rights	(22)				(22)
20	472 Structures	(833)	(67)			(900)
21	473 Services	(7,262)	(535)			(7,796)
22	474 House installations	(3,192)	(111)			(3,303)
23	475 Mains	(13,703)	(626)			(14,329)
24	476 Compressor equipment					
25	477 Regulating equipment	(1,335)	(16)			(1,350)
26	478 Meters	(974)	(194)			(1,168)
27	479 Other	(11)	(1)			(12)
28						
29		(27,332)	(1,549)			(28,881)
30						
31	General plant					
32	481 Land Rights	()				()
33	482 Structures	(929)	(58)			(987)
34	483 Office equipment	(104)	(7)			(112)
35	484 Transportation equipment	(613)	(146)	177		(582)
36	485 Heavy work equipment	(647)	(70)			(718)
37	486 Tools	(614)	(65)			(679)
38	487 Computer equipment	(259)	(17)			(276)
39	488 Communications	(225)	(6)			(230)
40	489 Other					
41		(3,392)	(369)	177		(3,584)
42						
43		($39,235)	($2,361)	$177	$0	($41,420)
44						
45	Amortization of CIAC		264			
46						
47	Depreciation capitalized		65			
48						
49	Net Depreciation Expense		($2,032)			

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE - CONTINUITY OF ACCUMULATED DEPRECIATION

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016
1	Balance, Beginning of Year	(39,235)	(37,116)	(36,277)	(34,766)
2	CIAC Accumulated Balance, Beginning of Year	7,109	6,844	6,565	6,279
3	Utility Accumulated Depreciation, Beginning of Year	(32,126)	(30,272)	(29,712)	(28,487)
4	Depreciation Provision:				
5	Plant	(2,361)	(2,183)	(2,346)	(2,198)
6	Contributions in Aid of Construction	264	265	280	286
7	Transfers				
8	Total Additions	(2,097)	(1,918)	(2,066)	(1,912)
9	Plant Retirements:				
10	Normal Course	177	64	(893)	687
11	Deactivated Assets				
12	CIAC Retirements				
13	Removal Costs				
14	Proceeds on Disposals				
15	Total Retirements	177	64	(893)	687
16	Balance, End of Year	(34,046)	(32,126)	(32,672)	(29,712)
17	Closing Balance Consists of:				
18	Accumulated Depreciation - Plant	(41,420)	(39,235)	(39,516)	(36,277)
19	Accumulated Amortization - CIAC	7,374	7,109	6,844	6,565
20	Balance, End of Year	($34,046)	($32,126)	($32,672)	($29,712)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

ACTUAL 2016
(000s)

Line No.	Description	Interest Rate	Amortization Period	Actual Balance '15	Additions	Imputed Interest	Amortization	Actual Balance '16
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	1 yr	(41)			(41)	
3	Plant Gains and Losses - ordinary	n/a	2-5 yrs	302	250		91	462
4	Plant Gains and Losses - salvage value	n/a	2-5 yrs	(31)	(91)		(9)	(113)
5	Plant Gains and Losses - retirement costs	n/a	2-5 yrs	286	55		72	269
6	Demand Side Management	n/a	5 yrs	55	16		11	60
7	Sub-total Gross Rate Base deferrals			572	231		124	678
8	Related Future Income Taxes (FIT)			(89)	(18)		(22)	(86)
9	Rate Base deferrals, net of FIT			**482**	**213**		**102**	**593**
10								
11	Average rate base for the year							**538**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr	4	(1)		2	
15	Short Term Interest Rate	STI	1 yr	(11)	(3)	( )	(11)	(3)
16	Long Term Interest Rate	STI	1 yr	(140)	22	(2)	(142)	21
17	Property tax variance	STI	1 yr	79	41	2	80	41
18	DC Industrial Deliveries	STI	1 yr	25	192	2	25	193
19	BCUC Hearing costs & CAP/ROE	STI	1 yr	(38)	(36)	(1)	(39)	(36)
20	Old Revolving Debt Issue Costs	STI	1 yr					
21	Permanent to Interim Rate Adjustment	STI	1 yr					
22	2013 Revenue Requirement Adjustment	STI	1 yr					
23	Investigative Digs	STI	1 yr	(34)		(1)	(35)	
24	GCOC - 2013	STI	1 yr					
25	UAF Losses 2016	STI	1 yr		276			276
26	2018/19 Rate smoothing	STI	1 yr					
27	Pension / NPPRB	WACD	3 yrs					
28	GCVA	STI	n/a	(2 296)	1 852	(45)		(488)
29	RSAM	WACD	n/a	805	1 686	69		2 559
30	Resource Plans	STI	1 yr		11			11
31	Legacy Deferred Income Taxes - Offset to NPPRB Regulatory Asset	WACD	3 yrs	(227)		(6)	(82)	(151)
32	Sub-total gross interest bearing deferrals			(1 834)	4 039	18	(200)	2 423
33	Related Future Income Taxes (FIT)			418	(1 050)	(6)	31	(669)
34	Interest Bearing deferrals, net of FIT			**(1 416)**	**2 989**	**12**	**(169)**	**1 754**
35								
36	NPPRB Regulatory Asset (Non-return bearing)	n/a	3 yrs	237			79	158
37	NPPRB Transitional Obligations (Non-return bearing)	n/a	3 yrs	68			23	45
38								
39	Total gross deferrals (excl. debt issue)			(957)	4 270	18	26	3 305
40	Future Income Taxes on deferrals (excl. debt issue			329	(1 068)	(6)	9	(755)
41								
42	Total deferrals, net of FIT (excl. debt issue)			**($629)**	**$3,202**	**$12**	**$35**	**$2,550**
43								
44								
45	Debt Issue Costs	n/a	varies with debt	**$101**	**$0**	**$0**	**$44**	**$57**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

ACTUAL 2017
(000s)

Line No.	Description	Interest Rate	Amortization Period	Actual Balance '16	Additions	Imputed Interest	Amortization	Outlook Balance '17
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	1 yr	()				()
3	Plant Gains and Losses - ordinary	n/a	2-5 yrs	462	136		88	509
4	Plant Gains and Losses - salvage value	n/a	2-5 yrs	(113)	(52)		(9)	(156)
5	Plant Gains and Losses - retirement costs	n/a	2-5 yrs	269	68		72	264
6	Demand Side Management	n/a	5 yrs	60	33		48	46
7	Sub-total Gross Rate Base deferrals			678	184		199	664
8	Related Future Income Taxes (FIT)			(86)	(26)		(31)	(81)
9	Rate Base deferrals, net of FIT			**593**	**158**		**168**	**583**
10								
11	Average rate base for the year							**588**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr		(3)			(3)
15	Short Term Interest Rate	STI	1 yr	(3)	(3)		()	(6)
16	Long Term Interest Rate	STI	1 yr	21	(31)	()	(1)	(10)
17	Property tax variance	STI	1 yr	41	(43)	1		(1)
18	DC Industrial Deliveries	STI	1 yr	193	(126)	7		73
19	BCUC Hearing costs & CAP/ROE	STI	1 yr	(36)	(42)	(1)		(80)
20	Old Revolving Debt Issue Costs	STI	1 yr					
21	Permanent to Interim Rate Adjustment	STI	1 yr					
22	2013 Revenue Requirement Adjustment	STI	1 yr					
23	Investigative Digs	STI	1 yr		(19)			(19)
24	GCOC - 2013	STI	1 yr					
25	UAF Losses 2016	STI	1 yr	274				274
26	2018/19 Rate smoothing	STI	1 yr					
27	Pension / NPPRB	WACD	3 yrs		30			30
28	GCVA	STI	n/a	(763)	(1,172)	(43)		(1,977)
29	RSAM	WACD	n/a	2,559	(973)	73		1,659
30	Resource Plans	STI	1 yr	11	(5)			7
31	Legacy Deferred Income Taxes - Offset to NPPRB	WACD	3 yrs	(151)		(4)	(79)	(76)
32	Sub-total gross interest bearing deferrals			2,147	(2,386)	32	(80)	(126)
33	Related Future Income Taxes (FIT)			(598)	628	(12)		19
34	Interest Bearing deferrals, net of FIT			**1,550**	**(1,758)**	**20**	**(80)**	**(108)**
35								
36	NPPRB Regulatory Asset (Non-return bearing)	n/a	3 yrs	158			79	79
37	NPPRB Transitional Obligations (Non-return bearing)	n/a	3 yrs	45			23	23
38								
39	Total gross deferrals (excl. debt issue)			3,029	(2,202)	32	220	639
40	Future Income Taxes on deferrals (excl. debt issue			(683)	602	(12)	(31)	(62)
41								
42	Total deferrals, net of FIT (excl. debt issue)			**$2,346**	**($1,600)**	**$20**	**$189**	**$577**
43								
44								
45	Debt Issue Costs	n/a	varies with debt	**$57**	**$0**	**$0**	**$46**	**$11**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

TEST YEAR 2018
(000s)

Line No.	Description	Interest Rate	Amortization Period	Outlook Balance '17	Additions	Imputed Interest	Amortization	Test Year Balance '18
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	1 yr					
3	Plant Gains and Losses - ordinary	n/a	2-5 yrs	509			158	352
4	Plant Gains and Losses - salvage value	n/a	2-5 yrs	(156)			(42)	(114)
5	Plant Gains and Losses - retirement costs	n/a	2-5 yrs	264			100	164
6	Demand Side Management	n/a	5 yrs	46	165		21	190
7	Sub-total Gross Rate Base deferrals			664	165		237	592
8	Related Future Income Taxes (FIT)			(81)	(45)		(30)	(96)
9	Rate Base deferrals, net of FIT			**583**	**121**		**207**	**497**
10								
11	Average rate base for the year							**540**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr	(3)		()	(3)	
15	Short Term Interest Rate	STI	1 yr	(6)		()	(6)	
16	Long Term Interest Rate	STI	1 yr	(10)		()	(10)	
17	Property tax variance	STI	1 yr	(1)		()	(1)	
18	DC Industrial Deliveries	STI	1 yr	73		2	75	
19	BCUC Hearing costs & CAP/ROE	STI	1 yr	(80)		(2)	(81)	
20	Old Revolving Debt Issue Costs	STI	1 yr		5		6	
21	Permanent to Interim Rate Adjustment	STI	1 yr					
22	2013 Revenue Requirement Adjustment	STI	1 yr					
23	Investigative Digs	STI	1 yr	(19)		()	(19)	
24	GCOC - 2013	STI	1 yr					
25	UAF Losses 2016	STI	1 yr					
26	2018/19 Rate smoothing	STI	1 yr		165	3		168
27	Pension / NPPB	WACD	3 yrs	30		1	11	20
28	GCVA	STI	n/a	(1,693)	1,503	(45)		(235)
29	RSAM	WACD	n/a	1,659	(1,398)	42		304
30	Resource Plans	STI	1 yr	7			7	
31	Legacy Deferred Income Taxes - Offset to NPPRB Regulatory Asset	WACD	3 yrs	(76)		(2)	(77)	
32	Sub-total gross interest bearing deferrals			(117)	276	(2)	(99)	257
33	Related Future Income Taxes (FIT)			19	(29)	1	10	(18)
34	Interest Bearing deferrals, net of FIT			**(98)**	**248**	**(1)**	**(89)**	**238**
35								
36	NPPRB Regulatory Asset (Non-return bearing)	n/a	3 yrs	79			79	
37	NPPRB Transitional Obligations (Non-return bearing)	n/a	3 yrs	23			23	
38								
39	Total gross deferrals (excl. debt issue)			649	441	(2)	240	849
40	Future Income Taxes on deferrals (excl. debt issue			(62)	(73)	1	(20)	(114)
41								
42	Total deferrals, net of FIT (excl. debt issue)			**$587**	**$368**	**($1)**	**$220**	**$735**
43								
44								
45	Debt Issue Costs	n/a	varies with debt	**$11**	**$76**	**$0**	**$17**	**$70**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

TEST YEAR 2019
(000s)

Line No.	Description	Interest Rate	Amortization Period	Test Year Balance '18	Additions	Imputed Interest	Amortization	Test Year Balance '19
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	n/a					
3	Plant Gains and Losses - ordinary	n/a	1-5 yrs	352			127	224
4	Plant Gains and Losses - salvage value	n/a	1-5 yrs	(114)			(37)	(77)
5	Plant Gains and Losses - retirement costs	n/a	1-5 yrs	164			74	91
6	Demand Side Management	n/a	4-5 yrs	190	165		54	302
7	Sub-total Gross Rate Base deferrals			592	165		218	540
8	Related Future Income Taxes (FIT)			(96)	(45)		(34)	(106)
9	Rate Base deferrals, net of FIT			**497**	**121**		**184**	**434**
10								
11	Average rate base for the year							**465**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr					
15	Short Term Interest Rate	STI	1 yr					
16	Long Term Interest Rate	STI	1 yr					
17	Property tax variance	STI	1 yr					
18	DC Industrial Deliveries	STI	1 yr					
19	BCUC Hearing costs & CAP/ROE	STI	1 yr					
20	Old Revolving Debt Issue Costs	STI	1 yr				()	
21	Permanent to Interim Rate Adjustment	STI	1 yr					
22	2013 Revenue Requirement Adjustment	STI	1 yr					
23	Investigative Digs	STI	1 yr					
24	GCOC - 2013	STI	1 yr					
25	UAF Losses 2016	STI	1 yr					
26	2018/19 Rate smoothing	STI	1 yr	168		4	172	()
27	Pension / NPPRB	WACD	3 yrs	20		1	11	10
28	GCVA	STI	n/a	(235)	1,518	23		1,306
29	RSAM	WACD	n/a	304	(188)	9		125
30	Resource Plans	STI	1 yr					
31	Legacy Deferred Income Taxes - Offset to NPPRB Regulatory Asset	WACD	2 yrs			()	()	
32	Sub-total gross interest bearing deferrals			257	1,330	37	183	1,441
33	Related Future Income Taxes (FIT)			(18)	(359)	(9)		(386)
34	Interest Bearing deferrals, net of FIT			**238**	**971**	**28**	**183**	**1,055**
35								
36	NPPRB Regulatory Asset (Non-return bearing)	n/a	2 yrs					()
37	NPPRB Transitional Obligations (Non-return bearing)	n/a	2 yrs					
38								
39	Total gross deferrals (excl. debt issue)			849	1,495	37	401	1,981
40	Future Income Taxes on deferrals (excl. debt issue)			(114)	(404)	(9)	(34)	(492)
41								
42	Total deferrals, net of FIT (excl. debt issue)			**$735**	**$1,092**	**$28**	**$366**	**$1,488**
43								
44								
45	Debt Issue Costs	n/a	varies with debt	**$70**	**$0**	**$0**	**$12**	**$58**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Lag /(Lead) Days	Expense	Working Capital
1	Revenue	58.1		
2	Expense	(34.7)		
3	Operating working capital	23.4	18,224	1,170
4	Adjustments:			
5	Allowance for Doubtful Accounts			(28)
6	Budget Billing Plan			(492)
7	Carbon Tax			88
8	GST			68
9	PST & ICEF Levy			19
10	Cash working capital			825

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Revenues	Revenue Lag Days	Revenue	Extended Revenue
1	Residential - monthly	47.4	$3,883	$184,174
2	- bimonthly	63.8	7,981	508,851
3				
4	Small commercial - monthly	61.4	1,065	65,380
5	- bimonthly	63.7	5,740	365,424
6				
7	Large commercial - firm	46.1	1,633	75,294
8				
9	Small industrial	50.2	2,389	120,006
10				
11	Revenue Deficiency	58.1	816	47,418
12				
13	Other operating revenue	58.1	218	12,655
14				
15	Average revenue lag days	58.1	$23,725	$1,379,201

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

EXPENSE LEAD DAYS

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Expenses	Expense (Lead) Days	Normalized Expenses	Extended Expenses
1	Gas purchases-baseload	(40.2)	741	(29,806)
2	Gas purchases-seasonal	(40.2)	6,371	(256,131)
3	Operating payrolls	(5.0)	2,409	(12,046)
4	Employee benefits	(20.9)	628	(13,133)
5	Employee expenses	(4.9)	123	(600)
6	Uncollectible accounts	(58.1)	56	(3,255)
7	Other operating expenses	(31.4)	5,946	(186,717)
8	Expenses credited/capitalized	(10.6)	(504)	5,318
9	Insurance	182.5	94	17,179
10	Property taxes	(1.0)	1,305	(1,305)
11	Provincial capital tax	(58.6)		0
11	Franchise Fees	(242.5)	598	(144,902)
12	Income taxes payable	(15.2)	456	(6,928)
13	Average expense lag days	(34.7)	18,224	(632,327)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - GOODS AND SERVICES TAX

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Taxable Amount	G.S.TAX @ 5%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential and commercial	$20,660	$1,033	19.6	(30.4)	(10.8)	($30.5)
3	Industrial - FSJ	1,266	63	30.7	(48.8)	(18.2)	(3.1)
4	Industrial - DC	925	46	39.0	(30.4)	8.6	1.1
5	Franchise fee	598	30	20.9	(31.2)	(10.3)	(0.8)
6	Carbon Tax	6,845	342	29.2	(32.8)	(3.6)	(3.4)
7							
8		$30,294	$1,515			(8.9)	($36.8)
9							
10							
11				Recovery	Payment	Net	Working
12				Lag Days	(Lead) Days	Lag/(Lead)	Capital
13	Purchases						
14	Capital expenditures	7,433	372	30.4	8.2	38.6	$39.3
15	Gas supply	7,113	356	60.8	(25.0)	35.8	34.9
16	Operating costs	5,813	291	30.4	8.2	38.6	30.7
17							
18		$20,360	$1,018			37.6	$104.9
19							
20							$68.1

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - PST

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Taxable Amount	P.S.T. @ 7%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Commercial sales	8,237	577	22.2	(15.0)	7.2	$11.3
3	Industrial sales - FSJ	498	35	33.2	(15.0)	18.2	1.7
4	Industrial sales - DC	925	65	39.0	(15.0)	24.0	4.3
5	Franchise fees	253	18	24.4	(15.0)	9.4	0.5
6	PST subtotal	$9,914	$694			9.4	$17.8
7							
8			ICEF Levy				
9			@ 0.4%				
10	Residential sales	12,206	49	17.8	(15.0)	2.8	$0.4
11	Commercial sales	8,237	33	22.2	(15.0)	7.2	0.6
12	Industrial sales - FSJ	498	2	33.2	(15.0)	18.2	0.1
13	Industrial sales - DC	925	4	39.0	(15.0)	24.0	0.2
14	Franchise fees	576	2	20.7	(15.0)	5.7	0.0
15	ICEF Levy Subtotal	$22,444	$90				$1.4
16							
17	PST & ICEF Levy total	$32,358	$784				$19.2

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - CARBON TAX

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Taxable GJs	Carbon Tax	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
	Gas sales subject to Carbon Tax						
1	Residential sales - January to March	743,356	$1,107	17.8	(15.0)	2.8	$8.4
2	- April to December	1,054,863	1,833	17.8	(15.0)	2.8	14.0
3	Commercial sales - January to March	727,020	1,083	22.1	(15.0)	7.1	21.0
4	- April to December	1,134,077	1,971	22.2	(15.0)	7.2	39.1
5	FSJ Small Industrial sales - January to March	58,114	87	33.2	(15.0)	18.2	4.3
6	- April to December	126,406	220	33.2	(15.0)	18.2	11.0
7	DC Small Industrial sales - January to March	97,900	146	39.0	(45.4)	(6.4)	(2.5)
8	- April to December	229,100	398	39.0	(45.4)	(6.4)	(6.9)
9	Carbon Tax Total	4,170,837	6,845	22.1	(17.5)		$88.3

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

OTHER WORKING CAPITAL ITEMS

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Transmission Line Pack & Storage	Materials & Supplies	Total
1	MONTH END BALANCES			
2	January	$325	$170	$495
3	February	13	160	173
4	March	(44)	170	125
5	April	(44)	165	120
6	May	(11)	164	153
7	June	197	197	394
8	July	421	202	623
9	August	646	200	846
10	September	680	202	882
11	October	680	178	857
12	November	645	195	840
13	December	422	184	607
14	Total	$3,927	$2,187	$6,114
15	Average balance	$327	$182	$510

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Lag /(Lead) Days	Expense	Working Capital
1	Revenue	58.1		
2	Expense	(35.0)		
3	Operating working capital	23.1	$19,774	$1,251
4	Adjustments:			
5	Allowance for Doubtful Accounts			(81)
6	Budget Billing Plan			(511)
7	Carbon Tax			94
8	GST			68
9	PST & ICEF Levy			21
10	Cash working capital			$841

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Revenues	Revenue Lag Days	Revenue	Extended Revenue
1	Residential - monthly	47.4	$4,234	$200,845
2	- bimonthly	63.8	8,706	555,051
3				
4	Small commercial - monthly	61.3	1,204	73,748
5	- bimonthly	63.7	6,451	410,646
6				
7	Large commercial - firm	46.1	1,812	83,518
8				
9	Small industrial	50.2	2,711	136,162
10				
11	Revenue Deficiency	58.1	842	48,962
12				
13	Other operating revenue	58.1	222	12,884
14				
15	Average revenue lag days	58.1	$26,182	$1,521,817

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

EXPENSE LEAD DAYS

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Expenses	Expense (Lead) Days	Normalized Expenses	Extended Expenses
1	Gas purchases-baseload	(40.2)	$737	($29,641)
2	Gas purchases-seasonal	(40.2)	7,838	(315,073)
3	Operating payrolls	(5.0)	2,461	(12,304)
4	Employee benefits	(20.9)	639	(13,353)
5	Employee expenses	(4.9)	125	(610)
6	Uncollectible accounts	(58.1)	52	(3,024)
7	Other operating expenses	(31.4)	6,050	(189,961)
8	Expenses credited/capitalized	(10.6)	(690)	7,280
9	Insurance	182.5	97	17,657
10	Property taxes	(1.0)	1,371	(1,371)
11	Provincial capital tax	(58.6)	-	-
11	Franchise Fees	(242.5)	598	(144,902)
12	Income taxes payable	(15.2)	498	(7,573)
13	Average expense lag days	(35.0)	$19,774	($692,874)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - GOODS AND SERVICES TAX

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Taxable Amount	G.S.TAX @ 5%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential and commercial	$21,563	$1,078	19.6	(30.4)	(10.8)	($31.8)
3	Industrial - FSJ	1,447	72	30.7	(48.5)	(17.8)	(3.5)
4	Industrial - DC	1,067	53	39.0	(30.4)	8.6	1.3
5	Franchise fee	598	30	21.1	(31.3)	(10.2)	(0.8)
6	Carbon Tax	7,501	375	29.0	(32.9)	(3.8)	(3.9)
7							
8		$32,175	$1,609			(8.8)	($38.9)
9							
10							
11				Recovery	Payment	Net	Working
12				Lag Days	(Lead) Days	Lag/(Lead)	Capital
13	Purchases						
14	Capital expenditures	6,275	314	30.4	8.2	38.6	$33.2
15	Gas supply	8,575	429	60.8	(25.0)	35.8	42.1
16	Operating costs	5,951	298	30.4	8.2	38.6	31.5
17							
18		$20,801	$1,040			37.4	$106.7
19							
20							$67.8

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - PST

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Taxable Amount	P.S.T. @ 7%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Commercial sales	8,732	611	22.1	(15.0)	7.1	$12.0
3	Industrial sales - FSJ	583	41	33.2	(15.0)	18.2	2.0
4	Industrial sales - DC	1,067	75	39.0	(15.0)	24.0	4.9
5	Franchise fees	258	18	24.5	(15.0)	9.5	0.5
6	PST subtotal	$10,640	$745			9.5	$19.4
7							
8			ICEF Levy				
9			@ 0.4%				
10	Residential sales	12,603	50	17.8	(15.0)	2.8	$0.4
11	Commercial sales	8,732	35	22.1	(15.0)	7.1	0.7
12	Industrial sales - FSJ	583	2	33.2	(15.0)	18.2	0.1
13	Industrial sales - DC	1,067	4	39.0	(15.0)	24.0	0.3
14	Franchise fees	575	2	20.8	(15.0)	5.8	0.0
15	ICEF Levy Subtotal	$23,561	$94				$1.5
16							
17	PST & ICEF Levy total	$34,201	$839				$20.9

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - CARBON TAX

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Taxable GJs	Carbon Tax	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
	Gas sales subject to Carbon Tax						
1	Residential sales - January to March	982,994	$1,709	17.8	(15.0)	2.8	$13.0
2	- April to December	813,607	1,616	17.8	(15.0)	2.8	12.3
3	Commercial sales - January to March	995,638	1,731	22.0	(15.0)	7.0	33.4
4	- April to December	751,560	1,493	22.1	(15.0)	7.1	28.9
5	FSJ Small Industrial sales - January to March	98,954	172	33.2	(15.0)	18.2	8.6
6	- April to December	86,996	173	33.2	(15.0)	18.2	8.6
7	DC Small Industrial sales - January to March	168,035	292	39.0	(45.4)	(6.4)	(5.1)
8	- April to December	158,965	316	39.0	(45.4)	(6.4)	(5.5)
9	Carbon Tax Total	4,056,749	7,501	22.1	(17.5)		$94.3

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

OTHER WORKING CAPITAL ITEMS

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Transmission Line Pack & Storage	Materials & Supplies	Total
1	MONTH END BALANCES			
2	January	$438	$170	$608
3	February	246	160	406
4	March	211	170	381
5	April	211	165	376
6	May	253	164	417
7	June	504	197	701
8	July	770	202	972
9	August	1,035	200	1,235
10	September	1,077	202	1,279
11	October	1,077	178	1,254
12	November	1,035	195	1,230
13	December	770	184	954
14	Total	$7,625	$2,187	$9,812
15	Average balance	$635	$182	$818

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTRIBUTIONS IN AID OF CONSTRUCTION

(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**Gas Plant In Service**								
2	Beginning balance	$17,259	$17,073	$16,926	$16,720	$16,739	$15,426	$14,990	$14,327
3	Additions	186	186	190	353	(19)	1,313	436	664
4	Ending balance	$17,445	$17,259	$17,116	$17,073	$16,720	$16,739	$15,426	$14,990
5	**Accumulated Amortization**								
6	Beginning balance	($7,109)	($6,844)	($6,565)	($6,565)	($6,279)	($6,021)	($5,765)	($5,519)
7	Additions	(264)	(265)	(281)	(280)	(286)	(258)	(257)	(245)
8	Ending balance	($7,374)	($7,109)	($6,845)	($6,844)	($6,565)	($6,279)	($6,021)	($5,765)
9	**Net Total**								
10	Beginning balance	$10,150	$10,229	$10,361	$10,156	$10,460	$9,405	$9,226	$8,807
11	Additions	(78)	(79)	(90)	73	(304)	1,055	179	418
12	Ending balance	$10,071	$10,150	$10,271	$10,229	$10,156	$10,460	$9,405	$9,226
13	Average balance	$10,110	$10,189	$10,316	$10,192	$10,308	$9,932	$9,315	$9,017

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Tomslake Cost Overrun Disallowance

(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Opening net plant disallowance	($51)	($51)	($51)	($51)	($52)	($53)	($54)	($55)
2									
3	Original gross plant disallowance	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)
4	Accumulated amortization at distribution mains rate	7	6	6	6	5	4	3	2
5	Closing net plant disallowance	(48)	(49)	(50)	(50)	(51)	(52)	(53)	(54)
6									
7	Average balance	($50)	($50)	($51)	($51)	($52)	($52)	($53)	($54)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

PENSION CONTRIBUTIONS AND EXPENSE

(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Cash contributions to plan	$375	$375	$195	$387	$211	$212	$722	$772
2	Expense	(264)	(287)	(306)	(326)	(316)	(354)	(306)	(406)
3	Additions/(reductions) in net B/S items	111	88	(111)	61	(105)	(142)	416	366
4									
5									
6	**Rate Base debit/(credit)**								
7	Prior year closing balance	1,056	996	895	1,020	1,084	1,159	874	603
8	Inter-divisional opening adjustment	0	(4)	(23)	(73)	13	30	(23)	0
9	Current year opening balance	1,056	992	872	947	1,098	1,190	851	603
10	Pre-tax additions	111	88	(111)	61	(105)	(142)	416	366
11	Current income taxes	(30)	(24)	29	(16)	27	37	(108)	(94)
12	Closing Balance	1,137	1,056	790	992	1,020	1,084	1,159	874
13									
14	Average rate base balance	1,096	1,024	831	970	1,059	1,137	1,005	739
15									
16									
17	**Financial statement components (US GAAP)**								
18	Funding status								
19	Opening balance	(540)	(751)	(550)	(731)	(523)	(507)	(604)	(1,674)
20	Annual Expense	(154)	(164)	(206)	(214)	(213)	(228)	(203)	(268)
21	Contributions & benefit payments	375	375	195	387	211	242	699	772
22	Actuarial gains / (losses)	0	0	0	(193)	(206)	(30)	(399)	566
23	Ending balance	(319)	(540)	(561)	(751)	(731)	(523)	(507)	(604)
24									
25	Unamortized actuarial net loss								
26	Opening balance	2,067	2,190	1,797	2,021	1,900	2,023	1,753	2,532
27	Amortization included in expense	(110)	(123)	(100)	(112)	(103)	(126)	(103)	(138)
28	Actuarial (gains) / losses	0	0	0	120	215	30	399	(566)
29	Rebalancing of actuarial losses between divisions	0	0	0	161	9	(27)	(26)	(75)
30	Ending balance	1,957	2,067	1,697	2,190	2,021	1,900	2,023	1,753
31									
32	Net pre-tax pension asset/(liability) - closing balance	$1,638	$1,527	$1,136	$1,439	$1,290	$1,377	$1,516	$1,149

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

NON-PENSION POST RETIREMENT BENEFITS
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Cash contributions to RCA/tax account	$30	$128	$174	$183	$179	$187	$169	$248
2	Cash cost of retiree benefits	30	29	31	28	27	23	21	22
3	Expense (recovered in rates)	(60)	(55)	(103)	(113)	(103)	(113)	(91)	(168)
4	Amortization of regulatory assets (recovered in rates)	(0)	(102)	(102)	(102)	(102)	(102)	(102)	(102)
5	Change in unfunded status of NPPRB plans	0	0	0	(4)	1	(4)	(3)	0
6	Current income taxes	(0)	0	0	1	(0)	1	1	(0)
7	Related future income taxes	0	0	0	(1)	0	(1)	(1)	0
8									
9									
10	**Rate Base debit/(credit)**								
11	Opening Balances:								
12	- historical unrecovered NPPRB expense net of tax								
13	- stranded NPPRB transitional obligation net of tax								
14	- NPPRB liabilities net of tax								
15	Jan 1, 2012 amortization of historical unrecovered NPPRB expense & transitional obligations	0	0	0	0	0	0	0	0
16	Pre-tax additions	0	0	0	0	0	0	0	0
17	Current income taxes	0	0	0	0	0	0	0	0
18	Closing Balance	0	0	0	0	0	0	0	0
19									
20	Average rate base balance	0	0	0	0	0	0	0	0
21									
22									
23	**Financial statement components (US GAAP)**								
24	Funding status								
25	Opening balance	56	(46)	(441)	(536)	(550)	(710)	(693)	(1,311)
26	Annual Expense	(48)	(55)	(96)	(101)	(103)	(99)	(86)	(128)
27	Contributions & benefit payments	60	157	205	211	206	207	201	270
28	Actuarial losses	0	0	0	381	(89)	52	(132)	476
29	Ending balance	68	56	(333)	(45)	(536)	(550)	(710)	(693)
30									
31	Unamortized actuarial net loss								
32	Opening balance	(17)	(17)	246	290	253	319	192	701
33	Amount recognized in expense	(12)	0	(7)	(12)	(7)	(14)	(5)	(40)
34	Change in actuarial net losses	0	0	0	(333)	44	(52)	132	(469)
35	Ending balance	(29)	(17)	239	(55)	290	253	319	192
36									
37	Net after-tax NPPRB position - closing	$28	$28	($69)	($74)	($182)	($295)	($289)	($372)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

DEFERRED INCOME TAX BALANCES
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Rate Base debit/(credit)								
2	Opening Balance								
3	- historical recovered deferred income tax expense	$0	$0	$0	$0	$0	$0	($377)	($453)
4	Jan 1, 2012 amortization of historical recovered deferred income tax expense	0	0	0	0	0	0	0	0
5	Current year amortization	0	0	0	0	0	0	0	75
6	Reclassified to deferred charges	0	0	0	0	0	0	377	0
7	Closing Balance	$0	$0	$0	$0	$0	$0	$0	($377)
8									
9	Average rate base balance	$0	$0	$0	$0	$0	$0	$0	($415)

Tab 3

Income Taxes

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

INCOME TAXES

SCHEDULE 3
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	**Calculation of Taxable Income**									
2	Earned return before income taxes	$5,329	$4,885	$4,444	$4,343	$3,729	$3,691	$3,826	$3,209	Tab 1, page 1, line 34
3	Interest	(1,942)	(1,751)	(1,359)	(1,329)	(1,211)	(1,294)	(1,237)	(1,217)	Tab 5, page 1, lines 1x3 plus lines 6x8
4	Permanent differences	15	15	17	12	13	16	9	6	
5	Timing differences	(1,557)	(1,460)	(1,182)	(1,097)	(1,334)	(1,712)	(1,024)	(1,207)	Tab 3, page 1, line 26
6										
7	Taxable income	$1,845	$1,689	$1,920	$1,930	$1,197	$700	$1,575	$790	
8										
9	**Calculation of Income Tax Expense**									
10	Income taxes payable	$498	$456	$499	$502	$311	$182	$409	$204	
11	Income Tax Rate Deferral	0	0	0	0	0	0	0	0	
12	Deferred income tax	0	0	0	0	0	0	0	0	
13										
14	Income tax expense	$498	$456	$499	$502	$311	$182	$409	$204	
15										
16	**Particulars of Timing Differences**									
17	A. Tax Effects Subject To Flowthrough									
18	Depreciation	$2,032	$1,856	$2,023	$1,982	$1,836	$1,763	$1,587	$1,416	Tab 1, page 1, line 24
19	Amortization	229	240	221	220	26	(514)	80	(310)	Tab 1, page 1, line 25
20	Capital cost allowance	(3,818)	(3,454)	(3,325)	(3,198)	(3,094)	(2,859)	(2,590)	(2,212)	
21	Deferred charges	0	0	0	0	0	0	0	0	
22	Overheads capitalized	0	0	0	0	0	0	0	0	
23	Other (Incl. RCA Contributions of NPPRB Obligation Amortization)	(0)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	Tab 2, page 33, line 4
24										
25										
26	Timing differences	($1,557)	($1,460)	($1,182)	($1,097)	($1,334)	($1,712)	($1,024)	($1,207)	
27										
28	Tax rate	27.00%	27.00%	26.00%	26.00%	26.00%	26.00%	26.00%	25.75%	
29	Surtax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Deferred tax rate	27.00%	27.00%	26.00%	26.00%	26.00%	26.00%	26.00%	25.75%	

Tab 4

Common Equity

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

COMMON EQUITY

SCHEDULE 4
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Opening balance									
2	Share capital	$9,595	$9,595	$9,595	$9,595	$9,595	$9,595	$8,295	$8,295	
3	Contributed surplus	0	0	0	0	0	-	-	0	
4	Retained earnings	19,216	19,919	16,968	17,346	16,804	14,699	12,477	10,982	
5										
6		28,811	29,514	26,563	26,941	26,399	24,294	20,772	19,278	
7										
8	Net income	2,923	2,699	2,621	2,572	2,193	2,105	2,222	1,494	
9	Shares issued	2,627	0	856	0	0	0	1,300	0	
10	Preferred dividends	0	0	0	0	0	0	0	0	
11	Common dividends	30	(3,402)	(19)	0	(1,700)	0	0	0	
12										
13	Closing balance	$34,391	$28,811	$30,021	$29,514	$26,891	$26,399	$24,294	$20,772	
14										
15										
16	Midyear common equity	$31,601	$29,162	$28,292	$28,228	$26,645	$25,347	$22,533	$20,025	Tab 5, page 1, line 11

Tab 5

Return on Capital

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Short term borrowings	$4,053	$3,740	$3,480	$1,958	$6,188	$3,964	$2,489	$3,762	
2	proportion	5.26%	5.26%	5.04%	2.91%	9.76%	6.67%	4.52%	7.80%	
3	rate of return	4.50%	4.81%	4.13%	4.73%	3.53%	3.22%	3.02%	4.06%	Tab 5, page 2, line 12
4	return component	0.24%	0.25%	0.21%	0.14%	0.34%	0.21%	0.14%	0.32%	
5										
6	Long term debt	$41,421	$38,226	$37,233	$37,199	$30,550	$30,139	$30,100	$24,444	Tab 5, page 3, line 46
7	proportion	53.74%	53.74%	53.96%	55.20%	48.20%	50.70%	54.61%	50.68%	
8	rate of return	4.25%	4.11%	3.26%	3.32%	3.25%	3.87%	3.86%	4.36%	Tab 5, page 3, line 48
9	return component	2.28%	2.21%	1.76%	1.84%	1.57%	1.96%	2.11%	2.21%	
10										
11	Common equity	$31,601	$29,162	$28,292	$28,228	$26,645	$25,347	$22,533	$20,025	
12	proportion	41.00%	41.00%	41.00%	41.89%	42.04%	42.64%	40.88%	41.52%	
13	rate of return	9.25%	9.25%	9.25%	9.01%	8.24%	8.17%	9.47%	8.41%	
14	return component	3.79%	3.79%	3.79%	3.77%	3.47%	3.48%	3.87%	3.49%	
15										
16	Total capitalization	$77,075	$71,128	$69,005	$67,384	$63,383	$59,450	$55,122	$48,231	
17										
18	Return on rate base	6.31%	6.25%	5.76%	5.75%	5.38%	5.66%	6.11%	6.02%	
19										
20	Utility rate base	$77,075	$71,128	$69,005	$67,384	$63,383	$59,450	$55,122	$48,231	Tab 2, page 1, line 23

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SHORT TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

		Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**Customer Security Deposits**								
2	Average annual balance	$982	$982	$997	$966	$941	$989	$1,066	$1,123
3	Interest rate applicable to deposits	2.25%	1.73%	0.98%	1.02%	0.70%	1.04%	1.08%	1.04%
4	Annual Interest Expense	$22	$17	$10	$10	$7	$10	$12	$12
5									
6	**Operating Line / Other**								
7	Average annual draw	$3,072	$2,758	$2,483	$992	$5,246	$2,975	$1,423	$2,638
8	Interest rate	4.45%	3.93%	3.54%	3.68%	3.14%	3.07%	3.58%	3.74%
9	Annual Interest Expense	$137	$108	$88	$37	$165	$91	$51	$99
10	Other Interest Expense*	$24	$54	$46	$46	$47	$26	$13	$42
11									
12	Average short term interest rate	4.50%	4.81%	4.13%	4.73%	3.53%	3.22%	3.02%	4.06%

* service fees, standby fees, renewal expenses

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

		Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**Secured Debentures Series 2018**								
2	Liability beginning of year	$0	$796	$910	$910	$1,023	$1,137	$1,251	$1,319
3	Sinking fund payments	0	(796)	(114)	(114)	(114)	(114)	(114)	(68)
4	Average Capitalization	0	693	895	895	1,009	1,122	1,236	1,310
5	Annual Interest Expense	0	61	78	78	88	98	108	115
6	Issue costs beginning of year	0	0	2	2	3	4	6	7
7	Amortization of Issue Costs	0	1	1	2	1	1	1	1
8									
9	Effective Cost Rate	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
10									
11	**Roynat 2017 Loan**								
12	Liability beginning of year	$0	$0	$5,427	$5,427	$6,307	$7,187	$8,067	$8,947
13	Sinking fund payments	0	0	(5,427)	(5,427)	(880)	(880)	(880)	(880)
14	Average Capitalization	0	0	2,713	3,554	5,867	6,747	7,627	8,507
15	Annual Interest Expense	0	0	132	127	196	263	294	332
16	Issue costs beginning of year	0	0	22	22	46	75	108	148
17	Amortization of Issue Costs	0	0	22	22	25	29	33	40
18									
19	Effective Cost Rate	4.20%	4.20%	4.26%	4.21%	3.79%	4.37%	4.34%	4.41%
20									
21	**10-year Term Intercompany Loan**								
22	Liability beginning of year	$29,040	$0	$0	$0	$0	$0	$0	$9,466
23	Issue during the year	0	29,040	0	0	0	0	0	6,598
24	Sinking fund payments	0	0	0	0	0	0	0	(16,064)
25	Average Capitalization	29,040	21,780	0	0	0	0	0	4,730
26	Annual Interest Expense	1,220	919	0	0	0	0	0	188
27	Stand-by fees	0	0	0	0	0	0	0	11
28	Issue costs beginning of year	9	0	0	0	0	0	0	44
29	Amortization of Issue Costs	1	1	0	0	0	0	0	8
30									
31	Effective Cost Rate	4.20%	4.20%	0.00%	0.00%	0.00%	0.00%	0.00%	4.40%
32									
33	**5-year Revolving Loan**								
34	Liability beginning of year	$11,275	$32,750	$33,725	$32,750	$22,000	$22,940	$19,000	$0
35	Issue during the year	1,975	0	0	0	10,750	(940)	3,940	19,000
36	Sinking fund payments	0	(21,475)	(200)	0	0	0	0	0
37	Average Capitalization	12,381	15,752	33,625	32,750	23,675	22,270	21,237	9,897
38	Annual Interest Expense	512	547	996	973	643	727	674	325
39	Stand-by fees	33	32	3	12	19	25	29	23
40	Issue costs beginning of year	62	11	33	33	51	68	84	98
41	Amortization of Issue Costs	11	15	22	22	18	17	15	14
42									
43	Effective Cost Rate	4.35%	3.77%	3.03%	3.08%	2.88%	3.46%	3.39%	3.69%
44									
45	**Total Actual Debt**								
46	Total Average Capitalization	41,421	38,226	37,233	37,199	30,550	30,139	30,100	24,444
47									
48	Effective Cost Rate	4.25%	4.11%	3.26%	3.32%	3.25%	3.87%	3.86%	4.36%

Tab 6

Rates

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)

Summary of Proposed / Indicative Rates Effective January 1, 2018
($/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2017	Proposed 2018 Revenue Requirement	Indicative 2018 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2018	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	4.060	0.251		4.311	0.251
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
RSAM	0.472		(0.030)	0.442	(0.030)
Subtotal Delivery	4.502	0.251	(0.013)	4.740	0.238
Gas Supply Demand	0.163		(0.003)	0.160	(0.003)
Gas Supply Commodity	1.989		(0.379)	1.610	(0.379)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.854	-	(0.544)	1.310	(0.544)
Total	6.356	0.251	(0.557)	6.050	(0.306)
Small Commercial (RS2)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	3.227	0.167		3.394	0.167
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
RSAM	0.472		(0.030)	0.442	(0.030)
Subtotal Delivery	3.669	0.167	(0.013)	3.823	0.154
Gas Supply Demand	0.166		(0.012)	0.154	(0.012)
Gas Supply Commodity	1.993		(0.379)	1.614	(0.379)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.861	-	(0.553)	1.308	(0.553)
Total	5.530	0.167	(0.566)	5.131	(0.399)
Large Commercial (RS3)					
Monthly Fixed Charge	$150.00			$150.00	$0.00
Delivery Charge	2.421	0.120		2.541	0.120
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
Subtotal Delivery	2.391	0.120	0.017	2.528	0.137
Gas Supply Demand	0.132		0.022	0.154	0.022
Gas Supply Commodity	1.946		(0.420)	1.526	(0.420)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.780	-	(0.560)	1.220	(0.560)
Total	4.171	0.120	(0.543)	3.748	(0.423)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)

Summary of Proposed / Indicative Rates Effective January 1, 2018
($/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2017	Proposed 2018 Revenue Requirement	Indicative 2018 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2018	Rate Changes
Commercial Transportation (RS23)					
Monthly Fixed Charge	$125.00			$125.00	$0.00
Delivery Charge	2.549	0.147		2.696	0.147
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
Subtotal Delivery	2.519	0.147	0.017	2.683	0.164
Small Industrial (RS4)					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	1.378	0.087		1.465	0.087
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
Subtotal Delivery	1.348	0.087	0.017	1.452	0.104
Gas Supply Demand	0.106		(0.042)	0.064	(0.042)
Gas Supply Commodity	1.947		(0.486)	1.461	(0.486)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.755	-	(0.690)	1.065	(0.690)
Total	3.103	0.087	(0.673)	2.517	(0.586)
Small Industrial Service (RS6)					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	1.5581	0.0940		1.6521	0.0940
Company Use	0.0420		(0.0120)	0.0300	(0.0120)
GCVA Co. Use Rider	(0.0720)		0.0290	(0.0430)	0.0290
Subtotal Delivery	1.5281	0.0940	0.017	1.6391	0.1110
Small Industrial Service (RS10)					
Monthly Fixed Charge	$3,095.00			$3,095.00	$0.00
Delivery Charge	0.6182	0.0506		0.6688	0.0506
Company Use	0.0420		(0.0120)	0.0300	(0.0120)
GCVA Co. Use Rider	(0.0720)		0.0290	(0.0430)	0.0290
Subtotal Delivery	0.5882	0.0506	0.017	0.6558	0.0676

Pacific Northern Gas (N.E.) Ltd.
(Dawson Creek Division)

Summary of Proposed / Indicative Rates Effective January 1, 2018
($/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2017	Proposed 2018 Revenue Requirement	Indicative 2018 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2018	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	3.862	0.251		4.113	0.251
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
RSAM	0.472		(0.030)	0.442	(0.030)
Interim Rate Refund Rider	0.000				0.000
Subtotal Delivery	4.304	0.251	(0.013)	4.542	0.238
Gas Supply Demand	0.163		(0.003)	0.160	(0.003)
Gas Supply Commodity	1.989		(0.379)	1.610	(0.379)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.854	-	(0.544)	1.310	(0.544)
Total	6.158	0.251	(0.557)	5.852	(0.306)
Small Commercial (RS2)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	2.690	0.167		2.857	0.167
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
RSAM	0.472		(0.030)	0.442	(0.030)
Interim Rate Refund Rider	0.000				0.000
Subtotal Delivery	3.132	0.167	(0.013)	3.286	0.154
Gas Supply Demand	0.166		(0.012)	0.154	(0.012)
Gas Supply Commodity	1.993		(0.379)	1.614	(0.379)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.861	-	(0.553)	1.308	(0.553)
Total	4.993	0.167	(0.566)	4.594	(0.399)
Large Commercial (RS3)					
Monthly Fixed Charge	$150.00			$150.00	$0.00
Delivery Charge	1.873	0.120		1.993	0.120
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
Interim Rate Refund Rider	0.000				0.000
Subtotal Delivery	1.843	0.120	0.017	1.980	0.137
Gas Supply Demand	0.132		0.022	0.154	0.022
Gas Supply Commodity	1.946		(0.420)	1.526	(0.420)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.780	-	(0.560)	1.220	(0.560)
Total	3.623	0.120	(0.543)	3.200	(0.423)
Commercial Transportation (RS23)					
Monthly Fixed Charge	$125.00			$125.00	$0.00
Delivery Charge	2.001	0.147		2.148	0.147
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
Subtotal Delivery	1.971	0.147	0.017	2.135	0.164

Pacific Northern Gas (N.E.) Ltd.
(Dawson Creek Division)

Summary of Proposed / Indicative Rates Effective January 1, 2018
($/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2017	Proposed 2018 Revenue Requirement	Indicative 2018 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2018	Rate Changes
Small Industrial (RS4)					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	1.646	0.087		1.733	0.087
Company Use	0.042		(0.012)	0.030	(0.012)
GCVA Co. Use Rider	(0.072)		0.029	(0.043)	0.029
Subtotal Delivery	1.616	0.087	0.017	1.720	0.104
Gas Supply Demand	0.106		(0.042)	0.064	(0.042)
Gas Supply Commodity	1.947		(0.486)	1.461	(0.486)
GCVA Commodity Rider	(0.298)		(0.162)	(0.460)	(0.162)
Subtotal Commodity	1.755	-	(0.690)	1.065	(0.690)
Total	3.371	0.087	(0.673)	2.785	(0.586)
Small Industrial Service (RS7					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	0.2050	-		0.2050	-
Company Use	0.0000		-	-	-
GCVA Co. Use Rider	0.0000			-	-
Subtotal Delivery	0.2050	-	-	0.2050	-

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Bill Comparison
October 2017 to January 2018

FORT ST. JOHN AREA

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2017 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	107.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.781	84.00	0.781	84.00	-	
Delivery Charge		4.102	441.38	4.341	467.04	25.66	5.8%
GCVA Co. Use Rider		(0.072)	(7.75)	(0.043)	(4.63)	3.12	
RSAM Rider		0.472	50.79	0.442	47.56	(3.23)	
			568.42		593.97	25.56	4.5%
Gas Supply Charge		2.152	231.56	1.770	190.45	(41.10)	
GCVA Rider		(0.298)	(32.06)	(0.460)	(49.50)	(17.43)	
			199.49		140.96	(58.53)	-29.3%
Carbon Tax		1.4898	160.30	1.4898	160.30	-	
		$8.626 /GJ	$928.21	$8.320 /GJ	$895.23	($32.98)	-3.6%
Small Commercial:	495.8 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.169	84.00	0.169	84.00	-	
Delivery Charge		3.269	1,620.77	3.424	1,697.71	76.94	4.7%
GCVA Co. Use Rider		(0.072)	(35.70)	(0.043)	(21.32)	14.38	
RSAM Rider		0.472	234.02	0.442	219.14	(14.88)	
			1,903.09		1,979.53	76.44	4.0%
Gas Supply Charge		2.159	1,070.43	1.768	876.57	(193.86)	
GCVA Rider		(0.298)	(147.75)	(0.460)	(228.07)	(80.32)	
			922.68		648.51	(274.18)	-29.7%
Carbon Tax		1.4898	738.64	1.4898	738.64	-	
		$7.189 /GJ	$3,564.42	$6.790 /GJ	$3,366.68	($197.74)	-5.5%

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Bill Comparison
October 2017 to January 2018

DAWSON CREEK AREA

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2017 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	97.5 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.862	84.00	0.862	84.00	-	
Delivery Charge		3.904	380.64	4.143	403.90	23.26	6.1%
GCVA Co. Use Rider		(0.072)	(7.02)	(0.043)	(4.19)	2.83	
RSAM Rider		0.472	46.02	0.442	43.10	(2.93)	
			503.64		526.80	23.16	4.6%
Gas Supply Charge		2.152	209.82	1.770	172.58	(37.25)	
GCVA Rider		(0.298)	(29.06)	(0.460)	(44.85)	(15.80)	
			180.77		127.73	(53.04)	-29.3%
Carbon Tax		1.4898	145.26	1.4898	145.26	-	
		$8.509 /GJ	$829.66	$8.203 /GJ	$799.78	($29.88)	-3.6%
Small Commercial:	555.8 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.151	84.00	0.151	84.00	-	
Delivery Charge		2.732	1,518.45	2.887	1,604.70	86.25	5.7%
GCVA Co. Use Rider		(0.072)	(40.02)	(0.043)	(23.90)	16.12	
RSAM Rider		0.472	262.34	0.442	245.66	(16.67)	
			1,824.77		1,910.46	85.69	4.7%
Gas Supply Charge		2.159	1,199.97	1.768	982.65	(217.32)	
GCVA Rider		(0.298)	(165.63)	(0.460)	(255.67)	(90.04)	
			1,034.34		726.99	(307.36)	-29.7%
Carbon Tax		1.4898	828.03	1.4898	828.03	-	
		$6.634 /GJ	$3,687.14	$6.235 /GJ	$3,465.48	($221.66)	-6.0%

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Bill Comparison
October 2017 to January 2018

Average of Fort St. John and Dawson Creek

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2017 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	102.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.819	84.00	0.819	84.00	-	
Delivery Charge		4.003	410.51	4.242	434.97	24.46	6.0%
GCVA Co. Use Rider		(0.072)	(7.38)	(0.043)	(4.41)	2.97	
RSAM Rider		0.472	48.40	0.442	45.33	(3.08)	
			535.53		559.88	24.36	4.5%
Gas Supply Charge		2.152	220.69	1.770	181.51	(39.17)	
GCVA Rider		(0.298)	(30.56)	(0.460)	(47.17)	(16.61)	
			190.13		134.34	(55.79)	-29.3%
Carbon Tax		1.4898	152.78	1.4898	152.78	0.00	
		$8.566 /GJ	$878.43	$8.259 /GJ	$847.01	($31.43)	-3.6%
Small Commercial:	525.8 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.160	84.00	0.160	84.00	-	
Delivery Charge		3.001	1,577.66	3.156	1,659.26	81.60	5.2%
GCVA Co. Use Rider		(0.072)	(37.86)	(0.043)	(22.61)	15.25	
RSAM Rider		0.472	248.18	0.442	232.40	(15.78)	
			1,871.98		1,953.05	81.07	4.3%
Gas Supply Charge		2.159	1,135.20	1.768	929.61	(205.59)	
GCVA Rider		(0.298)	(156.69)	(0.460)	(241.87)	(85.18)	
			978.51		687.75	(290.77)	-29.7%
Carbon Tax		1.4898	783.34	1.4898	783.34	-	
		$6.911 /GJ	$3,633.83	$6.512 /GJ	$3,424.13	($209.70)	-5.8%

Note: This bill comparison is the average of the uses per account and rates that apply to each of the Fort St. John and Dawson Creek delivery areas.

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
EFFECTIVE JANUARY 1, 2018

Customer Classification	2018 Test Year Gas Deliveries (GJ)	2018 Test Year Marginable Deliveries (GJ)	2018 Gross Margin ($)	Allocation of Revenue Deficiency ($)	Rate Changes for Revenue Deficiency ($/GJ)
Residential (RS1)	1,798,219	1,798,219	8,681,412	450,479	0.251
Commercial					
Small Commercial (RS2)	1,363,762	1,363,762	4,393,860	227,998	0.167
Large Commercial Firm (RS3)	355,900	355,900	826,296	42,877	0.120
Commercial Transportation (RS23)	73,350	73,350	208,498	10,819	0.147
Bulk CNG Service (RS30)	0	0	0	0	0.000
Small Industrial Sales (RS4)	511,520	511,520	856,645	44,451	0.087
Industrial Transport					
RS6	242,000	242,000	438,440	22,751	0.0940
RS7	980,025	980,025	205,825	0	0.0000
RS10	322,210	322,210	314,087	16,298	0.0506
RS11	0	0	0	0	
TOTAL	**5,646,986**	**5,646,986**	**15,925,062**	**815,673**	
Summary					
Sales	4,029,401	4,029,401	14,758,212	765,805	
Transportation	1,617,585	1,617,585	1,166,850	49,868	
Total	**5,646,986**	**5,646,986**	**15,925,062**	**815,673**	

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	2018 Test Year Gas Deliveries (GJ)	Revenue ($)	Cost of Gas ($)	Gross Margin ($)
Residential (RS1)	1,798,219	11,864,259	3,182,847	8,681,412
Commercial				
Small Commercial (RS2)	1,363,762	6,804,989	2,411,129	4,393,860
Large Commercial Firm (RS3)	355,900	1,424,210	597,915	826,296
Total Commercial				
Commercial Transportation (RS23)	73,350	208,498	0	208,498
Small Industrial Sales (RS4)	511,520	1,636,715	780,070	856,645
Industrial Transport				
RS6	242,000	438,440	0	438,440
RS7	980,025	205,825	0	205,825
RS10	322,210	314,087	0	314,087
Total	**5,646,986**	**22,897,023**	**6,971,961**	**15,925,062**
Summary				
Sales	4,029,401	21,730,174	6,971,961	14,758,212
Transportation	1,617,585	1,166,850	0	1,166,850
Total	**5,646,986**	**22,897,023**	**6,971,961**	**15,925,062**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gas Deliveries
FORT ST. JOHN

Customer Classification	Actual Customer Count At Dec. 31st, 2017	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2018	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2018 Test Year Deliveries (GJ)
Residential (Rate 1)	10,962		95		11,057	10,984		107.6		1,181,883
Commercial										
Small Commercial Sales (Rate 2)	1,739		5		1,744	1,740		495.8		862,451
Large Commercial Firm Sales (Rate 3)	8		0		8					193,100
Commercial Transportation (RS23)	14				14					51,150
Small Industrial Sales (RS4)	6		1		7					184,520
Industrial Transportation										
RS6	11		0		11					242,000
RS9	0		0		0					0
RS10	4		(1)		3					322,210
Subtotal Sales	12,729		101		12,830					2,421,954
Subtotal Transportation Service	15		-1		14					615,360
Total	**12 744**		**100**		**12 844**					**3,037,314**

DAWSON CREEK

Customer Classification	Actual Customer Count At Dec. 31st, 2017	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2018	Test Year Weighted Average Customer Count	Test Year Average Use Per Account (GJ)	2018 Test Year Deliveries (GJ)
Residential (Rate 1)	6,312		40		6,352	6,321	97.5	616,336
Commercial								
Small Commercial Sales (Rate 2)	907		6		913	902	555.8	501,311
Large Commercial Firm Sales (Rate 3)	16		0		16			162,800
Commercial Transportation (RS23)	7		0		7			22,200
Bulk CNG Sales (RS30)								0
Small Industrial Sales (RS4)	3		0		3			327,000
Small Industrial Transport (RS7)	1		0		1			980,025
Subtotal Sales	7,238		46		7,284			1,607,447
Subtotal Transportation Service	8		0		8			1,002,225
Total	**7,246**		**46**		**7,292**			**2,609,672**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)
Derivation of Test Year Forecast Gas Deliveries

Customer Classification	Actual Customer Count At Dec. 31st, 2017	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2018	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2018 Test Year Deliveries (GJ)
Residential (Rate 1)	17,274		135		17,409	17,305		103.9		1,798,219
Commercial										
Small Commercial Sales (Rate 2)	2,646		11		2,657	2,641		516.3		1,363,762
Large Commercial Firm Sales (Rate 3)	24		0		24					355,900
Commercial Transportation (RS23)	21		0		21					73,350
Small Industrial Sales (RS4)	9		1		10					511,520
Industrial Transportation										
RS6	11		0		11					242,000
RS7	1		0		1					980,025
RS9	0		0		0					0
RS10	4		(1)		3					322,210
Subtotal Sales	19,953		147		20,100					4,029,401
Subtotal Transportation Service	37		(1)		36					1,617,585
Total	**19,990**		**146**		**20,136**					**5,646,986**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

Fort St. John **Customer Classification**	**2018 Test Year Deliveries (GJ)**	**Current Delivery Charge ($ / GJ)**	**Delivery Margin ($)**	**Average Customer Count**	**Current Fixed Charge ($ / Month)**	**Fixed Charge Margin ($)**	**Total Delivery & Fixed Charge Margin ($)**	**2018 Test Year Gross Margin ($)**
Residential (Rate 1)	1,181,883	4.090	4,833,901	10,945	7.00	919,380	5,753,281	5,753,281
Commercial								
Small Commercial Sales (Rate 2)	862,451	3.257	2,809,003	1,735	7.00	145,740	2,954,743	2,954,743
Large Commercial Sales (Rate 3)	193,100	2.451	473,288	8	150.00	14,400	487,688	487,688
Commercial Transport (Rate 23)	51,150	2.579	131,916	14	125.00	21,000	152,916	152,916
Small Industrial Sales (Rate 4)	184,520	1.408	259,804	7	410.00	34,030	293,834	293,834
Industrial Transportation								
Rate 6	242,000	1.5881	384,320	11	410.00	54,120	438,440	438,440
Rate 10	322,210	0.6482	208,857	3	3,095.00	105,230	314,087	314,087
Total Fort St. John	**3,037,314**		**9,101,089**	**12,723**		**1,293,900**	**10,394,989**	**10,394,989**

Dawson Creek **Customer Classification**	**2018 Test Year Deliveries (GJ)**	**Current Delivery Charge ($ / GJ)**	**Delivery Margin ($)**	**Average Customer Count**	**Current Fixed Charge ($ / Month)**	**Fixed Charge Margin ($)**	**Total Delivery & Fixed Charge Margin ($)**	**2018 Test Year Gross Margin ($)**
Residential (Rate 1)	616,336	3.892	2,398,780	6,302	7.00	529,368	2,928,148	2,928,148
Commercial								
Small Commercial Sales (Rate 2)	501,311	2.720	1,363,566	899	7.00	75,516	1,439,082	1,439,082
Large Commercial Sales (Rate 3)	162,800	1.903	309,808	16	150.00	28,800	338,608	338,608
Commercial Transportation (Rate 23)	22,200	2.031	45,088	7	125.00	10,500	55,588	55,588
Small Industrial Sales (Rate 4)	327,000	1.676	548,052	3	410.00	14,760	562,812	562,812
Small Industrial Transportation (Rate 7)	980,025	0.2050	200,905	1	410.00	4,920	205,825	205,825
Total Dawson Creek	**2,609,672**		**4,866,199**	**7,229**		**663,864**	**5,530,063**	**5,530,063**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

FSJ / DC Combined **Customer Classification**	**2018 Test Year Deliveries (GJ)**	**Current Delivery Charge ($ / GJ)**	**Delivery Margin ($)**	**Average Customer Count**	**Current Fixed Charge ($ / Month)**	**Fixed Charge Margin ($)**	**Total Delivery & Fixed Charge Margin ($)**	**2018 Test Year Gross Margin ($)**
Residential (Rate 1)	1,798,219		7,232,681	17,247	7.00	1,448,748	8,681,429	8,681,429
Commercial								
Small Commercial Sales (Rate 2)	1,363,762		4,172,569	2,634	7.00	221,256	4,393,825	4,393,825
Large Commercial Sales (Rate 3)	355,900		783,097	24	150.00	43,200	826,297	826,297
Commercial Transport (Rate 23)	73,350		177,004	21	125.00	31,500	208,504	208,504
Small Industrial Sales (Rate 4)	511,520		807,856	10	410.00	48,790	856,646	856,646
Industrial Transportation								
Rate 6	242,000	1.5461	384,320	11	410.00	54,120	438,440	438,440
Rate 7	980,025	0.2050	200,905	1	410.00	4,920	205,825	205,825
Rate 10	322,210	0.6182	208,857	3	3,095.00	105,230	314,087	314,087
Total Fort St. John / Dawson Creek	**5,646,986**		**13,967,289**	**19,952**		**1,957,764**	**15,925,053**	**15,925,053**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

Fort St. John **Customer Classification**	**2018 Test Year Deliveries (GJ)**	**Indicative Gas Cost Charge ($ / GJ)**	**Indicative Gas Cost ($)**
Residential (Rate 1)	1,181,883	1.770	2,091,933
Commercial			
Small Commercial Sales (Rate 2)	862,451	1.768	1,524,813
Large Commercial Sales (Rate 3)	193,100	1.680	324,408
Small Industrial Sales (Rate 4)	184,520	1.525	281,393
Total Fort St. John	**2,421,954**		**4,222,547**

Dawson Creek **Customer Classification**	**2018 Test Year Deliveries (GJ)**	**Gas Cost Charge ($ / GJ)**	**Total Gas Cost ($)**
Residential (Rate 1)	616,336	1.770	1,090,915
Commercial			
Small Commercial Sales (Rate 2)	501,311	1.768	886,318
Large Commercial Sales (Rate 3)	162,800	1.680	273,504
Small Industrial Sales (Rate 4)	327,000	1.525	498,675
Total Dawson Creek	**1,607,447**		**2,749,412**

Note: (1) Customer has a transportation service contract but has opted to purchase their gas from the utility

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

FSJ / DC Combined **Customer Classification**	**2018 Test Year Deliveries (GJ)**	**Gas Cost Charge ($ / GJ)**	**Total Gas Cost ($)**
Residential (Rate 1)	1,798,219	1.770	3,182,848
Commercial			
Small Commercial Sales (Rate 2)	1,363,762	1.768	2,411,131
Large Commercial Sales (Rate 3)	355,900	1.680	597,912
Small Industrial Sales (Rate 4)	511,520	1.525	780,068
Small Industrial Transportation (Rate 5)	0	0.000	0
Total Fort St. John / Dawson Creek	**4,029,401**		**6,971,959**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative Gas Supply Cost Rate Changes Effective January 1, 2018

Using Average of 5 Day Forward Strip ending November 21, 2017

Customer Classification	Gas Supply Costs Rates Rates Effective October 1, 2017				Gas Supply Costs Indicative Rates Effective January 1, 2018				Indicative Gas Supply Cost Rate Changes Effective January 1, 2018			
	Demand ($/GJ)	Commodity ($/GJ)	Total D&C	Company Use Gas ($/GJ)	Demand 0	Commodity ($/GJ)	Total D&C	Company Use Gas ($/GJ)	Demand ($/GJ)	Commodity ($/GJ)	Total D&C	Company Use Gas ($/GJ)
Residential (RS1)	0.163	1.989	2.152	0.042	0.160	1.610	1.770	0.030	(0.003)	(0.379)	(0.382)	(0.012)
Small Commercial (RS2)	0.166	1.993	2.159	0.042	0.154	1.614	1.768	0.030	(0.012)	(0.379)	(0.391)	(0.012)
Large Commercial (RS3)	0.132	1.946	2.078	0.042	0.154	1.526	1.680	0.030	0.022	(0.420)	(0.398)	(0.012)
Small Industrial (RS4)	0.106	1.947	2.053	0.042	0.064	1.461	1.525	0.030	(0.042)	(0.486)	(0.528)	(0.012)
Company Use				0.042				0.030				(0.012)
Transportation Service				0.042				0.030				(0.012)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

ALLOCATION OF DEMAND CHARGES EFFECTIVE JANUARY 1, 2018

Customer Classification	**Peak Day Requirement** (GJ)	(%)	**Allocation of Demand Charges** ($)	**Test Year Requirements** (GJ)	**Unit Demand Charge** ($/GJ)
Residential (RS1)	20,415	48.73	287,697	1,798,219	0.160
Small Commercial (RS2)	14,900	35.57	209,980	1,363,762	0.154
Large Commercial (RS3)	3,888	9.28	54,790	355,900	0.154
Industrial Sales (RS4)	2,336	5.58	32,916	511,520	0.064
Company Use Gas	353	0.84	4,969	76,697	0.065
Total	**41,891**	**100.0**	**590,352**	**4,106,098**	

Notes:

1) PNG allocates its demand charges to each customer classification based on the proportion of their projected peak day gas requirement.

2) The unit demand charge is the allocated demand charge divided by the projected annual gas requirements for each customer classification. There is no unit demand charge for Company use gas as the demand charges and the commodity charges for company use gas are totalled and then spread over total sales (i.e. the sum of sales and transportation service.)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative 2018 Unit Company Use Gas Cost Rate

Using Average of 5 Day Forward Strip ending November 21, 2017		
Demand Cost	$4,969	
Commodity Cost	$110,626	
B.C.S.S. Tax	1,533	
Ice Levy	90	
Carbon Tax	23,671	
	$140,889	
Total Company use gas requirement	76,697	GJ
Total GJ attracting margin	4,666,961	GJ

2018 Unit Company Use Gas Cost Rate

$0.0302 /GJ = $140,889 / 4,666,961

Commodity Cost of Company Use Gas per GJ Purchased

$1.442 /GJ = $110,626 / 76,697

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative 2018 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	2015 RSAM Pool	2016 RSAM Pool	2017 RSAM Pool	2018 RSAM Pool	Total
Residential - balance at end of 2015	$492,206	$0	$0	$0	$492,206
Residential - 2016 rate riders	($175,520)				($175,520)
Residential - 2016 additions		$1,382,284			$1,382,284
Residential - 2016 imputed interest		$47,224			$47,224
Residential - balance at end of 2016	$316,687	$1,429,508	$0	$0	$1,746,195
Residential - 2017 rate riders	($316,687)	($522,644)			($839,331)
Residential - 2017 additions			$407,440		$407,440
Residential - 2017 imputed interest			$54,525		$54,525
Residential - balance at end of 2017	$0	$906,864	$461,965	$0	$1,368,829
Residential - 2018 imputed interest				$42,176	$42,176
Residential - RSAM pool	**$0**	**$906,864**	**$461,965**	**$42,176**	**$1,411,005**
Small Commercial - balance at end of 2015	$312,321	$0	$0	$0	$312,321
Small Commercial - 2016 rate riders	($109,178)				($109,178)
Small Commercial - 2016 additions		$588,003			$588,003
Small Commercial - 2016 imputed interest		$21,570			$21,570
Small Commercial - balance at end of 2016	$203,143	$609,573	$0	$0	$812,716
Small Commercial - 2017 rate riders	($203,143)	($425,291)			($628,434)
Small Commercial - 2017 additions			$87,803		$87,803
Small Commercial - 2017 imputed interest			$18,269		$18,269
Small Commercial - balance at end of 2017	$0	$184,282	$106,072	$0	$290,354
Small Commercial - 2018 imputed interest				($88)	($88)
Small Commercial - RSAM pool	**$0**	**$184,282**	**$106,072**	**($88)**	**$290,266**
RSAM pools - amounts to be recovered / (credited)	**$0**	**$1,091,146**	**$568,037**	**$42,088**	**$1,701,270**
Years of amortization remaining	1	1	2	2	
RSAM amounts to be recovered in current year	**$0**	**$1,091,146**	**$284,019**	**$21,044**	**$1,396,208**
Residential - forecast 2018 deliveries (GJ)					1,798,219
Small Commercial - forecast 2018 deliveries (GJ)					1,363,762
Forecast 2018 total deliveries (GJ)					**3,161,981**
RSAM rate rider ($/GJ)					**$0.442**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Forward Gas Price Strip
Average of 5 Day Forward Strip ending November 21, 2017

	STATION #2 CDN$/GJ	AECO CDN$/GJ
Jan-18	1.3833	2.0133
Feb-18	1.3841	2.0141
Mar-18	1.3410	1.9710
Apr-18	1.0209	1.6709
May-18	1.0016	1.6516
Jun-18	1.0347	1.6847
Jul-18	1.0717	1.7217
Aug-18	1.0756	1.7256
Sep-18	1.0565	1.7065
Oct-18	1.0867	1.7367
Nov-18	1.9004	2.1904
Dec-18	2.0634	2.3534
Average	**1.2850**	**1.8700**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)

Summary of Proposed / Indicative Rates Effective January 1, 2019
($/GJ unless otherwise specified)

Customer Class	Rates Effective Jan 1, 2018	Proposed 2019 Revenue Requirement	Indicative 2019 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2019	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	4.311	0.257		4.567	0.257
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	-
RSAM	0.442		(0.383)	0.059	(0.383)
Subtotal Delivery	4.740	0.257	(0.376)	4.620	(0.119)
Gas Supply Demand	0.160		(0.004)	0.156	(0.004)
Gas Supply Commodity	1.610		0.342	1.952	0.342
GCVA Commodity Rider	(0.460)		-	(0.460)	-
Subtotal Commodity	1.310	-	0.338	1.648	0.338
Total	6.050	0.257	(0.038)	6.268	0.219
Small Commercial (RS2)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	3.394	0.171		3.565	0.171
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	-
RSAM	0.442		(0.383)	0.059	(0.383)
Subtotal Delivery	3.823	0.171	(0.376)	3.618	(0.205)
Gas Supply Demand	0.154		(0.004)	0.150	(0.004)
Gas Supply Commodity	1.614		0.346	1.960	0.346
GCVA Commodity Rider	(0.460)		-	(0.460)	-
Subtotal Commodity	1.308	-	0.342	1.650	0.342
Total	5.131	0.171	(0.034)	5.268	0.137
Large Commercial (RS3)					
Monthly Fixed Charge	$150.00			$150.00	$0.00
Delivery Charge	2.541	0.123		2.665	0.123
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	-
Subtotal Delivery	2.528	0.123	0.007	2.659	0.130
Gas Supply Demand	0.154		(0.004)	0.150	(0.004)
Gas Supply Commodity	1.526		0.348	1.874	0.348
GCVA Commodity Rider	(0.460)		-	(0.460)	-
Subtotal Commodity	1.220	-	0.344	1.564	0.344
Total	3.748	0.123	0.351	4.223	0.474

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)

Summary of Proposed / Indicative Rates Effective January 1, 2019
($/GJ unless otherwise specified)

Customer Class	Rates Effective Jan 1, 2018	Proposed 2019 Revenue Requirement	Indicative 2019 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2019	Rate Changes
Commercial Transportation (RS23)					
Monthly Fixed Charge	$125.00			$125.00	$0.00
Delivery Charge	2.696	0.151		2.847	0.151
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	-
Subtotal Delivery	2.683	0.151	0.007	2.841	0.158
Small Industrial (RS4)					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	1.465	0.089		1.554	0.089
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	-
Subtotal Delivery	1.452	0.089	0.007	1.548	0.096
Gas Supply Demand	0.064		(0.001)	0.063	(0.001)
Gas Supply Commodity	1.461		0.339	1.800	0.339
GCVA Commodity Rider	(0.460)		-	(0.460)	-
Subtotal Commodity	1.065	-	0.338	1.403	0.338
Total	2.517	0.089	0.345	2.951	0.434
Small Industrial Service (RS6)					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	1.6521	0.0966		1.7487	0.0966
Company Use	0.0300		0.0070	0.0370	0.0070
GCVA Co. Use Rider	(0.0430)		-	(0.0430)	-
Subtotal Delivery	1.6391	0.0966	0.007	1.7427	0.1036
Small Industrial Service (RS10)					
Monthly Fixed Charge	$3,095.00			$3,095.00	$0.00
Delivery Charge	0.6688	0.0496		0.7184	0.0496
Company Use	0.0300		0.0070	0.0370	0.0070
GCVA Co. Use Rider	(0.0430)		-	(0.0430)	-
Subtotal Delivery	0.6558	0.0496	0.007	0.7124	0.0566

Pacific Northern Gas (N.E.) Ltd.
(Dawson Creek Division)

Summary of Proposed / Indicative Rates Effective January 1, 2019
($/GJ unless otherwise specified)

Customer Class	Rates Effective Jan 1, 2018	Proposed 2019 Revenue Requirement	Indicative 2019 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2019	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	4.113	0.257		4.369	0.257
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	0.000
RSAM	0.442		(0.383)	0.059	(0.383)
Interim Rate Refund Rider	0.000				0.000
Subtotal Delivery	4.542	0.257	(0.376)	4.422	(0.119)
Gas Supply Demand	0.160		(0.004)	0.156	(0.004)
Gas Supply Commodity	1.610		0.342	1.952	0.342
GCVA Commodity Rider	(0.460)		-	(0.460)	0.000
Subtotal Commodity	1.310	-	0.338	1.648	0.338
Total	5.852	0.257	(0.038)	6.070	0.219
Small Commercial (RS2)					
Monthly Fixed Charge	$7.00			$7.00	$0.00
Delivery Charge	2.857	0.171		3.028	0.171
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	0.000
RSAM	0.442		(0.383)	0.059	(0.383)
Interim Rate Refund Rider	0.000				0.000
Subtotal Delivery	3.286	0.171	(0.376)	3.081	(0.205)
Gas Supply Demand	0.154		(0.004)	0.150	(0.004)
Gas Supply Commodity	1.614		0.346	1.960	0.346
GCVA Commodity Rider	(0.460)		-	(0.460)	-
Subtotal Commodity	1.308	-	0.342	1.650	0.342
Total	4.594	0.171	(0.034)	4.731	0.137
Large Commercial (RS3)					
Monthly Fixed Charge	$150.00			$150.00	$0.00
Delivery Charge	1.993	0.123		2.117	0.123
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	0.000
Interim Rate Refund Rider	0.000				0.000
Subtotal Delivery	1.980	0.123	0.007	2.111	0.130
Gas Supply Demand	0.154		(0.004)	0.150	(0.004)
Gas Supply Commodity	1.526		0.348	1.874	0.348
GCVA Commodity Rider	(0.460)		-	(0.460)	0.000
Subtotal Commodity	1.220	-	0.344	1.564	0.344
Total	3.200	0.123	0.351	3.675	0.474
Commercial Transportation (RS23)					
Monthly Fixed Charge	$125.00			$125.00	$0.00
Delivery Charge	2.148	0.151		2.299	0.151
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	0.000
Subtotal Delivery	2.135	0.151	0.007	2.293	0.158

Pacific Northern Gas (N.E.) Ltd.
(Dawson Creek Division)

Summary of Proposed / Indicative Rates Effective January 1, 2019
($/GJ unless otherwise specified)

Customer Class	Rates Effective Jan 1, 2018	Proposed 2019 Revenue Requirement	Indicative 2019 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2019	Rate Changes
Small Industrial (RS4)					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	1.733	0.089		1.822	0.089
Company Use	0.030		0.007	0.037	0.007
GCVA Co. Use Rider	(0.043)		-	(0.043)	0.000
Subtotal Delivery	1.720	0.089	0.007	1.816	0.096
Gas Supply Demand	0.064		(0.001)	0.063	(0.001)
Gas Supply Commodity	1.461		0.339	1.800	0.339
GCVA Commodity Rider	(0.460)		-	(0.460)	-
Subtotal Commodity	1.065	-	0.338	1.403	0.338
Total	2.785	0.089	0.345	3.219	0.434
Small Industrial Service (RS7					
Monthly Fixed Charge	$410.00			$410.00	$0.00
Delivery Charge	0.2050	-		0.2050	-
Company Use	0.0000		-	-	-
GCVA Co. Use Rider	0.0000			-	-
Subtotal Delivery	0.2050	-	-	0.2050	-

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Bill Comparison
January 2018 to January 2019

FORT ST. JOHN AREA

Customer Classification	Annual Use	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2019 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	106.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.788	84.00	0.788	84.00	-	
Delivery Charge		4.341	462.70	4.604	490.81	28.11	6.1%
GCVA Co. Use Rider		(0.043)	(4.58)	(0.043)	(4.58)	-	
RSAM Rider		0.442	47.12	0.059	6.29	(40.83)	
			589.23		576.51	(12.72)	-2.2%
Gas Supply Charge		1.770	188.68	2.108	224.71	36.03	
GCVA Rider		(0.460)	(49.04)	(0.460)	(49.04)	-	
			139.65		175.68	36.03	25.8%
Carbon Tax		1.4898	158.81	1.7381	185.28	26.47	
		$8.327 /GJ	$887.69	$8.794 /GJ	$937.47	49.78	5.6%
Small Commercial:	500.3 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.168	84.00	0.168	84.00	-	
Delivery Charge		3.424	1,713.12	3.602	1,802.13	89.01	5.2%
GCVA Co. Use Rider		(0.043)	(21.51)	(0.043)	(21.51)	-	
RSAM Rider		0.442	221.13	0.059	29.52	(191.61)	
			1,996.74		1,894.14	(102.60)	-5.1%
Gas Supply Charge		1.768	884.53	2.110	1,055.63	171.10	
GCVA Rider		(0.460)	(230.14)	(0.460)	(230.14)	-	
			654.39		825.50	171.10	26.1%
Carbon Tax		1.4898	745.35	1.7381	869.57	124.22	
		$6.789 /GJ	$3,396.48	$7.174 /GJ	$3,589.20	$68.50	2.0%

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Bill Comparison
January 2018 to January 2019

DAWSON CREEK AREA

Customer Classification	Annual Use	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2019 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	96.3 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.872	84.00	0.872	84.00	-	
Delivery Charge		4.143	398.92	4.406	424.32	25.39	6.4%
GCVA Co. Use Rider		(0.043)	(4.14)	(0.043)	(4.14)	-	
RSAM Rider		0.442	42.56	0.059	5.68	(36.88)	
			521.35		509.86	(11.49)	-2.2%
Gas Supply Charge		1.770	170.45	2.108	203.00	32.55	
GCVA Rider		(0.460)	(44.30)	(0.460)	(44.30)	-	
			126.15		158.70	32.55	25.8%
Carbon Tax		1.4898	143.47	1.7381	143.47	-	
		$8.214 /GJ	$790.97	$8.681 /GJ	$812.03	$21.06	2.7%
Small Commercial:	566.0 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.148	84.00	0.148	84.00	-	
Delivery Charge		2.887	1,634.15	3.065	1,734.84	100.70	6.2%
GCVA Co. Use Rider		(0.043)	(24.34)	(0.043)	(24.34)	-	
RSAM Rider		0.442	250.17	0.059	33.39	(216.78)	
			1,943.98		1,827.90	(116.08)	-6.0%
Gas Supply Charge		1.768	1,000.69	1.768	1,000.69	-	
GCVA Rider		(0.460)	(260.36)	(0.460)	(260.36)	-	
			740.33		740.33	-	0.0%
Carbon Tax		1.4898	843.23	1.7381	843.23	-	
		$6.232 /GJ	$3,527.53	$6.276 /GJ	$3,411.45	($116.08)	-3.3%

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Bill Comparison
January 2018 to January 2019

Average of Fort St. John and Dawson Creek

Customer Classification	Annual Use	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2019 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	101.5 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.828	84.00	0.828	84.00	-	
Delivery Charge		4.242	430.30	4.505	457.05	26.75	6.2%
GCVA Co. Use Rider		(0.043)	(4.36)	(0.043)	(4.36)	-	
RSAM Rider		0.442	44.84	0.059	5.99	(38.86)	
			554.78		542.67	(12.11)	-2.2%
Gas Supply Charge		1.770	179.57	2.108	213.86	34.29	
GCVA Rider		(0.460)	(46.67)	(0.460)	(46.67)	-	
			132.90		167.19	34.29	25.8%
Carbon Tax		1.4898	151.14	1.7381	176.33	25.19	
		$8.268 /GJ	$838.82	$8.735 /GJ	$886.19	$47.37	5.6%
Small Commercial:	533.2 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.158	84.00	0.158	84.00	-	
Delivery Charge		3.156	1,682.45	3.334	1,777.30	94.85	5.6%
GCVA Co. Use Rider		(0.043)	(22.93)	(0.043)	(22.93)	-	
RSAM Rider		0.442	235.65	0.059	31.46	(204.19)	
			1,979.18		1,869.83	(109.34)	-5.5%
Gas Supply Charge		1.768	942.61	1.768	942.61	-	
GCVA Rider		(0.460)	(245.25)	(0.460)	(245.25)	-	
			697.36		697.36	-	0.0%
Carbon Tax		1.4898	794.29	1.7381	926.67	132.38	
		$6.510 /GJ	$3,470.83	$6.553 /GJ	$3,493.86	$23.04	0.7%

Note: This bill comparison is the average of the uses per account and rates that apply to each of the Fort St. John and Dawson Creek delivery areas.

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
EFFECTIVE JANUARY 1, 2019

Customer Classification	2019 Test Year Gas Deliveries (GJ)	2019 Test Year Marginable Deliveries (GJ)	2019 Gross Margin ($)	($/GJ)	2019 Normalized Gross Margin ($)	Allocation of Revenue Deficiency ($)	Rate Changes for Revenue Deficiency ($/GJ)
Residential (RS1)	1,796,601	1,796,601	9,152,796	5.095	9,152,796	461,143	0.257
Commercial							
Small Commercial (RS2)	1,391,298	1,391,298	4,719,571	3.392	4,719,571	237,785	0.171
Large Commercial Firm (RS3)	355,900	355,900	871,666	2.449	871,666	43,917	0.123
Commercial Transportation (RS23)	73,350	73,350	219,829	2.997	219,829	11,076	0.151
Bulk CNG Service (RS30)	0	0	0		0	0	0.000
Small Industrial Sales (RS4)	512,950	512,950	907,239	1.769	907,239	45,709	0.089
Industrial Transport							
RS6	237,000	237,000	454,439	1.917	454,439	22,896	0.0966
RS7	980,025	980,025	205,825	0.210	205,825	0	0.0000
RS10	400,170	400,170	393,853	0.984	393,853	19,843	0.0496
TOTAL	**5,747,294**	**5,747,294**	**16,925,219**		**16,925,219**	**842,368**	
Summary							
Sales	4,056,749	4,056,749	15,651,272		15,651,272	788,553	
Transportation	1,690,545	1,690,545	1,273,947		1,273,947	53,815	
Total	**5,747,294**	**5,747,294**	**16,925,219**		**16,925,219**	**842,368**	

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	2019 Test Year Gas Deliveries (GJ)	Revenue ($)	Cost of Gas ($)	Gross Margin ($)
Residential (RS1)	1,796,601	12,940,029	3,787,233	9,152,796
Commercial				
Small Commercial (RS2)	1,391,298	7,655,211	2,935,640	4,719,571
Large Commercial Firm (RS3)	355,900	1,592,007	720,341	871,666
Total Commercial				
Commercial Transportation (RS23)	73,350	219,829	0	219,829
Small Industrial Sales (RS4)	512,950	1,862,862	955,623	907,239
Industrial Transport				
RS6	237,000	454,439	0	454,439
RS7	980,025	205,825	0	205,825
RS10	400,170	393,853	0	393,853
Total	**5,747,294**	**25,324,055**	**8,398,837**	**16,925,219**
Summary				
Sales	4,056,749	24,050,109	8,398,837	15,651,272
Transportation	1,690,545	1,273,947	0	1,273,947
Total	**5,747,294**	**25,324,055**	**8,398,837**	**16,925,219**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gas Deliveries
FORT ST. JOHN

Customer Classification	Forecast Customer Count At Dec. 31st, 2018	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2019	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2019 Test Year Deliveries (GJ)
Residential (Rate 1)	11,057		135		11,192	11,105		106.6		1,183,758
Commercial										
Small Commercial Sales (Rate 2)	1,744		8		1,752	1,748		500.3		874,412
Large Commercial Firm Sales (Rate 3)	8		0		8					193,100
Commercial Transportation (RS23)	14				14					51,150
Small Industrial Sales (RS4)	7		0		7					185,950
Industrial Transportation										
RS6	11		0		11					237,000
RS9	0		0		0					0
RS10	3		0		3					400,170
Subtotal Sales	12,830		143		12,973					2,437,220
Subtotal Transportation Service	14		0		14					688,320
Total	**12 844**		**143**		**12 987**					**3,125,540**

DAWSON CREEK

Customer Classification	Forecast Customer Count At Dec. 31st, 2018	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2019	Test Year Weighted Average Customer Count	Test Year Average Use Per Account (GJ)	2019 Test Year Deliveries (GJ)
Residential (Rate 1)	6,352		45		6,397	6,364	96.3	612,843
Commercial								
Small Commercial Sales (Rate 2)	913		2		915	913	566.0	516,886
Large Commercial Firm Sales (Rate 3)	16		0		16			162,800
Commercial Transportation (RS23)	7		0		7			22,200
Bulk CNG Sales (RS30)								0
Small Industrial Sales (RS4)	3		0		3			327,000
Small Industrial Transport (RS7)	1		0		1			980,025
Subtotal Sales	7,284		47		7,331			1,619,529
Subtotal Transportation Service	8		0		8			1,002,225
Total	**7,292**		**47**		**7,339**			**2,621,754**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)
Derivation of Test Year Forecast Gas Deliveries

Customer Classification	Forecast Customer Count At Dec. 31st, 2018	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2019	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2019 Test Year Deliveries (GJ)
Residential (Rate 1)	17,409		180		17,589	17,469		102.8		1,796,601
Commercial										
Small Commercial Sales (Rate 2)	2,657		10		2,667	2,661		522.8		1,391,298
Large Commercial Firm Sales (Rate 3)	24		0		24					355,900
Commercial Transportation (RS23)	21		0		21					73,350
Small Industrial Sales (RS4)	10		0		10					512,950
Industrial Transportation										
RS6	11		0		11					237,000
RS7	1		0		1					980,025
RS9	0		0		0					0
RS10	3		0		3					400,170
Subtotal Sales	20,100		190		20,290					4,056,749
Subtotal Transportation Service	36		0		36					1,690,545
Total	**20,136**		**190**		**20,326**					**5,747,294**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

Fort St. John **Customer Classification**	**2019 Test Year Deliveries (GJ)**	**Current Delivery Charge ($ / GJ)**	**Delivery Margin ($)**	**Average Customer Count**	**Current Fixed Charge ($ / Month)**	**Fixed Charge Margin ($)**	**Total Delivery & Fixed Charge Margin ($)**	**2019 Test Year Gross Margin ($)**
Residential (Rate 1)	1,183,758	4.348	5,146,405	11,076	7.00	930,384	6,076,789	6,076,789
Commercial								
Small Commercial Sales (Rate 2)	874,412	3.431	3,000,268	1,746	7.00	146,664	3,146,932	3,146,932
Large Commercial Sales (Rate 3)	193,100	2.578	497,903	8	150.00	14,400	512,303	512,303
Commercial Transport (Rate 23)	51,150	2.733	139,818	14	125.00	21,000	160,818	160,818
Small Industrial Sales (Rate 4)	185,950	1.502	279,278	7	410.00	34,440	313,718	313,718
Industrial Transportation								
Rate 6	237,000	1.6891	400,319	11	410.00	54,120	454,439	454,439
Rate 10	400,170	0.7058	282,433	3	3,095.00	111,420	393,853	393,853
Total Fort St. John	**3,125,540**		**9,746,425**	**12,865**		**1,312,428**	**11,058,853**	**11,058,853**

Dawson Creek **Customer Classification**	**2019 Test Year Deliveries (GJ)**	**Current Delivery Charge ($ / GJ)**	**Delivery Margin ($)**	**Average Customer Count**	**Current Fixed Charge ($ / Month)**	**Fixed Charge Margin ($)**	**Total Delivery & Fixed Charge Margin ($)**	**2019 Test Year Gross Margin ($)**
Residential (Rate 1)	612,843	4.150	2,543,001	6,345	7.00	532,980	3,075,981	3,075,981
Commercial								
Small Commercial Sales (Rate 2)	516,886	2.894	1,495,963	913	7.00	76,692	1,572,655	1,572,655
Large Commercial Sales (Rate 3)	162,800	2.030	330,561	16	150.00	28,800	359,361	359,361
Commercial Transportation (Rate 23)	22,200	2.185	48,518	7	125.00	10,500	59,018	59,018
Small Industrial Sales (Rate 4)	327,000	1.770	578,757	3	410.00	14,760	593,517	593,517
Small Industrial Transportation (Rate 7)	980,025	0.2050	200,905	1	410.00	4,920	205,825	205,825
Total Dawson Creek	**2,621,754**		**5,197,705**	**7,286**		**668,652**	**5,866,357**	**5,866,357**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

FSJ / DC Combined **Customer Classification**	**2019 Test Year Deliveries (GJ)**	**Current Delivery Charge ($ / GJ)**	**Delivery Margin ($)**	**Average Customer Count**	**Current Fixed Charge ($ / Month)**	**Fixed Charge Margin ($)**	**Total Delivery & Fixed Charge Margin ($)**	**2019 Test Year Gross Margin ($)**
Residential (Rate 1)	1,796,601		7,689,405	17,421	7.00	1,463,364	9,152,769	9,152,769
Commercial								
Small Commercial Sales (Rate 2)	1,391,298		4,496,230	2,659	7.00	223,356	4,719,586	4,719,586
Large Commercial Sales (Rate 3)	355,900		828,464	24	150.00	43,200	871,664	871,664
Commercial Transport (Rate 23)	73,350		188,336	21	125.00	31,500	219,836	219,836
Small Industrial Sales (Rate 4)	512,950		858,036	10	410.00	49,200	907,236	907,236
Industrial Transportation								
Rate 6	237,000	1.6591	400,319	11	410.00	54,120	454,439	454,439
Rate 7	980,025	0.2050	200,905	1	410.00	4,920	205,825	205,825
Rate 10	400,170	0.6688	282,433	3	3,095.00	111,420	393,853	393,853
Total Fort St. John / Dawson Creek	**5,747,294**		**14,944,130**	**20,151**		**1,981,080**	**16,925,210**	**16,925,210**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

Fort St. John **Customer Classification**	**2019 Test Year Deliveries (GJ)**	**Indicative Gas Cost Charge ($ / GJ)**	**Indicative Gas Cost ($)**
Residential (Rate 1)	1,183,758	2.108	2,495,362
Commercial			
Small Commercial Sales (Rate 2)	874,412	2.110	1,845,009
Large Commercial Sales (Rate 3)	193,100	2.024	390,834
Small Industrial Sales (Rate 4)	185,950	1.863	346,425
Total Fort St. John	**2,437,220**		**5,077,630**

Dawson Creek **Customer Classification**	**2019 Test Year Deliveries (GJ)**	**Gas Cost Charge ($ / GJ)**	**Total Gas Cost ($)**
Residential (Rate 1)	612,843	2.108	1,291,873
Commercial			
Small Commercial Sales (Rate 2)	516,886	2.110	1,090,629
Large Commercial Sales (Rate 3)	162,800	2.024	329,507
Small Industrial Sales (Rate 4)	327,000	1.863	609,201
Total Dawson Creek	**1,619,529**		**3,321,211**

Note: (1) Customer has a transportation service contract but has opted to purchase their gas from the utility

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

FSJ / DC Combined **Customer Classification**	**2019 Test Year Deliveries (GJ)**	**Gas Cost Charge ($ / GJ)**	**Total Gas Cost ($)**
Residential (Rate 1)	1,796,601	2.108	3,787,235
Commercial			
Small Commercial Sales (Rate 2)	1,391,298	2.110	2,935,639
Large Commercial Sales (Rate 3)	355,900	2.024	720,342
Small Industrial Sales (Rate 4)	512,950	1.863	955,626
Small Industrial Transportation (Rate 5)	0	0.000	0
Total Fort St. John / Dawson Creek	**4,056,749**		**8,398,841**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative Gas Supply Cost Rate Changes Effective January 1, 2018

Using Average of 5 Day Forward Strip ending November 21, 2017

Customer Classification	Gas Supply Costs Rates Rates Effective January 1, 2018				Gas Supply Costs Indicative Rates Effective January 1, 2019				Indicative Gas Supply Cost Rate Changes Effective January 1, 2019			
	Demand ($/GJ)	Commodity ($/GJ)	Total D&C	Company Use Gas ($/GJ)	Demand 0	Commodity ($/GJ)	Total D&C	Company Use Gas ($/GJ)	Demand ($/GJ)	Commodity ($/GJ)	Total D&C	Company Use Gas ($/GJ)
Residential (RS1)	0.160	1.61	1.770	0.03	0.156	1.952	2.108	0.037	(0.004)	0.342	0.338	0.007
Small Commercial (RS2)	0.154	1.614	1.768	0.03	0.150	1.960	2.110	0.037	(0.004)	0.346	0.342	0.007
Large Commercial (RS3)	0.154	1.526	1.680	0.03	0.150	1.874	2.024	0.037	(0.004)	0.348	0.344	0.007
Small Industrial (RS4)	0.064	1.461	1.525	0.03	0.063	1.800	1.863	0.037	(0.001)	0.339	0.338	0.007
Company Use				0.03				0.037				0.007
Transportation Service				0.03				0.037				0.007

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

ALLOCATION OF DEMAND CHARGES EFFECTIVE JANUARY 1, 2018

Customer Classification	**Peak Day Requirement** (GJ)	(%)	**Allocation of Demand Charges** ($)	**Test Year Requirements** (GJ)	**Unit Demand Charge** ($/GJ)
Residential (RS1)	20,416	48.35	280,063	1,796,601	0.156
Small Commercial (RS2)	15,216	36.03	208,730	1,391,298	0.150
Large Commercial (RS3)	3,888	9.21	53,333	355,900	0.150
Industrial Sales (RS4)	2,342	5.55	32,130	512,950	0.063
Company Use Gas	364	0.86	4,998	78,614	0.064
Total	**42,226**	**100.0**	**579,254**	**4,135,363**	

Notes:

1) PNG allocates its demand charges to each customer classification based on the proportion of their projected peak day gas requirement.

2) The unit demand charge is the allocated demand charge divided by the projected annual gas requirements for each customer classification. There is no unit demand charge for Company use gas as the demand charges and the commodity charges for company use gas are totalled and then spread over total sales (i.e. the sum of sales and transportation service.)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative 2019 Unit Company Use Gas Cost Rate

Using Average of 5 Day Forward Strip ending November 21, 2017		
Demand Cost	$4,998	
Commodity Cost	$139,957	
B.C.S.S. Tax	2,005	
Ice Levy	114	
Carbon Tax	29,064	
	$176,138	
Total Company use gas requirement	78,614	GJ
Total GJ attracting margin	4,767,269	GJ

2018 Unit Company Use Gas Cost Rate

$0.0369 /GJ = $176,138 / 4,767,269

Commodity Cost of Company Use Gas per GJ Purchased

$1.780 /GJ = $139,957 / 78,614

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative 2019 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	2016 RSAM Pool	2017 RSAM Pool	2018 RSAM Pool	2019 RSAM Pool	Total
Residential - balance at end of 2016	$1,746,195	$0	$0	$0	$1,746,195
Residential - 2017 rate riders	($839,331)				($839,331)
Residential - 2017 additions		$407,440			$407,440
Residential - 2017 imputed interest		$54,525			$54,525
Residential - balance at end of 2017	$906,864	$461,965	$0	$0	$1,368,829
Residential - 2018 rate riders	($906,864)	$112,051			($794,813)
Residential - 2018 additions					$0
Residential - 2018 imputed interest			$42,176		$42,176
Residential - balance at end of 2018	$0	$574,016	$42,176	$0	$616,192
Residential - 2019 imputed interest				$24,646	$24,646
Residential - RSAM pool	**$0**	**$574,016**	**$42,176**	**$24,646**	**$640,838**
Small Commercial - balance at end of 2016	$812,715	$0	$0	$0	$812,715
Small Commercial - 2017 rate riders	($628,434)				($628,434)
Small Commercial - 2017 additions		$87,804			$87,804
Small Commercial - 2017 imputed interest		$18,269			$18,269
Small Commercial - balance at end of 2017	$184,281	$106,073	$0	$0	$290,354
Small Commercial - 2018 rate riders	($184,281)	($517,857)			($702,138)
Small Commercial - 2018 additions					$0
Small Commercial - 2018 imputed interest			($88)		($88)
Small Commercial - balance at end of 2018	$0	($411,784)	($88)	$0	($411,873)
Small Commercial - 2019 imputed interest				($15,345)	($15,345)
Small Commercial - RSAM pool	**$0**	**($411,784)**	**($88)**	**($15,345)**	**($427,218)**
RSAM pools - amounts to be recovered / (credited)	**$0**	**$162,232**	**$42,088**	**$9,301**	**$213,620**
Years of amortization remaining	1	1	2	2	
RSAM amounts to be recovered in current year	**$0**	**$162,232**	**$21,044**	**$4,650**	**$187,926**
Residential - forecast 2019 deliveries (GJ)					1,796,601
Small Commercial - forecast 2019 deliveries (GJ)					1,391,298
Forecast 2019 total deliveries (GJ)					**3,187,899**
RSAM rate rider ($/GJ)					**$0.059**

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Forward Gas Price Strip
Average of 5 Day Forward Strip ending November 21, 2017

	STATION #2 CDN$/GJ	AECO CDN$/GJ
Jan-19	2.1640	2.4540
Feb-19	2.1255	2.4155
Mar-19	2.0336	2.3236
Apr-19	1.4251	1.9051
May-19	1.3669	1.8469
Jun-19	1.3911	1.8711
Jul-19	1.4210	1.9010
Aug-19	1.4210	1.9010
Sep-19	1.3952	1.8752
Oct-19	1.4297	1.9097
Nov-19	2.1029	2.3204
Dec-19	2.2884	2.5059
Average	**1.7137**	**2.1025**

PACIFIC NORTHERN GAS (N.E.) LTD.

(Tumbler Ridge Division)

AMENDED Application to the British Columbia Utilities Commission for Approval of 2018 and 2019 Revenue Requirements

February 28, 2018

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Tab Application

1 Formal Amended Application

PACIFIC NORTHERN GAS (N.E.) LTD. (PNG(NE)) natural gas and propane rates and operations are regulated by the British Columbia Utilities Commission (Commission).

On November 30, 2017, PNG(NE) submitted to the Commission its 2018-2019 Revenue Requirements Application (Original Application), seeking, among other things, Commission approval to amend the rate schedules for its Tumbler Ridge Division (TR Division) effective January 1, 2018.

On December 19, 2017, the Commission issued Order G-193-17, approving the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Original Application, on an interim basis, effective January 1, 2018, with provision for the refund/recovery of any differences between the interim and permanent rates that are determined by the Commission following final disposition of this proceeding.

Commission Order G-193-17 also established a preliminary regulatory timetable (see Section 1.6.1) for this proceeding, including the scheduling for PNG(NE) to file an updated application on February 28, 2018.

This submission represents PNG(NE)'s amended 2018-2019 Revenue Requirements Application (Amended Application). This Amended Application generally includes all of the Original Application, as well as all revisions arising from the normal evidentiary update information, such as revised demand forecasts which take into consideration the effects of 2017 actual deliveries, updated cost forecasts, as well as the impact of 2017 actual operating results on rate-base items.

Information contained in this Amended Application that PNG(NE) has assessed to be a significant change or material new information in comparison to the Original Application have been highlighted in grey-shaded text to draw the reader's attention to the information.

The following narrative provides the submissions by PNG(NE) in support of the permanent rates applied for and other approvals sought in this Amended Application. A detailed list of the approvals sought in this Amended Application is set out in Section 1.5 – Amended Approvals Sought.

1.1 Background

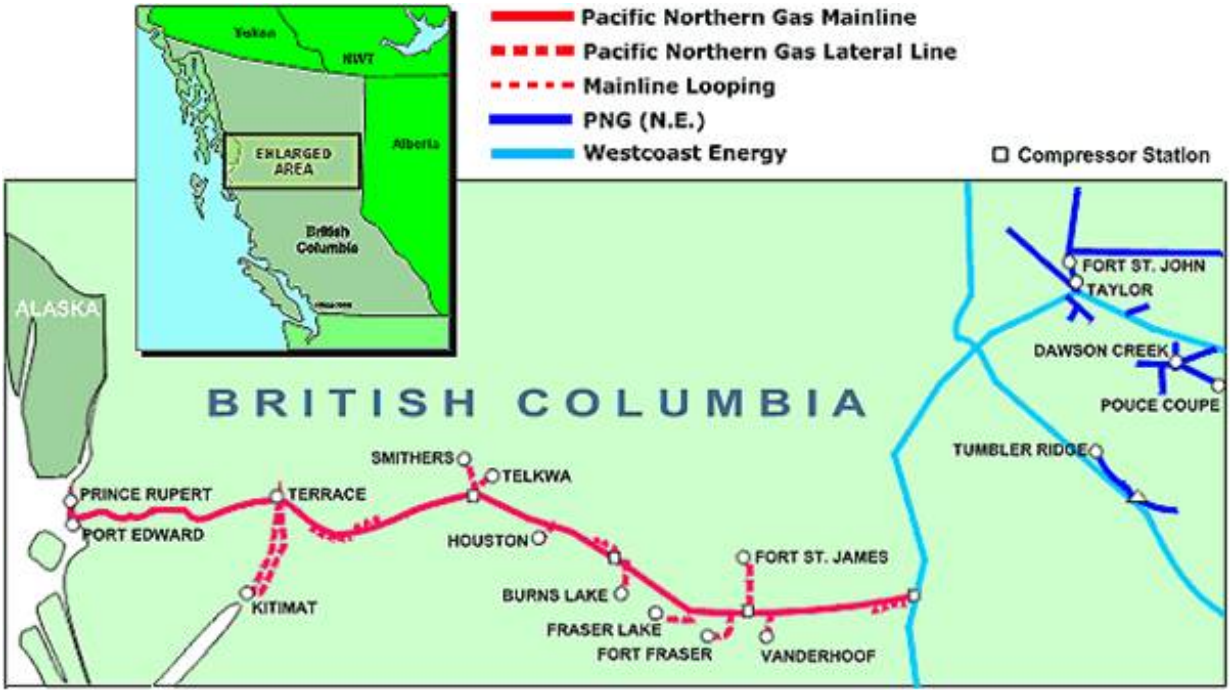
PNG(NE) is a wholly-owned subsidiary of Pacific Northern Gas Ltd. (PNG), which in turn is a wholly-owned subsidiary of AltaGas Utility Holdings (Pacific) Inc., which in turn is a wholly-owned subsidiary of AltaGas Ltd. (AltaGas).

PNG(NE) owns and operates natural gas distribution systems and a gas processing plant in northeastern British Columbia and provides service to approximately 21,400 natural gas customers in the communities of Fort St. John (FSJ), Dawson Creek (DC) and Tumbler Ridge (TR). PNG(NE) maintains separate rate schedules for both the FSJ/DC Division and the TR Division and submits standalone revenue requirements application to the Commission for each of these divisions.

PNG also has a western division (PNG-West) that owns and operates a natural gas transmission and distribution system in west central British Columbia. The pipeline system commences at Summit Lake, just north of Prince George, and extends west to the deep water ports of Prince Rupert and Kitimat. PNG-West serves approximately 20,400 natural gas customers along this corridor. PNG-West also serves approximately 150 propane customers in the community of Granisle, B.C.

The PNG System Map, including PNG(NE) and PNG-West is illustrated in the figure below.

PNG System Map – PNG-West and PNG(NE)



1.2 Amended Application Overview

PNG(NE) has prepared this Amended Application for submission to the Commission in support of its request for approval of permanent rate changes for 2018 and 2019.

The Amended Application primarily reflects the following changes from the Original Application filed on November 30, 2017:

- The impacts of incorporating Actual 2017 figures into the financial model which will mainly result in changes to plant in service, deferred charges and demand forecasts;
- A decrease in pension and non-pension post-retirement benefits expenses primarily due to a change in the discount rate from 3.81% down to 3.6% as per a recently completed actuarial valuation; and
- A correction to properly model the CCA deductions resulting in lower income taxes for Test Year 2018.

PNG(NE) is forecasting a revenue deficiency of approximately $207,000 for Test Year 2018 compared to Decision 2017 and a revenue deficiency of approximately $229,000 for Test Year 2019 compared to Test Year 2018. PNG(NE) is seeking approval to increase the delivery charge component of its customer rates in order to recover these amounts.

These results for Test Year 2018 and Test Year 2019 also reflect PNG(NE)'s proposal to implement a rate deferral mechanism in order to levelize the impact of the customer rate increases over the two-year period addressed in this Amended Application. Please see Section 1.3 – Proposed Rate Deferral Mechanism.

The following table summarizes the derivation of the Test Year 2018 and Test Year 2019 revenue deficiencies by comparing forecast Test Year 2018 and Test Year 2019 figures with the corresponding budgeted figures used to set delivery rates under the Commission-approved Decision 2017.

Table 1: Summary of Amended Test Year 2018 and Test Year 2019 Revenue Deficiency

Cost of Service Items ($000's)	Decision 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017		Decision 2017
		$000's	%		$000's	%	
Operating, maintenance, administrative and general expenses	1,085	25	2.3%	1,060	8	0.8%	1,052
Transfers to capital operating, administrative and general	(36)	7	(21.0)%	(43)	16	(37.5)%	(59)
Other cost of service Items including property taxes, depreciation and amortization	238	(86)	(36.1)%	325	106	32.7%	218
Return components including return on equity, income taxes and debt costs.	349	95	27.1%	254	(4)	(1.4)%	258
Cost of Service Excluding Company Use Gas	1,637	41	2.6%	1,596	127	8.6%	1,469
Operating Margin Using Existing Year Rates	1,580	15		1,305	164		1,469
Test Year Revenue Deficiency (Sufficiency) Before Proposed Rate Deferral	57	57		291	291		
Impact of Proposed Rate Deferral	174	174		(85)	(85)		
Test Year Revenue Deficiency	230	230		206	206		

The forecast revenue deficiency for Test Year 2018 compared to Decision 2017 can be attributed to a variety of factors, including:

Lower forecast margins of $166,000 primarily due to lower forecast deliveries in 2018 to PNG(NE)'s only industrial customer;

Net higher operating, maintenance and administrative and general expenses of $8,000 or 0.8% compared to Decision 2017 primarily due to inflationary increases as well as increases in amine costs, and additional resources required for field operations to address engineering work, records management, digital mapping and a new geographical information system offset by lower pension and non-pension benefits in Test Year 2018; and

Amortization of the ICCDA account of $243,000 for the lower deliveries to CNRL in 2016 and 2017 being fully amortized in Test Year 2018.

The adverse impacts of the above factors have been partially offset by:

The amortization of the remaining credit balance of the Legacy Deferred Income Taxes of $106,000 to help mitigate the lower deliveries to PNG(NE)'s only industrial customer;

Various factors relating to capital including lower depreciation rates from the Depreciation Study, higher financing costs relating to capital investments, lower transfers to capital and lower income taxes resulting in a net decrease of $20,000 ;

A decrease of $85,000 for PNG(NE)'s proposal to create a new rate deferral account to smooth the impact of the combined forecast increases for Test Year 2018 and Test Year

2019 on customer rates over these two years.

The forecast revenue deficiency for Test Year 2019 from Test Year 2018 can be attributed mainly to the following factors:

Net impact of approximately $84,000 due to increasing capital investment in PNG(NE) which results in higher depreciation expense, higher return on equity and financing costs primarily due to the significant capital project to repair the Tumbler Ridge transmission pipeline;

Higher future income taxes of $57,000 due to higher return on common equity and a reduction in the amortization of deferred charges thereby reducing timing differences;;

Net higher operating and maintenance and administrative and general costs of $25,000, a 2.3% increase over Test Year 2018, resulting mainly from inflationary increases;

Lower forecast margins of $16,000 mainly due to decreasing use per account for residential customers; and

$174,000 related to PNG(NE)'s proposal to create a new rate deferral account to levelize the impact of the combined forecast increases for Test Year 2018 and Test Year 2019 on customer rates over these two years; offset by

Lower amortization expense of $125,000 as there is no ICCDA debit amortization and Legacy DIT credit amortization.

1.3 Proposed Rate Deferral Mechanism

For this two-year Amended Application, PNG(NE) is proposing that the full impact of the combined rate changes anticipated for Test Year 2018 and Test Year 2019 be levelized and smoothed over the two-year period. This would be achieved by recording $85,000 of the Test Year 2018 anticipated revenue deficiency in Test Year 2019 in an interest bearing deferral account. As noted in this Amended Application, the calculated revenue deficiency would be $0.206 million for Test Year 2018 and $0.230 million for Test Year 2019, which would result in a residential rate increase of 19.1% and 18.1%, respectively, on the delivery rate component of customer rates.

PNG(NE) recognizes that the proposed rate increases are significant and is therefore seeking approval to implement its rate smoothing proposal. Without the proposed rate deferral mechanism, PNG(NE)'s calculations indicate a revenue deficiency of $0.291million for Test Year 2018 and a revenue deficiency of $0.058 million for Test Year 2019, with a cumulative total revenue deficiency of $0.349 million for the two-year period. These results would necessitate a residential delivery rate increase of 26.9% in 2018 and a subsequent increase of 4.3% in 2019. The primary reason for the large revenue deficiency in Test Year 2018 is mainly due to the lower forecast deliveries to PNG(NE)'s only industrial customer. PNG(NE) also continues to see a declining use per account for its residential customers while needing to invest significantly to repair and maintain its transmission pipeline.

PNG(NE) is proposing this rate deferral mechanism in view of other factors that are also impacting customer rates effective January 1, 2018, including a significant reduction in the RSAM rate rider and a decrease in commodity rates. PNG(NE) acknowledges that changes in gas commodity rates and GCVA rate riders are addressed through a separate process, the Commission's quarterly review of gas supply costs. However, PNG(NE) is also cognizant that its customers prefer stable rates and reduced rate volatility. Therefore, with the reductions in both the RSAM rate rider and commodity costs effective January 1, 2018, PNG(NE) submits that creating the proposed rate deferral mechanism to alleviate the impact of the anticipated rate increase in Test Year 2018 is prudent and beneficial to customers as it provides rate stability by reducing rate volatility. PNG is seeking a similar rate deferral mechanism across all its divisions for both Test Year 2018 and Test Year 2019.

For this purpose, PNG(NE) therefore seeks Commission approval to create an interest bearing rate deferral account in 2018 to be fully amortized in 2019.

1.4 Permanent Rates Requested

As noted previously, on December 19, 2017, the Commission issued Order G-193-17, approving the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Original Application, on an interim basis, effective January 1, 2018. Approval of interim rates is the usual practice of the Commission in these circumstances and ensures that final rates determined by the Commission in this proceeding can be applied beginning January 1, 2018. If the Commission ultimately determines in this proceeding that a change to PNG(NE)'s rates is necessary, then any difference between the final approved rates and the interim rates would be refunded to or collected from customers, as applicable. Final approved delivery rates for Test Year 2019 would become effective as permanent rates on January 1, 2019.

Based on the identified revenue deficiencies for Test Year 2018 and Test Year 2019, PNG(NE) is applying to the Commission for approval of permanent delivery rate increases effective January 1, 2018 and January 1, 2019 from rates determined per Decision 2017. The table that follows summarizes the allocation of the amended Test Year 2018 and Test Year 2019 revenue deficiencies, and the proposed delivery rate changes arising from this allocation.

Table 2: Amended Summary of Proposed Delivery Charge Rate Changes

Customer Classification	Allocation of 2019 Revenue Deficiency	Test Year 2019 Delivery Charge	Proposed Rate Change from 2018 to 2019		Allocation of 2018 Revenue Deficiency	Test Year 2018 Delivery Charge	Proposed Rate Change from Decision 2017 to 2018		Decision 2017 Delivery Charge
	$	$/GJ	$/GJ	%	$	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	123,563	10.059	1.543	18.1%	110,510	8.516	1.364	19.1%	7.152
Commercial									
Small Commercial Firm (Rate 2)	39,593	7.974	1.126	16.4%	35,990	6.848	0.994	17.0%	5.854
Large Commercial Firm (Rate 3)	14,480	6.545	0.905	16.0%	12,763	5.640	0.798	16.5%	4.842
Total Commercial	54,074				48,753				
Industrial Transport									
CNRL	52,703	0.641	0.117	22.3%	46,950	0.524	0.104	24.8%	0.420
TOTAL	230,339				206,214				

Source: Tab Schedules, Tab 6, Pages 1-3 and 12-14; 2016-2017 RRA Compliance Filing

For Test Year 2018, the average delivery rate increase (excluding Company use gas) is estimated to be approximately $97 per year for a typical residential customer consuming 71.2 GJ per year. This represents an increase of 19.1% compared to Decision 2017 delivery rates. The Test Year 2019 average delivery rate increase for a residential customer over Test Year 2018 is estimated to be approximately $108 per year assuming an average consumption of 70.3 GJ per year, representing an 18.1% increase. Similarly, for Test Year 2018, an average small commercial customer consuming 351.7 GJ per year will pay approximately $349 per year more for gas delivery service. This corresponds to an increase of 17.0% compared to Decision 2017 delivery rates. For Test Year 2019, the average small commercial delivery rate increase is estimated at $384 which represents a 16.4% increase over Test Year 2018.

As noted, the amended cost of service forecast presented in this Amended Application has changed from that presented in the Original Application. The table that follows summarizes the changes to the allocation of the computed revenue deficiency and resultant rate impacts for each of the test years, including the impact of changes on the interim rates approved for Test Year 2018 effective January 1, 2018.

Table 3: Summary of Proposed Delivery Charge Rate Changes - Amended vs Original

Customer Classification	Test Year 2019						Test Year 2018					
	Update		Change		Original		Update		Change		Original	
	Allocation of Revenue	Delivery Charge	Allocation of Revenue	Delivery Charge	Allocation of Revenue	Delivery Charge	Allocation of Revenue	Delivery Charge	Allocation of Revenue	Delivery Charge	Allocation of Revenue	Delivery Charge
	$	$/GJ	$	$/GJ	$	$/GJ	$	$/GJ	$	$/GJ	$	$/GJ
Residential (Rate 1)	123,563	10.059	11,036	(0.453)	112,527	10.512	110,510	8.516	(40,475)	(0.548)	150,985	9.064
Commercial												
Small Commercial Firm (Rate 2)	39,593	7.974	2,019	(0.317)	37,574	8.291	35,990	6.848	(15,161)	(0.391)	51,151	7.239
Large Commercial Firm (Rate 3)	14,480	6.545	3,464	(0.258)	11,016	6.803	12,763	5.640	(1,718)	(0.316)	14,481	5.956
Total Commercial	54,074		5,485		48,589		48,753		(16,879)		65,632	
Industrial Transport												
CNRL	52,703	0.641	(3,029)	(0.015)	55,732	0.656	46,950	0.524	(27,360)	(0.031)	74,310	0.555
TOTAL	230,339		13,491		216,848		206,214		(84,713)		290,927	

1.5 Amended Approvals Sought

In this Amended Application, PNG(NE) is seeking an Order of the Commission granting the approvals as described below.

1) Approval, effective January 1, 2018, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2018" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated into the Amended Application and to adjustments and undertakings identified through the regulatory review process.

2) Approval, effective January 1, 2019, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2019" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated into the Amended Application and to adjustments and undertakings identified through the regulatory review process.

3) Approval of PNG(NE)'s proposal to create a short term interest bearing rate deferral account in 2018 to levelize and smooth the impact of the combined net revenue deficiencies for 2018 and 2019 to be fully amortized in 2019.

4) Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2018 and 2019, pursuant to sections 58 to 61 of the *Utilities Commission Act*, as detailed in Section 2.9 – Amortization, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, pages 12 through 15, including:

    a. Approval to fully amortize the Legacy Deferred Income Taxes deferral account balance in 2018;

    b. Approval to eliminate the Legacy Deferred Income Taxes deferral account following the final amortization of the remaining balance in Test Year 2018; and

    c. Approval to eliminate the NPPRB Regulatory Asset Deferral account following the final amortization of the remaining balance in Test Year 2018.

5) Approval of the depreciation expense determined in this Amended Application based on the findings of a new depreciation study as set forth in set forth in Section 2.9 – Depreciation of this Amended Application.

6) Approval to continue the unaccounted for gas (UAF) volume deferral account on the basis, pursuant to sections 58 to 61 of the *Utilities Commission Act* that the UAF volume forecast for Test Year 2018 and Test Year 2019 are set at zero with PNG(NE) recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further Commission approval. PNG(NE) would be required to file an application with the Commission to obtain approval to record UAF losses above 1.0 percent in this deferral account.

A draft Commission Order for the approvals sought has been set out as Appendix A to this Amended Application.

All of which is respectfully submitted.

DATED at Vancouver, British Columbia this 28th day of February 2018.

PACIFIC NORTHERN GAS (N.E.) LTD.

Leigh Ann Shoji-Lee
President

1.6 Regulatory Process

1.6.1 Regulatory Process and Regulatory Timetable

In recent years, PNG(NE)'s revenue requirements applications have been subject to both written hearing processes and the negotiated settlement process. In the Original Application, PNG(NE) expressed its view that, consistent with the proceeding on PNG(NE)'s 2016-2017 revenue requirements application, a written hearing process with provision for two rounds of information requests would allow for an effective and efficient review of the instant Amended Application.

Order G-193-17 established a preliminary timetable with provision for comments by Interveners and PNG(NE) on further process. Based on feedback provided, on February 2, 2018 the Commission issued Order G-31-18 confirming a written hearing process under the following regulatory timetable and with the remaining actions for this proceeding.

Table 4: Regulatory Timetable

ACTION	DATE
PNG(NE) Submits Original Application	November 30, 2017
Interim Rates Established	January 1, 2018
Intervener and Interested Party Registration	January 12 2018
Intervener Comments on Further Process	January 24, 2018
PNG(NE) Reply Comments on Further Process	January 31, 2018
PNG(NE) Submits Amended Application	February 28, 2018
Commission Information Request No. 1 to PNG(NE)	April 5, 2018
Intervener Information Request No. 1 to PNG(NE)	April 12, 2018
PNG(NE) Responses to Information Requests No. 1	April 26, 2018
Commission and Intervener Information Request No. 2 to PNG(NE)	May 10, 2018
PNG(NE) Responses to Information Requests No. 2	May 25, 2018
PNG(NE) Written Final Argument	June 1, 2018
Intervener Written Final Argument	June 12, 2018
PNG(NE) Written Reply Argument	June 19, 2018

1.6.2 Scope of Regulatory Review

In consideration of PNG(NE)'s recent experience with its revenue requirements applications, the following scope limitation is proposed to increase the efficiency of the proceeding around this Amended Application.

Cost of Gas

PNG(NE) is not applying for Commission approval of the indicative gas supply cost recovery rates in this Amended Application. PNG(NE)'s gas supply costs are reviewed by the Commission under a separate regulatory review process, the quarterly review and approval of gas commodity costs. Gas costs presented in this Amended Application are indicative only and are consistent with those applied for in PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report and approved under Commission Order G-187-17. Consequently, PNG(NE) submits that it is not appropriate to review gas supply costs in the context of the review of PNG(NE)'s revenue requirements applications as to do so is an unnecessary duplication of effort on the part of all parties to this regulatory proceeding.

PNG(NE) notes that, despite the foregoing, reference is made in this Amended Application to the 2017 Fourth Quarter Gas Supply Cost Report in addressing its proposal for a rate deferral mechanism for Test Year 2018 and Test Year 2019 as per Section 1.3 – Proposed Rate Deferral Mechanism.

1.6.3 Principal Contact

All notices and other communications in connection with this Amended Application should be directed to:

J.P. Kennedy
Vice President, Regulatory Affairs and Gas Supply
Pacific Northern Gas (N.E.) Ltd.
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Vancouver, British Columbia V6E 3X2
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1.7 Organization of the Amended Application

This Amended Application provides detailed information in support of PNG(NE)'s revenue requirements and the underlying proposed customer rates for Test Year 2018 and Test Year 2019. This Amended Application is comprised of two principle components:

Tab Application

Tab Application provides PNG(NE)'s complete Amended Application, including relevant narrative and schedules providing background and context for the current years' submission, including the following sections:

Tab 1 – Formal Amended Application – presents background information and details PNG(NE)'s formal Amended Application for approval of its 2018 and 2019 revenue requirements.

Tab 2 – Amended Forecast – includes narrative and schedules in support of forecast demand and forecast costs underlying the revenue requirements and the resultant rates.

Tab 3 – Other Matters – includes discussion on a variety of other issues relevant to the current application, including accounting policies, service quality metrics and other matters, as applicable.

Tab 4 – Appendices – includes reference and supporting material, including a draft Commission order, financial benchmark support and supporting reports and studies.

Tab Schedules

Tab Schedules provides the detailed financial information in support of the proposed permanent rates effective January 1, 2018, the permanent rates effective January 1, 2019, and the underlying revenue requirements as presented in this Amended Application, including the following schedules:

Tab 1 – Utility Income & Return

Tab 2 – Utility Rate Base

Tab 3 – Income Taxes

Tab 4 – Common Equity

Tab 5 – Return on Capital

Tab 6 – Rates

These financial regulatory schedules compare the Test Year 2018 and Test Year 2019 figures to the Decision 2017 figures. In some instances there are comparisons to Decision 2016 figures. The Decision 2016 and Decision 2017 amounts are those as determined under PNG(NE)'s 2016-2017 revenue requirements application and as approved by Commission Order G-132-16. Further, references to Commission directives under Order G-132-16 have been noted as Decision 2016-2017 in this Amended Application. For comparative purposes, PNG(NE) has provided the actual cost of service figures for the years 2013, 2014, 2015, 2016 and 2017.

Additional Information

PNG(NE) notes that it has previously submitted electronic PDF copies of the following documents as supplemental information to the Original Application to provide background and for the reference of participants to this proceeding:

Organizational Chart (November 2017)

Uniform Code of Accounts

2016 Annual Report to the BCUC

2012 Shared Services Study

2010 Overhead Capitalization Study

2009 Depreciation Study

Further, PNG(NE) notes that this Amended Application and the noted supplemental information have been made available on PNG's external website at: http://www.png.ca/regulatory-applications/.

2 Amended Forecast

This section sets out PNG(NE)'s forecast gas deliveries, margins and costs for 2018 and 2019. The forecast 2018 calendar year figures are identified in this Amended Application under the heading "Test Year 2018", and the forecast 2019 calendar year figures are identified in this Amended Application under the heading "Test Year 2019". Forecast margins are computed using currently approved rates and forecast 2018 and 2019 gas deliveries. The extent to which forecast revenues vary from forecast costs determines whether PNG(NE) is seeking Commission approval for rate increases or decreases.

To provide context for forecast 2018 and 2019 figures, the analysis that follows provides a comparison of forecast amounts for 2018 to amounts approved for 2017 as per the review of PNG(NE)'s 2016-2017 revenue requirements application (Decision 2017) as well as to 2017 Actual results, and a comparison of amounts forecast for 2019 to amounts forecast for 2018. Historical comparisons are also made to amounts approved for 2016 as per PNG(NE) 2016-2017 revenue requirements application (Decision 2016).

Tables are provided on the pages that follow, the first one comparing the Test Year 2018 cost of service described in this Amended Application to the Decision 2017 cost of service approved by the Commission. PNG(NE) is forecasting a revenue deficiency of approximately $206,000 for Test Year 2018, comprised of a $127,000 increase in the cost of service, a $164,000 decrease in the forecast margin, with both of these effects offset by a credit of $85,000 to reflect the impact of PNG(NE)'s rate deferral proposal to levelize the impact of rate increases for customers over the two-year period of this Amended Application.

The second table compares the Test Year 2019 cost of service to the Test Year 2018 cost of service, both as described in this Amended Application. PNG(NE) is forecasting a revenue deficiency of approximately $230,000 for Test Year 2019, comprised of a $41,000 increase in the cost of service, a $15,000 decrease in the forecast margin, and the $174,000 impact of PNG(NE)'s rate deferral proposal to levelize the impact of rate increases for customers over the two-year period of this Amended Application.

The discussion that follows addresses changes in forecast volumes and costs that underlie the forecast revenue deficiencies for Test Year 2018 and Test Year 2019, as well as the factors that have contributed to these changes.

Table 5: Cost of Service Comparison – Test Year 2018 vs Decision 2017

EXPENSES ($000's)	Test Year 2018	Decision 2017	Difference Total	Difference Subtotal
Operating				
Labour	299	281	18	
Other	429	399	30	
Sub-total	728	680	48	
Maintenance				
Labour	36	35	1	
Other	46	45	1	
Sub-total	82	80	2	
Administrative and General				
Total Company Benefits	106	139	(33)	
Other	144	153	(9)	
Sub-total	250	292	(42)	
Total (O, M, A & G) Excluding Co. Use	1,060	1,052	8	8
Transfers to Capital Operating	(26)	(19)	(7)	
Transfers to Capital Admin. & Gen.	(17)	(40)	23	
Property Taxes	78	94	(16)	
Depreciation	125	152	(27)	
Amortization	139	(9)	147	
Other Income	(17)	(19)	2	122
Total Expenses Excluding Co. Use Gas Cost	1,342	1,211	131	131
Income Taxes	(9)	24	(33)	
Return on Common Equity	169	158	11	
Short Term Debt	9	8	1	
Long Term Debt	85	70	15	(6)
Total Cost of Service Excluding Co. Use Gas Cost	1,596	1,471	125	125
Company Use Gas	53	52		
Total Cost of Service Including Co. Use Gas Cost	1,649	1,523		

2017 to 2018 Cost of Service Increase / (Decrease)	125
2017 to 2018 Margin (Increase) / Decrease	166
2018 Rate Deferral Increase / (Decrease)	(85)
2018 Revenue Deficiency / (Sufficiency)	206

Table 6: Cost of Service Comparison – Test Year 2019 vs Test Year 2018

EXPENSES ($000's)	Test Year 2019	Test Year 2018	Difference Total	Difference Subtotal
Operating				
Labour	305	299	6	
Other	441	429	12	
Sub-total	746	728	18	
Maintenance				
Labour	37	36	1	
Other	47	46	1	
Sub-total	84	82	2	
Administrative and General				
Total Company Benefits	106	106	(1)	
Other	150	144	6	
Sub-total	255	250	5	
Total (O, M, A & G) Excluding Co. Use	1,085	1,060	25	25
Transfers to Capital Operating	(23)	(26)	3	
Transfers to Capital Admin. & Gen.	(12)	(17)	4	
Property Taxes	83	78	5	
Depreciation	159	125	34	
Amortization	14	139	(125)	
Other Income	(17)	(17)	0	(79)
Total Expenses Excluding Co. Use Gas Cost	1,288	1,342	(53)	(53)
Income Taxes	48	(9)	57	
Return on Common Equity	198	169	29	
Short Term Debt	12	9	3	
Long Term Debt	91	85	6	95
Total Cost of Service Excluding Co. Use Gas Cost	1,637	1,596	41	41
Company Use Gas	60	53		
Total Cost of Service Including Co. Use Gas Cost	1,697	1,649		

2017 to 2018 Cost of Service Increase / (Decrease)	41
2017 to 2018 Margin (Increase) / Decrease	16
2018 Rate Deferral Increase / (Decrease)	85
2019 Rate Deferral Increase / (Decrease)	89
2019 Revenue Deficiency / (Sufficiency)	230

For illustrative purposes, PNG(NE) also provides the table that follows to compare the Test Year 2018 cost of service elements as per the Original Application to those per this Amended Application. A discussion of significant variances follows the table.

Table 7: Cost of Service Comparison – Test Year 2018 Amended vs Original

EXPENSES ($OOO's)	Amended Test Year 2018	Original Test Year 2018	Difference Total	Difference Subtotal
Operating				
Labour	299	299	0	
Other	429	430	(2)	
Sub-total	728	729	(2)	
Maintenance				
Labour	36	36	0	
Other	46	46	0	
Sub-total	82	82	0	
Administrative and General				
Total Company Benefits	106	161	(54)	
Other	144	145	(1)	
Sub-total	250	306	(56)	
Total (O, M, A & G) Excluding Company Use Gas Cost	1,060	1,117	(57)	(57)
Transfers to Capital Operating	(26)	(29)	3	
Transfers to Capital - Administrative & General	(17)	(26)	9	
Property Taxes	78	96	(18)	
Depreciation	125	130	(5)	
Amortization	139	128	11	
Other Income	(17)	(17)	0	0
Total Expenses Excluding Company Use Gas Cost	1,342	1,399	(57)	(57)
Income Taxes	(9)	39	(48)	
Return on Common Equity	169	172	(2)	
Short Term Debt	9	10	(1)	
Long Term Debt	85	89	(4)	(55)
Total Cost of Service Excluding Company Use Gas Cost	1,596	1,708	(112)	(112)
Company Use Gas Cost	53	52	1	
Total Cost of Service Including Company Use Gas Cost	1,649	1,760	(111)	
2017 to 2018 Cost of Service Increase / (Decrease)	125	237	(112)	
2017 to 2018 Margin (Increase) / Decrease	166	149	17	
2018 Rate Deferral Increase / (Decrease)	(85)	(95)	10	
2018 Revenue Deficiency / (Sufficiency)	206	291	(85)	

The Amended Application cost of service figures for Test Year 2018 primarily reflect the impacts of incorporating Actual 2017 results into the financial model, as well as the following noted changes:

Administrative & General Expenses

The decrease reflects the lower forecast pension and non-pension post-retirement benefits due to a decrease in the discount rate from 3.81% in the Original Application to 3.60% in the Amended Application, as well as the recognition of actuarial gains in the plans in 2017 impacting lower pension obligations and resultant pension expense for 2018.

Property Taxes

The change mainly reflects an updated forecast.

Income Taxes

Lower income taxes reflects a correction to the CCA calculation.

Forecast Margin

The decrease primarily reflects a downward revision to forecast deliveries of PNG(NE)'s industrial customer based on 2017 actual deliveries and discussions with the customer.

For illustrative purposes, PNG(NE) provides the table that follows to compare the Test Year 2019 cost of service elements as per the Original Application to those per this Amended Application. A discussion of significant variances follows the table.

Table 8: Cost of Service Comparison – Test Year 2019 Amended vs Original

EXPENSES ($OOO's)	Amended Test Year 2019	Original Test Year 2019	Difference Total	Difference Subtotal
Operating				
Labour	305	305	0	
Other	441	442	(2)	
Sub-total	746	748	(2)	
Maintenance				
Labour	37	37	0	
Other	47	47	0	
Sub-total	84	84	0	
Administrative and General				
Total Company Benefits	106	164	(58)	
Other	150	152	(2)	
Sub-total	255	315	(60)	
Total (O, M, A & G) Excluding Company Use Gas Cost	1,085	1,147	(62)	(62)
Transfers to Capital Operating	(23)	(23)	(0)	
Transfers to Capital - Administrative & General	(12)	(14)	2	
Property Taxes	82	97	(15)	
Depreciation	159	163	(4)	
Amortization	14	12	2	
Other Income	(17)	(17)	0	(15)
Total Expenses Excluding Company Use Gas Cost	1,287	1,364	(77)	(77)
Income Taxes	48	49	(0)	
Return on Common Equity	198	199	(2)	
Short Term Debt	12	12	0	
Long Term Debt	91	87	4	2
Total Cost of Service Excluding Company Use Gas Cost	1,636	1,710	(74)	(74)
Company Use Gas Cost	60	63	(2)	
Total Cost of Service Including Company Use Gas Cost	1,696	1,773	(76)	
2018 to 2019 Cost of Service Increase / (Decrease)	40	2	38	
2018 to 2019 Margin (Increase) / Decrease	15	21	(6)	
2018 Rate Deferral Increase / (Decrease)	85	95	(10)	
2019 Rate Deferral Increase / (Decrease)	89	99	(10)	
2019 Revenue Deficiency / (Sufficiency)	229	217	12	

The Amended Application cost of service figures for Test Year 2019 primarily reflect the impacts of incorporating Actual 2017 results into the financial model, as well as the following noted changes:

Administrative & General Expenses

The decrease reflects the lower forecast pension and non-pension post-retirement benefits due to a decrease in the discount rate from 3.81% in the Original Application to 3.60% in the Amended Application, as well as the recognition of actuarial gains in the plans in 2017 impacting lower pension obligations and resultant pension expense for 2019.

Property Taxes

Change mainly reflects an updated forecast.

2.1 Demand Forecast, Revenue and Margin

The Test Year 2018 and Test Year 2019 forecast of gas deliveries determine the projected margin PNG(NE) will receive from its customers during 2018 and 2019 to recover the cost of serving those customers. PNG(NE)'s methodology for forecasting customer demand, including forecasts of Residential and Small Commercial Use per Account (UPA), is consistent with that applied in prior years.

The forecast gas delivery volumes and margin for Test Year 2018 and Test Year 2019 are summarized and compared to the Decision 2017 forecast amounts in the table below. Reductions in Test Year 2018 and Test Year 2019 amounts from Decision 2017 are indicated by figures in brackets. A discussion of significant variances follows.

Table 9: Forecast Gas Deliveries

Customer Classification	Test Year 2019 Deliveries	2019 to 2018 Change in Forecast		Test Year 2018 Deliveries	2018 to 2017 Change in Forecast		Decision 2017 Deliveries	Actual 2017 Deliveries	Actual 2016 Deliveries	Actual 2015 Deliveries	Actual 2014 Deliveries	Actual 2013 Deliveries
		Deliveries	Margin		Deliveries	Margin						
	GJ	GJ	$	GJ	GJ	$	GJ					
Residential	80,063	(958)	(8,100)	81,021	(2,135)	(14,408)	83,156	84,503	70,939	78,755	96,784	81,534
Commercial												
Small Commercial Firm (Rate 2)	35,156	(1,068)	(7,300)	36,224	(2,189)	(13,052)	38,413	35,659	33,942	34,627	44,907	47,937
Large Commercial Firm (Rate 3)	16,000	-	-	16,000	3,000	14,522	13,000	18,446	11,650	16,931	58,278	74,711
Total Commercial	51,156	(1,068)	(7,300)	52,224	811	1,470	51,413	54,105	45,592	51,558	103,185	122,648
Industrial Transport (CNRL)	450,000	-	-	450,000	(365,000)	(153,366)	815,000	463,093	596,334	815,142	628,584	602,495
Total	581,219	(2,026)	(15,400)	583,245	(366,324)	(166,304)	949,569	601,701	712,865	945,455	828,553	806,677

Source: Tab Financials, Tab 6, Page 6 and 17; 2016-2017 RRA Compliance Filing

2.1.1 Residential Deliveries and Margin

PNG(NE) has updated its original customer count and UPAs for the test years under consideration. The following table summarized changes to the residential customer forecast.

Table 10: Forecast Residential Customer Count and UPA

	Forecast			Actual									
Residential Customers - TR	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	1,138	1,140	1,127	1,139	1,141	1,137	1,149	1,151	1,109	1,092	1,084	1,077	1,073
Normalized Use per Account (GJ)	70.3	71.2	73.7	74.3	68.5	74.2	77.7	81.8	82.9	87.7	80.3	81.6	83.1

2.1.2 Small Commercial Deliveries and Margin

PNG(NE) has updated its original customer count and UPAs for the test years under consideration. The following table summarized changes to the small commercial customer forecast.

Table 11: Forecast Small Commercial Customer Count and UPA

	Forecast			Actual									
Small Commercial Customers - TR	Test Year 2018	Test Year 2017	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	103	103	105	103	102	106	105	103	103	102	96	79	76
Normalized Use per Account (GJ)	341.3	351.7	364.4	349.6	369.3	352.9	409.5	494.3	463.9	443.5	456.2	703.3	670.3

2.1.3 Other Customer Classes

Table 12: Forecast Other Customer Count

	Forecast			Actual									
Other Customer Class - TR	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Large Commercial Sales	2	2	2	2	2	3	3	3	3	3	4	3	3
Industrial Transport	1	1	1	1	1	1	1	1	1	1	1	1	1

2.1.3.1 Large Commercial Deliveries and Margin

The forecast deliveries are based on discussions with customers and a review of their historical usage. There has been no change in the number of customers and an increased forecast usage of 3,000 GJ for Test Year 2018 and Test Year 2019 compared to Decision 2017.

2.1.3.2 Industrial Transport Deliveries and Margin

PNG(NE) has one industrial customer, CNRL, that receives transportation service. Forecast 2018 and 2019 deliveries are 450,000 GJ annually which is much lower than the Decision 2017 deliveries of 815,000 GJ but consistent with recent usage. Discussions with CNRL have also confirmed the shutdown of their low-pressure wells due to the low commodity price environment, resulting in the lower forecast deliveries. A gas deliveries deferral account (ICDDA) is used to record the difference between forecast and actual deliveries to this customer.

2.2 Cost of Gas

As noted in Section 1.6.2 – Scope of Regulatory Review, gas costs presented in this Amended Application are indicative only. PNG(NE)'s gas supply costs are reviewed by the Commission under a separate regulatory review process, the quarterly review and approval of gas commodity costs. As the gas supply costs are indicative only, and as PNG(NE) is not applying for Commission approval of the indicative gas supply rates in this Amended Application, PNG(NE) submits that it is not necessary to review these costs in the context of this Amended Application.

PNG(NE) has derived the indicative natural gas supply costs incorporated into this Amended Application based on average forward price strips for the five-day period ending November 21, 2017.

2.2.1 Cost of Gas Summary

The following table provides a summary of the indicative gas cost applied to Test Year 2018 and Test Year 2019, as well as Commission-approved gas costs for 2017 and 2018.

Table 13: Indicative Gas Cost

	Test Year 2019			Test Year 2018							
Customer Classification	Forecast Deliveries	Indicative Gas Cost Charge*	Indicative Gas Cost	Forecast Deliveries	Indicative Gas Cost Charge*	Indicative Gas Cost	2017 and 2018 Approved Gas Costs*				
							Jan 1, 2018	Oct 1, 2017	Jul 1, 2017	Apr 1, 2017**	Jan 1, 2017
	GJ	$/GJ	$	GJ	$/GJ	$	$/GJ	$/GJ	$/GJ	$/GJ	$/GJ
Residential	80,063	3.156	252,679	81,021	2.685	217,541	2.689	3.236	3.707	3.693	3.693
Small Commercial	35,156	3.156	110,952	36,224	2.685	97,261	2.689	3.236	3.707	3.693	3.693
Large Commercial	16,000	3.156	50,496	16,000	2.685	42,960	2.689	3.236	3.707	3.693	3.693
Total	131,219		414,127	133,245		357,763					

** Note: Gas cost charges exclude rate riders*
*** No commodity rate changes in this period; provided for illustrative purposes*

Source: Tab Schedules, Tab 6, Page 7 and 18; 2017 Quarterly Gas Cost Submissions

2.2.2 Company Use Gas Requirements

Table 14: Company Use Gas Cost

Cost of Service Items	Test Year 2019	Difference 2019 to 2018		Test Year 2018	Difference 2018 to 2017		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		Amount	%		Amount	%						
Cost ($)*	60,325	7,709	14.7%	52,616	825	1.6%	51,791	79,298	49,080	53,584	89,838	80,865
Requirements (GJ)												
Blowdowns and Losses	-	-	0.0%	-	-	0.0%	-	7	125	7	4	68
Process Plant Fuel and Lineheaters	11,355	(187)	(1.6%)	11,543	2,054	21.6%	9,489	12,878	10,096	8,092	14,343	16,831
Process Plant Fuel - CNRL Share	37,829	0	0.0%	37,829	(14,318)	(27.5%)	52,147	43,295	43,848	41,984	49,099	54,795
Unaccounted for Gas (Gain)/Loss	-	-	0.0%	-	-	0.0%	-	(10,194)	4,983	(7,090)	(24,472)	4,714
	49,184	(187)	(1.6%)	49,371	(12,265)	(5.8%)	61,636	45,986	59,052	42,993	38,974	76,408

** Note: Includes Provincial taxes and levies*

Source: Tab Schedules, Tab 6, Page 9 and 20; 2016-2017 RRA Compliance Filing

The volume of company use gas forecast for Test Year 2018 and Test Year 2019 are derived using recent historical averages of company use as a proportion of deliveries much like the methodology used to forecast under Decision 2017. The company use requirements consist primarily of process plant fuel and gas for line heaters. The increase in cost of company use gas in Test Year 2018 reflects the impact of an increase in the carbon tax rate of $0.25 per GJ effective April 1, 2018, offset in part by the effects of lower volume and lower gas commodity costs. The increase in company use cost for Test Year 2019 over Test Year 2018 reflects higher forecast commodity costs, a further carbon tax rate increase of $0.25 per GJ that will be effective April 1, 2019, and a nominal decrease in volume. PNG(NE) notes that the commodity pricing includes a $1.26 per GJ facilities charge levied by CNRL that became effective the 2013/2014 gas supply year.

Unaccounted For Gas

The unaccounted for gas component of Company use gas has been set at zero percent of deliveries for Test Year 2018 and Test Year 2019, consistent with Decision 2017. The foregoing is based on the assumption that a UAF volume deferral account will continue in 2018 and 2019 with a UAF loss cap of 1.0%. As in prior years, PNG(NE) would be required to obtain Commission approval to record the impact of UAF losses above 1.0%.

2.3 Operating Expenses

Table 15: Forecast Operating Expenses

	$000's											
BCUC Account	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to 2017 Change $	2018 to 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
621 Processing	258	5	2.0%	253	18	7.5%	235	332	327	238	218	233
665 Pipelines	25	0	2.0%	25	0	1.5%	24	2	10	4	17	16
670 Supervision	19	0	2.0%	18	0	2.1%	18	5	14	16	32	16
675 Mains and Services	8	0	2.0%	8	0	2.3%	8	5	19	5	7	4
685 General Operations	106	5	5.0%	101	20	23.9%	82	82	46	53	64	46
688 Other General Operations	95	2	2.0%	93	5	5.5%	88	45	72	66	49	44
711/713/714 Customer Care	56	1	1.7%	55	(1)	(2.6)%	57	49	50	55	50	43
Other inc. 673	139	9	7.1%	130	4	3.3%	126	113	95	102	133	134
Subtotal	707	23	3.4%	684	46	7.1%	638	632	632	540	568	536
Add: Shared Service Cost Allocation	99	3	2.8%	97	3	3.2%	94	94	93	93	91	93
Operating Expenses	806	26	3.3%	780	48	6.6%	732	725	725	633	659	628
Less: Cost of Gas - 621 Processing	(60)	(8)	14.7%	(53)	(1)	1.6%	(52)	(66)	(46)	(49)	(85)	(75)
Less: Cost of Gas - 665 Pipelines	-	-	n/a	-	-	n/a	-	(4)	(3)	(4)	(5)	(6)
Operating Expenses (Net of Company Use Cost of Gas)	746	18	2.5%	728	48	7.0%	680	655	676	580	570	548
Less: Transfers to Capital	(23)	3	(11.3)%	(26)	(7)	36.7%	(19)	(26)	(18)	(13)	(23)	(9)
Net Operating Expenses (Net of Transfers to Capital)	722	21	3.0%	701	41	6.1%	661	629	659	567	546	539

Source: Tab Schedules, Tab 1, Page 3

Gross operating expenses, before shared service cost allocations, are increasing from $638,000 under Decision 2017 to $684,000 in Test Year 2018, an increase of $46,000 or 7.1%. Operating expenses for Test Year 2019 are forecast to be higher than Test Year 2018 amounts, increasing $23,000 or 3.4%. The reasons underlying the more significant operating expense changes from Decision 2017 to Test Year 2018, and from Test Year 2018 to Test Year 2019, are provided in the discussion that follows.

2.3.1 Account 621 – Processing

This account includes costs incurred in operation of the Tumbler Ridge Gas Plant including activities such as inspecting and testing instruments and equipment, sampling the gas stream, operating the valves, equipment, and machinery, as well the costs for materials such as chemicals, electricity, telecommunications, water, etc.

Forecast expenses in this account are expected to increase by $18,000 or 7.5% from Decision 2017 to Test Year 2018. This increase primarily reflects higher than forecast amine and emissions monitoring costs, as well as inflationary adjustments. Test Year 2019 costs are consistent with those of 2018, with the adjustment being due to inflation.

2.3.2 Account 665 – Pipelines

The costs in this account cover the routine operating costs of the pipelines that PNG(NE) operates. Typical activities include: inspecting and operating above ground structures, as well as other facilities for safety and reliability; performing in-line inspections and close interval surveys and follow-up investigative digs; operating and monitoring the Supervisory Control and Data Acquisition (SCADA) system; maintenance of vegetation on the rights of way (ROW) and operation of the cathodic protection system.

Pipeline costs are forecast to remain consistent with Decision 2017 for both Test Year 2018 and Test Year 2019.

2.3.3 Account 670 – Supervision

The costs in this account cover the routine operating costs of the distribution system that cannot be charged to a specific code. Typical activities include: supervision; general planning and scheduling of current and future distribution projects and activities that are not yet fully developed stand-alone projects; operations meetings; janitorial services; and upkeep of distribution offices and equipment.

Supervision costs are forecast to remain consistent with Decision 2017 for both Test Year 2018 and Test Year 2019.

2.3.4 Account 675 – Mains and Services

Activities related to the operation of the distribution system mains and services are recorded this account. This includes performing leak surveys, protecting facilities during work by others, locating and operating valves, etc.

Mains and services costs for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017.

2.3.5 Account 685 – General Operations

The costs in this account cover the routine operating cost of the gas system that cannot be charged to a specific code. Typical activities include supervision, general planning and scheduling of current and future projects and activities that have are not yet fully developed stand-alone projects which cannot be assigned to distribution or transmission, operations meetings, janitorial services and upkeep of Regional Offices and equipment, office supplies, general communication equipment and monthly charges, travel and subsistence of supervisors and managers.

Test Year 2018 costs are forecast to increase by $20,000 or 23.9% from Decision 2017. Factors contributing to this increase include: additional engineering projects including digital data mapping and the implementation of a geographical information system; increased labour costs attributable to a new position in the areas of engineering; asset management system licensing costs; and inflation.

Test Year 2019 costs are forecast to increase by $5,000 or 5.0% from Test Year 2018 due to a greater auto expense allocation to operating costs due to lower planned capital expenditures.

2.3.6 Account 688 – Other General Operations

The costs in this account cover all types of allowable time off with pay, such as vacation, sick time and banked time off. In addition all safety and training costs (both third party and labour) are included in this account.

Test Year 2018 costs are forecast to increase $5,000 or 5.5% over Decision 2017, primarily due to increased labour costs related to the progression of staff at the processing facility.

Test Year 2019 costs are forecast to remain consistent with Test Year 2018, subject only to inflation.

2.3.7 Account 711/713/714 – Customer Care

Collectively these accounts include the majority of the activities that are performed in PNG's customer care centre as well as some time spent by customer service technicians in interacting with customers. The costs in Account 711 cover the labour, supplies and expenses to work on customer applications and contracts. The costs in Account 713 cover the labour, supplies and expenses to invoice and account for the gas used by Customers. It also includes an allocation of the costs of outsourcing of the CIS services. The costs in Account 714 cover the labour, supplies and expenses to work to receive and apply customer deposits, collect, balance and prepare reports on revenue from customers, check credit ratings, and collect delinquent accounts.

Costs for customer care are forecast to remain consistent with Decision 2017 for both Test Year 2018 and Test Year 2019.

2.3.8 Other - Including Account 673

The costs in this line include all other accounts not otherwise listed in the table, with the items primarily related to metering services (673).

Costs for Test Year 2018 are forecast to be consistent with Decision 2017 and recent experience.

Test Year 2019 costs are forecast to be $9,000 or 7.1% greater than Test Year 2018, primarily due to a higher forecast for Company use gas.

2.3.9 Shared Services Cost Allocation

Please see Section 2.6 – Shared Services Cost Allocation for further discussion of this item.

2.3.10 Transfers to Capital

Please see Section 2.7 – Transfers to Capital (Capitalized Overhead) for further discussion of this item.

2.3.11 Cost of Gas

Please see Section 2.2.2 – Company Use Cost of Gas for further discussion of this item.

2.4 Maintenance Expenses

Table 16: Maintenance Expenses

BCUC Account	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
821 Process Plant	64	1	2.0%	63	1	2.1%	62	50	123	38	30	123
865 Pipe lines	2	0	1.9%	2	0	2.2%	2	-	4	9	56	5
867 Regulating stations	7	0	2.0%	7	0	2.2%	7	4	8	5	20	12
All Other	11	1	6.4%	10	1	9.2%	10	1	4	18	19	25
Total	84	2	2.6%	82	2	3.0%	80	56	138	70	124	164

Source: Tab Schedules, Tab 1, Page 4

Planned maintenance activities are responsive to system needs and are at a level PNG(NE) considers will ensure facilities are kept in good working order to ensure continued safe, reliable and secure gas delivery service to its customers. Maintenance expenses for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017. A description of the nature of costs included in each account and reasons underlying the more significant expense changes are provided in the discussion that follows.

2.4.1 Account 821 – Process Plant

This account includes the costs for labour, supplies and expenses to maintain the Tumbler Ridge Gas Plant. Typical examples are repairs to pumps, motors, towers, condensers and generators. In addition repairs to plant grounds, fences, buildings, tanks, and regulating and measuring equipment are also included in this account.

Process plant maintenance expense for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017.

2.4.2 Account 865 – Pipelines

The costs for maintaining the transmission system pipeline are included in this account. This includes repairs to the pipeline, right-of-way, fences, signs, water crossings, etc., and all the materials and supplies used in carrying out these activities.

Pipeline maintenance expense for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017.

2.4.3 Account 867 – Regulating Stations

The costs in this account cover the labour, supplies and expenses to repair broken high pressure regulating and measurement stations and their constituent parts, repairs to tools and testing equipment, repairs to station grounds, fences and buildings, repairs to access roads and repainting.

Regulating station maintenance expense for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017.

2.4.4 All Other

The costs in this line include all other accounts not otherwise listed in the table. Other maintenance expenses for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017.

2.5 Administrative & General Expenses

Table 17: Administrative and General Expenses

	$000's											
BCUC Account	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
721 Administration	2	0	2.0%	2	(5)	(77.5)%	7	7	7	7	1	23
722 Special Services - Audit/Legal	6	0	2.0%	6	(1)	(13.9)%	7	24	8	21	9	25
723 Insurance	8	0	4.2%	8	1	22.1%	6	6	7	7	8	8
725 Employee Ben.	107	(1)	(0.8)%	108	(33)	(23.2)%	140	142	146	152	130	138
728 General	14	0	2.0%	13	(1)	(6.9)%	14	14	14	13	14	13
Sub-Total	136	(0)	(0.1)%	136	(39)	(22.0)%	175	194	181	200	161	206
Add: Shared Service Cost Allocation - 721	98	4	4.5%	94	(4)	(3.9)%	98	98	93	93	83	79
Add: Shared Service Cost Allocation - 728	21	1	4.7%	20	1	3.2%	19	19	19	19	19	16
Administrative and General Expenses	255	5	2.0%	250	(42)	(14.3)%	292	311	293	312	263	301
Less: Transfers to Capital	(12)	4	(27.0)%	(17)	23	(58.3)%	(40)	(65)	(21)	(9)	(11)	(18)
Net Administrative and General Expenses (Net of Company Use Cost of Gas)	243	10	4.1%	234	(18)	(7.3)%	252	246	272	303	252	284

Source: Tab Schedules, Tab 1, Page 5

Net administrative and general expenses for both Test Year 2018 and Test Year 2019 are forecast to remain consistent with Decision 2017. Before shared service cost allocations, gross administrative and general expenses are decreasing from $175,000 under Decision 2017 to $136,000 in Test Year 2018, a decrease of $39,000 or 22.0%. For Test Year 2019, administrative and general expenses are forecast to remain at $136,000, consistent with Test Year 2018. A description of the nature of costs included in each account and reasons underlying the more significant expense changes are provided in the discussion that follows.

2.5.1 Account 721 – Administration

This account mainly captures the costs associated with the general administration of this division that are not chargeable to a specific operating function. They include an allocation of payroll administration charges and regulatory proceeding costs.

Test Year 2018 costs of $2,000 are forecast to be $5,000 or 77.5% less than Decision 2017, primarily due to the absence of a provision in 2018 for costs pertaining to a rate design initiative that was performed with internal resources in 2017. Test Year 2019 amounts reflect an inflationary cost increase.

2.5.2 Account 722 – Special Services – Audit/Legal

Account 722 captures the fees and expenses of professional consultants and others for general services not applicable to a particular operating function. They are composed mainly of audit fees, legal fees and consulting fees.

Test Year 2018 and Test Year 2019 forecasts for these expenses are consistent with Decision 2017 amounts

2.5.3 Account 723 – Insurance

Insurance is arranged by PNG on a consolidated basis to achieve economies of scale under the umbrella of the AltaGas group of companies. The premiums to PNG are then allocated among the PNG-West and PNG(NE) divisions in accordance with the Commission's approved methodology set forth under Decision 2005.

The Test Year 2018 insurance expense forecast was determined using the actual October 1, 2017 renewal of PNG's consolidated liability and property policies. Forecast insurance costs allocated to the PNG(NE) for Test Year 2018 are $1,000 or 22.1% greater than Decision 2017 due to an increase in the percentage allocation to PNG(NE) due to the shift of allocation components for replacement cost, employee count and plant in service towards PNG(NE). Test Year 2019 insurance costs reflect an inflationary increase.

2.5.4 Account 725 – Employee Benefits

2.5.4.1 Employee Benefit Program Costs

Overall, employee benefit costs included in BCUC Account 725 are forecast to decrease by $33,000 or 23.2% in Test Year 2018 from costs approved under Decision 2017 primarily due to lower pension and non-pension post-retirement benefit costs, offset in part by higher costs for life, disability and medical programs. Employee benefit costs forecast for Test Year 2019 are expected to be $1,000 or 0.8% lower than Test Year 2018 forecast costs primarily due to a further decrease in pension costs.

PNG(NE) notes that a new health spending account benefit for bargaining unit employees has been established as part of the 2017 negotiations in finalizing the collective agreement applicable to the period November 1, 2016 to October 31, 2019. Other than this change, there have been no significant changes to the PNG(NE) employee benefit plan since the last revenue requirements application approved under Decision 2017.

Pension, NPPRB and Other Programs

The majority of the increase in employee benefits costs for 2018 can be attributed to higher defined benefit pension (DB) and non-pension post-retirement benefit (NPPRB) program costs.

Table 18: Pension, NPPRB and Other Programs

Cost Adjustment	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Company Pension Plans	66	(2)	(3.4)%	68	(4)	(5.6)%	72	78	74	80	70	72
NPPRB and Other Programs	4	0	9.7%	4	(38)	(90.5)%	42	48	42	42	34	43
Total	**70**	**(2)**	**(2.7)%**	**72**	**(42)**	**(36.8)%**	**114**	**126**	**116**	**122**	**104**	**115**

Defined Benefit (DB) pension and non-pension post-retirement benefit (NPPRB) program costs are actuarially determined. Amounts presented in the table above reflect an updated valuation completed at December 2017. The decrease in DB and NPPRB costs for Test Year 2018 and Test Year 2019 over Decision 2017 are primarily a result of discount rates going down (3.81% to 3.60%) and as a result of actuarial gains in the plans recognized at the end of 2017. This caused lower pension and benefit obligations at the end of 2017, and therefore less expense for Test Year 2018 and Test Year 2019.

Other Program costs for Test Year 2018 and Test Year 2019 include provision for costs related to health spending accounts for bargaining unit employees. The health spending account benefit is a new benefit for this employee group that was established as part of the 2017 negotiations in finalizing the collective agreement applicable to the period November 1, 2016 to October 31, 2019.

Employee Savings Plan

Employee savings plan costs are forecast to increase in each of Test Year 2018 and 2019 over Decision 2017. The increases are primarily due to increased company-matching contributions to employee contributions as recent hires gain more years of service, from an initial 50% to 75%, then to 100% after six years of service, as per plan design. Further, employee and employer contributions are based upon a percentage of pay, therefore any wage increases result in increased employer contributions

The increase in expense also reflects a 1% improvement to the plan for non-bargaining unit employees that was implemented by PNG(NE) in 2013 to match the results of collective bargaining with union employees. In Decision 2013, the Commission denied the additional 1% increase in the Company-match under the employee savings plan for non-bargaining unit employees. The additional 1% increase was disallowed again under NSP 2014.

Based on these previous determinations, PNG(NE) has made a cost of service adjustment (See Section 2.5.8 – Cost Adjustments) for the 1% increase. As described in Section 2.5.8, this provision has been made without prejudice and inconsideration of the revenue deficiencies forecast for Test Year 2018 and Test Year 2019. PNG(NE) reserves the right to seek recovery of these costs in the future as a valid element of the cost of service.

Employee Life, Long-term Disability, Medical and Hospital Insurance

The costs of premiums for PNG(NE)'s life, disability and medical programs are forecast to increase in each of Test Year 2018 and 2019 over Decision 2017 as per annual quotes received from PNG(NE)'s benefits consultant. Employee wage increases and staff additions also contribute to the overall increase. PNG(NE)'s benefits consultant advises that the forecast increases are consistent with general industry trend factors for increased benefit plan costs.

Government-sponsored Benefit Programs

PNG(NE) has forecast slight changes to government-sponsored CPP and EI plan costs, primarily due to anticipated increases to earnings caps for these plans.

2.5.4.2 Employee Benefit Load Rates

Employee benefits costs are used to derive a benefit load rate to be applied to base labour costs in order to include an appropriate allocation of employee benefit costs to base labour costs included in shared service cost recoveries, transfers to capital and transfer pricing related to non-regulated activities. The benefit load rates are computed for each employee affiliation (i.e. executive, non-bargaining unit, bargaining unit) and are updated on an annual basis to reflect forecast benefit costs (i.e. pension, non-pension, extended health care, savings plans, etc.). The table that follows summarizes historic benefit load rates applied.

Table 19: Employee Benefit Load Rates

Employee Affiliation	Test Year 2019	2019/2018 Change %	Test Year 2018	2018/Decision 2017 Change %	Decision 2017	Decision 2016	NSP 2014	Decision 2013
Executive	34.0%	0.1%	33.9%	(9.5)%	43.4%	41.4%	38.4%	56.3%
Non-bargaining Unit	32.0%	(1.1)%	33.1%	(4.6)%	37.7%	36.9%	37.6%	32.7%
Bargaining Unit - PNG-West	36.1%	(1.5)%	37.6%	(9.5)%	47.1%	47.9%	52.4%	66.5%
Bargaining Unit - PNG(N.E.)	37.5%	(1.3)%	38.7%	(10.8)%	49.5%	48.0%	47.2%	58.2%

Employee benefit load rates are generally forecast to be lower for Test Year 2018 and Test Year 2019 than they were under Decision 2017. This decrease is primarily due to lower Pension and NPPRB costs for Test Year 2018 and Test Year 2019 compared to Decision 2017 as discussed under Section 2.5.4.1 – Employee Benefit Program Costs.

2.5.5 Account 728 – General

Account 728 includes expenses incurred in connection with the general management of the Company not provided for elsewhere. They are comprised mainly of fiscal and corporate expenses, such as costs of regulation (BCUC fees) and donations. 50% of donations are

adjusted out of the cost of service. See Section 2.5.8 – Cost Adjustments.

Test Year 2018 and 2019 forecasts for these expenses are in line with expenses for Decision 2017 and in recent years.

2.5.6 Shared Services Cost Allocation

Please see Section 2.6 – Shared Services Cost Allocation for further discussion of this item.

2.5.7 Transfers to Capital

Please see Section 2.7 – Transfers to Capital (Capitalized Overhead) for further discussion of this item.

2.5.8 Cost Adjustments

Cost Adjustments are expenses expected to be incurred by PNG(NE) where the Commission has determined that it is not reasonable for either all or a portion of the expense to be recovered in rates. The table that follows shows the details of the disallowances of expected expenses, both historical and PNG(NE)'s applied-for changes relative to disallowances under Decision 2017.

Table 20: Forecast Cost Adjustments

	$000's						
Cost Adjustment	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Test Year 2017
		$	%		$	%	
50% of donations and sponsorships	(0.29)	(0.01)	1.9%	(0.28)	(0.01)	2.0%	(0.28)
1% of non-bargaining unit employee savings plan	(0.28)	(0.03)	10.0%	(0.25)	(0.05)	25.0%	(0.20)
Total	(0.56)	(0.03)	5.7%	(0.53)	(0.06)	11.6%	(0.48)

Source: Tab Schedules, Tab 1, Page 6

For 2018 and 2019, PNG(NE) has applied the Commission's 2013 Decision and disallowance of 50% for corporate donations and sponsorships, and the NSP 2014 disallowance of full recovery for PNG(NE)'s 1% improvement to the employee saving plan program costs for non-bargaining unit employees.

PNG(NE) has included the 1% employee savings plan cost adjustment for Test Year 2018 and Test Year 2019 in consideration of the forecast revenue deficiencies for these periods. This cost adjustment has been made without prejudice and PNG(NE) reserves the right to apply to recover the full amount of these expense items that may be forecast in future years.

As background on this program, in 2013 PNG(NE) implemented a 1% improvement to the employee savings plan for non-bargaining unit employees to match the recent results of collective bargaining with union employees. PNG(NE) submits that it should be able to recover these costs as a valid element of the cost of service on the following basis:

Generally organizations prefer to avoid more generous programs for bargaining unit groups versus their non-union staff.

The savings plan increase for the bargaining unit employees was negotiated with the IBEW to achieve an agreement with the IBEW rather than through larger wage increases. The Company agreed to this incentive with the IBEW fully intending that PNG(NE) would not provide its management and exempt employees with a lesser benefit plan design.

PNG(NE) has identified that there are a number of companies within our industry sector offering employer matching contributions beyond 5%, thus at 6% the PNG(NE) plan remains competitive.

Further, PNG(NE)'s management and exempt employee compensation programs are integrated programs made up of several components each with its own purpose. Denying any one aspect of these packages may undermine the integrity of the program design. Each element under the plan design serves a specific purpose. Given the above, PNG(NE) believes it is reasonable to recover the full cost of the savings plan, as is the case with PNG(NE)'s other benefit programs.

2.6 Shared Services Cost Allocation to PNG(NE) TR Division

As the parent company of PNG(NE), PNG provides a number of operational, administrative, accounting, regulatory and other services to support PNG(NE)'s TR Division. These services are provided to PNG(NE) by PNG-West employees located in PNG's Vancouver corporate office and in its Terrace regional office. PNG allocates its costs for such shared services using a number of different cost allocators, including allocators based upon relative time, relative number of customers, relative number of employees and relative rate base.

PNG continues to apply the shared services cost allocation and recovery methodology for PNG(NE) as reviewed and approved under Decision 2013. A full discussion of factors contributing to the shared services cost allocations is provided in the respective PNG-West Revenue Requirements Application. For reference, summary information is provided in the section that follows.

The table that follows provides a historic summary, by respective BCUC Account cost pool, of PNG-West shared services cost recoveries from PNG(NE) TR, broken down by base costs and benefit load recoveries on labour costs included in base costs.

Table 21: Shared Services Cost Allocation from PNG-West

	$000's											
Allocated Costs	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
685 - General Operations	43	2	3.9%	41	6	18.6%	35	35	35	33	31	31
711/713/714 - Cust. Care	40	1	3.2%	38	0	0.6%	38	38	37	38	38	37
	82	3	3.5%	79	7	9.2%	73	73	72	71	70	68
725 - Benefits on:												
685 - General Operations	7	(0)	(0.2)%	7	(1)	(17.7)%	8	8	8	9	8	8
711/713/714 - Cust. Care	10	(0)	(0.5)%	10	(2)	(17.5)%	13	13	12	14	14	17
	17	(0)	(0.4)%	17	(4)	(17.6)%	21	21	21	22	22	25
Subtotal Operating	99	3	2.8%	97	3	3.2%	94	94	93	93	91	93
721 - Administration	80	4	5.1%	76	(1)	(1.2)%	77	77	73	72	65	61
725 - Benefits on:												
721 - Administration	18	0	1.9%	18	(3)	(13.7)%	21	21	19	21	18	18
	98	4	4.5%	94	(4)	(3.9)%	98	98	93	93	83	79
728 - Corporate	21	1	4.7%	20	1	3.2%	19	19	19	19	19	16
Subtotal Administrative and General	119	5	4.5%	114	(3)	(2.7)%	117	117	112	112	102	95
Total	218	8	3.7%	210	(0)	(0.1)%	211	211	204	205	193	188
Allocated Costs	183	8	4.3%	175	6	3.8%	169	169	165	161	153	145
Allocated Benefits	35	0	0.8%	35	(7)	(15.6)%	42	42	40	43	40	43
Total	218	8	3.7%	210	(0)	(0.1)%	211	211	204	205	193	188

The recovery by PNG-West of pooled shared service costs from the TR Division has remained consistent for Test Year 2018 compared to Decision 2017, and has increased modestly for Test Year 2019 compared to Test Year 2018. These changes can be mainly attributed to lower benefit load rates due to lower pension and other post-retirement benefit costs as described under Section 2.5.4.2 – Employee Benefit Load Rates. Specific items of note for the PNG(NE) TR Division include:

685 – General Operations

Test Year 2018 vs Decision 2017

- Increased cost allocation of approximately $5,000 due to:

  Overall PNG-West cost pool increase of approximately $198,000 primarily due to costs related to new engineering initiatives including digital data mapping and the geographic information system (GIS) project, as well for licensing costs for the computerized maintenance management system (CMMS). The increase in these cost pool elements has partially been offset by a reduction in labour costs as a result of increased capitalized labour costs from this pool due to greater capital expenditures planned for Test Year 2018, and also partially offset by a decrease in the employee benefit load factors applicable to PNG-West employee labour costs included in this cost pool (see Section 2.5.4.2 – Employee Benefit Load Rates).

  The composite allocator has remained flat with only minor changes in the proportionate PNG(NE) TR component for each of customer count, employee count and rate base over Decision 2017, having a negligible impact on the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $2,000 due to:

  Overall PNG-West cost pool increase of approximately $32,000 primarily due to inflationary pressures on costs.

  The composite allocator has remained flat having a negligible impact on the cost allocation.

711/713/714 – Customer Care

Test Year 2018 vs Decision 2017

- Decreased cost allocation of approximately $2,000 due to:

  Overall PNG-West cost pool decrease of approximately $81,000 primarily due to the effect of a decrease in the employee benefit load factor on PNG-West bargaining unit employee labour costs included in the Terrace Customer Care Centre cost pool (see Section 2.5.4.2 – Employee Benefit Load Rates) and to a reduction in data line costs, offset in part by inflationary increases to other costs in this cost pool.

  Flat composite and customer count allocators have had negligible impact on the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $1,000 due to:

  Overall PNG-West cost pool increase of approximately $22,000 primarily due to inflationary cost pressures on cost pool elements for Test Year 2019 over Test Year 2018.

  Flat composite and customer count allocators have had negligible impact on the cost allocation.

721 – Administration

Test Year 2018 vs Decision 2017

- Decreased cost allocation of approximately $4,000 due to:

  Overall PNG-West cost pool decrease of approximately $253,000 due to a number of factors, including: a decrease in labour costs, reflecting reflects differences in the salaries of former PNG executives that retired in 2016 and the salaries of replacements for those positions, as described in Section 2.5.1 Account 721 – Administration, as well as a decrease in employee benefit load factors on executive and non-bargaining unit employee labour costs included in the Vancouver Administration cost pool (see Section 2.5.4.2 – Employee Benefit Load Rates); a decrease in non-labour costs in the Vancouver Administration cost pool, reflecting lower contractor, travel, training, data and communication, and rent expenses, offset in part by general inflationary costs increases on all costs in this cost pool over Decision 2017 amounts.

  Flat composite allocator has negligible impact on the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $4,000 due to:

  Overall PNG-West cost pool increase of approximately $145,000 primarily due to inflationary labour and non-labour cost increases for Test Year 2019.

  Flat composite allocator has negligible impact on the cost allocation.

728 – Corporate

Test Year 2018 vs Decision 2017

- Increased cost allocation of approximately $1,000 due to:

  Overall PNG-West cost pool increase of approximately $24,000 primarily due to inflationary cost increases.

Flat composite and customer count allocators have had negligible impact on the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $1,000 due to:

  Overall PNG-West cost pool increase of approximately $17,000 primarily due to inflationary cost increases for Test Year 2019 over Test Year 2018.

  Flat composite and customer count allocators have had negligible impact on the cost allocation.

As noted, PNG-West also recovers costs from PNG(NE) that pertain to specific third-party expenditures that have a common benefit, including CIS system services fees, internal and external audit fees and insurance premiums. The following items are of note:

713 – Vancouver Vertex Billing Services

Test Year 2018 vs Decision 2017

- Decreased cost allocation of approximately $2,000 due to:

  Overall cost pool decrease of approximately $52,000 primarily due to Decision 2017 including provision for external support services to assist with planning for a CIS replacement project, with no comparable expenditure in Test Year 2018. This decrease is offset in part by general inflationary cost increases.

  Flat customer count allocator has negligible impact on the cost allocation.

Test Year 2019 vs Test Year 2018

- Increased cost allocation of approximately $1,000 due to:

  Overall cost pool increase of approximately $24,000 primarily due to inflationary cost increases.

  Flat customer count allocator has negligible impact on the cost allocation.

722 – Vancouver Special Services

Test Year 2018 vs Decision 2017

- Negligible increase in allocation due to:

  Overall cost pool increase of approximately $9,000 primarily due to inflationary increases in audit fees.

  No change to the composite allocator as effective 2015, to simplify the modelling of the allocation of these costs, PNG commenced making use of the composite

allocator from the previously approved revenue requirements application, hence the allocator applied for this instance is that per Decision 2017.

Test Year 2019 vs Test Year 2018

- Negligible increase in allocation due to:

  Overall cost pool increase of approximately $4,000 primarily due to inflationary cost increases for Test Year 2019 over Test Year 2018.

  The same as for Test Year 2018 verses Decision 2017, no change to the composite allocator as effective 2015, to simplify the modelling of the allocation of these costs, PNG commenced making use of the composite allocator from the previously approved revenue requirements application, hence the allocator applied for this instance is that per Decision 2017.

723 – Vancouver Insurance

Test Year 2018 vs Decision 2017

- Increased cost recovery of approximately $1,000 due to:

  Overall cost pool increase of approximately $10,000 due to increased premiums.

  A slight increase in the composite insurance allocation factor.

Test Year 2019 vs Test Year 2018

- Negligible increase in allocation due to:

  Overall cost pool increase of approximately $11,000 due to inflationary cost increases for Test Year 2019 over Test Year 2018.

  No change in the composite insurance allocation factor.

2.7 Transfers to Capital (Capitalized Overhead)

PNG(NE) continues to apply the capital overhead allocation methodology approved under NSP 2011, with minor amendments approved under Decision 2012, to calculate the transfers of budgeted operating, administrative and general expenses to Test Year capital projects, and continues to use the same overhead capitalization rates for both rate setting and external reporting purposes.

The methodology includes the following allocations:

- corporate and management salary and benefit costs based on estimated time in support of forecast capital activities and allocated based on forecast divisional capital expenditures;
- support staff (accounting and warehouse) labour and benefit costs based on estimated time in support of forecast capital activities and allocated based on forecast divisional capital expenditures; and
- field staff benefit costs (see Section 2.5.4.2 – Employee Benefit Load Rates) based on estimated direct capital labour costs for each division.

Table 22: Transfers to Capital

	$000's											
Expense Item	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Operating	(23)	3	(11.3)%	(26)	(7)	36.7%	(19)	(26)	(18)	(13)	(23)	(9)
Administrative and General	(12)	4	(27.0)%	(17)	23	(58.3)%	(40)	(1)	(40)	(9)	(11)	(18)
Total	(36)	7	(17.3)%	(43)	16	(27.3)%	(59)	(27)	(57)	(21)	(34)	(26)

Source: Tab Schedules, Tab 1, Pages 3 and 5

Transfers to Capital for Test Year 2018 are forecast to decrease in comparison to Decision 2017, and are forecast to drop for Test Year 2019 from Test Year 2018 amounts. These changes can primarily be attributed to the effect of the PNG(NE) TR Division forecast capital expenditures for Test Year 2018 decreasing to 4.09% of consolidated capital expenditures, and forecast capital expenditures for Test Year 2019 decreasing to 2.00% of consolidated capital expenditures, compared to 6.05% for Decision 2017.

2.8 Property Taxes

Table 23: Property Taxes

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Property taxes	63	1	2.0%	62	(7)	(9.8)%	69	69	68	66	64	61
1% in lieu	20	4	24.0%	16	(10)	(37.9)%	25	25	25	22	21	15
Total	83	5	6.5%	78	(16)	(17.3)%	94	94	93	88	85	76

Source: Tab Schedules, Tab 1, Page 7

Total property taxes were $80,000 in 2017 resulting in a $14,000 property tax credit deferral which will be amortized in 2018. The Test Year 2018 and Test Year 2019 property taxes based on assessed values have been set at a 2% inflationary increase relative to Decision 2017. The 1 percent in lieu component of property taxes is based on revenues inside municipal boundaries and is affected by service rates and customer demand, with the Test Year 2018 and Test Year 2019 forecast amounts reflecting forecast changes in these variables from Decision 2017.

2.9 Depreciation

2.9.1 Depreciation Expense

The depreciation expense forecast for Test Year 2018 and Test Year 2019 reflects the findings of the recently completed depreciation study based on plant in service at December 31, 2016. The result is a reduction in depreciation expense compared to that which would have been calculated under the rate previously in place based on the parameters of a prior study, with Test Year 2018 depreciation expense decreasing to $125,000 from $152,000 for Decision 2017. Test Year 2019 depreciation expense is forecast to be $159,000. Further information on the depreciation study, and the implications of changes incorporated into the determination of depreciation expense is presented in the discussion that follows.

2.9.2 Depreciation Study and Rates

PNG(NE) last received approval to update its depreciation rates effective January 1, 2011 in the 2011 Negotiated Settlement Agreement (2011 NSP) approved under Commission Order G-93-11. The rates set at that time were based on a depreciation study conducted in 2010 by Gannett Fleming Inc. (acquired by Concentric Advisors ULC (Concentric) in 2017) based on plant in service at December 31, 2009 (2010 Depreciation Study).

PNG engaged Concentric to undertake a review of the depreciation rates for all service areas based on plant in service at December 31, 2016 (2017 Depreciation Study). A copy of the 2017 Depreciation Study is included as Appendix B. The 2017 Depreciation Study includes recommendations for both depreciation rates and net salvage rates.

PNG notes that it has deviated from the recommendations of the 2017 Depreciation Study on certain matters, as described below:

Net Salvage Values

The 2017 Depreciation Study makes recommendations on net salvage rates for certain accounts. The 2010 Depreciation Study included only recommendations for positive salvage values (i.e. anticipated proceeds on disposition) for certain accounts. In addition to recommendations for positive salvage values, the 2017 Depreciation Study also incorporates recommendations for negative salvage values (i.e. anticipated retirement costs) as directed by the Commission.

<u>Positive Salvage Values</u>

The 2010 Depreciation Study recommended positive salvage values for Account 484 – Transport Equipment and Account 485 – Heavy Work Equipment. PNG incorporated the positive salvage recommendation for Account 484 – Transport Equipment in its depreciation provision as it determined that the recommended salvage was reflective of its experience of

realizing proceeds on the disposition of assets in this account. For Account 485 – Heavy Work Equipment, PNG made the decision to not to incorporate the positive salvage recommendation based on the company's experience of owning and operating the equipment in this account for the entirety of their useful lives and of not realizing any proceeds on disposition.

PNG continues to abide by its previous determination on this matter and continues to only make provision for positive salvage on assets in Account 484 – Transport Equipment. If PNG(NE) were to record a provision for positive salvage in its depreciation of Account 485 – Heavy Work Equipment, depreciation expense for Test Year 2018 and Test Year 2019 would each be lower by $300.

Negative Salvage Values

As noted, an element new to the 2017 Depreciation Study is the recommendation to incorporate negative salvage values into depreciation rates for certain accounts. This methodology provides for the recovery of the anticipated cost of removal at the end of an assets life through depreciation expense, as compared to PNG's historic practice of collecting the cost of removal in the year of occurrence.

While PNG recognizes that incorporation of negative salvage in depreciation rates matches with cost of the asset to the service it provides and preserves intergenerational equity, PNG has made the decision to not make provision for negative salvage on any of the applicable accounts identified in the 2017 Depreciation Study. PNG's basis for not incorporating negative salvage at this time is the materiality of the negative salvage estimates and the significant adverse rate impacts that will result from incorporating these estimates into depreciation expense. If PNG(NE) were to record a provision for negative salvage in its depreciation for the applicable accounts, depreciation expense for Test Year 2018 and Test Year 2019 would be greater by $190,000 and $194,000, respectively.

Depreciation of Land Rights

Consistent with the 2010 Depreciation Study, the 2017 Depreciation Study recommends the depreciation of Land Rights (Accounts 411 and 471) over a period of 75 years. At the time of implementing the recommendations of the 2010 Depreciation Study, PNG made the determination that its Land Rights had an indefinite life and as such should not be depreciated.

PNG continues to abide by this previous determination and has made no provision for depreciation of Land Rights in this Amended Application. If PNG(NE) were to record a provision for depreciation of Land Rights, depreciation expense for each of Test Year 2018 and Test Year 2019 would be greater by $100.

2.9.2.1 Depreciation Rates

Consistent with the prior study, Concentric has estimated the depreciation rates using various statistical methods, operation interviews with PNG staff and informed judgment based on their experience in the natural gas industry. For most accounts, the annual and accrued depreciation has been calculated by the straight-line method using the average life group procedure for the assets in a particular class. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. The application of these depreciation methodologies to the specified accounts in the 2017 Depreciation Study is consistent with those applied in the 2010 Depreciation Study.

A key finding in the 2017 Depreciation Study was the extension of the useful life of assets in many of the accounts. This finding is consistent with peer group utilities and management's expectations and estimates. The incorporation of this finding has had the effect of reduced depreciation expense for both Test Year 2018 and Test Year 2019.

2.9.2.2 Net Salvage

PNG(NE) does not currently record a provision for the estimated cost to ultimately retire assets currently in use (negative salvage value). PNG(NE), like many utilities, prefers to record actual costs of removal at the time incurred. This treatment is consistent with the practice of other utilities and is an allowable method under the Commission's Uniform System of Accounts.

PNG(NE) most recently obtained Commission approval to record depreciation (without a provision for negative salvage) in the 2011 Negotiated Settlement Agreement approved under Commission Order G-93-11. In the Commission decision on the PNG-West 2012 revenue requirements application approved under Commission Order G-130-12, PNG-West was directed to provide an analysis of the potential use of negative salvage accounting in its next revenue requirements application. In the Commission decision on the PNG-West 2013 revenue requirements application, approved under Commission Order G-114-13, the Commission accepted PNG-West's proposal to include the evaluation of the potential of using negative salvage accounting in it next depreciation study.

As directed by the Commission, the 2017 Depreciation Study incorporates recommendations for negative salvage values (i.e. anticipated retirement costs). However, PNG has made the decision to not make provision for negative salvage on any of the applicable accounts identified in the 2017 Depreciation Study. PNG's basis for not incorporating negative salvage is the materiality of the negative salvage estimates and the significant adverse rate impacts that will result from incorporating these estimates into depreciation expense at this time.

2.10 Amortization

The table below provides the gross amortization for specific deferral accounts and then a deduction of the future income taxes at the bottom of the table to result in the after tax amortization expense for Test Years 2018 and 2019 compared to Decision 2017.

Table 24: Amortization Expense

	Account Type		Amortization Expenses ($000's)				
Deferral Account	Rate Base - RB WACD Int - WACD Short-term Int - STI	Amortization Period (in years)	Test Year 2019	2019 to 2018 Change	Test Year 2018	2018 to Decision 2017 Change	Decision 2017
Plant Gains and Losses	RB	5	7	(7)	14	(2)	16
Demand Side Management	RB	5	3	2	2	(1)	2
Resource Plans	STI	1	0	0	0	0	(0)
BCUC Fees	STI	1	0	1	(1)	(1)	0
Investigative Digs	STI	1	0	0	0	0	0
Short Term Interest	STI	1	0	0	0	0	0
Long Term Interest	STI	1	0	1	(1)	(1)	(0)
Industrial Customer Deliveries	STI	1	0	(243)	243	243	0
BCUC Hearing & CAP/ROE	STI	1	0	14	(14)	(14)	0
Property Tax	STI	1	0	15	(15)	(15)	0
Pension/NPPRB	WACD	3	4	(0)	4	4	0
Studies	WACD	2	0	(8)	8	(0)	8
Legacy Deferred Income Taxes	WACD	7	0	115	(115)	(67)	(48)
Non-Pension Benefits Obligations	N/A	6	0	(14)	14	0	14
		Subtotal	14	(124)	139	148	(9)
		Future Income Taxes	(1)	59	(60)	(56)	(4)
		Net Total	13	(65)	79	92	(13)

Under Tab Schedules, Tab 1, page 1, the computation of Utility Income and Return presents the gross amortization expense figure in computing earned return and then presents an offsetting deduction to income tax expense equal to the future income tax associated with the amortization expense. More detailed commentary is provided below in the context of each deferral account.

Plant Gains and Losses

Under Decision 2012, the Commission approved the use of this deferral account to track the historical extraordinary plant losses, the under depreciated value of assets that were retired but not fully depreciated (i.e. recoverable from customers) or over depreciated (i.e. to be credited to customers), to record gains and losses from the disposition of assets in the ordinary course of business and to record costs incurred when assets are taken out of service. The Commission also directed PNG(NE) to track these components separately and to amortize these Plant Gains and Losses deferral accounts over five years. These components categorized as extraordinary, ordinary, salvage value and retirement costs are noted in Tab 2, Pages 10 to 12.

The decrease in amortization in Test Years 2018 and Test Year 2019 compared to Decision 2017 is due to the nil amortization for assets that were retired prior to 2014 and 2015.

Demand Side Management

In June 2015, PNG and PNG(NE) submitted a Consolidated Energy Management and Efficiency Program Funding Application (Demand Side Management (DSM) Funding Application) seeking approval for funding of various DSM programs and proposed that the DSM expenditures (For PNG(NE): $4,000 in 2015; $9,000 in 2016; and $8,000 in 2017) be included in a rate base deferral account. Under Commission Order G-203-15A, PNG(NE) was directed to amortize these DSM expenditures over a 5-year period.

The amortization in Test Year 2018 and Test Year 2019 reflect actual DSM expenditures incurred of $4,000 in 2015 and $1,000 in 2016, and also actual DSM expenditures of $1,000 in 2017 and $8,000 in Test Year 2018. In accordance with order G-203-15A, details of PNG's DSM programs and expenditures are reported to the Commission in an annual report that must be filed by April 30th of the immediately following year. This report also provides a comparison of accepted budget to expenditures actually incurred, a description of key milestones achieved in the delivery of programs, an update on new programs or expansion of programs, as well as an evaluation of the programs.

Resource Plans

This deferral account records the variance between actual and forecast costs incurred in the PNG(NE) Resource Plans filed every few years. There is nil amortization in Test Years 2018 and 2019 as there have been no recent additions to this account.

BCUC Fees

This account records the variance between actual and forecast BCUC fees. In 2017, a positive variance of $1,000 was recorded in this account. This remains an interest bearing deferral account with a one year amortization period.

Short Term Interest and Long Term Interest

The short term interest deferral account records the impact of differences between the underlying customer security deposit and short term operating line interest rates. The long term interest deferral account records the impact of differences between the underlying long term forecast interest rates and actual interest rates. There will be no changes to how these deferral accounts will be administered in Test Years 2018 and 2019 compared to what has applied over the last several years. Each remains an interest bearing deferral account with a one year amortization period.

Industrial Customer Deliveries

This deferral account records the variance between the forecast margin used to set rates and actual margin recovery from PNG(NE)'s large industrial customer. The 2018 Test Year amortization reflects the full amortization of the lower deliveries in 2016 and lower deliveries forecast for 2017.

BCUC Hearing & CAP/ROE App

This deferral account records the variance between budgeted costs used for rate-setting purposes and actual costs incurred for BCUC proceedings. The 2018 Test Year amortization reflects the positive variances with interest for actual BCUC hearing costs in 2016 and 2017.

Property Tax Variance

This deferral account records the difference between budgeted property tax costs used for rate-setting purposes and actual costs incurred. This remains an interest bearing deferral account with a one year amortization period. The Test Year 2018 amortization reflects a 2017 positive variance.

Legacy Deferred Income Taxes

This account records the legacy Tumbler Ridge deferred income tax balances which the Commission directed PNG(NE) to amortize a portion over 6 years in PNG(NE)'s pension and non-pension post-retirement benefits plans application's Decision (Order G-89-13) and to amortize the remainder balance over 7 years in Decision 2013 under Order G-131-13). This deferral account earns interest at PNG(NE)'s WACD with such interest being amortized in the year earned in addition to the amortization of the principal balances.

For Test Year 2018, PNG(NE) is requesting Commission approval for the full amortization of the remaining credit balance of the Legacy Deferred Income Taxes which amounts to $106,000 including accrued interest. PNG(NE) is requesting this approval in order to help mitigate the impact of the significant increase in its cost of service as addressed in this Amended Application. PNG(NE) also notes that the Legacy Deferred Income Taxes balances in both PNG-West and PNG(NE) FSJ/DC divisions would be fully amortized at the end of Test Year 2018. Accordingly, PNG(NE) would also request the dissolution of this deferral account after Test Year 2018.

Non-Pension Benefits Obligations

Under Decision 2012, the Commission approved PNG(NE)'s request to establish a regulatory asset equal to the Non-Pension Post-Retirement Benefit (NPPRB) unamortized transitional liability in a non-interest bearing deferral account to be amortized into rates over 7 years.

Under the 2013 Pension Decision, the Commission approved PNG's request to establish a NPPRB Regulatory Asset Deferral account equal to the historical unrecovered NPPRB expense. This account is to be a non-rate base, non-interest bearing account with no further additions and is to be amortized over six years commencing January 1, 2013 with an equal and offsetting amortization of the deferred income tax balance (see Legacy Deferred Income Taxes). Test Year 2018 represents the sixth and final year of this amortization, therefore there is no amortization provided for in Test Year 2019. PNG(NE) therefore requests the dissolution of this deferral account after Test Year 2018.

2.11 Miscellaneous Other Income & Credits

Table 25: Miscellaneous Operating Revenues and Credits

Revenue/Credit Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Penalty charges	6.4	-	0.0%	6.4	(3.3)	(34.1)%	9.6	5.7	5.7	7.0	9.5	9.8
Connection fees	9.5	-	0.0%	9.5	-	0.0%	9.5	8.6	10.3	6.5	7.1	9.4
Overheads recovered	1.5	-	0.0%	1.5	1.8	(539.4)%	(0.3)	0.1	2.2	0.3	0.4	(1.1)
Other	-	-	0.0%	-	(0.2)	(100.0)%	0.2	-	-	0.4	13.0	0.4
Total	17.3	-	0.0%	17.3	(1.7)	(9.1)%	19.0	14.3	18.3	14.2	30.0	18.5

Source: Tab Schedules, Tab 1, Page 8

The other income for Test Year 2018 and Test Year 2019 is forecast based on recent experience and is comparable to other income for Decision 2017.

2.12 Income Taxes

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Income Taxes	49	(2)	(3.5)%	51	23	82.2%	28	46	5	40	69	15
Future Income Taxes	(1)	59	(98.3)%	(60)	(56)	1,405.9%	(4)	(4)	(4)	(5)	(11)	25
Dererred Income Tax Drawdown	-	-	n/a	-	-	n/a	-	-	-	-	-	(49)
Total	48	57	(662.6)%	(9)	(33)	(135.6)%	24	42	1	35	58	(9)

Source: Tab Schedules, Tab 3, Page 1

The Test Year 2018 and Test Year 2019 income taxes reflect the recent increase to 27% in the corporate rate applicable to British Columbia commencing January 1, 2018. This rate is 1% higher than the rate that applied in 2017.

The decrease in Test Year 2018 income taxes compared to Decision 2017 is due to increased credit amortization of future income taxes balances more than offsetting the increased provision for income taxes on earned return. The increased provision for income taxes on earned return largely reflects increased timing differences. The amortization of deferred charges, driven by the industrial deliveries deferral account, has increased significantly with a follow-on effect on income taxes. The 2018 provision for amortization of future income taxes has been increased by $1,000 to adjust for the impact that the corporate tax rate increase in British Columbia has had on the aggregate future income tax (FIT) provision for PNG(NE)'s deferred charges.

The increase in Test Year 2019 income taxes compared to Test Year 2018 is due largely to a higher return on common equity resulting from an increase in rate base combined with a significant reduction in the amortization of deferred charges in 2019 which in turn reduces timing differences.

2.13 Rate Base

2.13.1 Plant in Service

2.13.1.1 Capital Additions

The capital expenditure program for PNG(NE) varies year-to-year depending on requirements for new or replacement facilities and equipment. The table that follows provides a historic view of recent capital expenditure levels (excluding work in progress).

Table 26: Capital Expenditures

	$000's											
Capital Expenditure Element	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Expenditures Including Overhead	237	(841)	(78.0)%	1,078	522	93.9%	556	422	336	195	206	319
Less: Capitalized Overhead	(39)	17	(30.6)%	(56)	9	(13.5)%	(65)	(100)	(50)	(26)	(30)	(33)
Net Expenditures Before Overhead	198	(824)	(80.7)%	1,022	531	108.1%	491	322	286	169	177	286

Source: Tab Schedules, Tab 2, Page 2 to 6

Significant Capital Expenditures

The tables that follow set out planned capital additions for each of Test Year 2018 and Test Year 2019 broken down by capital project items with a cost in excess of $50,000, and reflecting what Plant in Service Accounts will be impacted. Also note that the table provides a categorization of the capital expenditure, including:

System Betterment – includes expenditures to ensure the ongoing safety, reliability and integrity of the transmission and distribution systems; for system reinforcements, renewals and alterations to the distribution and transmission systems to ensure adequate capacity exists to meet existing and forecast load requirements; and for meter recall and meter exchange programs.

New Business – includes expenditures for the installation of new mains, services, meters and other facilities to provide service to new customers.

General Plant – includes expenditures for equipment, tools, facilities and IT hardware.

General Plant Intangibles – includes IT software & licenses.

Test Year 2018 – Significant Capital Expenditures

Table 27: Test Year 2018 Capital Expenditures

2018 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	Budgeted Cost Excluding Overhead
Planned - Recurring			
Mobile/Heavy Equipment	GP	484	59,160
			59,160
No Minor Projects <$50,000	Various	Various	-
Subtotal			59,160
Planned - Non-recurring			
Building and Structure Improvements	GP	482	53,730
			53,730
Other Minor Projects <$50,000	Various	Various	8,683
Subtotal			62,413
Carryforward Projects			
Transmission Line Repair	SB	465	900,000
Subtotal			900,000
Total Capital Expenditures without Overhead			1,021,573

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

The specific major capital projects identified in the table above account for substantively all of the capital expenditures forecast for 2018, excluding overhead. The balance of 2018 expenditures represent a number of minor capital projects budgeted to ensure PNG(NE) continues to provide its customers with safe, reliable and secure gas delivery service in 2018 and the future. Further details on the noted major capital projects for 2018 are provided in the discussion that follows.

Planned – Recurring Capital Expenditures

Mobile/Heavy Equipment ($59,000)

In Test Year 2018, PNG(NE) will be replacing one three-quarter ton pick-up truck with the same type of vehicle as it meets the replacement criteria of 7 years or 160,000 km, whichever comes first. Details of the vehicle to be replaced are as shown below:

Unit #	Year Purchased	Mileage to October 2017
874	2013	145,665

Planned – Non-recurring Capital Expenditures

Building and Structure Improvements ($54,000)

The forecast expenditures address a number of smaller items related to addressing issues with the mobile office and control room, including addressing a water softener unit near the control panel and degradation of the building itself.

Carryforward Projects

Transmission Pipe Repair ($900,000)

This project will rehabilitate an exposed section of the 114 mm high pressure pipeline that runs from the Tumbler Ridge area gas plant to the Tumbler Ridge community. This exposed pipeline is the lone natural gas supply to residential, commercial, and industrial development in the area of Tumbler Ridge. To date, PNG(NE) has received outside geotechnical and engineering support to help evaluate the risk to the pipeline, as well as potential rehabilitation options. A horizontal directional drilling (HDD) solution has been determined to be the best solution from a cost/benefit basis given the ongoing geotechnical activity in the immediate vicinity. To date, incurred costs for engineering, project development, and permitting associated works are $298,000.

A significant change to the BC Oil and Gas Commission permit application process significantly delayed completion of permitting activities in 2017. Remaining cost to complete in 2018 includes obtaining required permitting and physical construction.

Test Year 2019 – Significant Capital Expenditures

Table 28: Test Year 2019 Capital Expenditures

2019 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	Budgeted Cost Excluding Overhead
Planned - Recurring			
None over $50,000	n/a	n/a	-
			-
No Minor Projects <$50,000	Various	Various	-
Subtotal			-
Planned - Non-recurring			
Processing Plant Improvements	SB	418	178,807
			178,807
Other Minor Projects <$50,000	Various	Various	18,818
Subtotal			197,625
Total Capital Expenditures without Overhead			197,625

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

The specific major capital project identified in the table above accounts for substantively all of the capital expenditures forecast for 2019, excluding overhead. The expenditures shown above are considered necessary to ensure PNG(NE) continues to provide its customers with safe, reliable and secure gas delivery service in 2019. Further details on the noted major capital projects for 2019 are provided in the discussion that follows.

Planned – Recurring Capital Expenditures

There are no major projects in this classification proposed for Test Year 2019.

Planned – Non-recurring Capital Expenditures

Station Modifications ($96,000)

The planned station modifications will be made to a station originally designed/constructed over 30 years ago and has reached the end of its useful life. The modifications will ensure the facility is fully compliant with all current code requirements in order to provide for the on-going safe and reliable operation of the station.

Carryforward Projects

At this time, PNG(NE) is unable to anticipate major projects from Test Year 2018 that may be carried forward to Test Year 2019.

Capitalized Overhead Allocation

Gross capital additions include capitalized overheads comprised of capitalized operating, administrative and general and equipment depreciation expense amounts. Additional information on capitalized operating and capitalized administrative and general expenses can be found in Section 2.7 – Transfers to Capital (Capitalized Overhead).

PNG(NE) also capitalizes depreciation expenditures related to equipment in certain asset classes that is directly involved in capital projects, specifically BCUC 484 – Transportation Equipment and BCUC 485 – Heavy Work Equipment. The allocation methodology involves applying the actual percentage of equipment hours used for capital work of the total equipment hours worked to allocate the actual depreciation expense to capital projects.

2.13.1.2 Contributions in Aid of Construction

PNG(NE) receives contributions in aid of construction (CIAC) in the form of a cash payment by a customer towards a project that is related to their service request, either provided on their own initiative or as may be required in order for the project in question to be deemed economic. CIACs have the effect of decreasing the applicable capital costs rolled into PNG(NE)'s rate base. Details of forecast and historic CIACs received by PNG(NE) can be found under Tab Schedules, Tab 2, page 30.

2.13.1.3 Depreciation Expense

As noted previously under Section 2.9 – Depreciation, depreciation expense is calculated using depreciation rates determined following a Depreciation Study completed in 2011 and the historical methodology of recording depreciation on additions to plant and equipment commencing in the following year an asset is placed in service. Details of forecast and historic accumulated depreciation, including Test Year 2018 and Test Year 2019 Depreciation Expense, can be found under Tab Schedules, Tab 2, on pages 7 through 11.

2.13.2 Post-Retirement Benefit Plans

Pension Funding in Excess of Expense

The details of PNG(NE)'s pension funding and expense rate base item is found under Tab Schedules, Tab 2, page 31. PNG(NE) has calculated its rate base pension asset in accordance with the 2013 Decision on its consolidated 2012 Pension and Non-Pension Benefits Application. Forecast cash contributions to PNG(NE)'s pension plan for Test Year 2018 and Test Year 2019 reflect expected normal cash contributions as well as special contributions. PNG(NE) notes that its 2016 pension valuation identified a solvency deficiency such that, commencing once again in 2017, there is a requirement for PNG(NE) to make special cash contributions to its registered pension plan.

Non-Pension Post Retirement Benefits

While PNG(NE) does not have a rate base asset or credit associated with non-pension post-retirement benefits (NPPRB) due to the Commission's requirement that PNG(NE) continue to contribute funds recovered from customers in excess of NPPRB premiums paid to its retirement compensation arrangement (RCA), PNG(NE) has provided continuity schedules under Tab Schedules, Tab 2, page 32. As shown in the referenced schedule, PNG(NE) expects to make cash contributions of $17,000 to its RCA in Test Year 2018, down from $53,000 in Decision 2017. However, the cash contributions are expected to increase to $51,000 in Test Year 2019 as Test Year 2018 represents the sixth and final year of amortization of regulatory assets associated with historical NPPRB expense. In accordance with the Commission's 2012 and 2013 decisions on these matters, the amortization recovered in PNG(NE)'s rates has been contributed to PNG(NE)'s RCA. PNG(NE) notes that the Test Year 2018 amortization amount of $14,000 is unchanged from Decision 2017.

2.13.3 Deferral Accounts

Schedules supporting PNG(NE)'s deferral accounts can be found under Tab Schedules, Tab 2, pages 12 through 15, including continuity schedules that detail additions/reductions to and amortization of individual account balances. Further details on individual deferral accounts can also be found in Section 2.10 – Amortization, including historical background information and information on the classification of each account.

2.13.4 Working Capital

Cash Working Capital

Table 29: Cash Working Capital

	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to Decision 2017 Change $	2018 to Decision 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
Revenue lag days	56.0	0.1	0.0	55.9	(1.0)	(0.0)	56.9	57.1	57.7	55.9	52.9	53.3
Expense lead days	25.2	0.4	0.0	24.8	(1.6)	(0.1)	26.4	25.9	22.3	25.5	29.1	27.1
Net lag days	30.8	(0.3)	(0.0)	31.1	0.6	0.0	30.5	31.2	35.4	30.4	23.8	26.2
($000's)												
Annual expenses	$ 1,657	$ 100	6.4%	$ 1,556	$ (108)	(6.5)%	$ 1,664	$ 1,495	$ 1,404	$ 1,565	$ 2,104	$ 1,716
Operating working capital requirement	140	$ 7	5.3%	133	$ (7)	(4.8)%	139	128	136	130	137	123
Adjustments:												
Budget Billing Plan	(31)	(4)	13.2%	(28)	0	(1.3)%	(28)	(4)	(6)	(63)	(17)	(14)
Allowance for Doubtful Accounts	(5)	(2)	77.4%	(3)	2	(40.2)%	(5)	7	(28)	(5)	(5)	-
Carbon Tax	0	0	22.9%	0	0	529.0%	0	-	0	0	2	3
GST	2	(4)	(64.5)%	7	2	49.1%	5	3	2	2	4	3
PST & ICEF Levy	0	0	n/a	0	0	n/a	-	-	0	0	1	-
HST	-	-	n/a	-	-	n/a	-	-	-	-	-	4
Cash working capital	$ 106	$ (3)	(2.8)%	$ 109	$ (2)	(1.7)%	$ 111	$ 134	$ 104	$ 64	$ 122	$ 119

Source: Tab Schedules, Tab 2, Page 16 and 23

The table above provides a history of PNG(NE) TR's cash working capital requirements as calculated in accordance with previous Commission decisions. PNG(NE) has not completed new lead/lag studies for its 2018/2019 revenue requirements application and therefore relies on lead/lag analysis in accordance with previous Commission decisions. Further information on Cash Working Capital can be found under Tab Schedules, Tab 2, pages 16 through 28.

The cash working capital provision increases in Test Year 2018, relative to Decision 2017, before declining in Test Year 2019. In 2018, long payment lag expense items, such as gas purchases, have declined relative to other expenses reducing the average days for payment of expenses. The GST driven working capital requirement also increases in Test Year 2018 due to the large capital program in Tumbler Ridge. The decline in working capital requirements for Test Year 2019 are driven by an increase in the budget billing credit, due to higher customer rates, as well as a reduction in GST driven working capital requirements due to much lower budgeted capital expenditures relative to Test Year 2018. These factors offset an increase in working capital requirements due to rising purchase costs of natural gas.

Other Working Capital

PNG(NE) continues to propose a nil provision for other working capital in the PNG(NE) TR division as it does not maintain any substantive inventories in this division.

2.14 Capital Structure and Return on Capital

Table 30: Capital Structure

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to Decision 2017 Change $	2018 to Decision 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
Short-term Debt												
Balance ($000's)	242	39	19.5%	202	8	4.3%	194	(142)	23	42	169	169
Proportion (%)	5.40%	0.11%	2.15%	5.29%	(0.15)%	(2.78)%	5.44%	(4.44)%	0.76%	1.37%	5.47%	5.47%
Long-term Debt												
Balance ($000's)	2,154	308	16.7%	1,845	130	7.6%	1,715	1,565	1,355	1,417	1,514	1,514
Proportion (%)	48.10%	(0.11)%	(0.24)%	48.21%	0.15%	0.31%	48.06%	48.88%	44.16%	46.57%	48.95%	48.95%
Common Equity												
Balance ($000's)	2,082	302	17.0%	1,780	120	7.3%	1,659	1,780	1,690	1,584	1,410	1,410
Proportion (%)	46.50%	0.00%	0.00%	46.50%	0.00%	0.00%	46.50%	55.59%	55.08%	52.06%	45.58%	45.58%
Total Capitalization ($000's)	4,478	650	17.0%	3,828	259	7.3%	3,569	3,203	3,069	3,042	3,092	3,092

Source: Tab Schedules, Tab 5, Page 1

2.14.1 Financing Costs

Table 31: Interest Expense

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to Decision 2017 Change $	2018 to Decision 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
Short-term Debt	12	3	34.1%	9	1	14.8%	8	(4)	2	1	7	10
Long-term Debt	91	6	6.8%	85	15	20.7%	70	67	61	69	74	69
Total	103	9	9.3%	94	16	20.1%	78	63	63	70	81	79

Source: Tab Schedules, Tab 5, Pages 2 and 3

Short-term Debt Interest Expense

The short-term debt component of PNG(NE)'s capital structure for rate making purposes is set to comprise approximately 5 percent of rate base. The 5 percent level reflects the fact that the substantial majority of assets comprising rate base are long-term in nature and should be funded with capital that is also long-term in nature.

The short-term debt interest expense for 2018 is slightly higher than 2017 due to an 84 basis point increase in underlying forecast interest rates as well as an increased amount of short-term debt due to rate base growth. The increase in the underlying interest rate is partially offset by the lower credit spread reflected in the proposal that PNG(NE) has obtained from its operating lender for which PNG(NE) received BCUC approval per Order G-185-17.

In Test Year 2019, PNG(NE)'s short-term debt expense increases relative to 2018 due to the forecast increase of 52 basis points in underlying interest rates in 2019 over 2018. There is also an increased amount of short-term debt in 2019, reflecting rate base growth relative to 2018.

The forecast of the underlying prime rate for operating line borrowings in both Test Year 2018 and Test Year 2019 is a consensus forecast of the increase in the average 90-day

treasury bill rate for 2018 and 2019 respectively, relative to the actual 2017 90-day treasury bill rate which is then added to the actual 2017 average prime rate. The consensus forecast for the 2018 and 2019 90-day treasury bill rates were obtained from the January 2018 Econolink Report, which unfortunately no longer publishes a consensus prime rate forecast. The 90-day treasury bill rate forecasts used by PNG(NE) is shown in the extract of page 11 from the January 2018 Econolink Report included as Appendix C. PNG(NE)'s new credit spread of 20 basis points is added to the prime rate forecast for deemed draws on its operating line.

The forecast customer deposit interest rate for 2018 and 2019 has also been increased from Decision 2017 by the increase in the forecast average prime rate for 2018 as noted above. In addition to the interest rate increase, the increase in short term debt expense in 2018 and 2019 also reflects a provision for operating line renewal fees in those years while 2017 did not require a provision for renewal fees.

PNG(NE) proposes to continue the use of a deferral account to capture expense differences arising from interest rate variances between the test year forecast and actual rates on its floating rate operating line.

Long-term Debt Interest Expense

PNG(NE)'s Test Year 2018 forecast interest expense on long-term debt increases significantly relative to Decision 2017 due to a combination of a higher average effective interest rate and an increased amount of long-term debt in PNG(NE)'s proposed capital structure. The higher average effective interest rate in 2018 reflects a number of factors. First, the forecast increase in underlying market interest rates, as discussed in the section above on short-term debt, is the most significant factor. PNG(NE)'s forecast of 3-month Bankers' Acceptance (BA) rates is more than 80 basis points higher in 2018 than it was for Decision 2017.

In addition to the increasing underlying market interest rates, the key additional factors affecting the 2018 average effective interest rate are related to PNG(NE)'s proposed refinancing for which it received Commission approval per Order G-185-17. The refinancing includes a new smaller revolving term facility with a credit spread that is 25 basis points lower than PNG(NE)'s existing revolving term facility, as well as a fixed rate 10-year term note at 4.20%, which is 35 basis points higher than the interest rate under PNG(NE)'s existing revolving term facility using PNG(NE)'s 2018 forecast of underlying market interest rates.

For PNG(NE)'s revolving term facility, the forecast of the applicable interest rate is based on the consensus forecast of 3-month treasury bill rates for 2018 from Econolink's January 2018 report. The 3-month treasury bill rate forecast used by PNG(NE) is shown in the extract of

page 11 from the January 2018 Econolink Report included as Appendix C. The historical ten-year average of the differential between 3-month treasury bill rates and 3-month Bankers' Acceptance rates are added to the forecast 2018 3-month treasury bill rate to derive the forecast of the underlying 3-month Bankers' Acceptance rate for PNG(NE)'s revolving term facility.

For Test Year 2019, the interest rate forecast for PNG(NE)'s floating rate long-term debt rate instrument is based on consensus forecast of 3-month treasury bill rates for 2019 from Econolink's October January 2018 report, adjusted to a 3-month Bankers' Acceptance forecast using the same methodology as described above for 2018.

The Test Year 2019 provision for long-term debt interest expense is higher than the Test Year 2018 provision. This result is the combination of three key factors. First is higher interest rates on PNG(NE)'s floating rate debt instruments, due to the forecast 52 basis point increase in underlying 3-month Bankers' Acceptance rates in 2019 relative to 2018. Second is the maturity of PNG(NE)'s 2018 debenture in late 2018, which has an effective interest rate of 8.89%. The debt under this debenture will be replaced with much lower cost long-term debt resulting in a forecast decline in PNG(NE)'s weighted average long-term debt rate in Test Year 2019 versus Test Year 2018. Finally, PNG(NE) is forecasting significant increases in the amount of long term debt required to capitalize its growing rate base.

PNG(NE) proposes to continue the use of a deferral account to capture expense differences arising from interest rate variances between the test year forecast and actual rates on floating rate long-term debt instruments.

Planned Refinancing Activities

PNG(NE)'s only planned refinancing activity for 2018 and 2019 is the renewal of its operating line in mid-2019.

2.14.2 Allowed Capital Structure and Return on Equity

Table 32: Return on Common Equity

	$000's											
Common Equity	Test Year 2019	2019 to 2018 Change $	2019 to 2018 Change %	Test Year 2018	2018 to Decision 2017 Change $	2018 to Decision 2017 Change %	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
Rate of Return on Equity	9.50%	n/a	0.0%	9.50%	n/a	0.0%	9.50%	11.58%	4.10%	9.83%	13.96%	27.31%
Common Equity Thickness	46.50%	n/a	0.0%	46.50%	n/a	0.0%	46.50%	55.59%	55.08%	52.06%	45.58%	44.30%
Common Equity ($000's)	2,082	302	14.5%	1,780	120	6.8%	1,659	1,780	1,690	1,584	1,410	1,166
Return on Equity ($000's)	198	29	14.5%	169	11	6.8%	158	206	69	156	197	318

Source: Tab Schedules, Tab 4, Page 1

For the purposes of this Amended Application for both Test Year 2018 and Test Year 2019, PNG(NE) has used the Decision 2017 approved rate of return on common equity (ROE) of 9.50% and common equity thickness of 46.50% following the issuance of the Stage 2 GCOC Decision in 2014 and the Decision on the Fortis BC Energy Inc.'s (the Benchmark Utility) Application for its Common Equity Component and Return on Equity for 2016. In the latter, the Commission ordered no changes to the Benchmark Utility's common equity component and no changes to the ROE, and noted that these metrics would remain in effect until otherwise determined by the Commission. In addition, the Automatic Adjustment Mechanism Formula was suspended indefinitely.

2.15 Proposed Rate Changes

The following section explains the methodologies used by PNG(NE) to calculate the rates PNG(NE) is asking the Commission to approve effective January 1, 2018 and January 1, 2019. The material underpinning the rate calculations is provided under Tab Schedules, Tab 6 of this Amended Application.

2.15.1 Allocation of Revenue Deficiency

PNG(NE) has allocated the Test Year 2018 and Test Year 2019 revenue deficiencies to its customers using the projected gross margins for those years by customer class as the allocator. This is consistent with the methodology approved by the Commission over the past several years.

2.15.2 Derivation of Forecast Test Year Gas Deliveries and Gross Margin

PNG(NE) has included under Tab Schedules, Tab 6 detailed schedules showing the derivation of the forecast Test Years 2018 and 2019 gas deliveries by applying the forecast use per account to the forecast average number of customers in the case of the residential and small commercial customers. For completeness the forecast deliveries to the other customers is also shown together with the split between sales and transportation service deliveries. This enables one to balance the figures shown on Tab Schedules, Tab 1 for sales and transportation service with the corresponding figures shown under Tab Schedules, Tab 6.

Similarly, the derivation of projected margin recovery in the test year using current rates is shown on schedules included in Tab Schedules, Tab 6 to verify the figures provided in the summary sheets. There may be some small differences between the detailed schedules and the summary schedules due to rounding that occurs when utilizing large spreadsheets to calculate gross revenue, delivery margin and gas supply costs.

2.15.3 RSAM Rate Rider

Tables are provided under Tab Schedules, Tab 6 to show the projected year-end 2017 RSAM balance and the derivation of the RSAM riders for Test Years 2018 and 2019 assuming a two year amortization of the projected balances. The two year amortization period was approved by the Commission for the 2012 Revenue Requirement in order to ensure compliance with US GAAP. The decrease in the forecast RSAM rate rider reflects the additions to the 2015 RSAM pools being fully amortized compared to the forecast lower additions to the RSAM pool in 2017 as a result of milder weather experienced during 2017.

2.15.4 Gas Supply Cost Charge Changes and GCVA Riders

The gas supply cost recovery rate shown in the "Summary of Proposed/Indicative Rates Effective January 1, 2018" and the January 1, 2019 gas supply cost recovery rates shown in the "Summary of Proposed/Indicative Rates Effective January 1, 2019" is based on the cost of gas shown at Tab Schedules, Tab 1, Page 1, Line 16 for each respective year. The forecast costs of gas for 2018 and 2019 are based on the 2017/2018 forecast gas supply price using the pricing parameters agreed to by PNG(NE) and its gas supplier and reflecting the impact of the forecast gas prices contained in a recent forward gas price strip (based on the average of 5 day forward strip ending November 21, 2017).

The revenue requirement model is designed to show the recovery of forecast gas supply costs on a flow through basis. In other words, the net margin (i.e. gross revenue less forecast cost of sales) will be the same regardless of what projected gas supply prices are used to calculate gas supply costs. Gas costs presented in this Amended Application are indicative only and are consistent with those applied for in PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report and approved under Commission Order G-187-17.

Tables under Tab Schedules, Tab 6 entitled "Derivation of Test Year Forecast Gas Supply Cost" shows the derivation of the cost of sales figure shown at Tab Schedules, Tab 1, Page 1, Line 16 for Test year 2018 and Test Year 2019. The forecast deliveries by customer class times the indicative gas supply price generates the cost of sales figure for each customer class.

2.15.5 Determination of 2018 and 2019 Company Use Gas Cost Rate

The Test Year 2018 and Test Year 2019 projected cost of Company use gas is based on the forecast gas prices and the quantity of gas PNG(NE) expects to purchase for Company use. The calculation of the indicative unit Company use gas cost recovery rate is shown on a schedule under Tab Rates. PNG(NE) divides the forecast cost of Company use gas by total deliveries to all customers, except its one transportation service customer, to determine the recovery rate to be embedded in rates. The Company use gas delivery rate presented in this Amended Application are indicative only and consistent with that applied for in PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report and approved under Commission Order G-187-17.

PNG(NE) notes that the transportation service customer supplies its share of Company use gas in kind to PNG(NE).

2.15.6 Bill Comparison – Current and Proposed Rates

PNG(NE) includes under Tab Schedules, Tab 6 a comparison of the projected annual gas bills for residential and small commercial customers using current rates effective June 1, 2015 (as customer rates were last changed at this time) and proposed January 1, 2018 rates. The latter are also compared to the proposed January 1, 2019 rates. The bill comparison focuses on the delivery rate increase that is required to recover the forecast 2018 and 2019 revenue deficiencies (including the Company use gas cost). PNG(NE) has also included the gas supply cost related rates for January 1, 2018 which were approved as part of PNG(NE)'s 2017 Fourth Quarter Gas Supply Cost Report. The average use per accounts reflected in the calculations are the same as the figures used for forecasting gas deliveries to these customer classes in 2018 and 2019.

For Test Year 2018, the average rate increase for residential customers is estimated to be 18.2 percent on the delivery charge component of rates or an increase of $94 per year for an average customer. The projected average bundled rate of $14.109 per GJ is $19.677 per GJ lower than the current electricity equivalent rate of $33.786 per GJ assuming a 90 percent gas to electricity efficiency factor and using the step 2 electricity rate applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 16.1 percent on the delivery charge component of rates or an increase of $353 per year for an average customer. The projected average bundled rate of $11.298 per GJ is $18.603 per GJ lower than the current electricity equivalent rate of $29.901 per GJ assuming a 90 percent gas to electricity efficiency factor.

For Test Year 2019, the average rate increase for residential customers is estimated to be 18.0 percent on the delivery charge component of rates or an increase of $113 per year for an average customer. The projected average bundled rate of $16.192 per GJ is $17.594 per GJ lower than the current electricity equivalent rate of $33.786 per GJ assuming a 90 percent gas to electricity efficiency factor and using the step 2 electricity rate currently applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 16.4 percent on the delivery charge component of rates or an increase of $407 per year for an average customer. The projected average bundled rate of $12.955 per GJ is $16.946 per GJ lower than the current electricity equivalent rate of $29.901 per GJ assuming a 90 percent gas to electricity efficiency factor.

2.15.7 Applied for Rates are Just and Reasonable

PNG(NE) submits that that the rate increases applied for under this Amended Application are just and reasonable based on long standing regulatory principles applied by the Commission in the exercise of its rate setting responsibilities under the *Utilities Commission Act*. In preparing each revenue requirements application, PNG(NE)'s senior management team keeps in mind the Commission's requirement to balance the need of PNG(NE) to recover its reasonable and prudent costs with the need to ensure ratepayers are charged fair and reasonable rates. PNG(NE) considers rates are fair and reasonable if the following criteria are met:

- Rates are set at a level that provide sufficient margin to enable PNG(NE) to provide safe, reliable and secure gas delivery service to its customers.

- PNG(NE)'s financial integrity is maintained which includes being able to meet financial covenants under outstanding debt instruments and to retain an investment bond rating.

- PNG(NE) has taken prudent steps to manage its costs to ensure there are no unnecessary or unreasonable costs included in the applied for cost of service.

- PNG(NE)'s rates are competitive with other energy sources and thereby provide a reasonable probability of preventing declining recovery of margin due to customers converting to alternative energy sources or reducing gas consumption.

- PNG(NE)'s shareholder has the opportunity to earn a reasonable rate of return on its equity investment in PNG(NE).

Earlier in this Amended Application PNG(NE) explained in detail the reasons why the cost of service in 2018 and 2019 have changed from that budgeted under Decision 2017. The level of costs presented and for which PNG(NE) seeks approval will reasonably ensure that PNG(NE) can provide safe, reliable and secure gas delivery service at an appropriate level. PNG(NE) has taken prudent steps to manage its 2018 and 2019 budgeted costs and submits there are no unnecessary or unreasonable costs included in its budgets.

In summary, the rates applied for under this Amended Application are just and reasonable having regard to the regulatory principles the Commission applies when determining whether rates are just and reasonable pursuant to the *Utilities Commission Act*.

3 Other Matters

3.1 Capital Expenditure Reporting – Actual vs Decision

In Decision 2012, PNG(NE) was directed to provide a more fulsome capital addition expenditure reporting to improve transparency on a project-by-project and year-by-year basis. On a go-forward basis PNG(NE) was directed to provide more detailed budget variance analysis in the context of its capital additions forecasting and to provide a schedule showing forecast plant additions compared to actual capital additions with explanatory information on all material differences. In this section, PNG(NE) provides a summary of actual capital expenditures for 2016 and 2017 compared to those approved under Decision 2016 and Decision 2017, respectively, along with explanations for significant variances.

3.1.1 2016 Capital Expenditure Variance Analysis

Table 33: 2016 Capital Expenditure Variance Analysis

2016 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	2016 Expenditure Excluding Overhead	2016 Approved Expenditure Excluding Overhead	Variance (Over) Under Expenditure
Planned - Recurring					
None over $50,000	n/a	n/a	-	-	-
			-	-	-
Other Minor Projects <$50,000	various	Various	10,192	56,734	46,542
Subtotal			10,192	56,734	46,542
Planned - Non-recurring					
Transmission Pipe Repair	SB	465	193,515	309,656	116,141
Replace Line Heaters	SB	467	29	91,800	91,771
			193,544	401,456	207,912
Other Minor Projects <$50,000	various	Various	33,550	76,265	42,715
Subtotal			227,094	477,721	250,627
Carryforward Projects					
Processing Plant Improvements	SB	418	48,983	-	(48,983)
Subtotal			48,983	-	(48,983)
Total Capital Expenditures without Overhead			286,269	534,455	248,186

Details on the sole 2016 capital expenditure variance in excess of $50,000 are provided in the discussion that follows.

Transmission Pipe Repair (less than approved by $116,000)

This project was to rehabilitate an exposed section of the 114mm high pressure pipeline that runs from the gas plant to the Tumbler Ridge community. The pipeline had become exposed through a creek that is located at the bottom of a very steep gulley which has unstable ground. This variance is due to a delay in the timing of geotechnical evaluation of the damage, with some of the anticipated activities postponed until 2017.

Replace Lineheater (less than approved by $92,000)

This variance is due to material delivery delays pushing the line heater purchase and installation to 2017.

Carryforward Projects

Processing Plant Improvements (greater than approved by $49,000)

Processing plant improvements carried over from 2015 include the replacement of the underground drain tank and drain line as well as the installation of a burner system. The completion of these projects was deferred to 2016 as they required a system shut down and frost free conditions to reduce impacts on customers.

Originally Estimated Project Expenditures

The table included at the beginning of this section has a column with a reference to "approved expenditure". This amount represents the originally planned estimate of expenditures for the projects noted. A variance from this assertion is for projects carried forward from prior periods. PNG(NE) includes the table that follows to present supplemental information that allows for a comparison of the total project cost at completion to the originally estimated project expenditure.

Table 34: 2016 Capital Expenditure Carryforward – Original Cost Variance Analysis

2016 Carryforward Projects	Project Type*	Plant in Service Account Number	Project Year	2015 Expenditure Excluding Overhead	2016 Expenditure Excluding Overhead	Total Project Cost at Completion Excluding Overhead	Originally Estimated Expenditure Excluding Overhead	Variance (Over) Under Expenditure
Carryforward Projects								
Processing Plant Improvements	SB	418	2015/2016	108,995	48,983	157,978	132,875	(25,103)
Total				108,995	48,983	157,978	132,875	(25,103)

** SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles*

Additional information on these projects can be found in the preceding discussion.

3.1.2 2017 Capital Expenditure Variance Analysis

Table 35: 2017 Capital Expenditure Variance Analysis

2017 Major Capital Projects (> $50,000)	Project Type *	Plant in Service Account Number	2017 Actual Excluding Overhead	2017 Approved Expenditure Excluding Overhead	Variance
Planned - Recurring					
None over $50,000	n/a	n/a	-	-	-
			-	-	-
Other Minor Projects <$50,000	Various	Various	-	45,388	45,388
Subtotal			-	45,388	45,388
Planned - Non-recurring					
Station Modifications	SB	467	-	96,007	96,007
TR Transmission Pipe Repair	SB	465	84,562	334,000	249,438
Gas Plant Cooler Bundle Replacement (unplanned)	SB	418	6,763	-	(6,763)
Underground Fitting Removal (unplanned)	SB	475	108,000	-	(108,000)
			199,325	430,007	230,682
Other Minor Projects <$50,000	Various	Various	-	15,606	15,606
Subtotal			199,325	445,613	246,288
Carryforward Projects					
Line Heater TR Gate Stn	SB	467	122,380	-	(122,380)
Subtotal			122,380	-	(122,380)
Total Capital Expenditures without Overhead			321,705	491,001	169,295

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

Details on the 2017 capital expenditure variances in excess of $50,000 are provided in the discussion that follows.

Station Modifications (less than approved by $96,000)

Modifications were planned to a station originally designed/constructed over 30 years to ensure the facility remains compliant with current code requirements in order to provide for the on-going safe and reliable operation of the station. The project has been deferred to 2018 and 2019 due to advancement of higher priority projects.

Transmission Pipe Repair (less than approved by $249,000)

To date, PNG(NE) has incurred costs in 2016 and 2017 for engineering, project development and permitting associated works amounting to $278,000. In 2017, PNG(NE) developed a better understanding of the geotechnical issues and the overall costs required for the project, including understanding the extent of a horizontal directional drill solution and costs. While the costs have increased for the overall strategy since 2016, given this pipeline is the main source of supply for Tumbler Ridge PNG(NE) continues to believe this is high-risk and needs to be addressed appropriately.

In terms of delays in spend for 2017 on this project, a significant change to the BC Oil and Gas Commission (OGC) permit application process resulted in an unforeseen delay in the

completion of permitting activities. Documentation and procedures necessary to fulfil the OGC application requirements are now complete. The remaining cost to complete forecast for Test Year 2018 of $900,000 includes obtaining required permitting and physical construction.

Underground Fitting Removal (greater than approved by $108,000)

This expenditure relates to electrofusion tee replacement activity that was not planned for the year. In conjunction with the reassessment of this work for Fort St. John/Dawson Creek as high risk and necessary activity to ensure system safety and reliability, replacements in Tumbler Ridge were also carried out in 2017. PNG(NE) notes that the cost of this initiative were offset in part by a CIAC of $40,000 from the contractor who undertook the original installation.

Carryforward Projects

Replace TR Gate Station Lineheater (greater than approved by $122,000)

The variance in this 2016 capital project is due to improved cost estimates for installation, as well as material delivery delays, pushing the line heater purchase and installation from 2016 to 2017.

Originally Estimated Project Expenditures

The table included at the beginning of this section has a column with a reference to "approved expenditure". This amount represents the originally planned estimate of expenditures for the projects noted. A variance from this assertion is for projects carried forward from prior periods. PNG(NE) includes the table that follows to present supplemental information that allows for a comparison of the total project cost at completion to the originally estimated project expenditure.

Table 36: 2017 Capital Expenditure Carryforward – Original Cost Variance Analysis

2017 Carryforward Projects	Project Type*	Plant in Service Account Number	Project Year	2016 Expenditure Excluding Overhead	2017 Expenditure Excluding Overhead	Total Project Cost at Completion Excluding Overhead	Originally Estimated Expenditure Excluding Overhead	Variance (Over) Under Expenditure
Carryforward Projects								
Line Heater TR Gate Stn	SB	467	2016/2017	29	122,379	122,408	91,800	(30,608)
Total				29	122,379	122,408	91,800	(30,608)

** SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles*

Additional information on this project can be found in the preceding discussion.

3.2 Cost of Service Reporting – Actual vs Decision

3.2.1 2016 Cost of Service Variance Analysis

The table below compares the Actual 2016 cost of service to the Decision 2016 cost of service as approved by the Commission. Explanations of significant variances are provided on the pages following the comparison table.

Table 37: 2016 Cost of Service Variance Analysis

EXPENSES ($OOO's)	Actual 2016	Decision 2016	Difference Total	Difference Subtotal
Operating				
Labour	350	277	73	
Other	329	371	(42)	
Sub-total	680	649	31	
Maintenance				
Labour	6	34	(28)	
Other	132	44	88	
Sub-total	138	78	60	
Administrative and General				
Total Company Benefits	146	140	6	
Other	147	147	0	
Sub-total	293	287	6	
Total (O, M, A & G) Excluding Company Use Gas Cost	1,110	1,014	96	96
Transfers to Capital Operating	(21)	(18)	(3)	
Transfers to Capital - Administrative & General	(21)	(29)	8	
Property Taxes	93	93	0	
Depreciation	140	140	(0)	
Amortization	(12)	(12)	(0)	
Other Income	(18)	(19)	1	5
Total Expenses Excluding Company Use Gas Cost	1,271	1,169	102	102
Income Taxes	1	23	(23)	
Return on Common Equity	70	138	(68)	
Short Term Debt	1	6	(5)	
Long Term Debt	63	64	(1)	(97)
Total Cost of Service Excluding Company Use Gas Cost	1,405	1,401	5	5
Company Use Gas Cost	49	46	3	
Total Cost of Service Including Company Use Gas Cost	1,454	1,447	8	

3.2.1.1 Operating Expenses

Operating expenses for 2016 were $34,000 or 4.8% greater than forecast as per Decision 2016. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2016 amounts follows.

Table 38: Operating Expenses – 2016

BCUC Account	$000's			
	2016		Difference	
	Actual	Decision	$	%
621 Processing	327	230	97	42.1%
665 Pipelines	10	24	(13)	(56.2)%
670 Supervision	14	18	(4)	(21.5)%
675 Mains and Services	19	11	8	67.6%
685 General Operations	50	80	(30)	(38.0)%
688 Other General Operations	72	67	5	7.2%
711/713/714 Customer Care	50	54	(4)	(7.3)%
Other inc. 673	95	119	(24)	(20.2)%
Subtotal	636	602	34	5.6%
Add: Shared Service Cost Allocation	93	93	0	0.0%
Operating Expenses	729	695	34	4.8%
Less: Cost of Gas - 621 Processing	(46)	(46)	1	(1.2)%
Less: Cost of Gas - 665 Pipelines	(3)	-	(3)	n/a
Net Operating Expenses (Net of Company Use Cost of Gas)	680	649	31	4.8%
Less: Transfers to Capital	(21)	(18)	(3)	19.8%
Operating Expenses (Net of Transfers to Capital)	659	631	28	4.4%

Source: Tab Schedules, Tab 1, Page 3

Account 621 – Processing

The actual costs for 2016 included in this account are $97,000 or 42.1% greater than those approved under Decision 2016. This is primarily due to increased labour and contractor charges due to a turnover in staff, as well as greater than forecast operations supplies due to cost misallocations involving purchasing card materials purchases charged to the default home code rather than allocating to related tasks.

Account 665 – Pipelines

The actual costs for 2016 included in this account are $13,000 or 56.2% less than those approved under Decision 2016. This is primarily due to the loss of a technician in this service area during 2016, resulting in some planned work activities being rescheduled to 2017.

Account 670 – Supervision

The actual costs for 2016 included in this account are $4,000 or 21.5% less than those approved under Decision 2016 primarily due to lower costs for operating supplies than forecast.

Account 675 – Mains and Services

The actual costs for 2016 included in this account are $8,000 or 67.6% greater than those approved under Decision 2016 primarily due to greater costs for supplies than forecast.

Account 685 – General Operations

The actual costs for 2016 included in this account are $30,000 or 38.0% less than those approved under Decision 2016. This is primarily due to a greater proportionate allocation of automotive costs to operations than forecast due to lower actual capital expenditures than planned, and to higher communications costs.

Account 673/675/712/718 – Other

The actual costs for 2016 included in this account are $24,000 or 20.2% less than those approved under Decision 2016. This is primarily due to savings on labour for meter recalls and removals compared to plan, and to lower meter reading and contractor costs than forecast.

3.2.1.2 Maintenance Expenses

Maintenance expenses for 2016 were $60,000 or 76.5% greater than anticipated as per Decision 2016. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2016 amounts follows.

Table 39: Maintenance Expenses - 2016

BCUC Account	$000's			
	2016		Difference	
	Actual	Decision	$	%
821 Process Plant	123	60	62	103.4%
865 Pipelines	4	1	2	161.4%
867 Regulating stations	8	7	1	9.2%
All Other	4	9	(6)	(61.0)%
Total	138	78	60	76.5%

Source: Tab Schedules, Tab 1, Page 4

Account 821 – Process Plant

The actual costs for 2016 included in this account are $62,000 or 103.4% greater than those approved under Decision 2016. This is primarily due to higher contractor and supplies costs related to temporary repairs to the shell and tube heating exchanger, with permanent repairs planned for late 2017.

Account 865 – Pipelines

The actual costs for 2016 included in this account are $2,000 or 161.4% greater than those approved under Decision 2016. This variance is primarily due to an incorrect coding of contractor charges that should have been recorded as an operating expense.

All Other

The actual costs for 2016 included in this account are $6,000 or 61.0% less than those approved under Decision 2016. This variance is primarily due to less maintenance and repair activity that anticipated in the forecast amounts.

3.2.1.3 Administrative & General Expenses

Administrative and General expenses for 2016 were $5,000 or 1.8% greater than forecast as per Decision 2016. The distribution of this change by BCUC Account is presented in the table below. There are no significant variances (>$25,000 or 10%) from Decision 2016 amounts that warrant further explanation.

Table 40: Administrative and General Expenses - 2016

BCUC Account	$000's			
	2016		Difference	
	Actual	Decision	$	%
721 Administration	7	7	0	2.0%
722 Special Services - Audit/Legal	7	7	0	2.4%
723 Insurance	6	6	0	3.4%
725 Employee Ben.	140	141	(1)	(0.8)%
728 General	14	14	0	2.0%
Sub-Total	175	175	(0)	(0.2)%
Add: Shared Service Cost Allocation - 721	98	93	5	5.4%
Add: Shared Service Cost Allocation - 728	19	19	1	2.7%
Administrative and General Expenses	292	287	5	1.8%
Less: Transfers to Capital	(40)	(29)	(11)	36.9%
Net Administrative and General Expenses (Net of Company Use Cost of Gas)	252	258	(6)	(2.2)%

Source: Tab Schedules, Tab 1, Page 5

3.2.1.4 Other Items

Transfers to Capital

Transfers to Capital for 2016 are consistent with those forecast as per Decision 2016.

Property Taxes

Property Taxes for 2016 are consistent with that forecast as per Decision 2016.

Depreciation

Depreciation expense for 2016 is consistent with that forecast as per Decision 2016.

Amortization

Amortization for 2016 is consistent with that forecast as per Decision 2016.

Miscellaneous Other Income & Credits

Other income for 2016 is consistent with that forecast as per Decision 2016.

Income Taxes

Income taxes for 2016 are $23,000 less than forecast as per Decision 2016 reflecting higher than forecast operating, maintenance and general and administrative costs than approved by the Commission, resulting in a lower earned return and, in turn, lower taxes.

Return on Common Equity

Actual Return on Common Equity for 2016 is $68,000 lower than forecast as per Decision 2016. While PNG(NE)'s actual gross margin in 2016 was higher than forecast by $7,000, actual operating, maintenance and A&G costs were higher than costs approved by the Commission, resulting in the lower return on common equity.

Short Term Debt

Interest and other expense on Short Term Debt for 2016 is consistent with that forecast as per Decision 2016.

Long Term Debt

Interest on Long Term Debt for 2016 is consistent with that forecast as per Decision 2016.

Company Use Gas Cost

Company Use Gas Cost for 2016 is consistent with that forecast as per Decision 2016.

3.2.2 2017 Cost of Service Variance Analysis

The table below compares the Actual 2017 cost of service to the Decision 2017 cost of service as approved by the Commission. Explanations of significant variances are provided on the pages following the comparison table.

Table 41: 2017 Cost of Service Variance Analysis

EXPENSES ($OOO's)	Actual 2017	Decision 2017	Difference Total	Difference Subtotal
Operating				
Labour	292	281	11	
Other	363	399	(36)	
Sub-total	655	680	(25)	
Maintenance				
Labour	3	35	(32)	
Other	53	45	8	
Sub-total	56	80	(24)	
Administrative and General				
Total Company Benefits	142	139	3	
Other	169	153	16	
Sub-total	311	292	19	
Total (O, M, A & G) Excluding Company Use Gas Cost	1,022	1,052	(29)	(29)
Transfers to Capital Operating	(26)	(19)	(7)	
Transfers to Capital - Administrative & General	(65)	(40)	(25)	
Property Taxes	94	93	1	
Depreciation	146	140	6	
Amortization	(9)	(12)	3	
Other Income	(14)	(19)	5	(17)
Total Expenses Excluding Company Use Gas Cost	1,148	1,194	(46)	(46)
Income Taxes	42	23	19	
Return on Common Equity	206	138	68	
Short Term Debt	(4)	6	(10)	
Long Term Debt	67	64	3	80
Total Cost of Service Excluding Company Use Gas Cost	1,459	1,426	33	33
Company Use Gas Cost	70	52	19	
Total Cost of Service Including Company Use Gas Cost	1,529	1,478	52	

3.2.2.1 Operating Expenses

Operating expenses for 2017 were $24,000 or 3.5% less than forecast as per Decision 2017. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2017 amounts follows.

Table 42: Operating Expenses – 2017

BCUC Account	$000's			
	2017		Difference	
	Actual	Decision	$	%
621 Processing	332	235	96	41.0%
665 Pipelines	2	24	(22)	(91.6)%
670 Supervision	5	18	(13)	(74.5)%
675 Mains and Services	5	8	(3)	(41.0)%
685 General Operations	82	82	(0)	(0.2)%
688 Other General Operations	45	88	(43)	(48.8)%
711/713/714 Customer Care	49	57	(7)	(12.8)%
Other inc. 673	113	126	(13)	(10.4)%
Subtotal	632	638	(6)	(1.0)%
Add: Shared Service Cost Allocation	94	94	(0)	(0.0)%
Operating Expenses	725	732	(6)	(0.9)%
Less: Cost of Gas - 621 Processing	(66)	(52)	(14)	27.2%
Less: Cost of Gas - 665 Pipelines	(4)	-	(4)	n/a
Net Operating Expenses (Net of Company Use Cost of Gas)	655	680	(25)	(3.6)%
Less: Transfers to Capital	(26)	(19)	(7)	36.0%
Operating Expenses (Net of Transfers to Capital)	629	661	(32)	(4.8)%

Source: Tab Schedules, Tab 1, Page 3

Account 621 – Processing

The actual costs for 2017 included in this account are $96,000 or 41.0% greater than those approved under Decision 2017. This is primarily due to higher than anticipated operating costs to maintain the amine process and the waste water disposal system, and to address a leaking cooler. In addition, there were unplanned contracted services to provide relief during the recruitment process for a plant operator to replace a retiree. Also noted was a $10,000 charge to this account in error for gas analysis that was budgeted under Account 665.

Account 665 – Pipelines

The actual costs for 2017 included in this account are $22,000 or 91.6% less than those approved under Decision 2017. This variance is primarily due to the gas analysis costs charged to Account 621 in error noted previously. Favourable cost variances were also realized from performing leak surveys with internal resources rather than by aerial survey, and from lower than planned slashing activity due to extensive work done in 2016.

Account 670 – Supervision

The actual costs for 2017 included in this account are $13,000 or 74.5% less than those approved under Decision 2017 primarily due to reduced internal resources available to plan, organize and perform general activities.

Account 675 – Mains and Services

The actual costs for 2017 included in this account are $3,000 or 41.0% less than those approved under Decision 2017 primarily due to less economic activity in the area resulting in less planning time, drafting services and requests for line locates.

Account 688 – Other General Operations

The actual costs for 2017 included in this account are $43,000 or 48.8% less than those approved under Decision 2017. This is primarily due to savings from involving both PNG-West and PNG(NE) employees in the safety and the functional table top exercises training.

Account 711/713/714 – Customer Care

The actual costs for 2017 included in this account are $7,000 or 12.8% less than those approved under Decision 2017 primarily due to lower gas sampling costs than forecast.

Account 673/675/712/718 – Other General Operations

The actual costs for 2017 included in this account are $13,000 or 10.4% less than those approved under Decision 2017. This variance is primarily due to fewer meter recalls than budgeted, with actual recalls varying depending on the sample groups chosen by Measurement Canada.

3.2.2.2 Maintenance Expenses

Maintenance expenses for 2017 were $24,000 or 30.2% lower than anticipated as per Decision 2017. The distribution of this change by BCUC Account is presented in the table below. A discussion of factors contributing to significant variances (>$25,000 or 10%) from Decision 2017 amounts follows.

Table 43: Maintenance Expenses - 2017

BCUC Account	$000's			
	2017		Difference	
	Actual	Decision	$	%
821 Process Plant	50	62	(12)	(18.8)%
865 Pipelines	-	2	(2)	(100.0)%
867 Regulating stations	4	7	(3)	(40.4)%
All Other	1	10	(8)	(85.3)%
Total	56	80	(24)	(30.2)%

Source: Tab Schedules, Tab 1, Page 4

Account 821 – Process Plant

The actual costs for 2017 included in this account are $12,000 or 18.8% lower than those approved under Decision 2017. This variance is primarily due to the plant turnaround not being done in 2017 as CNRL did not take the downtime necessary to allow completion of a full turnaround. The turnaround is scheduled for 2018.

Account 865 – Pipelines

The actual costs for 2017 included in this account are $2,000 or 100% lower than those approved under Decision 2017. This is primarily due to less unforeseen repairs required than forecast.

Account 867 – Regulating Stations

The actual costs for 2017 included in this account are $3,000 or 40.4% lower than those approved under Decision 2017. This is primarily due to less unforeseen repairs required than forecasted.

All Other

The actual costs for 2017 included in this account are $8,000 or 85.3% lower than those approved under Decision 2017. This variance is primarily due to less maintenance requirements than originally anticipated.

3.2.2.3 Administrative & General Expenses

Administrative and General expenses for 2017 were 6,000 or 2.4% lower than forecast as per Decision 2017. The distribution of this change by BCUC Account is presented in the table below. There are no significant variances (>$25,000 or 10%) from Decision 2017 amounts that warrant further explanation.

Table 44: Administrative and General Expenses - 2017

BCUC Account	$000's			
	2017		Difference	
	Actual	Decision	$	%
721 Administration	7	7	0	4.4%
722 Special Services - Audit/Legal	24	7	17	244.1%
723 Insurance	6	6	(0)	(1.4)%
725 Employee Ben.	142	140	2	1.6%
728 General	14	14	(0)	(1.9)%
Sub-Total	194	175	19	11.1%
Add: Shared Service Cost Allocation - 721	98	98	0	0.0%
Add: Shared Service Cost Allocation - 728	19	19	(0)	(0.0)%
Administrative and General Expenses	311	292	19	6.6%
Less: Transfers to Capital	(65)	(40)	(25)	63.6%
Net Administrative and General Expenses (Net of Company Use Cost of Gas)	246	252	(6)	(2.4)%

Source: Tab Schedules, Tab 1, Page 5

Account 722 – Special Services – Audit/Legal

The actual costs for 2017 included in this account are $17,000 or 244.1% greater than those approved under Decision 2017. This is primarily due to costs incurred for a technical plant assessment study undertaken in September 2017, to identify, at a high level, requirements for upgrades necessary to maintain the plant's continued safe and reliable operation.

3.2.2.4 Other Items

Transfers to Capital (Capitalized Overhead)

Operating and Administrative and General transfers to capital were greater than forecast due to unanticipated carryover capital projects from 2016 to 2017.

Property Taxes

Property Taxes for 2017 are consistent with that forecast as per Decision 2017.

Depreciation

Depreciation expense for 2017 is consistent with that forecast as per Decision 2017.

Amortization

Amortization for 2017 is consistent with that forecast as per Decision 2017.

Miscellaneous Other Income & Credits

Other income for 2017 is consistent with that forecast as per Decision 2017.

Income Taxes

Income taxes for 2017 are $19,000 greater than forecast as per Decision 2017, reflecting lower than forecast operating, maintenance and general and administrative costs than approved by the Commission, resulting in a higher earned return and, in turn, higher taxes.

Return on Common Equity

Actual Return on Common Equity for 2017 is $68,000 greater than forecast as per Decision 2017, primarily due to positive variances in operating, maintenance and general and administrative costs resulting in a higher earned return.

Short Term Debt

Interest and other expense on Short Term Debt for 2017 is $10,000 lower than forecast as per Decision 2017. This is largely due lower short term debt borrowings than anticipated.

Long Term Debt

Interest on Long Term Debt for 2017 is consistent with that forecast as per Decision 2017.

Company Use Gas Cost

Company Use Gas Cost for 2017 is $19,000 greater than forecast as per Decision 2017, primarily due to CNRL's 2017 actual deliveries being significantly less than Decision 2017 resulting in a higher proportion of the processing plant fuel being allocated to PNG(NE).

3.3 Identified Service Quality Metrics

Under Commission Order G-192-11, PNG(NE) was directed to report on a number of key service quality metrics. The requested data is provided the following table for all of the PNG(NE) divisions.

Table 45: Service Quality Metrics – All PNG(NE)

Service Quality Metric	2017	2016	2015	2014	2013
Number of Emergency Calls	331	450	581	403	431
Average Response Time per Call	16 minutes	17 minutes	18 minutes	19 minutes	21 minutes
Number of Calls with a Response Time over 40 Minutes	2	13	17	24	20
Number of Underground Leaks	24	17	11	8	23
Number of Reportable Environmental Incidents	–	–	1	–	–
Lost-time Injury Frequency Rate *	2.07	2.84	1.01	1.19	–
Customer Complaints to the BCUC **	2	–	–	1	1

* Reflects PNG consolidated rate; not tracked by individual service area
** Information reflects Commission's March 31 fiscal year end (i.e. data for 2017 is from April 1, 2016 to March 31, 2017)

Statistics on emergency call response times specific to the Tumbler Ridge Division are set forth below.

Table 46: Service Quality Metrics – Tumbler Ridge

Service Quality Metric	2017	2016	2015	2014	2013
Number of Emergency Calls	–	2	2	–	8
Average Response Time per Call	n/a	50 minutes	58 minutes	n/a	14 minutes
Number of Calls with a Response Time over 40 Minutes	n/a	1	2	n/a	–

3.4 Other Matter to Be Addressed from Prior Year Decisions

3.4.1 Directives from the 2016-2017 Revenue Requirements Application

Under Order G-132-16, the Commission directed PNG(NE) to address the following matters in its 2018-2019 Revenue Requirements Application:

> The establishment of a new regulatory account bearing interest at PNG(NE)'s weighted average cost of debt to record the net impact on PNG's 2016 and 2017 rates arising from the Commission's decision on the FortisBC Energy Inc. (FEI) Application for Common Equity Component and Return on Equity 2016 (directive 4.b.). PNG(NE) notes that there were no changes to its common equity component or rate of return on equity arising from the Commission's decision on the FEI application, therefore the establishment of a new regulatory account was not necessary.

> PNG(NE) was directed in future RRAs to file a copy of its Annual Pipeline Risk Mitigation Report or equivalent, together with any additional explanations or documentation required to support each significant category of forecast pipeline operating, maintenance and capital expenditure in each test period (directive 8). Given the sensitivity of certain operational and risk information contained in the 2017 Annual Pipeline Risk Mitigation Report, PNG(NE) has filed this document on a confidential basis as Appendix D to this Amended Application. PNG(NE) notes that explanations to support the need for each significant category of forecast pipeline operating, maintenance and capital expenditures have been provided in the applicable sections of this Amended Application's narrative.

3.4.2 Other Directives

In the Generic Cost of Capital (GCOC) Proceeding Stage 2 Decision as per Order G-47-14, the Commission directed the PNG utilities to include an updated business risk assessment in all future revenue requirements applications. An updated business risk assessment, as directed by the Commission, is appended to this Amended Application as Appendix E.

APPENDICES

APPENDIX A – Draft Commission Order

APPENDIX B – 2017 Depreciation Study (Concentric)

APPENDIX C – Econolink Extract – January 2018

APPENDIX D – 2017 Pipeline Risk Mitigation Report (filed confidentially)

APPENDIX E – Business Risk Assessment – 2018 Update

APPENDIX A – Draft Commission Order

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ORDER NUMBER
G-xx-18

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
2018-2019 Revenue Requirements Application
For the PNG (N.E.) Service Area

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on July xx, 2018

ORDER

WHEREAS:

A. On November 30, 2017, Pacific Northern Gas (N.E.) Ltd. [PNG(NE)] filed its 2018-2019 Revenue Requirements Application (RRA) for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions with the Commission pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA) seeking, among other things, approval to increase 2018 delivery rates as a result of a net increase in cost of service offset by increased deliveries (Applications);

B. By Order G-193-17 dated December 19, 2017, the Commission approved the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Applications on an interim and refundable basis, effective January 1, 2018. The Commission also established a preliminary regulatory timetable;

C. The British Columbia Old Age Pensioners' Organization et al. (BCOAPO) registered as interveners;

D. By Order G-31-18 dated February 2, 2018, the Commission established a written public hearing process, which directed PNG(NE) to file its updated applications on February 28, 2018, and included two rounds of Commission and intervener information requests, followed by final and reply arguments;

E. On February 28, 2018, PNG(NE) filed its updated applications for the FSJ/DC and TR divisions (Amended Applications); and

F. The Commission has considered the Applications, Amended Applications, evidence and submissions of the parties.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons for decisions attached as Appendix A to this order, the British Columbia Utilities Commission orders as follows:

1. Pacific Northern Gas (N.E.) Ltd.'s [PNG(NE)] request for recovery of the 2018 revenue requirement and resultant delivery rate changes presented in the Amended Applications for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions are approved on a permanent basis, effective January 1, 2018, subject to the adjustments identified by PNG(NE) in information requests and in argument as well as to the adjustments outlined in these directives.

2. The Rate Stabilization Adjustment Mechanism riders set forth in the Amended Applications are approved on a permanent basis, effective January 1, 2018.

3. PNG(NE)'s request for recovery of the 2019 revenue requirement and resultant delivery rate changes presented in the Amended Applications for the FSJ/DC and TR divisions are approved on a permanent basis, effective January 1, 2019, subject to the adjustments identified by PNG(NE) in information requests and in argument as well as to the adjustments outlined in these directives.

4. The following changes and additions to PNG(NE)'s regulatory accounts are approved:

    a. The creation of new regulatory accounts for the PNG(NE) FSJ/DC and TR divisions bearing interest at each division's respective short-term interest rate to levelize the impact of the combined net revenue deficiencies for divisions for 2018 and 2019 to be fully amortized in 2019;

    b. The transfer of the PNG(NE) FSJ/DC 2016 unaccounted for gas (UAF) losses above 1.5 percent from the temporary UAF deferral account to the UAF volume deferral account to be recovered from FSJ/DC division customers via the Company Use rider, and dissolution of the temporary UAF deferral account; and

    c. The dissolution of the PNG(NE) FSJ/DC and TR division Legacy Deferred Income Taxes deferral account and the NPPRB Regulatory Asset Deferral account.

5. PNG(NE) FSJ/DC is approved to continue the use of the unaccounted for gas (UAF) volume deferral account on the basis that the UAF volume forecast for Test Year 2018 and Test Year 2019 are set based on using 1.0 percent of deliveries UAF loss factor. PNG(NE) FSJ/DC must file an application with the Commission to obtain approval to record UAF losses above 1.5 percent in this deferral account.

6. PNG(NE) TR is approved to continue the use of the unaccounted for gas (UAF) volume deferral account on the basis that the UAF volume forecast for Test Year 2018 and Test Year 2019 are set at zero with PNG(NE) TR recording the variance between zero and a loss of up to 1.0 percent without requiring further Commission approval. PNG(NE) TR must file an application with the Commission to obtain approval to record UAF losses above 1.0 percent in this deferral account.

7. PNG(NE) is approved to apply the depreciation rates proposed for the FSJ/DC and TR divisions that exclude any new net salvage rate provisions, effective January 1, 2018.

8. PNG(NE) is directed to re-calculate the 2018 and 2019 revenue deficiencies and delivery rate changes for the FSJ/DC and TR divisions in a compliance filing and file revised regulatory schedules with the Commission reflecting the changes outlined in this order and further described in the attached reasons for decision by no later than 30 days from the date of this order.

9. PNG(NE) is directed to collect from/refund to customers the difference between the 2018 interim rates and the 2018 permanent rates for the FSJ/DC and TR divisions over the balance of 2018. PNG(NE) must inform all customers of permanent rates by way of written notice to be included with their next customer invoice.

10. PNG(NE) is directed to file its next RRA for the FSJ/DC and TR divisions for a period of two years encompassing a test period of 2020 and 2021.

DATED at the City of Vancouver, in the Province of British Columbia, this (xx) day of July 2018.

BY ORDER

(X. X. last name)
Commissioner

APPENDIX B – 2017 Depreciation Study

(Concentric)

VANCOUVER, BRITISH COLUMBIA

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2016

PREPARED FOR
PACIFIC NORTHERN GAS LTD
VANCOUVER, BRITISH COLUMBIA

AUGUST 25, 2017

WWW.CEADVISORS.COM

PACIFIC NORTHERN GAS LTD
Vancouver, British Columbia

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUAL RATES AS OF DECEMBER 31, 2016

CONCENTRIC ADVISORS ULC

Calgary, Alberta

CONCENTRIC ADVISORS

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EXECUTIVE SUMMARY

Pursuant to Pacific Northern Gas Ltd.'s ("PNG." or "Company") request, Concentric Advisors ULC ("Concentric") conducted a depreciation study related to natural gas distribution and general plant accounts as of December 31, 2016. The purpose of this study was to determine the annual depreciation accrual rates and amounts applicable to the original cost of gas plant as of December 31, 2016.

The depreciation rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The depreciation rates are based on the straight-line method using the average service life group procedure and were applied on a remaining life basis. The calculations were based on attained ages, estimated average service life, and forecasting net salvage characteristics for each depreciable group of assets.

While the methodology adopted in this study is generally consistent with that applied in determining the depreciation rates as per the 2009 depreciation study completed by Gannett Fleming, Concentric notes that it is proposing a change from PNG's last approved depreciation study. This study makes provision of the recovery of cost of removal to be collected through depreciation expense, as compared to the current collection of cost of removal in the year of occurrence. The inclusion of an allowance for net salvage provides for the proper matching of expenses to revenues and ensures for accurate intergenerational equity.

Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to natural gas plant in service as of December 31, 2016 as summarized by Tables 1A COR, 1B COR, 1C COR and 1D COR for components of Life. Tables 1E has also shown to illustrate the combined impacts for the Fort St. John and Dawson Creek combined entity. Detailed supporting data and calculations are provided within the study.

In BCUC Order G-130-12, the Commission directed "In PNG's next Revenue Requirements Application, it should provide an analysis of the potential use of negative salvage accounting. Also, in PNG's next depreciation study, the depreciation expert should be engaged to provide depreciation rates as well as negative salvage provision rates for each asset class. These two items should be presented separately from each other and the basis for the determination of negative salvage rates should be disclosed."

As a result of this Order, Concentric Advisors has added Tables 2A, 2B, 2C and 2D which are summary tables of the calculated annual accrual for depreciation expense and rates on a net salvage basis. Tables 2E has also been added to illustrate the combined impacts for the Fort St. John and Dawson Creek combined entity. Furthermore, the basis for Concentric Advisors determination of each applicable fixed asset account's net salvage has been provided in Part II as Survivor Curve and Net Salvage Judgements.

Detailed supporting data and calculations are further provided within the study.

In BCUC Order G-114-13, the Commission directed "The Commission Panel accepts that it continues to be appropriate for PNG to record the costs of asset retirements in the ordinary course of business to the Plant Gains and Losses deferral account as they are incurred. However, the Panel is supportive of PNG's decision to include an evaluation of the potential of using negative salvage accounting in its next Depreciation Study. Our expectation is that this evaluation will include a thorough examination of the pros and cos of utilizing negative salvage accounting and the costs of its implementation." In this regard, Concentric Advisors has provided its examination of utilizing net salvage in PNG's depreciation rates in Part I - Basis of The Study – Depreciation Net Salvage.

This study results in a consolidated annual depreciation expense accrual of $10.0 million when applied to depreciable plant balances as of December 31, 2016. The report study results are summarized at an aggregate functional group level and then at a system level as follows:

TOTAL CONSOLIDATED
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

	ORIGINAL COST	ANNUAL ACCRUAL	
PLANT GROUP	$'s	%'s	$'s
(1)	(2)	(3)	(4)
GATHERING	3,889,174	4.43	172,412
PROCESSING	33,200	2.70	895
TRANSMISSION	223,758,907	1.77	3,964,563
DISTRIBUTION	148,594,698	3.03	4,501,365
GENERAL	23,817,468	5.52	1,315,139
TOTAL PLANT IN SERVICE	**400,093,446**	**2.49**	**9,954,374**

WEST SYSTEM
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

	ORIGINAL COST	ANNUAL ACCRUAL	
PLANT GROUP	$'s	%'s	$'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	33,200	2.70	895
TRANSMISSION	199,842,201	1.74	3,480,895
DISTRIBUTION	65,880,621	3.34	2,201,711
GENERAL	16,873,587	5.66	955,644
TOTAL PLANT IN SERVICE	**282,629,608**	**2.35**	**6,639,145**

FORT ST. JOHN
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

	ORIGINAL COST	ANNUAL ACCRUAL	
PLANT GROUP	$'s	%'s	$'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	-		-
TRANSMISSION	13,097,887	1.97	257,916
DISTRIBUTION	53,962,473	2.58	1,394,625
GENERAL	2,347,674	5.25	123,225
TOTAL PLANT IN SERVICE	**69,408,034**	**2.56**	**1,775,766**

DAWSON CREEK
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	-		-
TRANSMISSION	8,639,235	2.07	178,668
DISTRIBUTION	25,785,055	3.12	803,893
GENERAL	3,924,576	5.65	221,905
TOTAL PLANT IN SERVICE	**38,348,866**	**3.14**	**1,204,466**

TUMBLER RIDGE
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GATHERING	3,889,174	4.43	172,412
PROCESSING	-		-
TRANSMISSION	2,179,584	2.16	47,084
DISTRIBUTION	2,966,549	3.41	101,136
GENERAL	671,631	2.14	14,365
TOTAL PLANT IN SERVICE	**9,706,938**	**3.45**	**334,997**

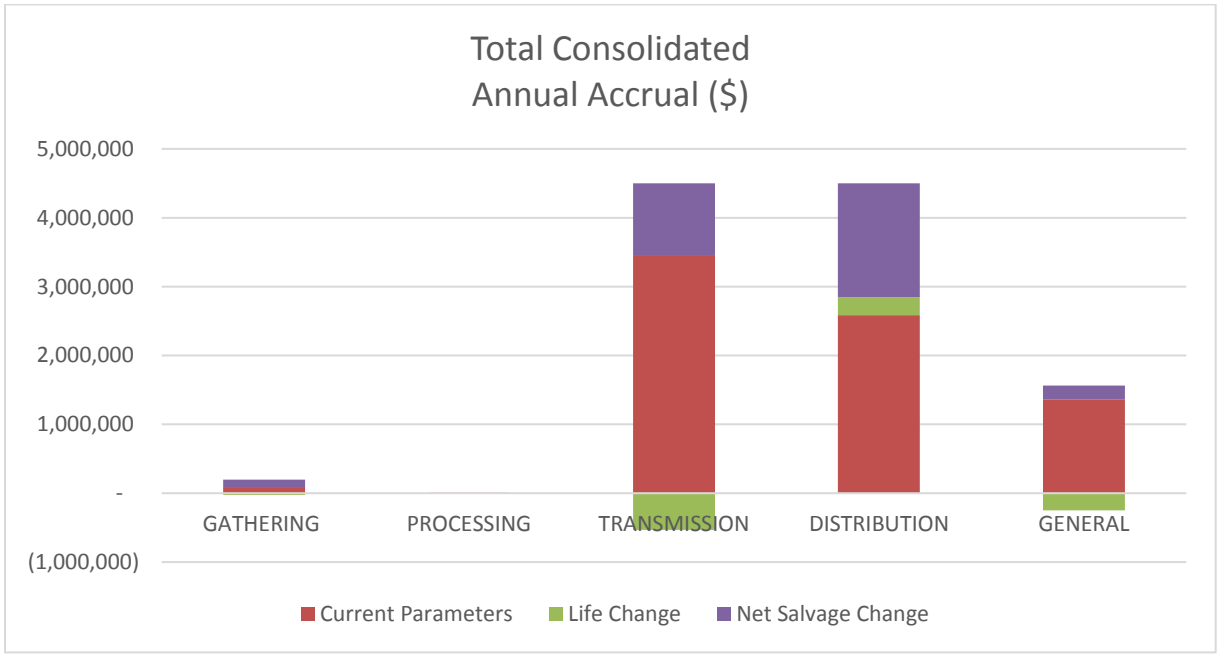
FORT ST. JOHN & DAWSON CREEK
SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GATHERING	-		-
PROCESSING	-		-
TRANSMISSION	21,737,122	2.01	436,584
DISTRIBUTION	79,747,528	2.76	2,198,518
GENERAL	6,272,250	5.50	345,130
TOTAL PLANT IN SERVICE	**107,756,900**	**2.77**	**2,980,232**

Finally, the application of the current depreciation parameters, applied to the 2016 depreciable balances, would result in an approximate $7.6M annual expense accrual. The recommended life parameter changes results in an annual expense accrual decrease of approximately $.1M. The recommended net salvage parameter changes result in an annual expense accrual increase of approximately $2.6M. These changes are further detailed by account in Tables 2 (and in each account's detailed Survivor Curve and Net Salvage Judgements) and summarized at an aggregate functional group level and then at a system level as follows:

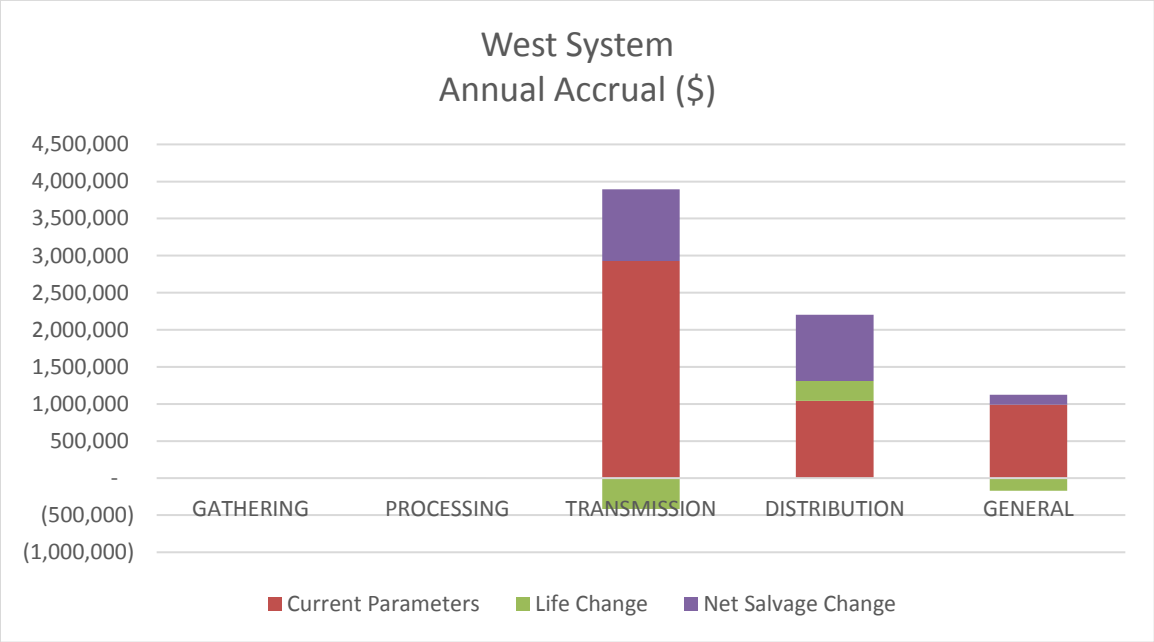
TOTAL CONSOLIDATED
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	75,854	(25,319)	121,877	172,412
PROCESSING	895	-	-	895
TRANSMISSION	3,443,170	(534,507)	1,055,900	3,964,563
DISTRIBUTION	2,583,730	261,748	1,655,887	4,501,365
GENERAL	1,364,089	(247,136)	198,186	1,315,139
TOTAL PLANT IN SERVICE	**7,467,738**	**(545,214)**	**3,031,850**	**9,954,374**



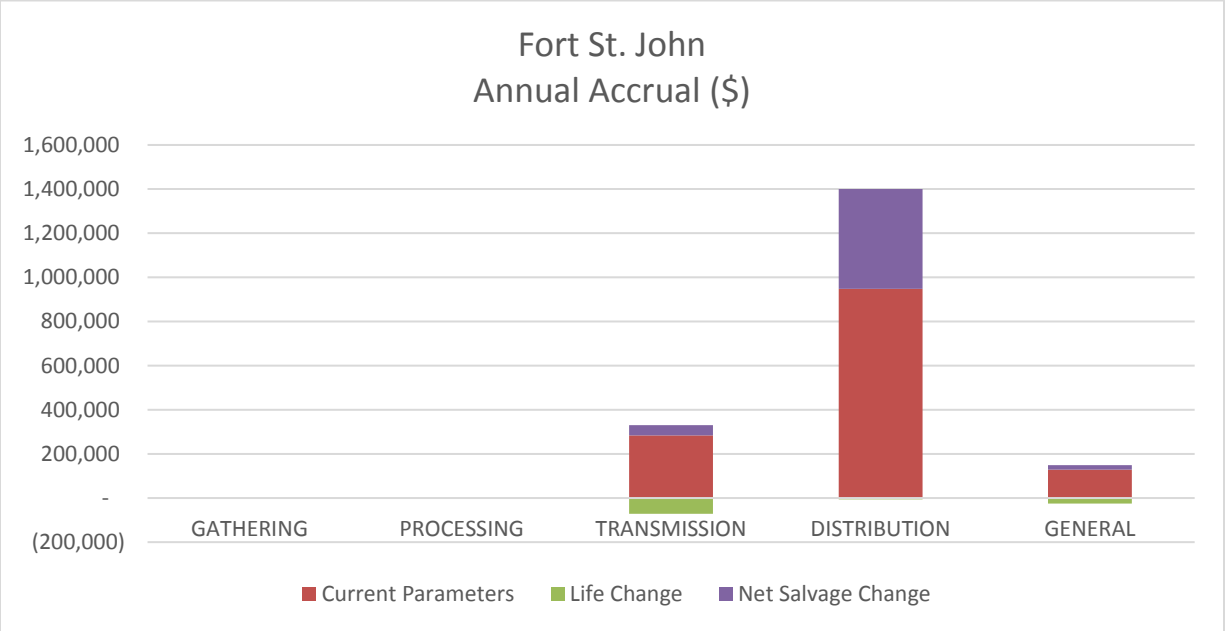
WEST SYSTEM
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	895	-	-	895
TRANSMISSION	2,928,435	(414,576)	967,036	3,480,895
DISTRIBUTION	1,043,087	264,917	893,707	2,201,711
GENERAL	990,462	(168,823)	134,005	955,644
TOTAL PLANT IN SERVICE	**4,962,879**	**(318,482)**	**1,994,748**	**6,639,145**



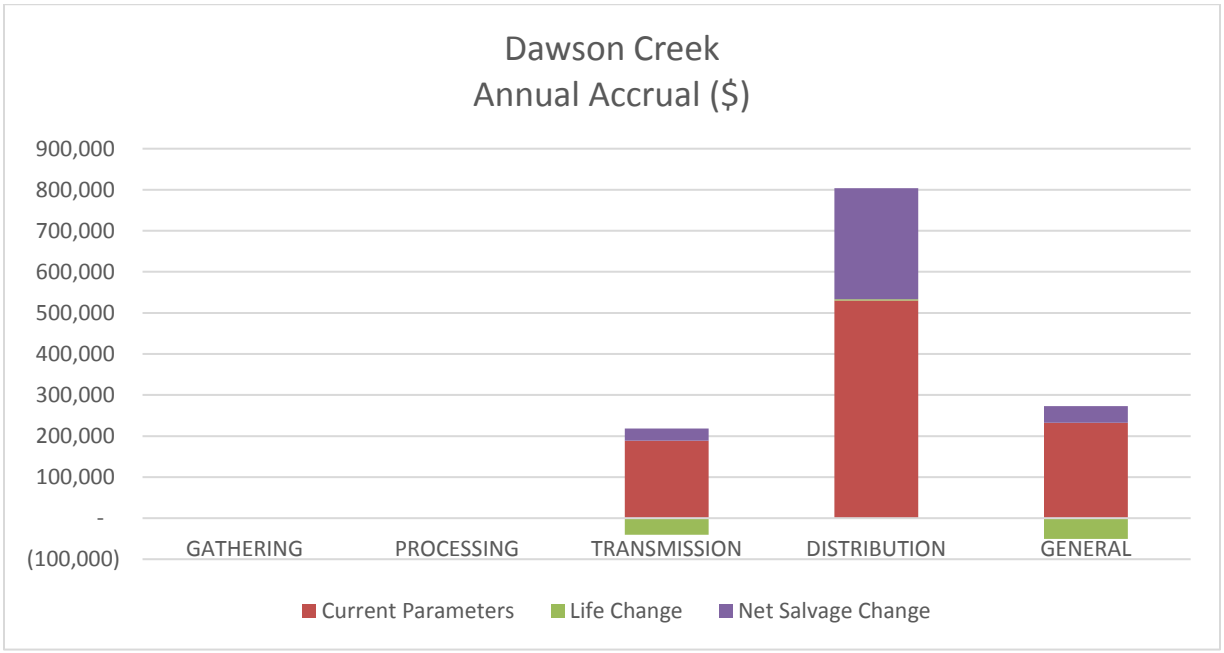
FORT ST. JOHN
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	-	-	-	-
TRANSMISSION	283,959	(72,071)	46,028	257,916
DISTRIBUTION	947,377	(6,351)	453,599	1,394,625
GENERAL	127,961	(25,432)	20,696	123,225
TOTAL PLANT IN SERVICE	**1,359,297**	**(103,854)**	**520,323**	**1,775,766**



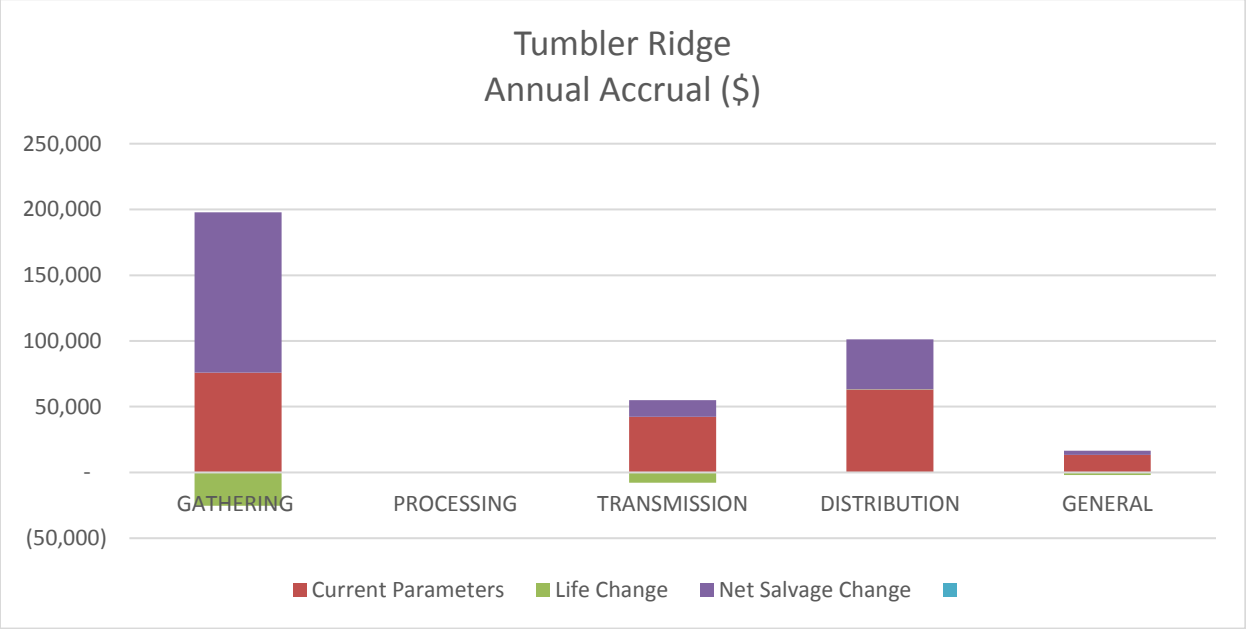
DAWSON CREEK
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	-	-	-	-
TRANSMISSION	188,540	(40,045)	30,173	178,668
DISTRIBUTION	530,225	3,002	270,666	803,893
GENERAL	232,261	(50,816)	40,460	221,905
TOTAL PLANT IN SERVICE	**951,026**	**(87,859)**	**341,299**	**1,204,466**



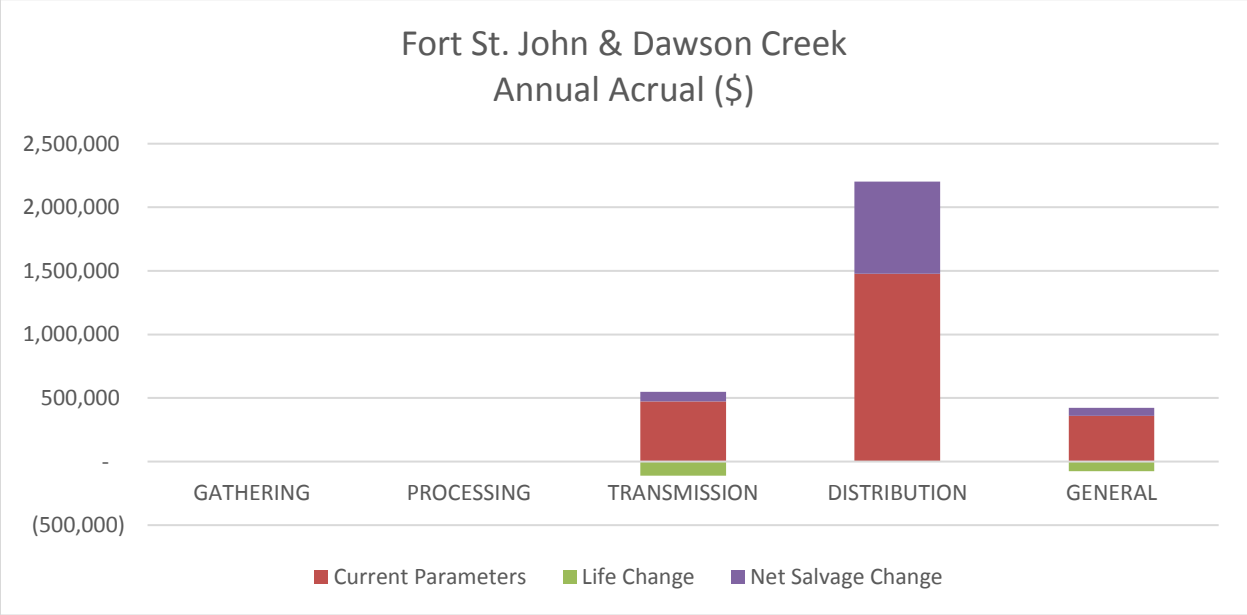
TUMBLER RIDGE
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	75,854	(25,319)	121,877	172,412
PROCESSING	-	-	-	-
TRANSMISSION	42,236	(7,815)	12,663	47,084
DISTRIBUTION	63,041	180	37,915	101,136
GENERAL	13,405	(2,065)	3,025	14,365
TOTAL PLANT IN SERVICE	**194,536**	**(35,019)**	**175,480**	**334,997**



FORT ST. JOHN & DAWSON CREEK
SUMMARY OF ANNUAL ACCRUAL CHANGES FROM PREVIOUS STUDY

PLANT GROUP	CURRENT PARAMETER ACCRUAL $'s	CHANGE DUE TO LIFE $'s	CHANGE DUE TO NET SALVAGE $'s	TOTAL CHANGE $'s
(1)	(2)	(3)	(4)	(4)
GATHERING	-	-	-	-
PROCESSING	-	-	-	-
TRANSMISSION	472,499	(112,116)	76,201	436,584
DISTRIBUTION	1,477,602	(3,349)	724,265	2,198,518
GENERAL	360,222	(76,248)	61,156	345,130
TOTAL PLANT IN SERVICE	**2,310,323**	**(191,713)**	**861,622**	**2,980,232**



PART I. INTRODUCTION

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Pacific Northern Gas Ltd. to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of Pacific Northern Gas Ltd.'s gathering, processing, transmission, distribution and general plant assets as of December 31, 2016. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the natural gas plant in service.

The service life and net salvage estimates resulting from the study were based on: informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2016; a review of company practice and outlook as they relate to plant operation and retirement; review of the company's upcoming capital and retirement projects; and consideration of current practice in the natural gas industry, including knowledge of service lives and net salvage estimates used for other natural gas utilities.

PLAN OF REPORT

Part I. Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II. Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life and net salvage studies. Part III. Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV. Results of Study, presents summaries by depreciable group of annual and accrued depreciation. Part V presents the results of the Retirement Rate and Service Life Statistics and Part VI presents Net Salvage Analysis. Detailed tabulations of annual and accrued depreciation are presented in Part VII of this report. An overview of Iowa curves and the Retirement Rate Analysis are set forth in Appendix A of the report. An overview of the net salvage analysis is presented in Appendix B of this report.

Depreciation - Life

For most accounts, the annual and accrued depreciation were calculated by the straight-line method using the average life group ("ALG") procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and salvage.

The straight-line method, average life group procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Concentric recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.

Depreciation – Net Salvage

This study recommends the incorporation of cost of removal (net negative salvage) in PNG's depreciation rates. The incorporation of negative net salvage has resulted in an approximate increase of $3.0M or 30 percent of PNG's total forecast $10.0M depreciation expense. Concentric Advisors recognizes the magnitude of including net negative salvage in depreciation rates. However, Concentric Advisors views that delaying the introduction of negative net salvage will increase the inter-generational inequity from customers that pay for the eventual removal costs from those that benefitted from those removed assets. The inclusion of an allowance for net salvage provides for the proper matching of expenses to revenues and ensures for accurate intergenerational equity. In other words, customers of PNG that benefit from the usage of their assets should also pay proportionately for those asset's eventual costs of demolishing, dismantling, tearing down or otherwise removing including the cost of transportation and handling incidental thereto. Allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accordance with authoritative texts and most Uniform Systems of Accounting including those published in Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission. The recovery of the net salvage in the depreciation rates is

widely accepted throughout North America, including Fortis BC Energy. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage. The longer the delay in recognizing net negative salvage, the higher future depreciation rate will be as PNG's depreciation rates are based on its net book value amortized over a remaining life basis. Each year of delay will increase the differential between booked net book value and calculated net book[1] value. As such, the resultant depreciation rates will increase proportionately.

The inclusion of net salvage percentages is widely accepted in regulatory jurisdictions throughout North America. Depreciation is not simply the allocation of original cost to expense. In the most widely used definition of depreciation for regulated utilities, the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts defines depreciation as "the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of property in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." The operative words in this definition are "*service value"*. The FERC Uniform System of Accounts goes on to define service value as "the difference between the original cost and the net salvage value of the utility plant". The service value rendered by an asset, i.e. depreciation, must reflect both its original cost and its net salvage. The FERC further defines "net salvage value" to mean the salvage value of property retired less the cost of removal, with "cost of removal" being defined as the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto.[2]

Allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accordance with authoritative texts[3] and most Uniform Systems of

[1] Calculated net book value (or Calculated Accumulated Depreciation) is the theoretical value for the accumulated depreciation reserve which is assumed to be applicable, and thus calculated, to the original date of installation.

[2] All referenced definitions are as per Chapter 1 – Federal Energy Regulatory Commission, Department of Energy, and Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, Definitions Section.

[3] Such as Depreciation Systems, Frank K. Wolf and W. Chester Fitch, Published, Iowa State University Press,

Accounting including those published in Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage. Additionally, the FERC Uniform System of Accounts requires that depreciation be recognized through accrual accounting. That is, the service value of an asset must be accrued during the life of the asset. Since net salvage is a part of the service value, it must be accrued during the life of the related asset in order to comply with the FERC Uniform System of Accounts. As such, regulatory decisions that require the expensing of costs of removal or that mandate the inclusion of costs of removal of retired plant as part of future capital costs of replacement plant need to understand that the decisions are in contrast to the FERC published and long-followed net salvage concepts from regulatory jurisdictions throughout North America. The revenue requirements that result from any type of "*expensing as incurred*" option are greater than the revenue requirements that result from accruing for net salvage during the life of the related asset for a regulated utility that includes a rate of return in its revenue requirement. Although a comparison of the current revenue requirements related to a net salvage accrual and the current revenue requirements related to expensing of net salvage may indicate that the accrual is higher at a single point in time, over time the revenue requirements and the present value of those revenue requirements will be less if the net salvage cost is accrued over the life of the asset. The reason for the lower revenue requirements with the accrual of net salvage is the impact of the accruals on rate base. That is, as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods

Many jurisdictions across Canada recognize the regulatory benefit and fairness to the inclusion of the recovery of the net salvage requirements over the period of time that assets are providing regulatory service. Regulatory decisions allowing the inclusion of net salvage

1994; and Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute, 1997.

percentages have been rendered by the following Canadian regulatory bodies for rates that are currently in place:

- The British Columbia Utilities Commission
- The Alberta Utilities Commission
- The Manitoba Public Utilities Board
- The Ontario Public Utilities Board
- The Regie de l'Energie du Quebec
- The Nova Scotia Utility and Review Board
- The Newfoundland and Labrador Board of Commissioners of Public Utilities
- Northwest Territories Public Utilities Board
- The National Energy Board of Canada

However, it is noted that not all utilities request recovery of net salvage within depreciation rates. The policy decision to recover net salvage within depreciation is made by the specific utility after consideration is given to all relevant factors, including:

- The accounting jurisdiction and principles being followed for financial disclosure purposes (US GAAP versus IFRS or modified IFRS);
- The potential for re-use of assets or facilities;
- The requirement for the utility to report an Asset Retirement Obligation;
- Review of the current funds for site removal and restoration;
- Materiality of the net salvage estimates; and
- Nature of retirement activity (interim or final retirement).

As such, it is not possible to conclude that all utilities within any jurisdiction either include or exclude net salvage recovery.

The BCUC has recently allowed the inclusion of costs of removal (net negative salvage) in the depreciation rates of FortisBC Energy, Inc. (formally Terasen Gas). In a 2011 Application before the BCUC in respect of 2012/2013 Revenue Requirements and Rates, FortisBC Energy Inc. Utilities ("FEU") requested a change to its practice of collecting salvage costs from ratepayers. FEU identified four possible methods to recover negative salvage

values from ratepayers: (i) the traditional approach (ie. as presented in this Application); (ii) a "pay-as-you-go" approach; (iii) Asset Retirement Obligation (ARO) style accounting; and (iv) a Hybrid approach (i.e. a combination of the traditional approach and ARO style accounting). FEU sought approval to adopt the traditional approach during the test period for all retirement obligations that are not AROs as defined by GAAP.

Under its 2011 Application to the BCUC, FEU sought approval for inclusion into its depreciation rate calculations, a provision for net salvage calculated in accordance with the "traditional" approach. The net salvage percentages were estimated in a Depreciation Study filed with the application. This application was a change from the approach used in a prior 2008 negotiated settlement which incorporated a pay-as-you-go approach which was considered to be more consistent with the BCUC 2005 BC Hydro Decision. However, in its 2011 Application FEU submitted the following arguments in support of its proposal to return to the tradition method of recovering net salvage through inclusion in the depreciation rate calculations:

- that the 3 years of history in using a pay-as-you-go method showed a large level of volatility;
- using a pay-as-you-go approach in the circumstance of actual retirement costs being forecast to increase as the assets near the end of their average useful lives, results in tomorrow's ratepayers paying to retire assets used today;
- The traditional negative salvage approach is a common, widely used practice amongst comparable utilities across the country and is also the method of accounting for salvage costs generally accepted for use in the United States within the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts.

After consideration of the above arguments, the BCUC ruled as follows:

> *The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a "pay as you go system" to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted. While net negative salvage rates are an*

estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.[4]

The above BCUC decision regarding the FEU Application clearly indicates that the BCUC understood the issues with a pay-as-you-go approach, and was willing to approve the inclusion of the net salvage estimates within the depreciation rate calculations, notwithstanding its prior BC Hydro decision.

Since the changes in the Financial Reporting Standards in the early 2000s, many depreciation studies completed by Larry Kennedy have developed separate provisions relating to the recovery of original cost of investment and for the recovery of costs of removal. In particular, this approach has been followed in applications completed for the following regulated utilities:

- FortisBC Energy Inc. related to a 2010 depreciation study approved by the BCUC in 2012, following a 2011 hearing;
- All regulated electric utilities in the province of Alberta (as specifically prescribed by the minimum filing requirements for Alberta electric utilities[5]);
- All regulated gas utilities in the Province of Alberta;
- Enbridge Consumers Gas in a 2012 Application to the Ontario Energy Board; and
- Gaz Metro in a 2010 Application to the Regie de l'Energie du Quebec.

The issue of recovery of net salvage requirements has received attention in virtually all recent depreciation applications in most jurisdictions across Canada. In particular, the issue was recently reviewed in the following jurisdictions:

[4] BCUC Order G-44-12 resulting from an Application by The FortisBC Energy Utilities in respect of 2012/2013 Revenue Requirements and Rates, pages 83-84.
[5] As prescribed by the Alberta Energy and Utilities Board (EUB) Bulletin 2006-25 issued May 8, 2006 for implementation on January 1, 2009.

- As indicated previously in this evidence, in applications in British Columbia by FortisBC Energy Inc. and separately for FortisBC Inc., the BCUC recently approved the reinstatement of net negative salvage costs. The BCUC approval was based on using the same calculation methods, as used in this current Yukon Electrical Company Limited ("YECL") application, for FortisBC Energy Inc. and suggested that FortisBC Inc. should consider the inclusion of net salvage in future applications.
- In Alberta, the Office of the Utility Consumers Advocate (the "UCA") has been extremely active in attempting to limit the amount of net salvage costs that are recovered through depreciation. While the UCA has, on a number of occasions, questioned the level of net salvage percentages, the UCA does not dispute the concept of recovery of net negative salvage. As such, the issue of net salvage in Alberta generally is an issue of the amount of recovery, rather than a dispute regarding the recoverability of the estimated costs of removal.
- In Ontario, Enbridge Gas Distribution and Union Gas have both recently filed applications that include very large provisions for the recovery of net salvage. Both applications included a depreciation study that calculated and applied the net salvage estimates in the same manner as used by Larry Kennedy in the current YECL application. The 2011 application by Union Gas did not result in any intervener evidence regarding the inclusion of costs of removal in the revenue requirement and the Ontario Energy Board (OEB) approved a revenue requirement incorporating a cost of removal provision. Enbridge Gas Distribution filed a 2012 depreciation study that also included the recovery of costs of removal in the depreciation rate calculations. The Enbridge study was settled via a negotiated settlement however, the settlement filed with and ultimately approved by the OEB included large provisions for net negative salvage. It is also noted that approval of the recovery of net salvage within depreciation rates has a long standing history before the OEB.
- In Quebec, Gaz Metro filed a depreciation study in 2011 that included a provision for net salvage. The application was approved after some debate with regard to

the ability of the company to reconcile regulatory and GAAP compliant financial statements. The procedure for development of a separate set of depreciation accrual rates (as described in previous sections of this evidence) was used by Gaz Metro to provide assurance to the regulator that the financial disclosure books and the regulatory sub-ledgers could be reconciled.

- Utilities in Nova Scotia, New Brunswick, and Newfoundland (Newfoundland Power) have all filed depreciation studies including provisions for net salvage. Generally, in these applications, the concept of the inclusion of the net salvage in the depreciation rates has not been the subject of opposing evidence and has been consistently approved by the regulators in those jurisdictions.
- The National Energy Board of Canada of Canada has commissioned a wide sweeping regulatory process - the Land Matter Consultative Initiative (LMCI) to consider the issues of site restoration and net salvage. This LMCI process has been on-going for a couple of years, with an oral hearing completed in 2012. The NEB has just released Decision MH-001-2012, which mandates NEB pipelines to include a recovery of pipeline abandonment costs in the revenue requirements of the company.

The appropriateness and accuracy of included net salvage costs into PNG's rates should be reviewed during each depreciation study to ensure they reflect that the most up to date information has been incorporated into net salvage rate development.

Service Life and Net Salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of the service life and net salvage estimates from our studies of other natural gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for natural gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future, which included discussions of detailed upcoming project business cases and operational staff interviews. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The procedure for estimating net salvage consisted to a large extent on the approved net salvage parameters for PNG peers, interviews with PNG's Management and Operational groups, and on the experience and judgement of Concentric.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

PART II. DEVELOPMENT OF DEPRECIATIONS PARAMETERS

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, and obsolescence, changes in the art, changes in demand, and the requirements of public authorities. When considering the action of the elements, the average service life calculations have considered the large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, wind storms, large scale flooding, fires, intentional actions of third parties, and other natural forces of nature.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing natural gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight-line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves "...were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."[6] The Iowa curves are described as L-type (i.e. left moded), R-type (i.e. right moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age 0. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness of fit" criterion which is the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of "goodness of fit" is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows a widely used practice of fitting Iowa

[6] Statistical Analyses of Industrial Property Retirements, Robley Winfrey, Bulletin 125, Engineering Research Institute, Iowa State University, page 65

curves up to one percent of the maximum exposures. This practice standard is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix A of this report. An overview of the net salvage analysis is presented in Appendix B of this report.

Survivor Curve and Net Salvage Judgments

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of the service life and net salvage estimates from our studies of other natural gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for natural gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future, which included discussions of detailed upcoming project business cases and operational staff interviews. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The procedure for estimating net salvage consisted to a large extent on the approved net salvage parameters for PNG peers, interviews with PNG's Management and Operational groups, and on the experience and judgement of Concentric.

The following discussion, dealing with the Company's accounts by function, which comprise the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates.

Gathering Plant

Account 411.00 – Gathering - Land Rights – The investment in Gathering Land Rights is approximately $275 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. Concentric views that an Iowa 75-R4 is a reasonable expectation for the equipment in this account and is consistent with the other PNG Land Right accounts. Interviews with PNG's Operations and Management staff have indicated that the Iowa 75-R4 is reasonable for the equipment in this account. They also would not expect a significant change to the observed average service life characteristics based on an operational perspective. Based on the above the Iowa 75-R4 is recommended to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
75-R4	0%			$ 7
		75-R4		$ -
			0%	$ -
Total Recommended				$ 7

Account 412.00 – Gathering – Compressor Structures and Improvements – The investment in Gathering Compressor Structures and Improvements is approximately $34,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. A peer comparison of a similar Canadian gas utility similarly has a Transmission Compressor Structures Iowa 30-R4 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 30-R3 is reasonable for the equipment in this account. Concentric views that an Iowa 30-R3 is a reasonable expectation for the equipment in this account and is also consistent with the life of PNG's Transmission Compressor Structures account. Based on the above the Iowa 30-R3 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a Transmission Compressor Structures net salvage value of negative 3 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 3 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 3 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R3	0%			$	1,510
		30-R3		$	-
			-3%	$	131
Total Recommended				$	1,641

Account 413.00 – Gathering – Measuring and Regulating Structures – The investment in Gathering Measuring and Regulating Structures is approximately $75,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. A peer comparison of a similar Canadian gas utility similarly has a Transmission Measuring and Regulating Structures Iowa 38-S2 as its life parameter. Concentric views that an Iowa 30-R3 is a reasonable expectation for the equipment in this account and is consistent with the life of PNG's Transmission Measuring and Regulating Structures account. Interviews with PNG's Operations and Management staff have indicated that the Iowa 30-R3 is reasonable for the equipment in this account. Based on the above the Iowa 30-R3 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility

similarly has Transmission Measuring and Regulating Structures net salvage value of negative 15 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 15 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 15 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R3	0%			$	260
		30-R3		$	-
			-15%	$	3,115
Total Recommended				$	3,375

Account 417.00 – Gathering – Measuring and Regulating Equipment – The investment in Gathering Measuring and Regulating Structures is approximately $30,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 25-R2. A peer comparison of a similar Canadian gas utility similarly has Transmission Measuring and Regulating Equipment has an Iowa 36-S0.5 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the Iowa 25-R2 is reasonable for the equipment in this account. Concentric views that an Iowa 25-R2 is a reasonable expectation for the equipment in this account and is consistent with the life of PNG's Transmission Measuring and Regulating Equipment account. Based on the above the Iowa 25-R2 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has Transmission Measuring and Regulating Equipment net salvage value of negative 7 percent as its net salvage parameter. Interviews with PNG's Operations and

Management staff have indicated that negative 7 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 7 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
25-R2	0%			$	1,137
		25-R2		$	-
			-7%	$	176
Total Recommended				$	1,313

Account 418.00 – Gathering – Purification Equipment – The investment in Gathering Purification Equipment is approximately $3.7M representing approximately 0.9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 25-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $254,986 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-11 and V-12 of this report. A fit of the observed data indicated an excellent fit to the Iowa 31-S5 with a related Residual Measure of 2.06. This compares to the current Iowa 25-R2, with a related Residual Measure of 22.28, which does not fit the observed data as well as the Iowa 31-S5. A peer comparison of a similar Canadian gas utility similarly has Pre-Treatment Equipment has an Iowa 25-R3 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the Iowa 31-S5 is reasonable for the equipment in this account. Concentric views that an Iowa 31-S5 is a reasonable life expectation. Based on the above the Iowa 31-S5 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has Pre-Treatment Equipment net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 25 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 25 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
25-R3	0%			$ 72,940
		31-S5		$ (25,319)
			-25%	$ 118,455
Total Recommended				$ 166,076

Processing Plant

Account 449.00 – Processing – Other Local Storage Equipment – The investment in Processing – Other Local Storage Equipment is approximately $3,000 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 33-R3. Concentric views that an Iowa 33-R3 is a reasonable life expectation. Interviews with PNG's Operations and Management staff have indicated that the Iowa 33-R3 is reasonable for the equipment in this account. Based on the above the Iowa 33-R3 is recommended to represent the expectations for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. Concentric views that 0 percent is a reasonable net salvage for the equipment in this account. Interviews with PNG's Operations and Management staff also indicated agreement with a 0 percent net salvage. Based on the above

negative 0 percent is recommended to represent the net salvage expectations for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
33-R3	0%			$ 71
		33-R3		$ -
			0%	$ -
Total Recommended				$ 71

Transmission Plant

Account 461.00 – Transmission - Land Rights – The investment in Transmission Land Rights is approximately $1.7M representing 0.4 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. No retirements have been booked to this account. Interviews with the PNG's Operations and Management have indicated that an appropriate life for Distribution Land Rights should be at least equal to the longest distribution life account. Account 465.00 – Transmission Mains has a recommended Iowa 65-R4 which results in a maximum life of approximately 100 years. Concentric viewed that the comments from the Operational and Management personnel was a reasonable expectation for the equipment in this account. Concentric views that an Iowa 75-R4 is a reasonable expectation and is consistent with the Operations and Management comments as the maximum life is approximately 110 years. Based on the above the Iowa 75-R4 is recommended to continue to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
75-R4	0%			$	38,549
		75-R4		$	-
			0%	$	-
Total Recommended				$	38,549

Account 462.00 – Transmission – Compressor Structures – The investment in Transmission Compressor Structures is approximately $3.4M representing 0.9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R4. Minimal retirements have been booked to this account. A peer comparison of a similar Canadian gas utility similarly has a 30-R4 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 30-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 30-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 3 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 3 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 3 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
462.00	30-R4	0%			$ 73,476
			30-R4		$ -
				-3%	$ 25,571
	Total Recommended				$ 99,047

Account 463.00 – Transmission – Measuring and Regulating Station Structures – The investment in Transmission Measuring and Regulating Station Structures is approximately $1.5M representing 0.4 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $149,108 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-22 and V-23 of this report. A fit of the observed data indicated a reasonable fit up to age 31.5 to the Iowa 39-R4 with a related Residual Measure of 23.23. This compares to the current Iowa 30-R3, with a related Residual Measure of 48.67, which does not fit the observed data as well as the Iowa 39-R4. A peer comparison of similar Canadian gas utilities has a ranged from 38 to 55 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 39-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 39-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 15 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 15 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable

expectation for the equipment in this account. As such, a net salvage of negative 15 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R3	0%			$	25,971
		39-R4		$	(10,077)
			-15%	$	16,129
Total Recommended				$	32,023

Account 465.00 – Transmission – Mains – The investment in Transmission Mains is approximately $170.1M representing 42.5 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 60-R3. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $2,608,128 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-25 and V-26 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 65-R4 with a related Residual Measure of 1.85. This compares to the current Iowa 60-R3, with a related Residual Measure of 5.59, which does not fit the observed data as well as the Iowa 65-R4. A peer comparison of similar Canadian gas utilities has a range from 60 to 65 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 65-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility

similarly has a net salvage value of negative 20 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated negative 20 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 20 percent is recommended to represent the expectations for the equipment in this account.

The application of the previous study depreciation rates to PNG's 2016 balances results in an annual accrual of $2,143,628. The application of the previous study depreciation parameters (i.e. survivor curve and net salvage) to PNG's 2016 vintage balances results in a further annual accrual increase of $59,560 which is due to capitalization changes (i.e. additions, adjustments, and retirements) from the previous study. The application of the recommended life (i.e. $-207,549) and net salvage (i.e. $901,910) changes results in an additional net increase of $694,361 to the annual accrual. These changes are summarized as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
60-R3	0%			$ 2,203,188
		65-R4		$ (207,549)
			-20%	$ 901,910
Total Recommended				$ 2,897,549

Account 466.00 – Transmission – Compressor Equipment – The investment in Transmission Compressor Equipment is approximately $25.2M representing 6.3 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R2.5. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $1,257,686 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-28 and V-29 of this report. A fit of the observed data indicated a conservative reasonable fit to the Iowa 35-R3 with a related Residual Measure of 33.74. This compares to the current Iowa

30-R2.5, with a related Residual Measure of 44.36, which does not fit the observed data as well as the Iowa 35-R3. Interviews with PNG's Operations and Management staff have indicated that the Iowa 35-R3 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 35-R3 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 2 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 2 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 2 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
30-R2.5	0%			$	446,978
		35-R3		$	(113,399)
			-2%	$	50,865
Total Recommended				$	384,444

Account 467.00 – Transmission – Measuring and Regulating Equipment – The investment in Transmission Measuring and Regulating Equipment is approximately $18.0M representing 4.5 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 25-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1967 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has

experienced $1,438,841 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-31 and V-32 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 35-S2.5 with a related Residual Measure of 19.33. This compares to the current Iowa 25-R2, with a related Residual Measure of 49.54, which does not fit the observed data as well as the Iowa 35-S2.5. A peer comparison of similar Canadian gas utilities has a range from 36 to 50 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 35-S2.5 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 35-S2.5 is recommended to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 7 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 7 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 7 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
25-R2	0%			$	577,844
		35-S2.5		$	(203,482)
			-7%	$	61,425
Total Recommended				$	435,787

Account 468.00 – Transmission – Communication Structures and Equipment – The investment in Transmission Communication Structures and Equipment is approximately $3.4M representing .9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 15-R2. Minimal retirements have been booked to this account. A peer comparison of a similar Canadian gas utility similarly has a 19-R3 as its life parameter. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 15-R2 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 15-R2 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of 0 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that 0 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of 0 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
15-R2	0%			$	64,389
		15-R2		$	-
			0%	$	-
Total Recommended				$	64,389

Distribution Plant

Account 471.00 – Distribution – Land Rights – The investment in Distribution Land Rights is approximately $0.3M representing 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. No retirements have been booked to this account. Interviews with the PNG's Operations and Management have indicated that an appropriate life for Distribution Land Rights should be at least equal to the longest distribution life account. Account 475.00 – Distribution Mains has a recommended Iowa 65-R4 which results in a maximum life of approximately 100 years. Concentric viewed that the comments from the Operational and Management personnel was a reasonable expectation for the equipment in this account. Concentric views that an Iowa 75-R4 is a reasonable expectation and is consistent with the Operations and Management comments as the maximum life is approximately 110 years. Based on the above the Iowa 75-R4 is recommended to continue to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual	
Parameters	Net Salvage	Life	Net Salvage	Accrual	
75-R4	0%			$	4,968
		75-R4		$	-
			0%	$	-
Total Recommended				$	4,968

Account 472.00 – Distribution – Structures and Improvements – The investment in Distribution Structures and Improvements is approximately $2.7M representing .7 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1972 through 2015 and retirement experience over the period of 1972 through 2016. Over this 44-year period this account has experienced $184,833 of retirements as provided on pages V-40 and V-41 of this report. A fit of the observed data

indicated that the Iowa 30-R3 continues to be a reasonable fit. A peer comparison of similar Canadian gas utilities has a range from 35 to 55 years. Interviews with PNG's Operations and Management staff have indicated that the current Iowa 30-R3 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 30-R3 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 10 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 10 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual	
	Parameters	Net Salvage	Life	Net Salvage	Accrual	
472.00	30-R3	0%			$	90,327
			30-R3		$	-
				-10%	$	18,125
	Total Recommended				$	108,452

Account 473.00 – Distribution – Services – The investment in Distribution Services is approximately $51.4M representing 12.9 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 50-R2.5. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year

period this account has experienced $914,237 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-43 and V-44 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 50-R4 with a related Residual Measure of 4.92. This compares to the current Iowa 50-R2.5, with a related Residual Measure of 9.96, which does not fit the observed data as well as the Iowa 50-R4. A peer comparison of similar Canadian gas utilities has a range from 45 to 57 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 50-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 50-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 60 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 60 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 60 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
50-R2.5	0%			$ 846,828
		50-R4		$ 48,982
			-60%	$ 1,081,711
Total Recommended				$ 1,977,521

Account 474.00 – Distribution – House Regulators and Equipment – The investment in Distribution House Regulators and Equipment is approximately $10.3M representing 2.6 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 30-R2. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $223,433 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-46 and V-47 of this report. A fit of the observed data indicated a conservative reasonable fit to the Iowa 40-R4 with a related Residual Measure of 10.53. This compares to the current Iowa 30-R2, with a related Residual Measure of 30.87, which does not fit the observed data as well as the Iowa 40-R4. A peer comparison of similar Canadian gas utilities has a range from 20 to 51 years. Interviews with PNG's Operations and Management staff have indicated that the historically indicated Iowa 40-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 40-R4 is recommended to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 20 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 20 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 20 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
30-R2	0%			$ 279,718
		40-R4		$ (90,255)
			-20%	$ 122,876
Total Recommended				$ 312,339

Account 475.00 – Distribution – Mains – The investment in Distribution Mains is approximately $75.1M representing 18.8 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 60-R3. Although minimal retirements have been booked to this account a retirement rate analysis was prepared in this study which reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $89,327 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-49 and V-50 of this report. A fit of the observed data indicated a reasonable fit to the Iowa 65-R4 with a related Residual Measure of 3.24. This compares to the current Iowa 60-R3, with a related Residual Measure of 7.10, which does not fit the observed data as well as the Iowa 65-R4. A peer comparison of similar Canadian gas utilities has a range from 62 to 80 years. Interviews with PNG's Operations and Management staff have indicated that the Iowa 65-R4 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, combined with the results of the peer comparison, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R4 is recommended to continue to represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 25 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 25 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable

expectation for the equipment in this account. As such, a net salvage of negative 25 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
60-R3	0%			$ 1,051,333
		65-R4		$ (94,361)
			-25%	$ 440,147
Total Recommended				$ 1,397,119

Account 477.00 – Distribution – Measuring and Regulating Equipment – The investment in Distribution Measuring and Regulating Equipment is approximately $2.3M representing .6 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 20-R3. Minimal retirements have been processed against this account. A peer comparison of similar Canadian gas utilities has a range from 15 to 50 years. Interviews with PNG's Operations and Management staff have indicated that the 35 year average service life recommended for their similar Transmission Measuring and Regulating Account 467.00 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 35-R4 is recommended represent the expectations for the equipment in this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 7 percent recommended for their similar Transmission Measuring and Regulating Account 467.00 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable

expectation for the equipment in this account. As such, a net salvage of negative 7 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
477.00	20-R3	0%			$ 52,884
			35-R4		$ (32,136)
				-7%	$ 10,304
	Total Recommended				$ 31,052

Account 478.00 – Distribution - Meters – The investment in Distribution Meters is approximately $6.4M representing 1.6 percent of the total depreciable plant studied. The majority of PNG's meters are residential with some commercial and industrial. The currently approved life parameter for this account is an Iowa 25-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1975 through 2016 and retirement experience over the period of 2010 through 2016. Over this 7-year period this account has experienced $2,695,955 of retirements as summarized on the observed life table as provided on pages V-54 and V-55 of this report. A fit of the observed data indicated a very good fit to the Iowa 28-R5 with a related Residual Measure of 4.93. This compares to the current Iowa 25-R2, with a related Residual Measure of 16.60, which does not fit the observed data as well as the Iowa 28-R5

Canadian Measurement Standards requires an initial seal period for regular-size residential meters of 10 years. At the end of the seal life, PNG tests a sample. If the sample passes, the existing meters stay in service. Most meters will pass the first test period. The second seal period is 8 years. PNG retires their meters after this 8 year extension thus resulting in a maximum residential meter life of 18 years. This account also includes commercial and industrial meters which are more expensive. PNG indicates a maximum life of commercial and industrial meters to be 25 years. Based on this Concentric views that a more appropriate life should be an Iowa 20-R4 curve. This recognizes the maximum 18 year

life of residential meters and an expected 25 year life for their commercial and industrial meters. As such, the Iowa 20-R4 curve is recommended for this account.

The previous depreciation study did not include an allowance for net salvage. The first year of recorded net salvage activity for this account is 2014. The net salvage for the years 2014 to 2016 has been 1 percent for each year with a cumulative 3 year value of 1 percent. A peer comparison of a similar Canadian gas utility similarly has a net salvage value of 0 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that the historically indicated 1 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 1 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
478.00	25-R2	0%			$ 256,663
			20-R4		$ 429,518
				1%	$ (17,276)
	Total Recommended				$ 668,905

General Plant

Account 481.00 – General Plant – Land Rights – The investment in General Plant Land Rights is approximately $1,700 representing less than 0.1 percent of the total depreciable plant studied. The current approved life parameter for this account is an Iowa 75-R4. No retirements have been booked to this account. Interviews with the PNG's Operations and Management have indicated that an appropriate life for General Plant Land Rights should be at least equal to the longest General Plant account. Account 482.00 – General Plant Structures and Improvements has a recommended Iowa 30-R3 which results in a maximum life of approximately 50 years. Concentric viewed that the comments from the Operational

and Management personnel was a reasonable expectation for the equipment in this account. Concentric views that an Iowa 75-R4 is a reasonable expectation and is consistent with the PNG's other Land Rights accounts. Based on the above the Iowa 75-R4 is recommended to continue to represent the expectations for this account.

No salvage has been recorded to this account and is not expected due to the intangible aspect of land rights. As such 0 percent is the net salvage recommendation for this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
75-R4	0%			$ 29
		75-R4		$ -
			0%	$ -
Total Recommended				$ 29

Account 482.00 – General Plant – Structures and Improvements – The investment in General Plant – Structures and Improvements is approximately $8.7M representing 2.2 percent of the total depreciable plant studied. The currently approved life parameter for this account is an Iowa 25-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1969 through 2016 and retirement experience over the period of 1969 through 2016. Over this 48-year period this account has experienced $1,146,264 of retirements over a wide range of ages as summarized on the observed life table as provided on pages V-58 and V-59 of this report. A fit of the observed data indicated a conservative reasonable fit to the Iowa 30-R3 with a related Residual Measure of 29.07. This compares to the current Iowa 25-R2, with a related Residual Measure of 39.73, which does not fit the observed data as well as the Iowa 30-R3. A peer comparison of Canadian utilities produced a range from 20-75 years. Interviews with PNG's Operations and Management staff have indicated that the Iowa 30-R3 is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel, the peer comparison results, and on the professional judgement of

Concentric was the most reasonable expectation for the equipment in this account. As such, the Iowa 30-R3 is recommended for this account.

The previous depreciation study did not include an allowance for net salvage and none has been recorded to this account. A peer comparison of a similar Canadian gas utility has a net salvage range from 0 percent to negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 0 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of 0 percent is recommended to represent the expectations for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
25-R2	0%			$ 268,133
		30-R3		$ (55,995)
			0%	$ -
Total Recommended				$ 212,138

Account 484.00 – General Plant – Transportation Equipment – The equipment in General Plant – Transportation Equipment is approximately $3.7M representing .9 percent of the total depreciable plant studied. The currently approved life parameter for this account is an Iowa 7-L1.5. A peer comparison of Canadian utilities produced a range from 6-10 years. Concentric viewed that the most current experience of 7 years would best represent the historical indications for this account due to the relative short life of this equipment. The retirement rate analysis prepared in this study reviewed the plant installed over the period of 1995 through 2016 and retirement experience over the period of 2010 through 2016. Over this 7-year period this account has experienced $3,171,311 of retirements as summarized on the observed life table as provided on page V-61 of this report. A fit of the

observed data indicated an excellent fit to an Iowa 8-L3 curve with a related Residual Measure of 11.16. This compares to the current Iowa 7-L1.5 curve with a related Residual Measure of 17.98, which does not fit the observed data as well as the Iowa 8-L3 curve. Interviews with the PNG's Operations and Management have indicated that although PNG has a 7 year retirement policy, the timing of purchasing and disposition is more indicative of the historical 8 year observed life. Concentric viewed that the historical results combined with the peer comparison and the comments from the Operational and Management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 8-L3 curve is recommended for this account based on the fit to historic data and the indications from Management and Operations and on the professional judgment of Concentric.

The previous depreciation study included a net salvage of 20 percent. The first year of recorded net salvage activity for this account is 2010. For the period 2010 to 2016, the net salvage has ranged from 7 percent to the most current vintage of 22 percent with a cumulative value of 16 percent. A three-year moving average analysis from 2010 forward produced a range from 11 percent to 17 percent. The five-year average indicates 17 percent. Interviews with the PNG's Operations and Management have indicated that 15 percent is a more reasonable expectation for the equipment in this account. Based on historical indications and the comments from the Operations and Management personnel, Concentric views that the historical data indications of 15 percent is a reasonable net salvage expectation for the equipment in this account. As such, Concentric recommends 15 percent net salvage.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

	Current		Recommendation		Annual
	Parameters	Net Salvage	Life	Net Salvage	Accrual
484.00	7-L1.5	20%			$ 361,501
			8-L3		$ (124,261)
				15%	$ 142,540
	Total Recommended				$ 379,780

Account 485.00 – General Plant – Heavy Work Equipment – The equipment in General Plant – Heavy Work Equipment is approximately $5.7M representing 1.4 percent of the total depreciable plant studied. The currently approved life parameter for this account is an Iowa 15-R2. The retirement rate analysis prepared in this study reviewed the plant installed over the period of 1976 through 2016 and retirement experience over the period of 2010 through 2016. Over this 7-year period this account has experienced $658,037 of retirements as summarized on the observed life table as provided on page V-63 of this report. A fit of the observed data indicated a reasonable fit to an Iowa 18-R3 curve with a related Residual Measure of 34.54. This compares to the current Iowa 15-R2 curve with a related Residual Measure of 40.50, which does not fit the observed data as well as the Iowa 8-L3 curve. A peer comparison of Canadian utilities produced a range from 8-20 years. Interviews with the PNG's Operations and Management have indicated that the historical indications of an Iowa 18-R3 were reasonable expectations. Concentric viewed that the comments from the Operational and Management personnel was a reasonable expectation for the equipment in this account. As such, the Iowa 18-R3 curve is recommended for this account based on the indications from Management and Operations and on the professional judgment of Concentric.

The previous depreciation study included a net salvage of 15 percent. The first year of recorded net salvage activity for this account is 2012. For the period 2012 to 2016, the net salvage has ranged from 7 percent to 24 percent with a cumulative value of 10 percent. Interviews with the PNG's Operations and Management have indicated that the historically indicated value of 10 percent is a reasonable expectation for the equipment in this account. Based on historical indications and the comments from the Operations and Management personnel, Concentric views that 10 percent is a reasonable net salvage expectation for the equipment in this account.

The effect on the annual accrual of the above recommended changes to the current depreciation parameters (i.e. Average Service Life-Iowa Curve, and Net Salvage) are as follows:

Current		Recommendation		Annual
Parameters	Net Salvage	Life	Net Salvage	Accrual
15-R2	15%			$ 195,227
		18-R3		$ 44,413
			10%	$ (55,646)
Total Recommended				$ 183,994

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART III. CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts. The accounts and their amortization periods are as follows:

ACCOUNT	TITLE	AMORTIZATION PERIOD YEARS
443.00	Processing Plant - Gas Holders – Storage	40
469.00	Transmission - Other	40
479.00	Distribution – Other	35
483.00	Office Furniture and Equipment	15
486.00	Tools and Work Equipment	20
487.00	Computer Equipment	5
488.00	Communication Structures and Equipment	14
489.00	Other General Equipment	20

For the purposes of calculating annual amortization amounts as of December 31, 2016, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual equal life group remaining lives in accordance with the following equation:

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve. In as much as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\text{Composite Remaining Life} = \frac{\text{Whole Life Future Accruals}}{\text{Whole Life Annual Accruals}}$$

Or

$$\text{Composite Remaining Life} = \frac{\text{Book Cost - Calc. Reserve}}{\text{Whole Life Annual Accrual}}.$$

PART IV. RESULTS OF STUDY

PART IV. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight-line method, using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other natural gas utilities. The results of the statistical analysis of service life are presented in Part V beginning on V-2 of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2016 are presented in account sequence starting on page VII-2 of the supporting documents. The following Tables 1 indicate the estimated average survivor

curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual. The following Tables 2 are the summaries of the service life and net salvage estimates and their effect of calculated annual accruals.

PACIFIC NORTHERN GAS LTD.
TOTAL SYSTEM
TABLE 1 SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	275	7	2.55	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	(3)	34,443	22,526	12,950	1,641	4.76	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	(15)	75,160	74,217	12,217	3,375	4.49	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	(7)	29,701	16,287	15,493	1,313	4.42	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	(25)	3,749,595	2,637,682	2,049,312	166,076	4.43	12.3
TOTAL GATHERING PLANT				**3,889,174**	**2,750,712**	**2,090,247**	**172,412**	4.43	
PROCESSING PLANT									
443.00	GAS HOLDERS - STORAGE	40-SQ	-	30,000	13,113	16,887	824	2.75	20.5
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	2,111	1,089	71	2.22	15.3
TOTAL PROCESSING PLANT				**33,200**	**15,224**	**17,976**	**895**	2.70	
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	1,696,046	93,821	1,602,225	38,549	2.27	41.6
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	3,365,788	2,657,623	809,139	99,047	2.94	8.2
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	1,491,198	1,127,683	587,196	32,023	2.15	18.3
465.00	MAINS	65-R4	(20)	170,129,175	81,294,078	122,860,932	2,897,549	1.70	42.4
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	25,201,337	19,841,105	5,864,259	384,444	1.53	15.3
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	17,966,528	7,947,174	11,277,011	435,787	2.43	25.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,403,490	2,911,318	492,172	64,389	1.89	7.6
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	505,344	8,227	497,116	12,775	2.53	38.9
TOTAL TRANSMISSION PLANT				**223,758,907**	**115,881,029**	**143,990,050**	**3,964,563**	1.77	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	257,861	21,861	236,000	4,968	1.93	47.5
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	2,705,198	938,004	2,037,714	108,452	4.01	18.8
473.00	SERVICES	50-R4	(60)	51,438,650	21,342,205	60,959,634	1,977,521	3.84	30.8
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	10,323,675	5,780,284	6,608,126	312,339	3.03	21.2
475.00	MAINS	65-R4	(25)	75,059,907	28,910,408	64,914,476	1,397,119	1.86	46.5
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	2,333,055	1,769,902	726,466	31,052	1.33	23.4
478.00	METERS	20-R4	1	6,426,221	2,424,780	3,937,179	668,905	10.41	5.9
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	50,131	33,925	16,206	1,009	2.01	16.1
TOTAL DISTRIBUTION PLANT				**148,594,698**	**61,221,369**	**139,435,801**	**4,501,365**	3.03	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,729	234	1,494	29	1.68	51.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	8,692,046	5,040,943	3,651,103	212,138	2.44	17.2
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	675,720	244,526	431,193	79,230	11.73	5.4
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	3,692,148	1,226,618	1,911,708	379,780	10.29	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	5,674,985	2,686,968	2,420,520	183,994	3.24	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	3,989,678	1,582,662	2,407,018	271,714	6.81	8.9
487.00	COMPUTER EQUIPMENT	5-SQ	-	607,385	296,122	311,264	147,007	24.20	2.1
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	481,777	244,967	236,809	41,226	8.56	5.7
489.00	OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	1,728	272	21	1.05	13.0
TOTAL GENERAL PLANT				**23,817,468**	**11,324,768**	**11,371,381**	**1,315,139**	5.52	
TOTAL GAS PLANT STUDIED				**400,093,446**	**191,193,102**	**296,905,455**	**9,954,374**	2.49	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			115,141	-				
470.00	LAND			47,943	-				
480.00	LAND			394,403	-				
490.00	COMPUTER SOFTWARE			1,438,184	1,162,785				
TOTAL PLANT NOT STUDIED				**1,998,761**	**1,162,785**				
				1,998,761					
TOTAL PLANT				**402,092,207**	**192,355,887**				

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 1A SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PROCESSING PLANT									
443.00	GAS HOLDERS - STORAGE	40-SQ	-	30,000	13,113	16,887	824	2.75	20.5
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	2,111	1,089	71	2.22	15.3
TOTAL PROCESSING PLANT				**33,200**	**15,224**	**17,976**	**895**	**2.70**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	1,236,760	35,215	1,201,545	32,881	2.66	36.5
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	2,900,743	2,392,601	595,165	81,730	2.82	7.3
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	1,281,843	1,050,295	423,825	25,904	2.02	16.4
465.00	MAINS	65-R4	(20)	155,681,495	75,931,928	110,885,866	2,662,306	1.71	41.7
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	25,196,925	19,837,962	5,862,902	384,331	1.53	15.3
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	9,809,396	5,010,680	5,485,374	218,781	2.23	25.1
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,248,146	2,781,162	466,984	62,635	1.93	7.5
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	486,894	1,210	485,683	12,327	2.53	39.4
TOTAL TRANSMISSION PLANT				**199,842,201**	**107,041,053**	**125,407,344**	**3,480,895**	**1.74**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	34,278	-	34,278	815	2.38	42.1
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	333,334	147,635	219,032	13,810	4.14	15.9
473.00	SERVICES	50-R4	(60)	25,828,532	14,737,981	26,587,670	1,007,709	3.90	26.4
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	4,296,732	2,625,008	2,531,070	133,221	3.10	19.0
475.00	MAINS	65-R4	(25)	31,534,898	15,808,798	23,609,824	600,209	1.90	39.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	276,550	271,335	24,573	1,977	0.71	12.4
478.00	METERS	20-R4	1	3,545,782	1,622,826	1,887,498	443,527	12.51	4.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	30,515	23,643	6,872	443	1.45	15.5
TOTAL DISTRIBUTION PLANT				**65,880,621**	**35,237,227**	**54,900,817**	**2,201,711**	**3.34**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	350	-	350	8	2.29	43.8
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	6,186,382	3,820,164	2,366,218	152,274	2.46	15.5
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	545,399	195,763	349,635	68,237	12.51	5.1
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	2,324,539	795,028	1,180,831	237,987	10.24	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	4,049,344	2,053,964	1,590,446	121,731	3.01	13.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	2,813,302	1,070,056	1,743,246	206,177	7.33	8.5
487.00	COMPUTER EQUIPMENT	5-SQ	-	564,461	288,274	276,187	136,505	24.18	2.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	387,810	219,902	167,908	32,704	8.43	5.1
489.00	OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	1,728	272	21	1.05	13.0
TOTAL GENERAL PLANT				**16,873,587**	**8,444,878**	**7,675,093**	**955,644**	**5.66**	
TOTAL GAS PLANT STUDIED				**282,629,608**	**150,738,382**	**188,001,230**	**6,639,145**	**2.35**	
PLANT NOT STUDIED									
410.00	LAND			-					
460.00	LAND			104,160					
470.00	LAND			552					
480.00	LAND			295,004					
490.00	COMPUTER SOFTWARE			1,190,803	930,852				
TOTAL PLANT NOT STUDIED				**1,590,519**	**930,852**				
TOTAL PLANT				**284,220,127**	**151,669,234**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 1B SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	284,620	58,606	226,014	3,181	1.12	71.1
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	265,022	213,974	17,317	3.72	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	83,484	50,113	45,893	2,408	2.88	19.1
465.00	MAINS	65-R4	(20)	6,878,819	2,964,857	5,289,726	98,195	1.43	53.9
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	5,365,795	2,313,113	3,428,288	135,432	2.52	25.3
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	20,124	-	20,124	1,383	6.87	14.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**13,097,887**	**5,651,711**	**9,224,019**	**257,916**	**1.97**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	156,677	21,861	134,816	2,459	1.57	54.8
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	1,158,054	399,713	874,147	45,404	3.92	19.3
473.00	SERVICES	50-R4	(60)	17,367,781	4,485,159	23,303,291	624,113	3.59	37.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	2,221,852	1,169,677	1,496,545	57,198	2.57	26.2
475.00	MAINS	65-R4	(25)	29,925,140	9,289,747	28,116,678	517,614	1.73	54.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,226,388	806,061	506,173	19,178	1.56	26.4
478.00	METERS	20-R4	1	1,886,965	543,598	1,324,497	128,093	6.79	10.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**53,962,473**	**16,726,099**	**55,765,481**	**1,394,625**	**2.58**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	948,924	661,048	287,876	21,044	2.22	13.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	29,513	7,188	22,325	1,920	6.51	11.6
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	543,958	166,059	296,305	58,782	10.81	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	299,518	161,923	107,643	8,897	2.97	12.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	479,331	223,111	256,221	27,617	5.76	9.3
487.00	COMPUTER EQUIPMENT	5-SQ	-	9,390	2,700	6,690	2,232	23.77	3.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	35,661	8,570	27,091	2,712	7.60	10.0
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**2,347,674**	**1,230,833**	**1,005,295**	**123,225**	**5.25**	
TOTAL GAS PLANT STUDIED				**69,408,034**	**23,608,644**	**65,994,795**	**1,775,766**	**2.56**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			6,395	-				
470.00	LAND			22,043	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			192,805	185,632				
TOTAL PLANT NOT STUDIED				**297,746**	**185,632**				
TOTAL PLANT				**69,705,780**	**23,794,276**				

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE 1C SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	174,666	-	174,666	2,487	1.42	70.2
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	125,872	27,275	117,478	3,711	2.95	31.7
465.00	MAINS	65-R4	(20)	5,827,847	1,334,951	5,658,464	103,202	1.77	54.8
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	2,362,606	546,000	1,981,988	68,820	2.91	28.8
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	129,794	129,794	-	-	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**8,639,235**	**2,045,038**	**7,944,029**	**178,668**	**2.07**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	64,895	-	64,895	1,646	2.54	39.4
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	873,028	301,637	658,694	35,677	4.09	18.5
473.00	SERVICES	50-R4	(60)	7,527,244	1,803,204	10,240,385	310,135	4.12	33.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	3,518,978	1,747,059	2,475,715	112,275	3.19	22.1
475.00	MAINS	65-R4	(25)	12,499,900	3,245,787	12,379,088	254,899	2.04	48.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	509,098	463,782	80,952	5,283	1.04	15.3
478.00	METERS	20-R4	1	791,912	181,476	602,517	83,978	10.60	7.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**25,785,055**	**7,742,946**	**26,502,246**	**803,893**	**3.12**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	1,154,428	159,777	994,651	37,645	3.26	26.4
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	76,782	32,130	44,652	7,038	9.17	6.3
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	783,574	251,791	414,247	78,621	10.03	5.3
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,208,623	387,512	700,249	51,789	4.28	13.5
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	613,799	260,018	353,782	33,488	5.46	10.6
487.00	COMPUTER EQUIPMENT	5-SQ	-	30,859	5,147	25,712	7,676	24.87	3.3
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	56,512	15,431	41,080	5,648	9.99	7.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**3,924,576**	**1,111,805**	**2,574,373**	**221,905**	**5.65**	
TOTAL GAS PLANT STUDIED				**38,348,866**	**10,899,789**	**37,020,648**	**1,204,466**	**3.14**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			4,586	-				
470.00	LAND			25,348	-				
480.00	LAND			-	-				
490.00	COMPUTER SOFTWARE			42,841	35,668				
TOTAL PLANT NOT STUDIED				**72,775**	**35,668**				
TOTAL PLANT				**38,421,641**	**10,935,457**				

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 1D SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	275	7	2.55	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	(3)	34,443	22,526	12,950	1,641	4.76	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	(15)	75,160	74,217	12,217	3,375	4.49	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	(7)	29,701	16,287	15,493	1,313	4.42	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	(25)	3,749,595	2,637,682	2,049,312	166,076	4.43	12.3
TOTAL GATHERING PLANT				**3,889,174**	**2,750,712**	**2,090,247**	**172,412**	**4.43**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS								
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS								
465.00	MAINS	65-R4	(20)	1,741,015	1,062,341	1,026,876	33,846	1.94	30.3
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	4,412	3,143	1,357	113	2.56	12.0
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	428,731	77,381	381,361	12,754	2.97	29.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	5,426	362	5,064	371	6.84	13.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**2,179,584**	**1,143,228**	**1,414,658**	**47,084**	**2.16**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	2,011	-	2,011	48	2.39	41.9
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	340,781	89,018	285,841	13,561	3.98	21.1
473.00	SERVICES	50-R4	(60)	715,093	315,861	828,288	35,564	4.97	23.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	286,113	238,540	104,796	9,645	3.37	10.9
475.00	MAINS	65-R4	(25)	1,099,969	566,075	808,886	24,397	2.22	33.2
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	321,020	228,723	114,768	4,614	1.44	24.9
478.00	METERS	20-R4	1	201,562	76,879	122,667	13,307	6.60	9.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**2,966,549**	**1,515,097**	**2,267,257**	**101,136**	**3.41**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R5	-	402,312	399,954	2,358	1,175	0.29	2.0
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	24,026	9,445	14,581	2,035	8.47	7.2
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	40,077	13,741	20,325	4,390	10.95	4.6
485.00	HEAVY WORK EQUIPMENT	18-R3	10	117,501	83,569	22,182	1,577	1.34	14.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	83,246	29,477	53,769	4,432	5.32	12.1
487.00	COMPUTER EQUIPMENT	5-SQ	-	2,675	-	2,675	594	22.21	4.5
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	1,795	1,065	730	162	9.03	4.5
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**671,631**	**537,251**	**116,620**	**14,365**	**2.14**	
TOTAL GAS PLANT STUDIED				**9,706,938**	**5,946,287**	**5,888,782**	**334,997**	**3.45**	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			-	-				
470.00	LAND			-	-				
480.00	LAND			22,896	-				
490.00	COMPUTER SOFTWARE			11,735	10,632				
TOTAL PLANT NOT STUDIED				**37,721**	**10,632**				
TOTAL PLANT				**9,744,659**	**5,956,919**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN AND DAWSON CREEK
TABLE 1E SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8)/(5)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	459,287	58,606	400,680	5,668	1.23	70.8
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	265,022	213,974	17,317	3.72	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	209,355	77,388	163,371	6,119	2.92	26.7
465.00	MAINS	65-R4	(20)	12,706,666	4,299,809	10,948,190	201,397	1.58	54.3
466.00	COMPRESSOR EQUIPMENT			-	-	-	-		
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	7,728,401	2,859,113	5,410,276	204,252	2.64	26.4
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	149,918	129,794	20,124	1,383	0.92	2.0
469.00	OTHER TRANSMISSION EQUIPMENT			18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**21,737,122**	**7,696,749**	**17,168,048**	**436,584**	**2.01**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	221,572	21,861	199,711	4,105	1.85	50.3
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	2,031,083	701,350	1,532,841	81,081	3.99	19.0
473.00	SERVICES	50-R4	(60)	24,895,025	6,288,363	33,543,676	934,248	3.75	36.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	5,740,830	2,916,736	3,972,260	169,473	2.95	23.7
475.00	MAINS	65-R4	(25)	42,425,040	12,535,535	40,495,766	772,513	1.82	52.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,735,485	1,269,843	587,125	24,461	1.41	23.1
478.00	METERS	20-R4	1	2,678,877	725,075	1,927,014	212,071	7.92	9.4
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**79,747,528**	**24,469,045**	**82,267,727**	**2,198,518**	**2.76**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	2,103,352	820,825	1,282,527	58,689	2.79	20.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	106,295	39,318	66,977	8,958	8.43	7.8
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	1,327,532	417,850	710,552	137,403	10.35	5.2
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,508,140	549,435	807,892	60,686	4.02	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	1,093,131	483,128	610,003	61,105	5.59	10.0
487.00	COMPUTER EQUIPMENT	5-SQ	-	40,249	7,848	32,402	9,908	24.62	3.2
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	92,173	24,001	68,171	8,360	9.07	8.3
489.00	OTHER GENERAL EQUIPMENT			-	-	-	-		
TOTAL GENERAL PLANT				**6,272,250**	**2,342,639**	**3,579,668**	**345,130**	**5.50**	
TOTAL GAS PLANT STUDIED				**107,756,900**	**34,508,433**	**103,015,443**	**2,980,232**	**2.77**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			10,981	-				
470.00	LAND			47,391	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			235,647	221,301				
TOTAL PLANT NOT STUDIED				**370,522**	**221,301**				
TOTAL PLANT				**108,127,422**	**34,729,733**				

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 1A-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT		DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PROCESSING PLANT										
443.00		GAS HOLDERS - STORAGE	40-SQ	-	30,000	13,113	16,887	824	2.75	20.5
449.00		OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	2,111	1,089	71	2.22	15.3
TOTAL PROCESSING PLANT					**33,200**	**15,224**	**17,976**	**895**	**2.70**	
TRANSMISSION PLANT										
461.00	461.00 4!	LAND RIGHTS	75-R4	-	1,236,760	35,215	1,201,545	32,881	2.66	36.5
462.00	462.00 4!	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	2,900,743	2,392,601	508,142	57,291	1.98	7.3
463.00	463.00 4!	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	1,281,843	1,050,295	231,548	11,113	0.87	16.4
465.00	465.00 4!	MAINS	65-R4	-	155,681,495	75,931,928	79,749,567	1,822,185	1.17	41.7
466.00	466.00 4!	COMPRESSOR EQUIPMENT	35-R3	-	25,196,925	19,837,962	5,358,963	333,473	1.32	15.3
467.00	467.00 4!	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	9,809,396	5,010,680	4,798,716	181,954	1.85	25.1
468.00	468.00 4!	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,248,146	2,781,162	466,984	62,635	1.93	7.5
469.00	469.00 4!	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	486,894	1,210	485,683	12,327	2.53	39.4
TOTAL TRANSMISSION PLANT					**199,842,201**	**107,041,053**	**92,801,148**	**2,513,859**	**1.26**	
DISTRIBUTION PLANT										
471.00	471.00 4!	LAND RIGHTS	75-R4	-	34,278	-	34,278	815	2.38	42.1
472.00	472.00 4!	STRUCTURES AND IMPROVEMENTS	30-R3	-	333,334	147,635	185,699	10,834	3.25	15.9
473.00	473.00 4!	SERVICES	50-R4	-	25,828,532	14,737,981	11,090,551	379,852	1.47	26.4
474.00	474.00 4!	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	4,296,732	2,625,008	1,671,724	76,484	1.78	19.0
475.00	475.00 4!	MAINS	65-R4	-	31,534,898	15,808,798	15,726,100	383,033	1.21	39.3
477.00	477.00 4!	MEASURING AND REGULATING EQUIPMENT	35-R4	-	276,550	271,335	5,214	236	0.09	12.4
478.00	478.00 4!	METERS	20-R4	1	3,545,782	1,622,826	1,887,498	443,527	12.51	4.3
479.00	479.00 4!	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	30,515	23,643	6,872	443	1.45	15.5
TOTAL DISTRIBUTION PLANT					**65,880,621**	**35,237,227**	**30,607,936**	**1,295,224**	**1.97**	
GENERAL PLANT										
481.00	481.00 4!	LAND RIGHTS	75-R4	-	350	-	350	8	2.29	43.8
482.00	482.00 4!	STRUCTURES AND EQUIPMENT	30-R3	-	6,186,382	3,820,164	2,366,218	152,274	2.46	15.5
483.00	483.00 4!	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	545,399	195,763	349,635	68,237	12.51	5.1
484.00	484.00 4!	TRANSPORTATION EQUIPMENT	8-L3	15	2,324,539	795,028	1,180,831	237,987	10.24	5.0
485.00	485.00 4!	HEAVY WORK EQUIPMENT	18-R3	10	4,049,344	2,053,964	1,590,446	121,731	3.01	13.1
486.00	486.00 4!	TOOLS AND WORK EQUIPMENT	20-SQ	-	2,813,302	1,070,056	1,743,246	206,177	7.33	8.5
487.00	487.00 4!	COMPUTER EQUIPMENT	5-SQ	-	564,461	288,274	276,187	136,505	24.18	2.0
488.00	488.00 4!	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	387,810	219,902	167,908	32,704	8.43	5.1
489.00		OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	1,728	272	21	1.05	13.0
TOTAL GENERAL PLANT					**16,873,587**	**8,444,878**	**7,675,093**	**955,644**	**5.66**	
TOTAL GAS PLANT STUDIED					**282,629,608**	**150,738,382**	**131,102,153**	**4,765,622**	**1.69**	
PLANT NOT STUDIED										
410.00		LAND			-					
460.00		LAND			104,160					
470.00		LAND			552					
480.00		LAND			295,004					
490.00		COMPUTER SOFTWARE			1,190,803	930,852				
TOTAL PLANT NOT STUDIED					**1,590,519**	**930,852**				
TOTAL PLANT					**284,220,127**	**151,669,234**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 1B-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	284,620	58,606	226,014	3,181	1.12	71.1
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	465,045	265,022	200,023	16,185	3.48	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	83,484	50,113	33,370	1,751	2.10	19.1
465.00	MAINS	65-R4	-	6,878,819	2,964,857	3,913,962	71,058	1.03	53.9
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	5,365,795	2,313,113	3,052,683	118,330	2.21	25.3
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	20,124	-	20,124	1,383	6.87	14.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**13,097,887**	**5,651,711**	**7,446,176**	**211,888**	**1.62**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	156,677	21,861	134,816	2,459	1.57	54.8
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	1,158,054	399,713	758,341	39,127	3.38	19.3
473.00	SERVICES	50-R4	-	17,367,781	4,485,159	12,882,623	339,029	1.95	37.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	2,221,852	1,169,677	1,052,174	38,783	1.75	26.2
475.00	MAINS	65-R4	-	29,925,140	9,289,747	20,635,393	375,288	1.25	54.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	1,226,388	806,061	420,326	15,439	1.26	26.4
478.00	METERS	20-R4	1	1,886,965	543,598	1,324,497	128,093	6.79	10.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**53,962,473**	**16,726,099**	**37,217,504**	**938,784**	**1.74**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	948,924	661,048	287,876	21,044	2.22	13.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	29,513	7,188	22,325	1,920	6.51	11.6
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	543,958	166,059	296,305	58,782	10.81	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	10	299,518	161,923	107,643	8,897	2.97	12.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	479,331	223,111	256,221	27,617	5.76	9.3
487.00	COMPUTER EQUIPMENT	5-SQ	-	9,390	2,700	6,690	2,232	23.77	3.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	35,661	8,570	27,091	2,712	7.60	10.0
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**2,347,674**	**1,230,833**	**1,005,295**	**123,225**	**5.25**	
TOTAL GAS PLANT STUDIED				**69,408,034**	**23,608,644**	**45,668,975**	**1,273,897**	**1.84**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			6,395	-				
470.00	LAND			22,043	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			192,805	185,632				
TOTAL PLANT NOT STUDIED				**297,746**	**185,632**				
TOTAL PLANT				**69,705,780**	**23,794,276**				

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE 1C SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	174,666	-	174,666	2,487	1.42	70.2
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	125,872	27,275	98,597	3,030	2.41	31.7
465.00	MAINS	65-R4	-	5,827,847	1,334,951	4,492,895	80,118	1.37	54.8
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	2,362,606	546,000	1,816,605	62,412	2.64	28.8
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	129,794	129,794	-	-	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**8,639,235**	**2,045,038**	**6,594,196**	**148,495**	**1.72**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	64,895	-	64,895	1,646	2.54	39.4
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	873,028	301,637	571,391	28,815	3.30	18.5
473.00	SERVICES	50-R4	-	7,527,244	1,803,204	5,724,039	161,374	2.14	33.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	3,518,978	1,747,059	1,771,920	71,107	2.02	22.1
475.00	MAINS	65-R4	-	12,499,900	3,245,787	9,254,113	182,891	1.46	48.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	509,098	463,782	45,316	1,820	0.36	15.3
478.00	METERS	20-R4	1	791,912	181,476	602,517	83,978	10.60	7.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**25,785,055**	**7,742,946**	**18,034,191**	**531,631**	**2.06**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	1,154,428	159,777	994,651	37,645	3.26	26.4
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	76,782	32,130	44,652	7,038	9.17	6.3
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	783,574	251,791	414,247	78,621	10.03	5.3
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,208,623	387,512	700,249	51,789	4.28	13.5
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	613,799	260,018	353,782	33,488	5.46	10.6
487.00	COMPUTER EQUIPMENT	5-SQ	-	30,859	5,147	25,712	7,676	24.87	3.3
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	56,512	15,431	41,080	5,648	9.99	7.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**3,924,576**	**1,111,805**	**2,574,373**	**221,905**	**5.65**	
TOTAL GAS PLANT STUDIED				**38,348,866**	**10,899,789**	**27,202,760**	**902,031**	**2.35**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			4,586	-				
470.00	LAND			25,348	-				
480.00	LAND			-	-				
490.00	COMPUTER SOFTWARE			42,841	35,668				
TOTAL PLANT NOT STUDIED				**72,775**	**35,668**				
TOTAL PLANT				**38,421,641**	**10,935,457**				

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 1D-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	LIFE NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	275	7	2.55	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	-	34,443	22,526	11,917	1,510	4.38	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	75,160	74,217	943	260	0.35	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	29,701	16,287	13,414	1,137	3.83	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	-	3,749,595	2,637,682	1,111,913	47,621	1.27	12.3
TOTAL GATHERING PLANT				**3,889,174**	**2,750,712**	**1,138,462**	**50,535**	**1.30**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS								
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS								
465.00	MAINS	65-R4	-	1,741,015	1,062,341	678,673	22,278	1.28	30.3
466.00	COMPRESSOR EQUIPMENT	35-R3	-	4,412	3,143	1,269	106	2.40	12.0
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	428,731	77,381	351,350	11,666	2.72	29.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	5,426	362	5,064	371	6.84	13.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**2,179,584**	**1,143,228**	**1,036,356**	**34,421**	**1.58**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	2,011	-	2,011	48	2.39	41.9
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	340,781	89,018	251,763	11,551	3.39	21.1
473.00	SERVICES	50-R4	-	715,093	315,861	399,232	15,555	2.18	23.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	286,113	238,540	47,573	3,089	1.08	10.9
475.00	MAINS	65-R4	-	1,099,969	566,075	533,894	15,760	1.43	33.2
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	321,020	228,723	92,296	3,253	1.01	24.9
478.00	METERS	20-R4	1	201,562	76,879	122,667	13,307	6.60	9.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**2,966,549**	**1,515,097**	**1,449,436**	**62,563**	**2.11**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R5	-	402,312	399,954	2,358	1,175	0.29	2.0
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	24,026	9,445	14,581	2,035	8.47	7.2
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	40,077	13,741	20,325	4,390	10.95	4.6
485.00	HEAVY WORK EQUIPMENT	18-R3	10	117,501	83,569	22,182	1,577	1.34	14.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	83,246	29,477	53,769	4,432	5.32	12.1
487.00	COMPUTER EQUIPMENT	5-SQ	-	2,675	-	2,675	594	22.21	4.5
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	1,795	1,065	730	162	9.03	4.5
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**671,631**	**537,251**	**116,620**	**14,365**	**2.14**	
TOTAL GAS PLANT STUDIED				**9,706,938**	**5,946,287**	**3,740,874**	**161,884**	**1.67**	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			-	-				
470.00	LAND			-	-				
480.00	LAND			22,896	-				
490.00	COMPUTER SOFTWARE			11,735	10,632				
TOTAL PLANT NOT STUDIED				**37,721**	**10,632**				
TOTAL PLANT				**9,744,659**	**5,956,919**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN & DAWSON CREEK
TABLE 1E-LIFE SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016

ACCOUNT	DESCRIPTION	LIFE ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8)/(5)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	459,287	58,606	400,680	5,668	1.23	70.8
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	465,045	265,022	200,023	16,185	3.48	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	-	209,355	77,388	131,967	4,781	2.28	26.7
465.00	MAINS	65-R4	-	12,706,666	4,299,809	8,406,857	151,176	1.19	54.3
466.00	COMPRESSOR EQUIPMENT			-	-	-	-		
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	-	7,728,401	2,859,113	4,869,288	180,742	2.34	26.4
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	149,918	129,794	20,124	1,383	0.92	2.0
469.00	OTHER TRANSMISSION EQUIPMENT			18,450	7,017	11,433	448	2.43	25.5
TOTAL TRANSMISSION PLANT				**21,737,122**	**7,696,749**	**14,040,372**	**360,383**	**1.66**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	221,572	21,861	199,711	4,105	1.85	50.3
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	2,031,083	701,350	1,329,732	67,942	3.35	19.0
473.00	SERVICES	50-R4	-	24,895,025	6,288,363	18,606,662	500,403	2.01	36.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	-	5,740,830	2,916,736	2,824,094	109,890	1.91	23.7
475.00	MAINS	65-R4	-	42,425,040	12,535,535	29,889,506	558,179	1.32	52.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	-	1,735,485	1,269,843	465,642	17,259	0.99	23.1
478.00	METERS	20-R4	1	2,678,877	725,075	1,927,014	212,071	7.92	9.4
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	10,282	9,334	566	2.89	16.5
TOTAL DISTRIBUTION PLANT				**79,747,528**	**24,469,045**	**55,251,695**	**1,470,415**	**1.84**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	234	1,144	21	1.52	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	2,103,352	820,825	1,282,527	58,689	2.79	20.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	106,295	39,318	66,977	8,958	8.43	7.8
484.00	TRANSPORTATION EQUIPMENT	8-L3	15	1,327,532	417,850	710,552	137,403	10.35	5.2
485.00	HEAVY WORK EQUIPMENT	18-R3	10	1,508,140	549,435	807,892	60,686	4.02	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	1,093,131	483,128	610,003	61,105	5.59	10.0
487.00	COMPUTER EQUIPMENT	5-SQ	-	40,249	7,848	32,402	9,908	24.62	3.2
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	92,173	24,001	68,171	8,360	9.07	8.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**6,272,250**	**2,342,639**	**3,579,668**	**345,130**	**5.50**	
TOTAL GAS PLANT STUDIED				**107,756,900**	**34,508,433**	**72,871,735**	**2,175,928**	**2.02**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			10,981	-				
470.00	LAND			47,391	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			235,647	221,301				
TOTAL PLANT NOT STUDIED				**370,522**	**221,301**				
TOTAL PLANT				**108,127,422**	**34,729,733**				

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 1A-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PROCESSING PLANT									
443.00	GAS HOLDERS - STORAGE	40-SQ	-	30,000	-	-	-	-	20.5
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	3,200	-	-	-	-	15.3
TOTAL PROCESSING PLANT				**33,200**	**0**	**0**	**0**	**-**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	1,236,760	-	-	-	-	36.5
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	2,900,743	-	87,023	24,439	0.84	7.3
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	1,281,843	-	192,277	14,791	1.15	16.4
465.00	MAINS	65-R4	(20)	155,681,495	-	31,136,299	840,121	0.54	41.7
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	25,196,925	-	503,939	50,858	0.21	15.3
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	9,809,396	-	686,658	36,827	0.38	25.1
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	3,248,146	-	-	-	-	7.5
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	486,894	-	-	-	-	39.4
TOTAL TRANSMISSION PLANT				**199,842,201**	**0**	**32,606,196**	**967,036**	**0.48**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	34,278	-	-	-	-	42.1
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	333,334	-	33,333	2,976	0.89	15.9
473.00	SERVICES	50-R4	(60)	25,828,532	-	15,497,119	627,857	2.43	26.4
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	4,296,732	-	859,346	56,737	1.32	19.0
475.00	MAINS	65-R4	(25)	31,534,898	-	7,883,724	217,176	0.69	39.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	276,550	-	19,359	1,741	0.62	12.4
478.00	METERS	20-R4	-	3,545,782	-	-	-	-	4.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	30,515	-	-	-	-	15.5
TOTAL DISTRIBUTION PLANT				**65,880,621**	**0**	**24,292,881**	**906,487**	**1.38**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	350	-	-	-	-	43.8
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	6,186,382	-	-	-	-	15.5
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	545,399	-	-	-	-	5.1
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	2,324,539	-	-	-	-	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	-	4,049,344	-	-	-	-	13.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	2,813,302	-	-	-	-	8.5
487.00	COMPUTER EQUIPMENT	5-SQ	-	564,461	-	-	-	-	2.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	387,810	-	-	-	-	5.1
489.00	OTHER GENERAL EQUIPMENT	20-R2.5	-	2,000	-	-	-	-	13.0
TOTAL GENERAL PLANT				**16,873,587**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**282,629,608**	**0**	**56,899,077**	**1,873,523**	**0.66**	
PLANT NOT STUDIED									
410.00	LAND			-					
460.00	LAND			104,160					
470.00	LAND			552					
480.00	LAND			295,004					
490.00	COMPUTER SOFTWARE			1,190,803	-				
TOTAL PLANT NOT STUDIED				**1,590,519**	**-**				
TOTAL PLANT				**284,220,127**	**-**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 1B-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	284,620	-	-	-	-	71.1
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	-	13,951	1,132	0.24	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	83,484	-	12,523	657	0.78	19.1
465.00	MAINS	65-R4	(20)	6,878,819	-	1,375,764	27,137	0.40	53.9
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	5,365,795	-	375,605	17,102	0.31	25.3
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	20,124	-	-	-	-	14.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**13,097,887**	**0**	**1,777,843**	**46,028**	**0.35**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	156,677	-	-	-	-	54.8
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	1,158,054	-	115,806	6,277	0.54	19.3
473.00	SERVICES	50-R4	(60)	17,367,781	-	10,420,668	285,084	1.64	37.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	2,221,852	-	444,371	18,415	0.82	26.2
475.00	MAINS	65-R4	(25)	29,925,140	-	7,481,285	142,326	0.48	54.3
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,226,388	-	85,847	3,739	0.30	26.4
478.00	METERS	20-R4	-	1,886,965	-	-	-	-	10.3
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	-	-	-	-	16.5
TOTAL DISTRIBUTION PLANT				**53,962,473**	**0**	**18,547,977**	**455,841**	**0.84**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	-	-	-	-	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	948,924	-	-	-	-	13.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	29,513	-	-	-	-	11.6
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	543,958	-	-	-	-	5.0
485.00	HEAVY WORK EQUIPMENT	18-R3	-	299,518	-	-	-	-	12.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	479,331	-	-	-	-	9.3
487.00	COMPUTER EQUIPMENT	5-SQ	-	9,390	-	-	-	-	3.0
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	35,661	-	-	-	-	10.0
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**2,347,674**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**69,408,034**	**0**	**20,325,820**	**501,869**	**0.72**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			6,395	-				
470.00	LAND			22,043	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			192,805	185,632				
TOTAL PLANT NOT STUDIED				**297,746**	**185,632**				
TOTAL PLANT				**69,705,780**	**185,632**				

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE-1C COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	174,666	-	-	-	-	70.2
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	125,872	-	18,881	681	0.54	31.7
465.00	MAINS	65-R4	(20)	5,827,847	-	1,165,569	23,084	0.40	54.8
466.00	COMPRESSOR EQUIPMENT								
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	2,362,606	-	165,383	6,408	0.27	28.8
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	129,794	-	-	-	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	18,450	-	-	-	-	25.5
TOTAL TRANSMISSION PLANT				**8,639,235**	**0**	**1,349,833**	**30,173**	**0.35**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	64,895	-	-	-	-	39.4
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	873,028	-	87,303	6,862	0.79	18.5
473.00	SERVICES	50-R4	(60)	7,527,244	-	4,516,346	148,761	1.98	33.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	3,518,978	-	703,795	41,168	1.17	22.1
475.00	MAINS	65-R4	(25)	12,499,900	-	3,124,975	72,008	0.58	48.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	509,098	-	35,636	3,463	0.68	15.3
478.00	METERS	20-R4	-	791,912	-	-	-	-	7.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**25,785,055**	**0**	**8,468,055**	**272,262**	**1.06**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	1,154,428	-	-	-	-	26.4
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	76,782	-	-	-	-	6.3
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	783,574	-	-	-	-	5.3
485.00	HEAVY WORK EQUIPMENT	18-R3	-	1,208,623	-	-	-	-	13.5
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	613,799	-	-	-	-	10.6
487.00	COMPUTER EQUIPMENT	5-SQ	-	30,859	-	-	-	-	3.3
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	56,512	-	-	-	-	7.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**3,924,576**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**38,348,866**	**0**	**9,817,888**	**302,435**	**0.79**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			4,586	-				
470.00	LAND			25,348	-				
480.00	LAND			-	-				
490.00	COMPUTER SOFTWARE			42,841	35,668				
TOTAL PLANT NOT STUDIED				**72,775**	**35,668**				
TOTAL PLANT				**38,421,641**	**35,668**				

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 1D-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GATHERING PLANT									
411.00	LAND RIGHTS	75-R4	-	275	-	-	-	-	39.3
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	(3)	34,443	-	1,033	131	0.38	7.9
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	(15)	75,160	-	11,274	3,115	4.14	3.6
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	(7)	29,701	-	2,079	176	0.59	11.8
418.00	PURIFICATION EQUIPMENT	31-S5	(25)	3,749,595	-	937,399	118,455	3.16	12.3
TOTAL GATHERING PLANT				**3,889,174**	**0**	**951,785**	**121,877**	**3.13**	
TRANSMISSION PLANT									
461.00	LAND RIGHTS								
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS								
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS								
465.00	MAINS	65-R4	(20)	1,741,015	-	348,203	11,568	0.66	30.3
466.00	COMPRESSOR EQUIPMENT	35-R3	(2)	4,412	-	88	7	0.16	12.0
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	428,731	-	30,011	1,088	0.25	29.9
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	5,426	-	-	-	-	13.6
469.00	OTHER TRANSMISSION EQUIPMENT								
TOTAL TRANSMISSION PLANT				**2,179,584**	**0**	**378,302**	**12,663**	**0.58**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	2,011	-	-	-	-	41.9
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	340,781	-	34,078	2,010	0.59	21.1
473.00	SERVICES	50-R4	(60)	715,093	-	429,056	20,009	2.79	23.3
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	286,113	-	57,223	6,556	2.29	10.9
475.00	MAINS	65-R4	(25)	1,099,969	-	274,992	8,637	0.79	33.2
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	321,020	-	22,472	1,361	0	24.9
478.00	METERS	20-R4	-	201,562	-	-	-	-	9.2
479.00	OTHER DISTRIBUTION EQUIPMENT								
TOTAL DISTRIBUTION PLANT				**2,966,549**	**0**	**817,821**	**38,573**	**1.30**	
GENERAL PLANT									
481.00	LAND RIGHTS								
482.00	STRUCTURES AND EQUIPMENT	30-R5	-	402,312	-	-	-	-	2.0
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	24,026	-	-	-	-	7.2
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	40,077	-	-	-	-	4.6
485.00	HEAVY WORK EQUIPMENT	18-R3	-	117,501	-	-	-	-	14.1
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	83,246	-	-	-	-	12.1
487.00	COMPUTER EQUIPMENT	5-SQ	-	2,675	-	-	-	-	4.5
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	1,795	-	-	-	-	4.5
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**671,631**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**9,706,938**	**0**	**2,147,908**	**173,113**	**1.78**	
PLANT NOT STUDIED									
410.00	LAND			3,089	-				
460.00	LAND			-	-				
470.00	LAND			-	-				
480.00	LAND			22,896	-				
490.00	COMPUTER SOFTWARE			11,735	10,632				
TOTAL PLANT NOT STUDIED				**37,721**	**10,632**				
TOTAL PLANT				**9,744,659**	**10,632**				

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN & DAWSON CREEK
TABLE 1E-COR SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
COST OF REMOVAL

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2016	BOOKED ACCRUED DEPRECIATION	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) = (8)/(5)	(10)
TRANSMISSION PLANT									
461.00	LAND RIGHTS	75-R4	-	459,287	-	-	-	-	70.8
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	(3)	465,045	-	13,951	1,132	0.24	12.4
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	39-R4	(15)	209,355	-	31,404	1,338	0.64	26.7
465.00	MAINS	65-R4	(20)	12,706,666	-	2,541,333	50,221	0.40	54.3
466.00	COMPRESSOR EQUIPMENT			-	-	-	-		-
467.00	MEASURING AND REGULATING EQUIPMENT	35-S2.5	(7)	7,728,401	-	540,988	23,510	0.30	26.4
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	149,918	-	-	-	-	2.0
469.00	OTHER TRANSMISSION EQUIPMENT			18,450	-	-	-	-	25.5
TOTAL TRANSMISSION PLANT				**21,737,122**	**0**	**3,127,676**	**76,201**	**0.35**	
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R4	-	221,572	-	-	-	-	50.3
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	(10)	2,031,083	-	203,109	13,139	0.65	19.0
473.00	SERVICES	50-R4	(60)	24,895,025	-	14,937,014	433,845	1.74	36.0
474.00	HOUSE REGULATOR AND METER INSTALLS	40-R4	(20)	5,740,830	-	1,148,166	59,583	1.04	23.7
475.00	MAINS	65-R4	(25)	42,425,040	-	10,606,260	214,334	0.51	52.6
477.00	MEASURING AND REGULATING EQUIPMENT	35-R4	(7)	1,735,485	-	121,483	7,202	0.41	23.1
478.00	METERS	20-R4	-	2,678,877	-	-	-	-	9.4
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	19,617	-	-	-	-	16.5
TOTAL DISTRIBUTION PLANT				**79,747,528**	**0**	**27,016,032**	**728,103**	**0.91**	
GENERAL PLANT									
481.00	LAND RIGHTS	75-R4	-	1,379	-	-	-	-	54.5
482.00	STRUCTURES AND EQUIPMENT	30-R3	-	2,103,352	-	-	-	-	20.7
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	106,295	-	-	-	-	7.8
484.00	TRANSPORTATION EQUIPMENT	8-L3	-	1,327,532	-	-	-	-	5.2
485.00	HEAVY WORK EQUIPMENT	18-R3	-	1,508,140	-	-	-	-	13.2
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	1,093,131	-	-	-	-	10.0
487.00	COMPUTER EQUIPMENT	5-SQ	-	40,249	-	-	-	-	3.2
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	92,173	-	-	-	-	8.3
489.00	OTHER GENERAL EQUIPMENT								
TOTAL GENERAL PLANT				**6,272,250**	**0**	**0**	**0**	**-**	
TOTAL GAS PLANT STUDIED				**107,756,900**	**0**	**30,143,708**	**804,304**	**0.75**	
PLANT NOT STUDIED									
410.00	LAND			-	-				
460.00	LAND			10,981	-				
470.00	LAND			47,391	-				
480.00	LAND			76,503	-				
490.00	COMPUTER SOFTWARE			235,647	221,301				
TOTAL PLANT NOT STUDIED				**370,522**	**221,301**				
TOTAL PLANT				**108,127,422**	**221,301**				

PACIFIC NORTHERN GAS LTD.
TOTAL SYSTEM
TABLE 2 SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	ANNUAL ACCRUALS
	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
GATHERING PLANT										
411.00	LAND RIGHTS	75-R4	-	7	-	-	-	75-R4	-	7
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	-	1,510	-	131	131	30-R3	(3)	1,641
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	260	-	3,115	3,115	30-R3	(15)	3,375
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	1,137	-	176	176	25-R2	(7)	1,313
418.00	PURIFICATION EQUIPMENT	25-R3	-	72,940	(25,319)	118,455	93,136	31-S5	(25)	166,076
TOTAL GATHERING PLANT				**75,854**	**(25,319)**	**121,877**	**96,558**			**172,412**
PROCESSING PLANT										
443.00	GAS HOLDERS - STORAGE	40-SQ	-	824	-	-	-	40-SQ	-	824
449.00	OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	71	-	-	-	33-R3	-	71
TOTAL PROCESSING PLANT				**895**	**-**	**-**	**-**			**895**
TRANSMISSION PLANT										
461.00	LAND RIGHTS	75-R4	-	38,549	-	-	-	75-R4	-	38,549
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	73,476	-	25,571	25,571	30-R4	(3)	99,047
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	25,971	(10,077)	16,129	6,052	39-R4	(15)	32,023
465.00	MAINS	60-R3	-	2,203,188	(207,549)	901,910	694,361	65-R4	(20)	2,897,549
466.00	COMPRESSOR EQUIPMENT	30-R2.5	-	446,978	(113,399)	50,865	(62,534)	35-R3	(2)	384,444
467.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	577,844	(203,482)	61,425	(142,057)	35-S2.5	(7)	435,787
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	64,389	-	-	-	15-R2	-	64,389
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	12,775	-	-	-	40-SQ	-	12,775
TOTAL TRANSMISSION PLANT				**3,443,170**	**(534,507)**	**1,055,900**	**521,393**			**3,964,563**
DISTRIBUTION PLANT										
471.00	LAND RIGHTS	75-R4	-	4,968	-	-	-	75-R4	-	4,968
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	90,327	-	18,125	18,125	30-R3	(10)	108,452
473.00	SERVICES	50-R2.5	-	846,828	48,982	1,081,711	1,130,693	50-R4	(60)	1,977,521
474.00	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	279,718	(90,255)	122,876	32,621	40-R4	(20)	312,339
475.00	MAINS	60-R3	-	1,051,333	(94,361)	440,147	345,786	65-R4	(25)	1,397,119
477.00	MEASURING AND REGULATING EQUIPMENT	20-R3	-	52,884	(32,136)	10,304	(21,832)	35-R4	(7)	31,052
478.00	METERS	25-R2	-	256,663	429,518	(17,276)	412,242	20-R4	1	668,905
479.00	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	1,009	-	-	-	35-SQ	-	1,009
TOTAL DISTRIBUTION PLANT				**2,583,730**	**261,748**	**1,655,887**	**1,917,635**			**4,501,365**
GENERAL PLANT										
481.00	LAND RIGHTS	75-R4	-	29	-	-	-	75-R4	-	29
482.00	STRUCTURES AND EQUIPMENT	25-R2	-	268,133	(55,995)	-	(55,995)	30-R3	-	212,138
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	79,230	-	-	-	15-SQ	-	79,230
484.00	TRANSPORTATION EQUIPMENT	7-L1.5	20	361,501	(124,261)	142,540	18,279	8-L3	15	379,780
485.00	HEAVY WORK EQUIPMENT	15-R2	15	195,227	(66,879)	55,646	(11,233)	18-R3	10	183,994
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	271,714	-	-	-	20-SQ	-	271,714
487.00	COMPUTER EQUIPMENT	5-SQ	-	147,007	-	-	-	5-SQ	-	147,007
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	41,226	-	-	-	14-SQ	-	41,226
489.00	OTHER GENERAL EQUIPMENT	20-SQ	-	22	(1)	-	(1)	20-R2.5	-	21
TOTAL GENERAL PLANT				**1,364,089**	**(247,136)**	**198,186**	**(48,950)**			**1,315,139**
TOTAL GAS PLANT STUDIED				**7,467,738**	**(545,214)**	**3,031,850**	**2,486,636**			**9,954,374**

PACIFIC NORTHERN GAS LTD.
WEST SYSTEM
TABLE 2A SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT		DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	RECOMMENDED SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	RECOMMENDED ANNUAL ACCRUALS
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
PROCESSING PLANT											
443.00		GAS HOLDERS - STORAGE	40-SQ	-	824	-	-	-	40-SQ	-	824
449.00		OTHER LOCAL STORAGE EQUIPMENT	33-R3	-	71	-	-	-	33-R3	-	71
TOTAL PROCESSING PLANT					**895**	**0**	**0**	**0**			**895**
TRANSMISSION PLANT											
461.00	461.00 4510	LAND RIGHTS	75-R4	-	32,881	-	-	-	75-R4	-	32,881
462.00	462.00 4510	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	57,291	-	24,439	24,439	30-R4	(3)	81,730
463.00	463.00 4510	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	18,845	(7,732)	14,791	7,059	39-R4	(15)	25,904
465.00	465.00 4510	MAINS	60-R3	-	2,013,497	(191,312)	840,121	648,809	65-R4	(20)	2,662,306
466.00	466.00 4510	COMPRESSOR EQUIPMENT	30-R2.5	-	446,836	(113,363)	50,858	(62,505)	35-R3	(2)	384,331
467.00	467.00 4510	MEASURING AND REGULATING EQUIPMENT	25-R2	-	284,123	(102,169)	36,827	(65,342)	35-S2.5	(7)	218,781
468.00	468.00 4510	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	62,635	-	-	-	15-R2	-	62,635
469.00	469.00 4510	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	12,327	-	-	-	40-SQ	-	12,327
TOTAL TRANSMISSION PLANT					**2,928,435**	**(414,576)**	**967,036**	**552,460**			**3,480,895**
DISTRIBUTION PLANT											
471.00	471.00 4510	LAND RIGHTS	75-R4	-	815	-	-	-	75-R4	-	815
472.00	472.00 4510	STRUCTURES AND IMPROVEMENTS	30-R3	-	10,834	-	2,976	2,976	30-R3	(10)	13,810
473.00	473.00 4510	SERVICES	50-R2.5	-	352,053	27,799	627,857	655,656	50-R4	(60)	1,007,709
474.00	474.00 4510	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	114,569	(38,085)	56,737	18,652	40-R4	(20)	133,221
475.00	475.00 4510	MAINS	60-R3	-	422,754	(39,721)	217,176	177,455	65-R4	(25)	600,209
477.00	477.00 4510	MEASURING AND REGULATING EQUIPMENT	20-R3	-	870	(634)	1,741	1,107	35-R4	(7)	1,977
478.00	478.00 4510	METERS	25-R2	-	140,749	315,558	(12,780)	302,778	20-R4	1	443,527
479.00	479.00 4510	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	443	-	-	-	35-SQ	-	443
TOTAL DISTRIBUTION PLANT					**1,043,087**	**264,917**	**893,707**	**1,158,624**			**2,201,711**
GENERAL PLANT											
481.00	481.00 4510	LAND RIGHTS	75-R4	-	8	-	-	-	75-R4	-	8
482.00	482.00 4510	STRUCTURES AND EQUIPMENT	25-R2	-	194,717	(42,443)	-	(42,443)	30-R3	-	152,274
483.00	483.00 4510	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	68,237	-	-	-	15-SQ	-	68,237
484.00	484.00 4510	TRANSPORTATION EQUIPMENT	7-L1.5	20	225,109	(80,498)	93,376	12,878	8-L3	15	237,987
485.00	485.00 4510	HEAVY WORK EQUIPMENT	15-R2	15	126,983	(45,881)	40,629	(5,252)	18-R3	10	121,731
486.00	486.00 4510	TOOLS AND WORK EQUIPMENT	20-SQ	-	206,177	-	-	-	20-SQ	-	206,177
487.00	487.00 4510	COMPUTER EQUIPMENT	5-SQ	-	136,505	-	-	-	5-SQ	-	136,505
488.00	488.00 4510	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	32,704	-	-	-	14-SQ	-	32,704
489.00		OTHER GENERAL EQUIPMENT	20-SQ	-	22	(1)	-	(1)	20-R2.5	-	21
TOTAL GENERAL PLANT					**990,462**	**(168,823)**	**134,005**	**(34,818)**			**955,644**
TOTAL GAS PLANT STUDIED					**4,962,879**	**(318,482)**	**1,994,748**	**1,676,266**			**6,639,145**

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN
TABLE 2B SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT		DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	RECOMMENDED SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	RECOMMENDED ANNUAL ACCRUALS
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
TRANSMISSION PLANT											
461.00	461.00 4513	LAND RIGHTS	75-R4	-	3,181	-	-	-	75-R4	-	3,181
462.00	462.00 4513	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	16,185	-	1,132	1,132	30-R4	(3)	17,317
463.00	463.00 4513	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	2,818	(1,067)	657	(410)	39-R4	(15)	2,408
465.00	465.00 4513	MAINS	60-R3	-	77,700	(6,642)	27,137	20,495	65-R4	(20)	98,195
466.00	466.00 4513	COMPRESSOR EQUIPMENT									
467.00	467.00 4513	MEASURING AND REGULATING EQUIPMENT	25-R2	-	182,692	(64,362)	17,102	(47,260)	35-S2.5	(7)	135,432
468.00	468.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	1,383	-	-	-	15-R2	-	1,383
469.00	469.00 4513	OTHER TRANSMISSION EQUIPMENT									
TOTAL TRANSMISSION PLANT					**283,959**	**(72,071)**	**46,028**	**(26,043)**			**257,916**
DISTRIBUTION PLANT											
471.00	471.00 4513	LAND RIGHTS	75-R4	-	2,459	-	-	-	75-R4	-	2,459
472.00	472.00 4513	STRUCTURES AND IMPROVEMENTS	30-R3	-	39,127	-	6,277	6,277	30-R3	(10)	45,404
473.00	473.00 4513	SERVICES	50-R2.5	-	329,090	9,939	285,084	295,023	50-R4	(60)	624,113
474.00	474.00 4513	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	55,349	(16,566)	18,415	1,849	40-R4	(20)	57,198
475.00	475.00 4513	MAINS	60-R3	-	410,553	(35,265)	142,326	107,061	65-R4	(25)	517,614
477.00	477.00 4513	MEASURING AND REGULATING EQUIPMENT	20-R3	-	35,703	(20,264)	3,739	(16,525)	35-R4	(7)	19,178
478.00	478.00 4513	METERS	25-R2	-	74,530	55,805	(2,242)	53,563	20-R4	1	128,093
479.00	479.00 4513	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	566	-	-	-	35-SQ	-	566
TOTAL DISTRIBUTION PLANT					**947,377**	**(6,351)**	**453,599**	**447,248**			**1,394,625**
GENERAL PLANT											
481.00	481.00 4513	LAND RIGHTS	75-R4	-	21	-	-	-	75-R4	-	21
482.00	482.00 4513	STRUCTURES AND EQUIPMENT	25-R2	-	26,702	(5,658)	-	(5,658)	30-R3	-	21,044
483.00	483.00 4513	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	1,920	-	-	-	15-SQ	-	1,920
484.00	484.00 4513	TRANSPORTATION EQUIPMENT	7-L1.5	20	57,636	(16,245)	17,391	1,146	8-L3	15	58,782
485.00	485.00 4513	HEAVY WORK EQUIPMENT	15-R2	15	9,121	(3,529)	3,305	(224)	18-R3	10	8,897
486.00	486.00 4513	TOOLS AND WORK EQUIPMENT	20-SQ	-	27,617	-	-	-	20-SQ	-	27,617
487.00	487.00 4513	COMPUTER EQUIPMENT	5-SQ	-	2,232	-	-	-	5-SQ	-	2,232
488.00	488.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	2,712	-	-	-	14-SQ	-	2,712
489.00		OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT					**127,961**	**(25,432)**	**20,696**	**(4,736)**			**123,225**
TOTAL GAS PLANT STUDIED					**1,359,297**	**(103,854)**	**520,323**	**416,469**			**1,775,766**

PACIFIC NORTHERN GAS LTD.
DAWSON CREEK
TABLE 2C SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT	DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	ANNUAL ACCRUALS
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
TRANSMISSION PLANT										
461.00	LAND RIGHTS	75-R4	-	2,487	-	-	-	75-R4	-	2,487
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS									
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	4,308	(1,278)	681	(597)	39-R4	(15)	3,711
465.00	MAINS	60-R3	-	87,534	(7,416)	23,084	15,668	65-R4	(20)	103,202
466.00	COMPRESSOR EQUIPMENT									
467.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	93,763	(31,351)	6,408	(24,943)	35-S2.5	(7)	68,820
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	-	-	-	-	15-R2	-	-
469.00	OTHER TRANSMISSION EQUIPMENT	40-SQ	-	448	-	-	-	40-SQ	-	448
TOTAL TRANSMISSION PLANT				**188,540**	**(40,045)**	**30,173**	**(9,872)**			**178,668**
DISTRIBUTION PLANT										
471.00	LAND RIGHTS	75-R4	-	1,646	-	-	-	75-R4	-	1,646
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	28,815	-	6,862	6,862	30-R3	(10)	35,677
473.00	SERVICES	50-R2.5	-	151,968	9,406	148,761	158,167	50-R4	(60)	310,135
474.00	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	105,358	(34,251)	41,168	6,917	40-R4	(20)	112,275
475.00	MAINS	60-R3	-	200,730	(17,839)	72,008	54,169	65-R4	(25)	254,899
477.00	MEASURING AND REGULATING EQUIPMENT	20-R3	-	6,743	(4,923)	3,463	(1,460)	35-R4	(7)	5,283
478.00	METERS	25-R2	-	34,965	50,609	(1,596)	49,013	20-R4	1	83,978
479.00	OTHER DISTRIBUTION EQUIPMENT									
TOTAL DISTRIBUTION PLANT				**530,225**	**3,002**	**270,666**	**273,668**			**803,893**
GENERAL PLANT										
481.00	LAND RIGHTS									
482.00	STRUCTURES AND EQUIPMENT	25-R2	-	46,184	(8,539)	-	(8,539)	30-R3	-	37,645
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	7,038	-	-	-	15-SQ	-	7,038
484.00	TRANSPORTATION EQUIPMENT	7-L1.5	20	74,445	(26,299)	30,475	4,176	8-L3	15	78,621
485.00	HEAVY WORK EQUIPMENT	15-R2	15	57,782	(15,978)	9,985	(5,993)	18-R3	10	51,789
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	33,488	-	-	-	20-SQ	-	33,488
487.00	COMPUTER EQUIPMENT	5-SQ	-	7,676	-	-	-	5-SQ	-	7,676
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	5,648	-	-	-	14-SQ	-	5,648
489.00	OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT				**232,261**	**(50,816)**	**40,460**	**(10,356)**			**221,905**
TOTAL GAS PLANT STUDIED				**951,026**	**(87,859)**	**341,299**	**253,440**			**1,204,466**

PACIFIC NORTHERN GAS LTD.
TUMBLER RIDGE
TABLE 2D SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

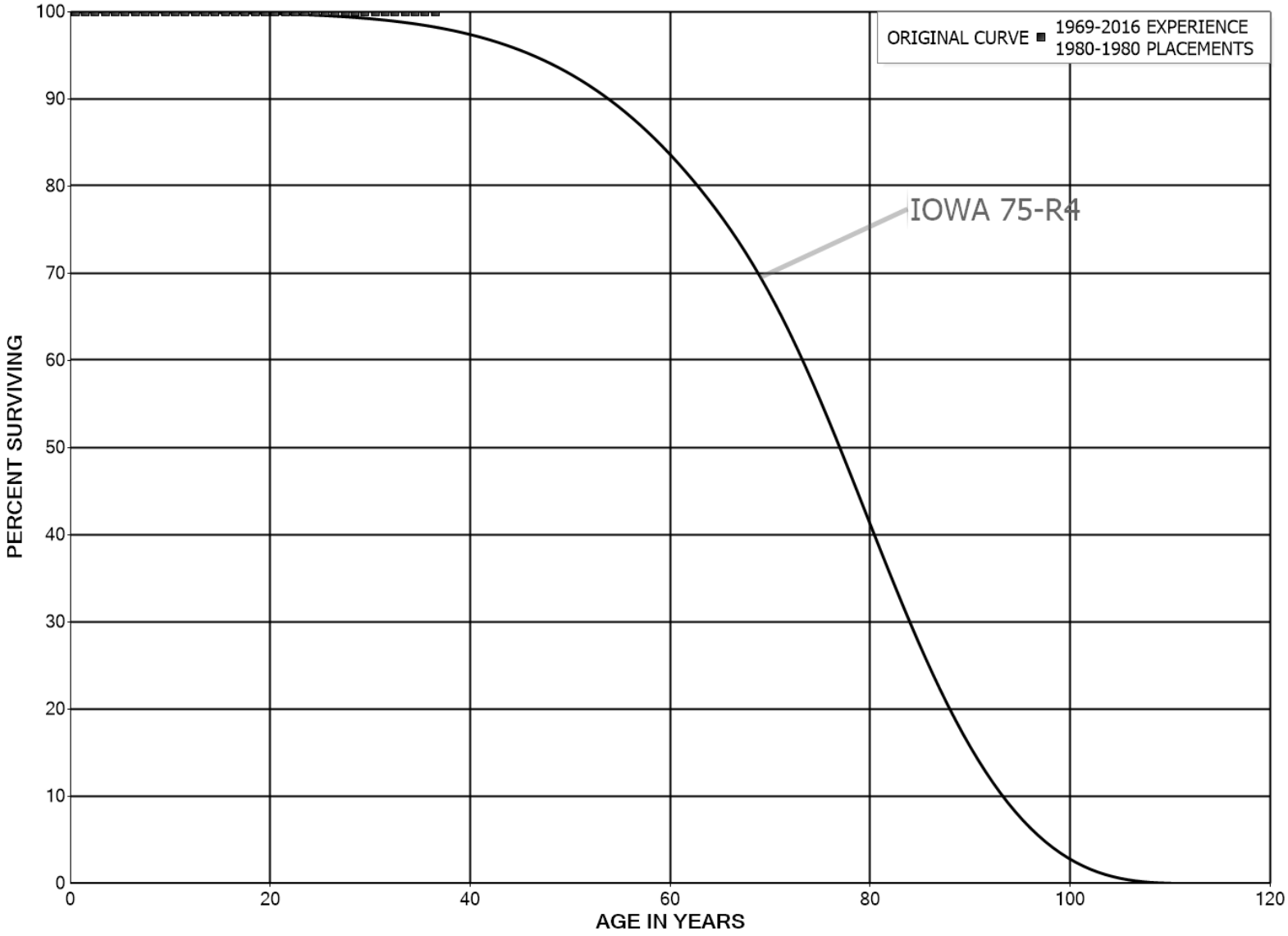
ACCOUNT	DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	ANNUAL ACCRUALS
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
GATHERING PLANT										
411.00	LAND RIGHTS	75-R4	-	7	-	-	-	75-R4	-	7
412.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R3	-	1,510	-	131	131	30-R3	(3)	1,641
413.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	260	-	3,115	3,115	30-R3	(15)	3,375
417.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	1,137	-	176	176	25-R2	(7)	1,313
418.00	PURIFICATION EQUIPMENT	25-R3	-	72,940	(25,319)	118,455	93,136	31-S5	(25)	166,076
TOTAL GATHERING PLANT				**75,854**	**(25,319)**	**121,877**	**96,558**			**172,412**
TRANSMISSION PLANT										
461.00	LAND RIGHTS									
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS									
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS									
465.00	MAINS	60-R3	-	24,457	(2,179)	11,568	9,389	65-R4	(20)	33,846
466.00	COMPRESSOR EQUIPMENT	30-R2.5	-	142	(36)	7	(29)	35-R3	(2)	113
467.00	MEASURING AND REGULATING EQUIPMENT	25-R2	-	17,266	(5,600)	1,088	(4,512)	35-S2.5	(7)	12,754
468.00	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	371	-	-	-	15-R2	-	371
469.00	OTHER TRANSMISSION EQUIPMENT									
TOTAL TRANSMISSION PLANT				**42,236**	**(7,815)**	**12,663**	**4,848**			**47,084**
DISTRIBUTION PLANT										
471.00	LAND RIGHTS	75-R4	-	48	-	-	-	75-R4	-	48
472.00	STRUCTURES AND IMPROVEMENTS	30-R3	-	11,551	-	2,010	2,010	30-R3	(10)	13,561
473.00	SERVICES	50-R2.5	-	13,717	1,838	20,009	21,847	50-R4	(60)	35,564
474.00	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	4,442	(1,353)	6,556	5,203	40-R4	(20)	9,645
475.00	MAINS	60-R3	-	17,296	(1,536)	8,637	7,101	65-R4	(25)	24,397
477.00	MEASURING AND REGULATING EQUIPMENT	20-R3	-	9,568	(6,315)	1,361	(4,954)	35-R4	(7)	4,614
478.00	METERS	25-R2	-	6,419	7,546	(658)	6,888	20-R4	1	13,307
479.00	OTHER DISTRIBUTION EQUIPMENT									
TOTAL DISTRIBUTION PLANT				**63,041**	**180**	**37,915**	**38,095**			**101,136**
GENERAL PLANT										
481.00	LAND RIGHTS									
482.00	STRUCTURES AND EQUIPMENT	25-R2	-	530	645	-	645	30-R5	-	1,175
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	2,035	-	-	-	15-SQ	-	2,035
484.00	TRANSPORTATION EQUIPMENT	7-L1.5	20	4,311	(1,219)	1,298	79	8-L3	15	4,390
485.00	HEAVY WORK EQUIPMENT	15-R2	15	1,341	(1,491)	1,727	236	18-R3	10	1,577
486.00	TOOLS AND WORK EQUIPMENT	20-SQ	-	4,432	-	-	-	20-SQ	-	4,432
487.00	COMPUTER EQUIPMENT	5-SQ	-	594	-	-	-	5-SQ	-	594
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	162	-	-	-	14-SQ	-	162
489.00	OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT				**13,405**	**(2,065)**	**3,025**	**960**			**14,365**
TOTAL GAS PLANT STUDIED				**194,536**	**(35,019)**	**175,480**	**140,461**			**334,997**

PACIFIC NORTHERN GAS LTD.
FORT SAINT JOHN & DAWSON CREEK
TABLE 2E SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND EFFECT ON CALCULATED ANNUAL ACCRUALS
BASED ON ORIGINAL COSTS AS OF DECEMBER 31, 2016
TOTAL LIFE AND NET SALVAGE

ACCOUNT		DESCRIPTION	SURVIVOR CURVE	CURRENT NET SALV. PERCENT	ANNUAL ACCRUAL	LIFE CHANGE ACCRUAL	NS CHANGE ACCRUAL	TOTAL CHANGE ACCRUAL	RECOMMENDED SURVIVOR CURVE	RECOMMENDED NET SALV. PERCENT	RECOMMENDED ANNUAL ACCRUALS
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
TRANSMISSION PLANT											
461.00	461.00 4513	LAND RIGHTS	75-R4	-	5,668	-	-	-	75-R4	-	5,668
462.00	462.00 4513	COMPRESSOR STRUCTURES AND IMPROVEMENTS	30-R4	-	16,185	-	1,132	1,132	30-R4	(3)	17,317
463.00	463.00 4513	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	30-R3	-	7,126	(2,345)	1,338	(1,007)	39-R4	(15)	6,119
465.00	465.00 4513	MAINS	60-R3	-	165,234	(14,058)	50,221	36,163	65-R4	(20)	201,397
466.00	466.00 4513	COMPRESSOR EQUIPMENT			-	-	-				-
467.00	467.00 4513	MEASURING AND REGULATING EQUIPMENT	25-R2	-	276,455	(95,713)	23,510	(72,203)	35-S2.5	(7)	204,252
468.00	468.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	15-R2	-	1,383	-	-	-	15-R2	-	1,383
469.00	469.00 4513	OTHER TRANSMISSION EQUIPMENT	40-SQ		448	-	-	-	40-SQ	-	448
TOTAL TRANSMISSION PLANT					**472,499**	**(112,116)**	**76,201**	**(35,915)**			**436,584**
DISTRIBUTION PLANT											
471.00	471.00 4513	LAND RIGHTS	75-R4	-	4,105	-	-	-	75-R4	-	4,105
472.00	472.00 4513	STRUCTURES AND IMPROVEMENTS	30-R3	-	67,942	-	13,139	13,139	30-R3	(10)	81,081
473.00	473.00 4513	SERVICES	50-R2.5	-	481,058	19,345	433,845	453,190	50-R4	(60)	934,248
474.00	474.00 4513	HOUSE REGULATOR AND METER INSTALLS	30-R2	-	160,707	(50,817)	59,583	8,766	40-R4	(20)	169,473
475.00	475.00 4513	MAINS	60-R3	-	611,283	(53,104)	214,334	161,230	65-R4	(25)	772,513
477.00	477.00 4513	MEASURING AND REGULATING EQUIPMENT	20-R3	-	42,446	(25,187)	7,202	(17,985)	35-R4	(7)	24,461
478.00	478.00 4513	METERS	25-R2	-	109,495	106,414	(3,838)	102,576	20-R4	1	212,071
479.00	479.00 4513	OTHER DISTRIBUTION EQUIPMENT	35-SQ	-	566	-	-	-	35-SQ	-	566
TOTAL DISTRIBUTION PLANT					**1,477,602**	**(3,349)**	**724,265**	**720,916**			**2,198,518**
GENERAL PLANT											
481.00	481.00 4513	LAND RIGHTS	75-R4	-	21	-	-	-	75-R4	-	21
482.00	482.00 4513	STRUCTURES AND EQUIPMENT	25-R2	-	72,886	(14,197)	-	(14,197)	30-R3	-	58,689
483.00	483.00 4513	OFFICE FURNITURE AND EQUIPMENT	15-SQ	-	8,958	-	-	-	15-SQ	-	8,958
484.00	484.00 4513	TRANSPORTATION EQUIPMENT	7-L1.5	20	132,081	(42,544)	47,866	5,322	8-L3	15	137,403
485.00	485.00 4513	HEAVY WORK EQUIPMENT	15-R2	15	66,903	(19,507)	13,290	(6,217)	18-R3	10	60,686
486.00	486.00 4513	TOOLS AND WORK EQUIPMENT	20-SQ	-	61,105	-	-	-	20-SQ	-	61,105
487.00	487.00 4513	COMPUTER EQUIPMENT	5-SQ	-	9,908	-	-	-	5-SQ	-	9,908
488.00	488.00 4513	COMMUNICATION STRUCTURES AND EQUIPMENT	14-SQ	-	8,360	-	-	-	14-SQ	-	8,360
489.00		OTHER GENERAL EQUIPMENT									
TOTAL GENERAL PLANT					**360,222**	**(76,248)**	**61,156**	**(15,092)**			**345,130**
TOTAL GAS PLANT STUDIED					**2,310,323**	**(191,713)**	**861,622**	**669,909**			**2,980,232**

PART V. SERVICE LIFE STATISTICS

PACIFIC NORTHERN GAS LTD.
ACCOUNT 411.00 - GATHERING PLANT - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

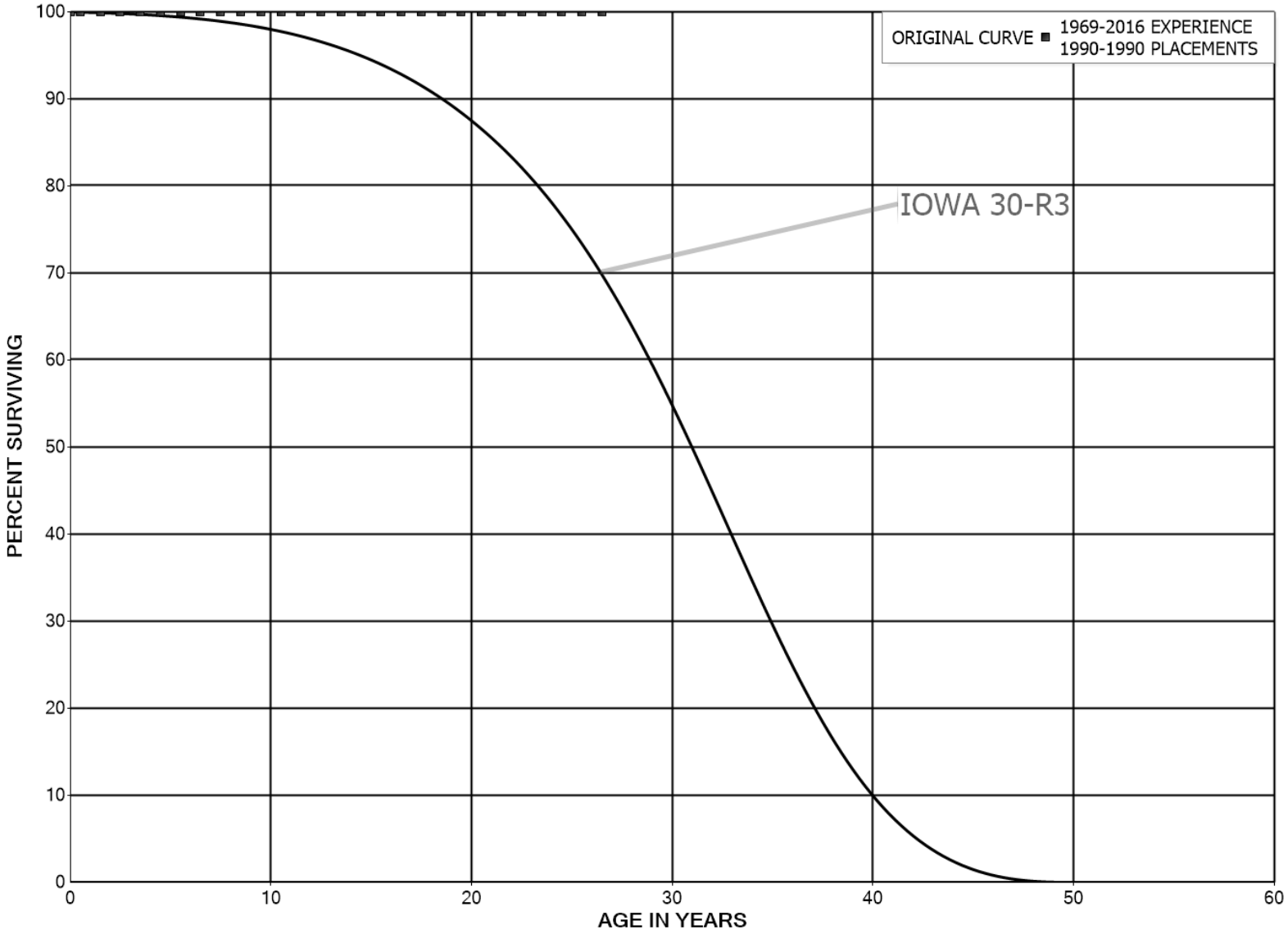
ACCOUNT 411.00 - GATHERING PLANT - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-1980 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	275		0.0000	1.0000	100.00
0.5	275		0.0000	1.0000	100.00
1.5	275		0.0000	1.0000	100.00
2.5	275		0.0000	1.0000	100.00
3.5	275		0.0000	1.0000	100.00
4.5	275		0.0000	1.0000	100.00
5.5	275		0.0000	1.0000	100.00
6.5	275		0.0000	1.0000	100.00
7.5	275		0.0000	1.0000	100.00
8.5	275		0.0000	1.0000	100.00
9.5	275		0.0000	1.0000	100.00
10.5	275		0.0000	1.0000	100.00
11.5	275		0.0000	1.0000	100.00
12.5	275		0.0000	1.0000	100.00
13.5	275		0.0000	1.0000	100.00
14.5	275		0.0000	1.0000	100.00
15.5	275		0.0000	1.0000	100.00
16.5	275		0.0000	1.0000	100.00
17.5	275		0.0000	1.0000	100.00
18.5	275		0.0000	1.0000	100.00
19.5	275		0.0000	1.0000	100.00
20.5	275		0.0000	1.0000	100.00
21.5	275		0.0000	1.0000	100.00
22.5	275		0.0000	1.0000	100.00
23.5	275		0.0000	1.0000	100.00
24.5	275		0.0000	1.0000	100.00
25.5	275		0.0000	1.0000	100.00
26.5	275		0.0000	1.0000	100.00
27.5	275		0.0000	1.0000	100.00
28.5	275		0.0000	1.0000	100.00
29.5	275		0.0000	1.0000	100.00
30.5	275		0.0000	1.0000	100.00
31.5	275		0.0000	1.0000	100.00
32.5	275		0.0000	1.0000	100.00
33.5	275		0.0000	1.0000	100.00
34.5	275		0.0000	1.0000	100.00
35.5	275		0.0000	1.0000	100.00
36.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 412.00 - GATHERING PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

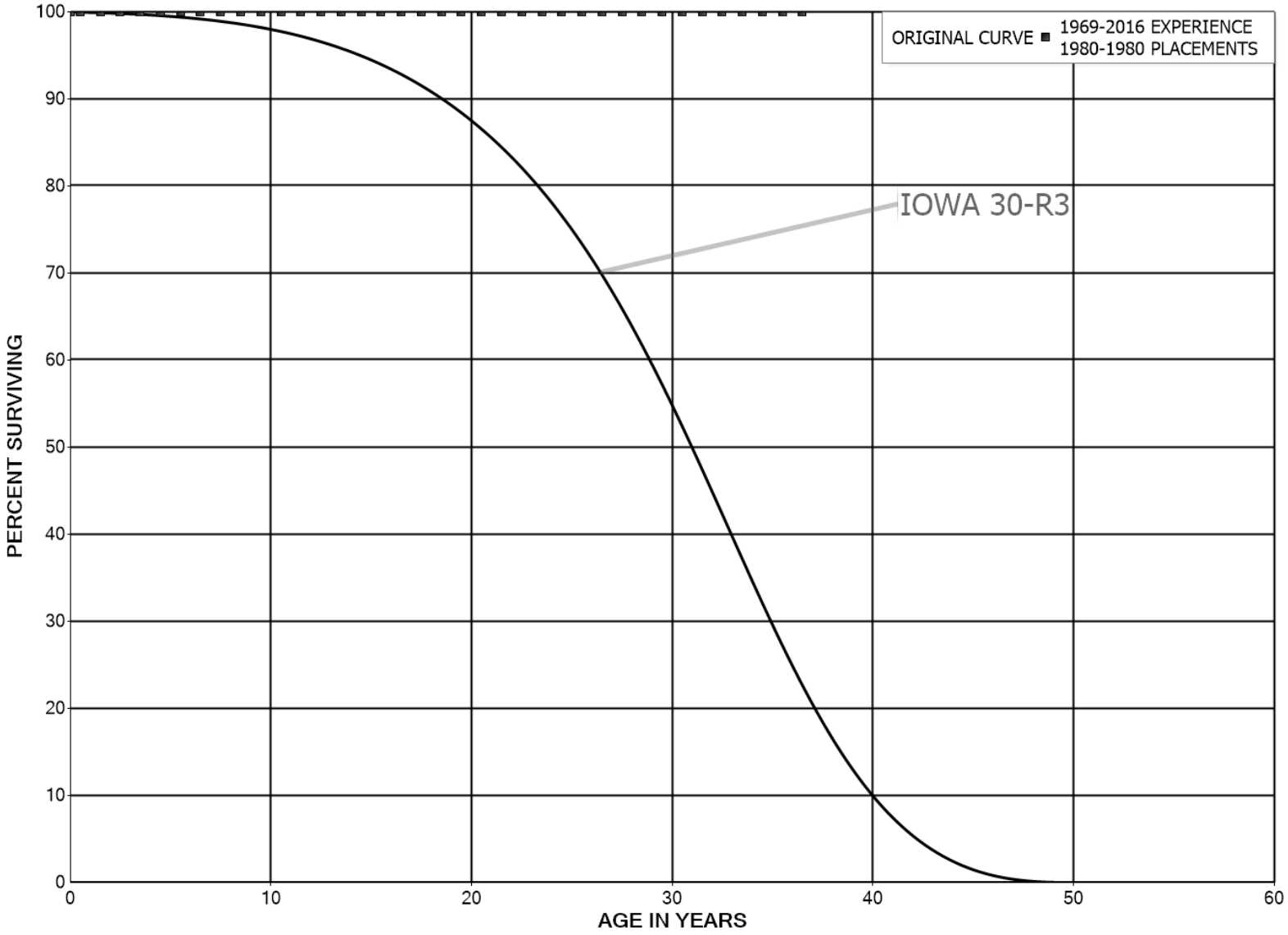
ACCOUNT 412.00 - GATHERING PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1990-1990 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	34,443		0.0000	1.0000	100.00
0.5	34,443		0.0000	1.0000	100.00
1.5	34,443		0.0000	1.0000	100.00
2.5	34,443		0.0000	1.0000	100.00
3.5	34,443		0.0000	1.0000	100.00
4.5	34,443		0.0000	1.0000	100.00
5.5	34,443		0.0000	1.0000	100.00
6.5	34,443		0.0000	1.0000	100.00
7.5	34,443		0.0000	1.0000	100.00
8.5	34,443		0.0000	1.0000	100.00
9.5	34,443		0.0000	1.0000	100.00
10.5	34,443		0.0000	1.0000	100.00
11.5	34,443		0.0000	1.0000	100.00
12.5	34,443		0.0000	1.0000	100.00
13.5	34,443		0.0000	1.0000	100.00
14.5	34,443		0.0000	1.0000	100.00
15.5	34,443		0.0000	1.0000	100.00
16.5	34,443		0.0000	1.0000	100.00
17.5	34,443		0.0000	1.0000	100.00
18.5	34,443		0.0000	1.0000	100.00
19.5	34,443		0.0000	1.0000	100.00
20.5	34,443		0.0000	1.0000	100.00
21.5	34,443		0.0000	1.0000	100.00
22.5	34,443		0.0000	1.0000	100.00
23.5	34,443		0.0000	1.0000	100.00
24.5	34,443		0.0000	1.0000	100.00
25.5	34,443		0.0000	1.0000	100.00
26.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 413.00 - GATHERING PLANT - MEASURING AND REGULATING STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

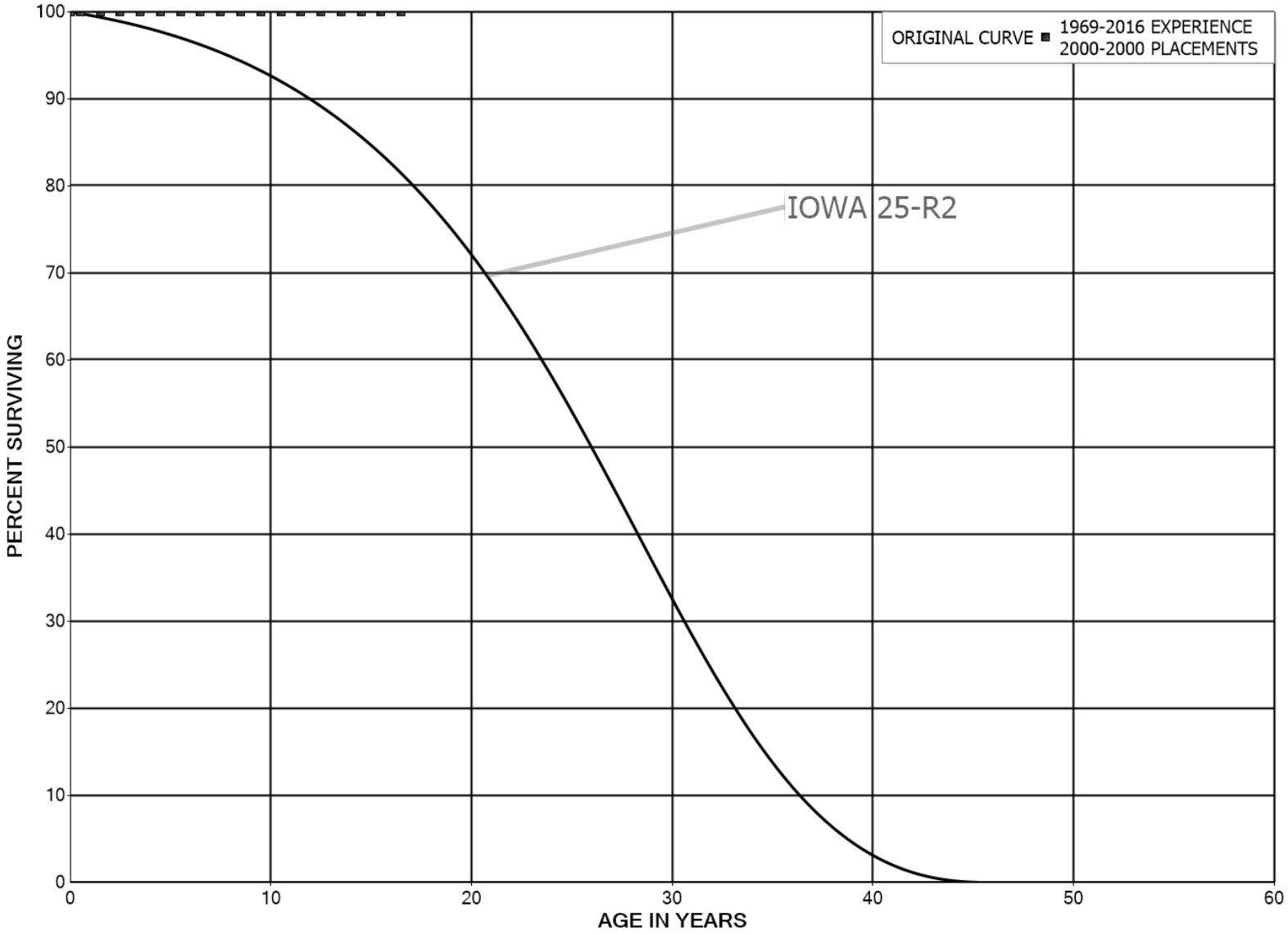
ACCOUNT 413.00 - GATHERING PLANT - MEASURING AND REGULATING STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-1980 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	75,160		0.0000	1.0000	100.00
0.5	75,160		0.0000	1.0000	100.00
1.5	75,160		0.0000	1.0000	100.00
2.5	75,160		0.0000	1.0000	100.00
3.5	75,160		0.0000	1.0000	100.00
4.5	75,160		0.0000	1.0000	100.00
5.5	75,160		0.0000	1.0000	100.00
6.5	75,160		0.0000	1.0000	100.00
7.5	75,160		0.0000	1.0000	100.00
8.5	75,160		0.0000	1.0000	100.00
9.5	75,160		0.0000	1.0000	100.00
10.5	75,160		0.0000	1.0000	100.00
11.5	75,160		0.0000	1.0000	100.00
12.5	75,160		0.0000	1.0000	100.00
13.5	75,160		0.0000	1.0000	100.00
14.5	75,160		0.0000	1.0000	100.00
15.5	75,160		0.0000	1.0000	100.00
16.5	75,160		0.0000	1.0000	100.00
17.5	75,160		0.0000	1.0000	100.00
18.5	75,160		0.0000	1.0000	100.00
19.5	75,160		0.0000	1.0000	100.00
20.5	75,160		0.0000	1.0000	100.00
21.5	75,160		0.0000	1.0000	100.00
22.5	75,160		0.0000	1.0000	100.00
23.5	75,160		0.0000	1.0000	100.00
24.5	75,160		0.0000	1.0000	100.00
25.5	75,160		0.0000	1.0000	100.00
26.5	75,160		0.0000	1.0000	100.00
27.5	75,160		0.0000	1.0000	100.00
28.5	75,160		0.0000	1.0000	100.00
29.5	75,160		0.0000	1.0000	100.00
30.5	75,160		0.0000	1.0000	100.00
31.5	75,160		0.0000	1.0000	100.00
32.5	75,160		0.0000	1.0000	100.00
33.5	75,160		0.0000	1.0000	100.00
34.5	75,160		0.0000	1.0000	100.00
35.5	75,160		0.0000	1.0000	100.00
36.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 417.00 - GATHERING PLANT - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

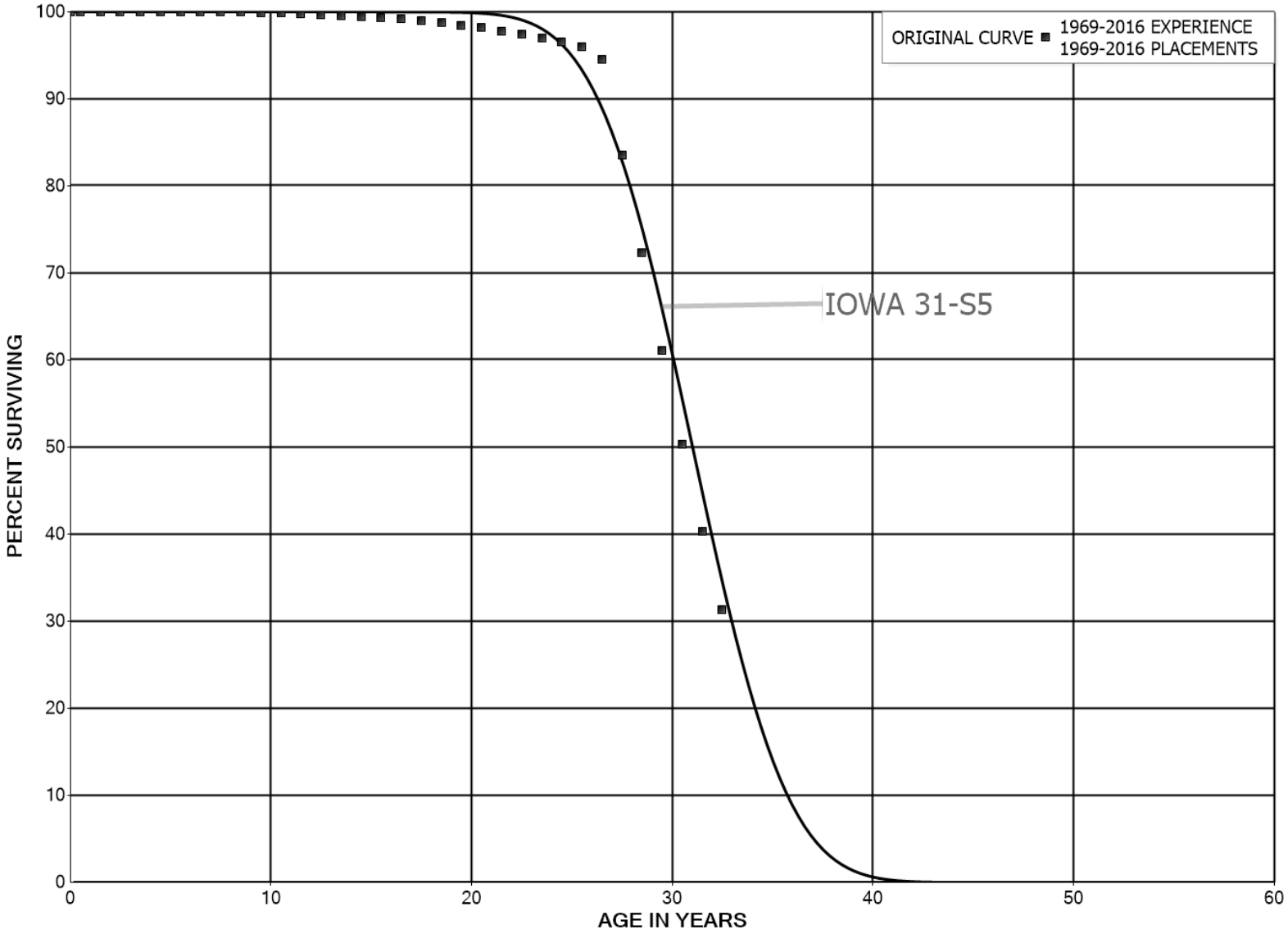
ACCOUNT 417.00 - GATHERING PLANT - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2000-2000 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	29,701		0.0000	1.0000	100.00
0.5	29,701		0.0000	1.0000	100.00
1.5	29,701		0.0000	1.0000	100.00
2.5	29,701		0.0000	1.0000	100.00
3.5	29,701		0.0000	1.0000	100.00
4.5	29,701		0.0000	1.0000	100.00
5.5	29,701		0.0000	1.0000	100.00
6.5	29,701		0.0000	1.0000	100.00
7.5	29,701		0.0000	1.0000	100.00
8.5	29,701		0.0000	1.0000	100.00
9.5	29,701		0.0000	1.0000	100.00
10.5	29,701		0.0000	1.0000	100.00
11.5	29,701		0.0000	1.0000	100.00
12.5	29,701		0.0000	1.0000	100.00
13.5	29,701		0.0000	1.0000	100.00
14.5	29,701		0.0000	1.0000	100.00
15.5	29,701		0.0000	1.0000	100.00
16.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 418.00 - GATHERING PLANT - PURIFICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 418.00 - GATHERING PLANT - PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,004,510		0.0000	1.0000	100.00
0.5	3,816,047	77	0.0000	1.0000	100.00
1.5	3,815,970	195	0.0001	0.9999	100.00
2.5	3,793,038	266	0.0001	0.9999	99.99
3.5	3,792,772	357	0.0001	0.9999	99.99
4.5	3,700,866	470	0.0001	0.9999	99.98
5.5	3,502,465	609	0.0002	0.9998	99.96
6.5	3,228,570	777	0.0002	0.9998	99.95
7.5	3,071,444	978	0.0003	0.9997	99.92
8.5	2,973,067	1,216	0.0004	0.9996	99.89
9.5	2,860,775	1,493	0.0005	0.9995	99.85
10.5	2,798,843	1,812	0.0006	0.9994	99.80
11.5	2,684,696	2,175	0.0008	0.9992	99.73
12.5	2,602,336	2,587	0.0010	0.9990	99.65
13.5	2,558,644	3,051	0.0012	0.9988	99.55
14.5	2,514,121	3,570	0.0014	0.9986	99.43
15.5	2,426,048	4,150	0.0017	0.9983	99.29
16.5	2,362,786	4,798	0.0020	0.9980	99.12
17.5	2,357,988	5,524	0.0023	0.9977	98.92
18.5	2,352,464	6,333	0.0027	0.9973	98.69
19.5	2,346,131	7,231	0.0031	0.9969	98.42
20.5	2,338,900	8,221	0.0035	0.9965	98.12
21.5	2,330,679	9,288	0.0040	0.9960	97.78
22.5	2,321,391	10,408	0.0045	0.9955	97.39
23.5	2,310,983	11,533	0.0050	0.9950	96.95
24.5	2,299,450	12,596	0.0055	0.9945	96.47
25.5	2,286,854	33,509	0.0147	0.9853	95.94
26.5	121,691	14,175	0.1165	0.8835	94.53
27.5	107,516	14,509	0.1349	0.8651	83.52
28.5	93,007	14,403	0.1549	0.8451	72.25
29.5	78,604	13,859	0.1763	0.8237	61.06
30.5	64,745	12,887	0.1990	0.8010	50.30
31.5	51,858	11,560	0.2229	0.7771	40.28
32.5	40,298	9,998	0.2481	0.7519	31.30
33.5	30,300	8,340	0.2752	0.7248	23.54
34.5	21,960	6,716	0.3058	0.6942	17.06
35.5	15,244	5,219	0.3424	0.6576	11.84
36.5	10,025	3,897	0.3887	0.6113	7.79
37.5	6,128	2,761	0.4506	0.5494	4.76
38.5	3,367	1,806	0.5364	0.4636	2.62

PACIFIC NORTHERN GAS LTD.

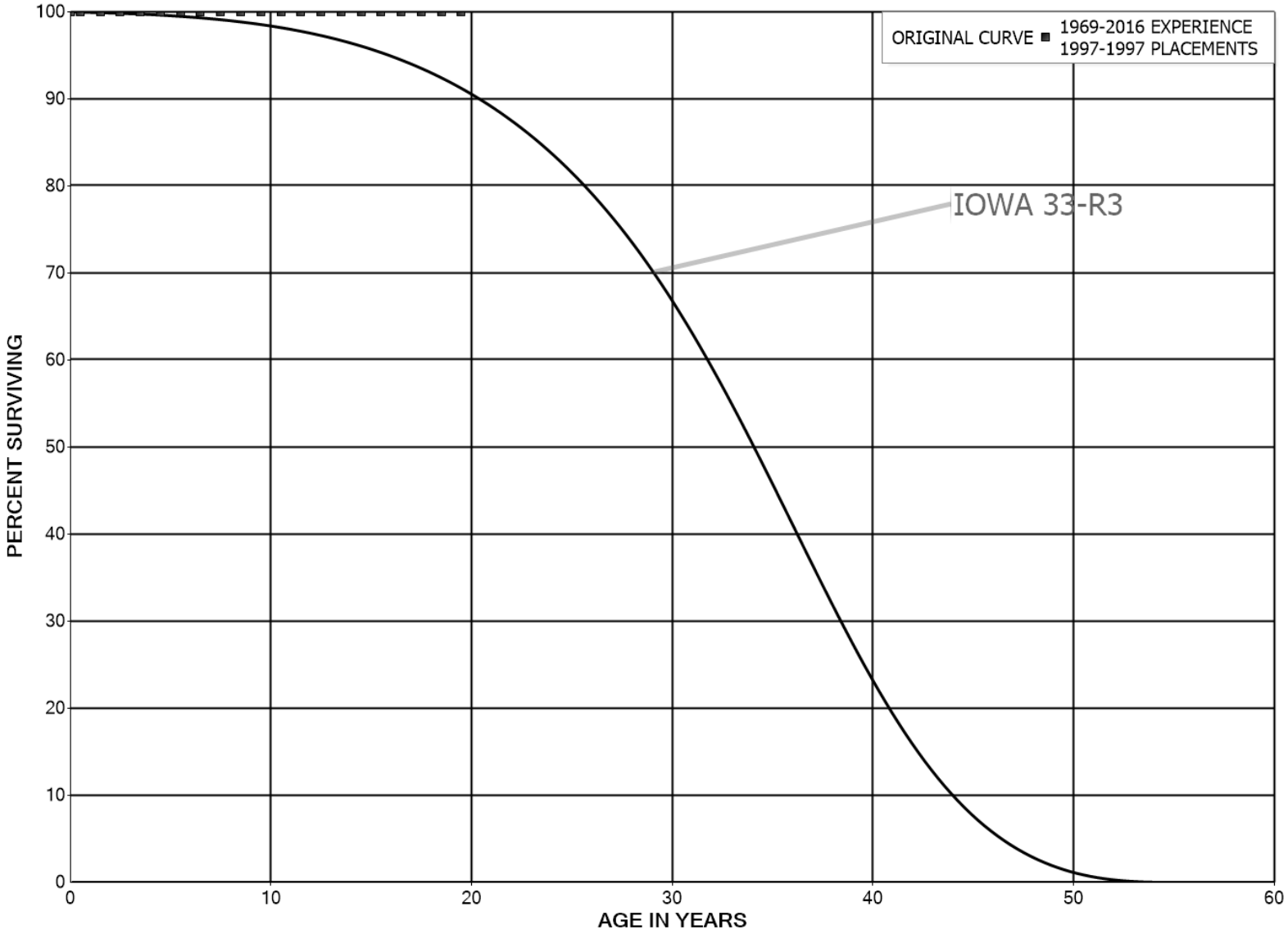
ACCOUNT 418.00 - GATHERING PLANT - PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,561	1,037	0.6643	0.3357	1.21
40.5	524	474	0.9046	0.0954	0.41
41.5					0.04

PACIFIC NORTHERN GAS LTD.
ACCOUNT 449.00 - PROCESSING PLANT - OTHER LOCAL STORAGE EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

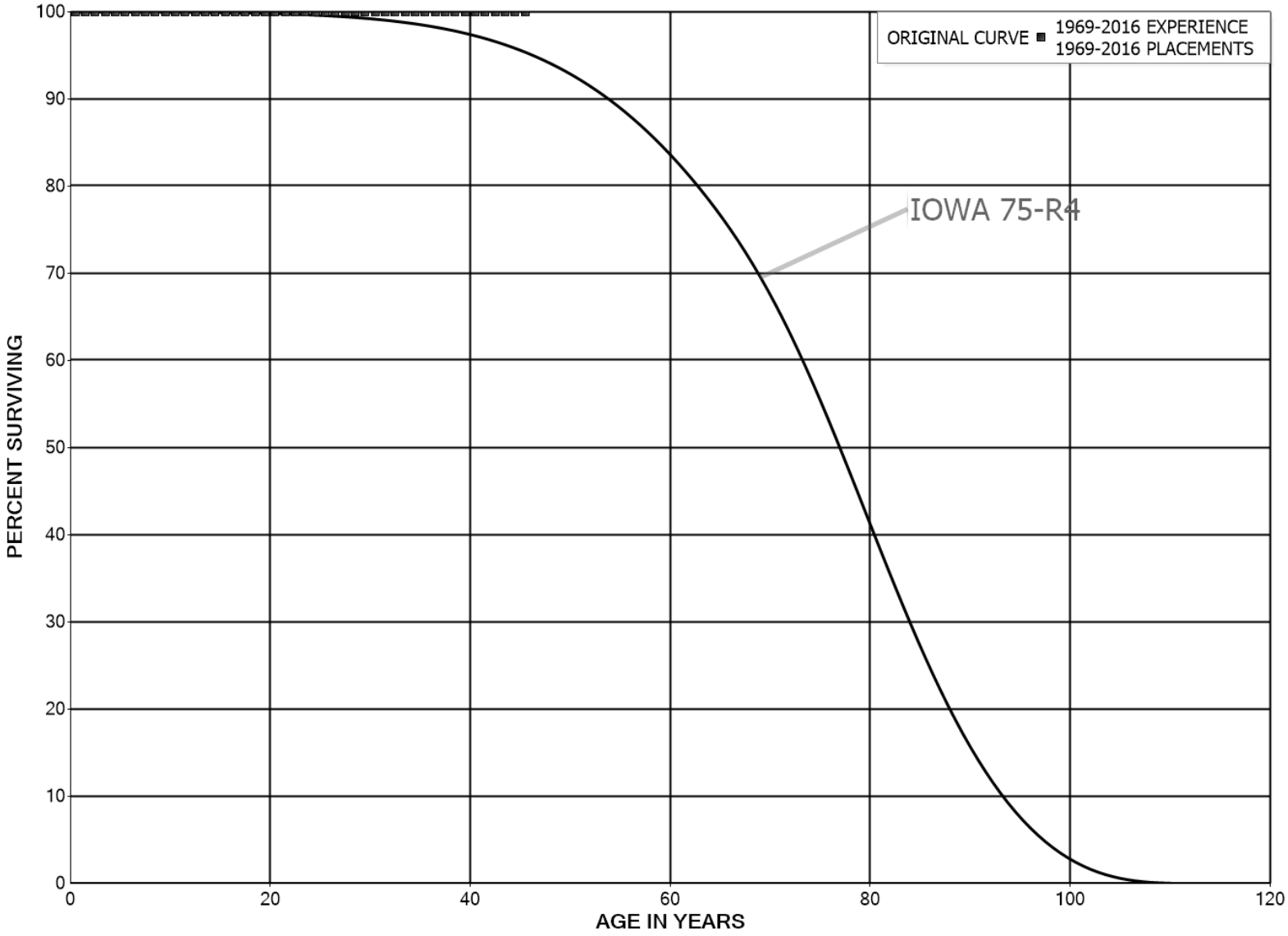
ACCOUNT 449.00 - PROCESSING PLANT - OTHER LOCAL STORAGE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1997-1997 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,200		0.0000	1.0000	100.00
0.5	3,200		0.0000	1.0000	100.00
1.5	3,200		0.0000	1.0000	100.00
2.5	3,200		0.0000	1.0000	100.00
3.5	3,200		0.0000	1.0000	100.00
4.5	3,200		0.0000	1.0000	100.00
5.5	3,200		0.0000	1.0000	100.00
6.5	3,200		0.0000	1.0000	100.00
7.5	3,200		0.0000	1.0000	100.00
8.5	3,200		0.0000	1.0000	100.00
9.5	3,200		0.0000	1.0000	100.00
10.5	3,200		0.0000	1.0000	100.00
11.5	3,200		0.0000	1.0000	100.00
12.5	3,200		0.0000	1.0000	100.00
13.5	3,200		0.0000	1.0000	100.00
14.5	3,200		0.0000	1.0000	100.00
15.5	3,200		0.0000	1.0000	100.00
16.5	3,200		0.0000	1.0000	100.00
17.5	3,200		0.0000	1.0000	100.00
18.5	3,200		0.0000	1.0000	100.00
19.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,399,087		0.0000	1.0000	100.00
0.5	1,372,010		0.0000	1.0000	100.00
1.5	1,157,865		0.0000	1.0000	100.00
2.5	1,099,978		0.0000	1.0000	100.00
3.5	1,021,243		0.0000	1.0000	100.00
4.5	1,021,243		0.0000	1.0000	100.00
5.5	1,021,243		0.0000	1.0000	100.00
6.5	1,021,243		0.0000	1.0000	100.00
7.5	1,021,243		0.0000	1.0000	100.00
8.5	1,021,243		0.0000	1.0000	100.00
9.5	1,021,243		0.0000	1.0000	100.00
10.5	1,021,243		0.0000	1.0000	100.00
11.5	1,021,243		0.0000	1.0000	100.00
12.5	1,021,243		0.0000	1.0000	100.00
13.5	1,021,243		0.0000	1.0000	100.00
14.5	1,021,243		0.0000	1.0000	100.00
15.5	1,021,243		0.0000	1.0000	100.00
16.5	1,021,243		0.0000	1.0000	100.00
17.5	1,021,243		0.0000	1.0000	100.00
18.5	1,021,243		0.0000	1.0000	100.00
19.5	1,021,243		0.0000	1.0000	100.00
20.5	950,768		0.0000	1.0000	100.00
21.5	950,768		0.0000	1.0000	100.00
22.5	905,452		0.0000	1.0000	100.00
23.5	892,225		0.0000	1.0000	100.00
24.5	891,784		0.0000	1.0000	100.00
25.5	886,544		0.0000	1.0000	100.00
26.5	822,027		0.0000	1.0000	100.00
27.5	771,957		0.0000	1.0000	100.00
28.5	759,347		0.0000	1.0000	100.00
29.5	729,656		0.0000	1.0000	100.00
30.5	689,706		0.0000	1.0000	100.00
31.5	678,966		0.0000	1.0000	100.00
32.5	666,487		0.0000	1.0000	100.00
33.5	564,965		0.0000	1.0000	100.00
34.5	515,235		0.0000	1.0000	100.00
35.5	207,207		0.0000	1.0000	100.00
36.5	207,087		0.0000	1.0000	100.00
37.5	207,087		0.0000	1.0000	100.00
38.5	205,608		0.0000	1.0000	100.00

PACIFIC NORTHERN GAS LTD.

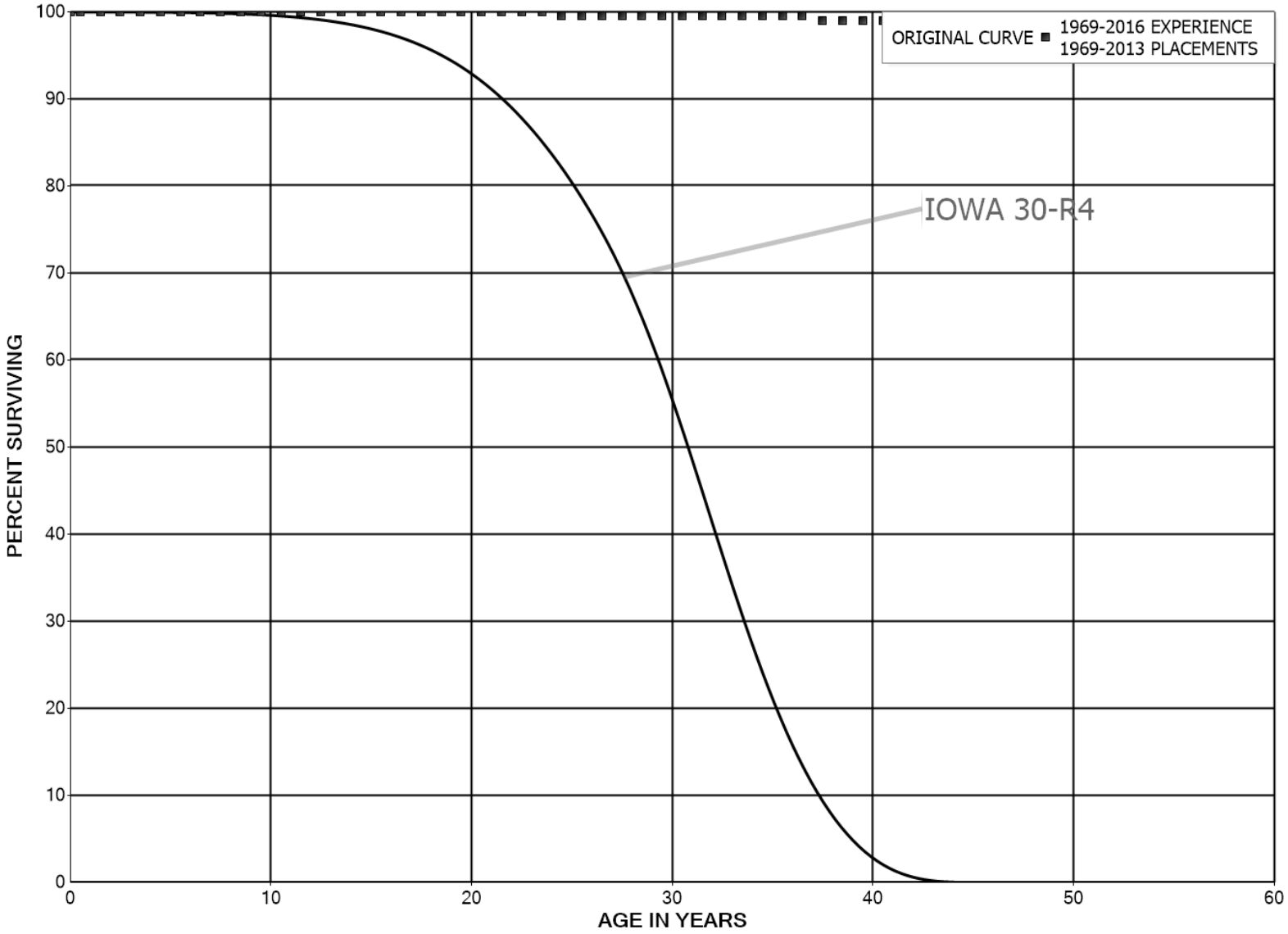
ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	204,214		0.0000	1.0000	100.00
40.5	194,516		0.0000	1.0000	100.00
41.5	194,196		0.0000	1.0000	100.00
42.5	193,910		0.0000	1.0000	100.00
43.5	188,023		0.0000	1.0000	100.00
44.5	158,275		0.0000	1.0000	100.00
45.5	92,595		0.0000	1.0000	100.00
46.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2013 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,377,046	2	0.0000	1.0000	100.00
0.5	3,377,044		0.0000	1.0000	100.00
1.5	3,377,044		0.0000	1.0000	100.00
2.5	3,377,044		0.0000	1.0000	100.00
3.5	3,317,982		0.0000	1.0000	100.00
4.5	3,317,982	41	0.0000	1.0000	100.00
5.5	3,299,053	19	0.0000	1.0000	100.00
6.5	3,299,034		0.0000	1.0000	100.00
7.5	3,293,219		0.0000	1.0000	100.00
8.5	3,288,318		0.0000	1.0000	100.00
9.5	3,273,030		0.0000	1.0000	100.00
10.5	3,173,848		0.0000	1.0000	100.00
11.5	3,092,080	53	0.0000	1.0000	100.00
12.5	3,081,249	35	0.0000	1.0000	100.00
13.5	3,075,826	13	0.0000	1.0000	100.00
14.5	3,075,813	65	0.0000	1.0000	99.99
15.5	3,075,748	46	0.0000	1.0000	99.99
16.5	3,055,965	212	0.0001	0.9999	99.99
17.5	2,846,659	265	0.0001	0.9999	99.98
18.5	2,428,836	117	0.0000	1.0000	99.98
19.5	2,365,085	817	0.0003	0.9997	99.97
20.5	2,337,169	194	0.0001	0.9999	99.94
21.5	2,248,217	453	0.0002	0.9998	99.93
22.5	2,156,495	301	0.0001	0.9999	99.91
23.5	2,019,989	6,777	0.0034	0.9966	99.89
24.5	1,954,673		0.0000	1.0000	99.56
25.5	1,813,068	1	0.0000	1.0000	99.56
26.5	1,788,033	16	0.0000	1.0000	99.56
27.5	1,786,454		0.0000	1.0000	99.56
28.5	1,767,506		0.0000	1.0000	99.56
29.5	1,745,355	5	0.0000	1.0000	99.56
30.5	1,734,196	6	0.0000	1.0000	99.56
31.5	1,719,426	2	0.0000	1.0000	99.56
32.5	1,604,436	27	0.0000	1.0000	99.56
33.5	1,589,399	6	0.0000	1.0000	99.55
34.5	316,822	9	0.0000	1.0000	99.55
35.5	316,813	35	0.0001	0.9999	99.55
36.5	313,047	1,741	0.0056	0.9944	99.54
37.5	311,306		0.0000	1.0000	98.99
38.5	311,306		0.0000	1.0000	98.99

PACIFIC NORTHERN GAS LTD.

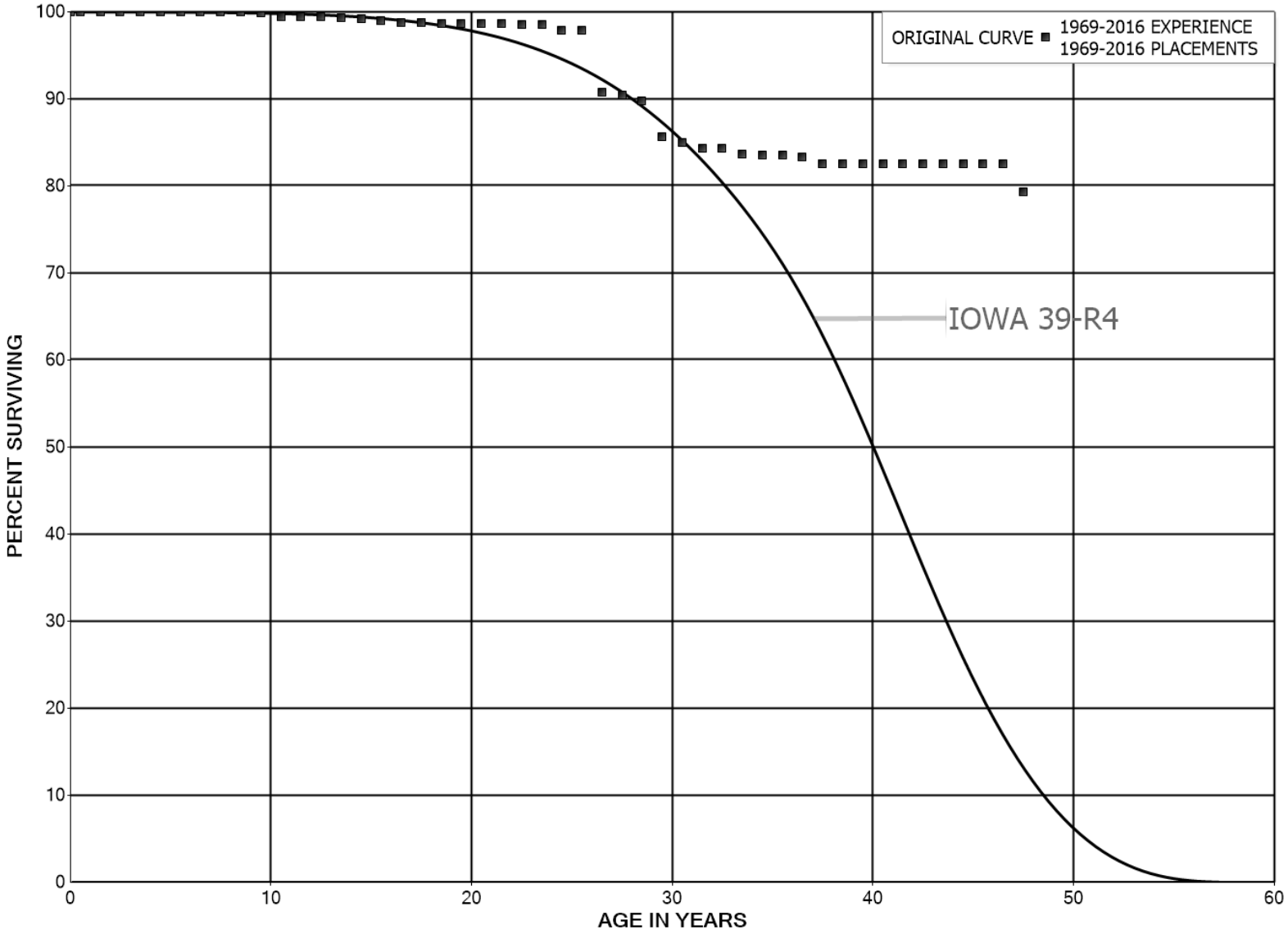
ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2013 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	310,712		0.0000	1.0000	98.99
40.5	307,576		0.0000	1.0000	98.99
41.5	306,849		0.0000	1.0000	98.99
42.5	306,265		0.0000	1.0000	98.99
43.5	304,447		0.0000	1.0000	98.99
44.5	302,527		0.0000	1.0000	98.99
45.5	302,527		0.0000	1.0000	98.99
46.5	299,496		0.0000	1.0000	98.99
47.5					98.99

PACIFIC NORTHERN GAS LTD.
ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,640,306	9	0.0000	1.0000	100.00
0.5	1,560,488	5	0.0000	1.0000	100.00
1.5	1,560,483	4	0.0000	1.0000	100.00
2.5	1,560,479	228	0.0001	0.9999	100.00
3.5	1,560,251	243	0.0002	0.9998	99.98
4.5	1,560,008	422	0.0003	0.9997	99.97
5.5	1,559,586	333	0.0002	0.9998	99.94
6.5	1,559,253	135	0.0001	0.9999	99.92
7.5	1,559,118	68	0.0000	1.0000	99.91
8.5	1,554,400	1,255	0.0008	0.9992	99.91
9.5	1,461,778	6,024	0.0041	0.9959	99.83
10.5	1,451,415	130	0.0001	0.9999	99.42
11.5	1,394,538	750	0.0005	0.9995	99.41
12.5	1,356,758	882	0.0007	0.9993	99.35
13.5	1,295,488	984	0.0008	0.9992	99.29
14.5	1,293,020	4,061	0.0031	0.9969	99.21
15.5	1,288,959	1,837	0.0014	0.9986	98.90
16.5	1,287,122	183	0.0001	0.9999	98.76
17.5	1,278,406	1,166	0.0009	0.9991	98.75
18.5	1,277,240	154	0.0001	0.9999	98.66
19.5	1,277,086	94	0.0001	0.9999	98.64
20.5	1,193,509	391	0.0003	0.9997	98.64
21.5	1,165,056	662	0.0006	0.9994	98.60
22.5	1,143,865	448	0.0004	0.9996	98.55
23.5	1,122,800	7,330	0.0065	0.9935	98.51
24.5	1,033,071	835	0.0008	0.9992	97.87
25.5	957,423	68,957	0.0720	0.9280	97.79
26.5	862,100	3,350	0.0039	0.9961	90.74
27.5	802,048	5,808	0.0072	0.9928	90.39
28.5	569,250	26,072	0.0458	0.9542	89.74
29.5	498,815	3,930	0.0079	0.9921	85.63
30.5	456,625	3,526	0.0077	0.9923	84.95
31.5	376,249	68	0.0002	0.9998	84.30
32.5	347,271	2,843	0.0082	0.9918	84.28
33.5	333,907	170	0.0005	0.9995	83.59
34.5	186,601	174	0.0009	0.9991	83.55
35.5	158,528	409	0.0026	0.9974	83.47
36.5	135,038	1,210	0.0090	0.9910	83.26
37.5	133,828		0.0000	1.0000	82.51
38.5	127,115		0.0000	1.0000	82.51

PACIFIC NORTHERN GAS LTD.

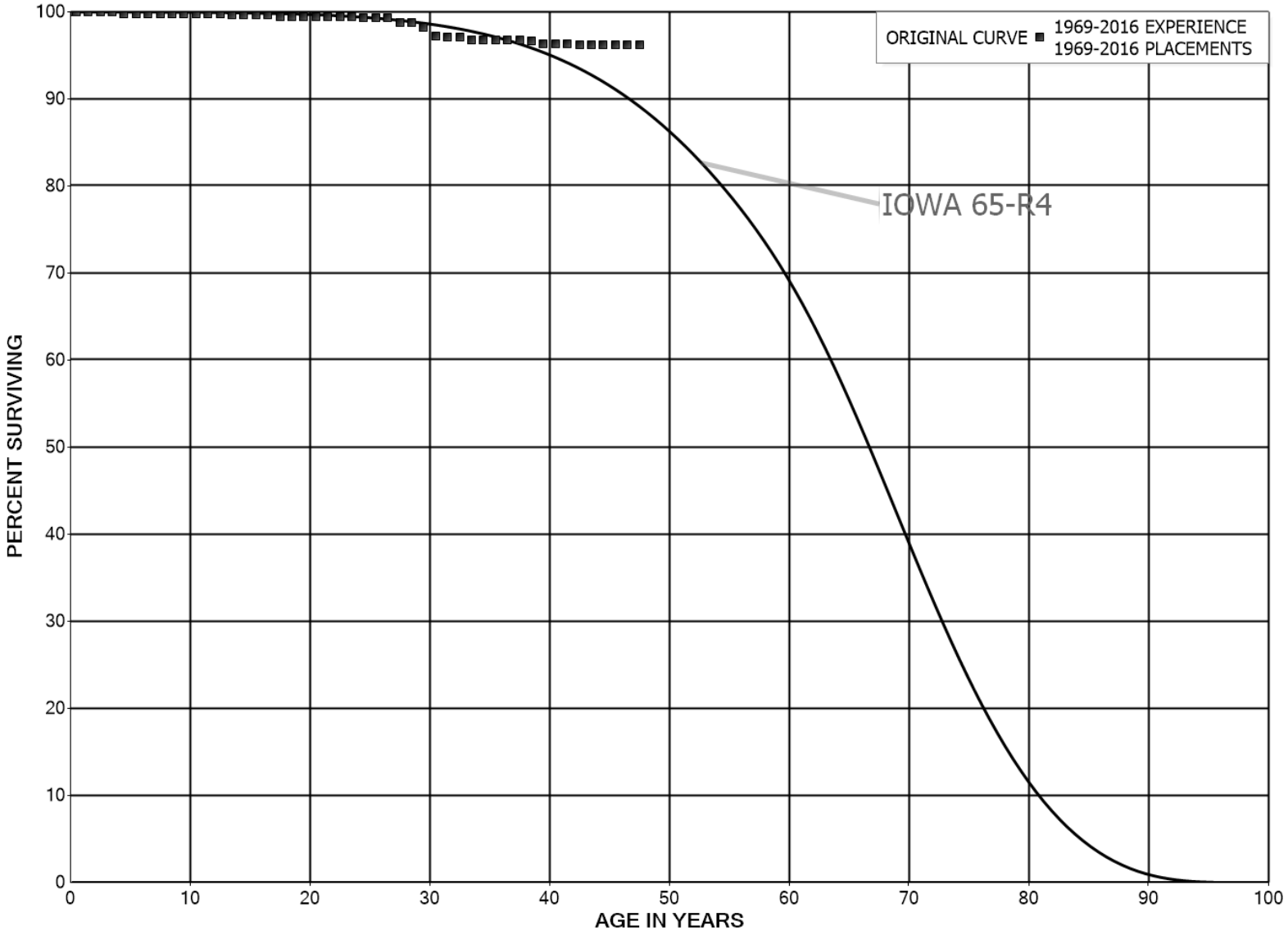
ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	124,277		0.0000	1.0000	82.51
40.5	120,835		0.0000	1.0000	82.51
41.5	118,541		0.0000	1.0000	82.51
42.5	118,541		0.0000	1.0000	82.51
43.5	117,733		0.0000	1.0000	82.51
44.5	115,843		0.0000	1.0000	82.51
45.5	110,417		0.0000	1.0000	82.51
46.5	102,412	3,958	0.0386	0.9614	82.51
47.5					79.32

PACIFIC NORTHERN GAS LTD.
ACCOUNT 465.00 - TRANSMISSION - MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	172,737,303	426	0.0000	1.0000	100.00
0.5	171,307,112	6,314	0.0000	1.0000	100.00
1.5	167,934,552	5,556	0.0000	1.0000	100.00
2.5	165,423,934	2,268	0.0000	1.0000	99.99
3.5	161,915,007	354,059	0.0022	0.9978	99.99
4.5	159,074,232	12,750	0.0001	0.9999	99.77
5.5	155,494,211	13,801	0.0001	0.9999	99.76
6.5	154,295,559	9,186	0.0001	0.9999	99.76
7.5	151,165,710	17,030	0.0001	0.9999	99.75
8.5	146,233,303	24,072	0.0002	0.9998	99.74
9.5	142,268,171	12,029	0.0001	0.9999	99.72
10.5	138,028,202	16,402	0.0001	0.9999	99.71
11.5	131,090,581	19,110	0.0001	0.9999	99.70
12.5	129,652,048	23,610	0.0002	0.9998	99.69
13.5	128,229,623	6,266	0.0000	1.0000	99.67
14.5	126,072,842	19,754	0.0002	0.9998	99.66
15.5	125,210,257	103,108	0.0008	0.9992	99.65
16.5	122,006,036	166,972	0.0014	0.9986	99.57
17.5	115,782,948	13,756	0.0001	0.9999	99.43
18.5	112,098,106	16,037	0.0001	0.9999	99.42
19.5	110,533,865	33,662	0.0003	0.9997	99.40
20.5	104,770,222	10,627	0.0001	0.9999	99.37
21.5	95,779,468	4,013	0.0000	1.0000	99.36
22.5	86,423,998	7,517	0.0001	0.9999	99.36
23.5	80,118,038	24,055	0.0003	0.9997	99.35
24.5	76,844,554	35,278	0.0005	0.9995	99.32
25.5	74,802,277	9,725	0.0001	0.9999	99.28
26.5	64,960,755	332,704	0.0051	0.9949	99.26
27.5	63,599,006	31,885	0.0005	0.9995	98.75
28.5	59,321,808	308,643	0.0052	0.9948	98.71
29.5	58,115,801	605,662	0.0104	0.9896	98.19
30.5	52,134,307	32,485	0.0006	0.9994	97.17
31.5	51,939,769	20,524	0.0004	0.9996	97.11
32.5	51,111,473	170,464	0.0033	0.9967	97.07
33.5	49,972,944	13,692	0.0003	0.9997	96.75
34.5	25,263,153	4,609	0.0002	0.9998	96.72
35.5	24,648,976	46	0.0000	1.0000	96.70
36.5	22,063,307	4,639	0.0002	0.9998	96.70
37.5	21,006,839	4,905	0.0002	0.9998	96.68
38.5	20,980,067	69,824	0.0033	0.9967	96.66

PACIFIC NORTHERN GAS LTD.

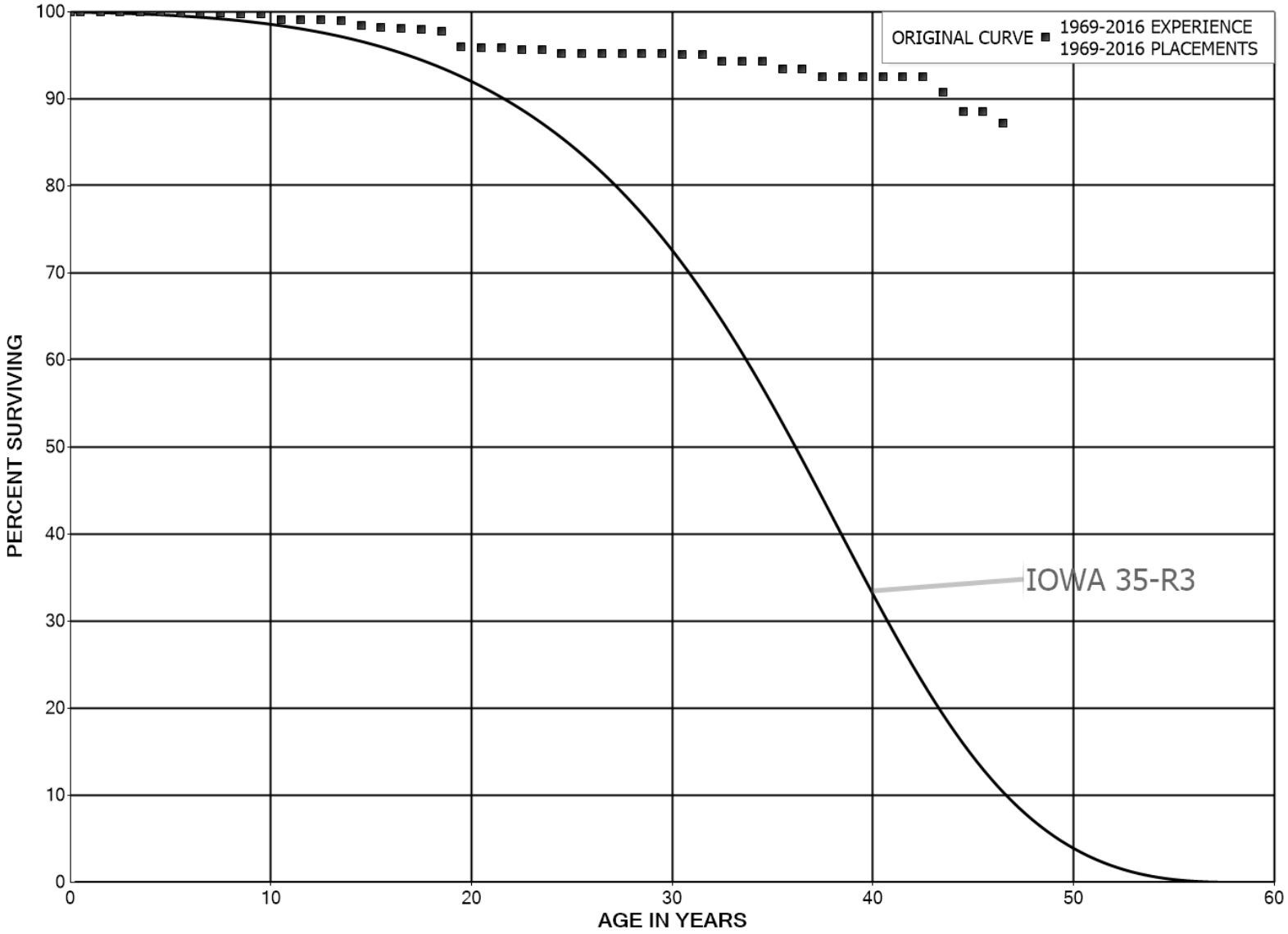
ACCOUNT 465.00 - TRANSMISSION - MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,842,011		0.0000	1.0000	96.34
40.5	20,727,192	19,176	0.0009	0.9991	96.34
41.5	20,425,117	9,783	0.0005	0.9995	96.25
42.5	18,440,399	821	0.0000	1.0000	96.20
43.5	18,394,773	10,154	0.0006	0.9994	96.20
44.5	17,865,251		0.0000	1.0000	96.14
45.5	17,812,106	729	0.0000	1.0000	96.14
46.5	17,380,047		0.0000	1.0000	96.14
47.5					96.14

PACIFIC NORTHERN GAS LTD.
ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	26,459,022	4,237	0.0002	0.9998	100.00
0.5	26,264,996	1,804	0.0001	0.9999	99.98
1.5	25,753,085	1,860	0.0001	0.9999	99.98
2.5	25,349,357	5,963	0.0002	0.9998	99.97
3.5	24,988,945	10,933	0.0004	0.9996	99.95
4.5	24,816,607	6,929	0.0003	0.9997	99.90
5.5	24,779,046	3,887	0.0002	0.9998	99.87
6.5	24,740,300	18,279	0.0007	0.9993	99.86
7.5	24,705,457	4,856	0.0002	0.9998	99.79
8.5	24,687,776	2,225	0.0001	0.9999	99.77
9.5	24,614,706	157,409	0.0064	0.9936	99.76
10.5	24,429,536	6,644	0.0003	0.9997	99.12
11.5	24,189,594	19,493	0.0008	0.9992	99.09
12.5	23,651,050	22,594	0.0010	0.9990	99.01
13.5	23,362,870	115,370	0.0049	0.9951	98.92
14.5	22,822,784	66,758	0.0029	0.9971	98.43
15.5	22,330,895	16,517	0.0007	0.9993	98.14
16.5	22,064,375	34,103	0.0015	0.9985	98.07
17.5	21,698,439	31,429	0.0014	0.9986	97.92
18.5	21,610,342	406,318	0.0188	0.9812	97.78
19.5	20,523,841	17,709	0.0009	0.9991	95.94
20.5	19,715,411	5,482	0.0003	0.9997	95.85
21.5	19,259,581	47,287	0.0025	0.9975	95.83
22.5	18,699,036	4,066	0.0002	0.9998	95.59
23.5	18,416,770	80,410	0.0044	0.9956	95.57
24.5	18,248,219	2,105	0.0001	0.9999	95.15
25.5	17,612,171	397	0.0000	1.0000	95.14
26.5	17,586,668	911	0.0001	0.9999	95.14
27.5	16,388,324	2,242	0.0001	0.9999	95.14
28.5	16,341,975	348	0.0000	1.0000	95.12
29.5	16,227,715	524	0.0000	1.0000	95.12
30.5	13,226,262	11,149	0.0008	0.9992	95.12
31.5	11,247,727	82,670	0.0073	0.9927	95.04
32.5	10,066,297	182	0.0000	1.0000	94.34
33.5	9,578,193	2,705	0.0003	0.9997	94.34
34.5	827,630	8,234	0.0099	0.9901	94.31
35.5	819,396	169	0.0002	0.9998	93.37
36.5	819,227	7,455	0.0091	0.9909	93.35
37.5	811,772		0.0000	1.0000	92.50
38.5	811,772		0.0000	1.0000	92.50

PACIFIC NORTHERN GAS LTD.

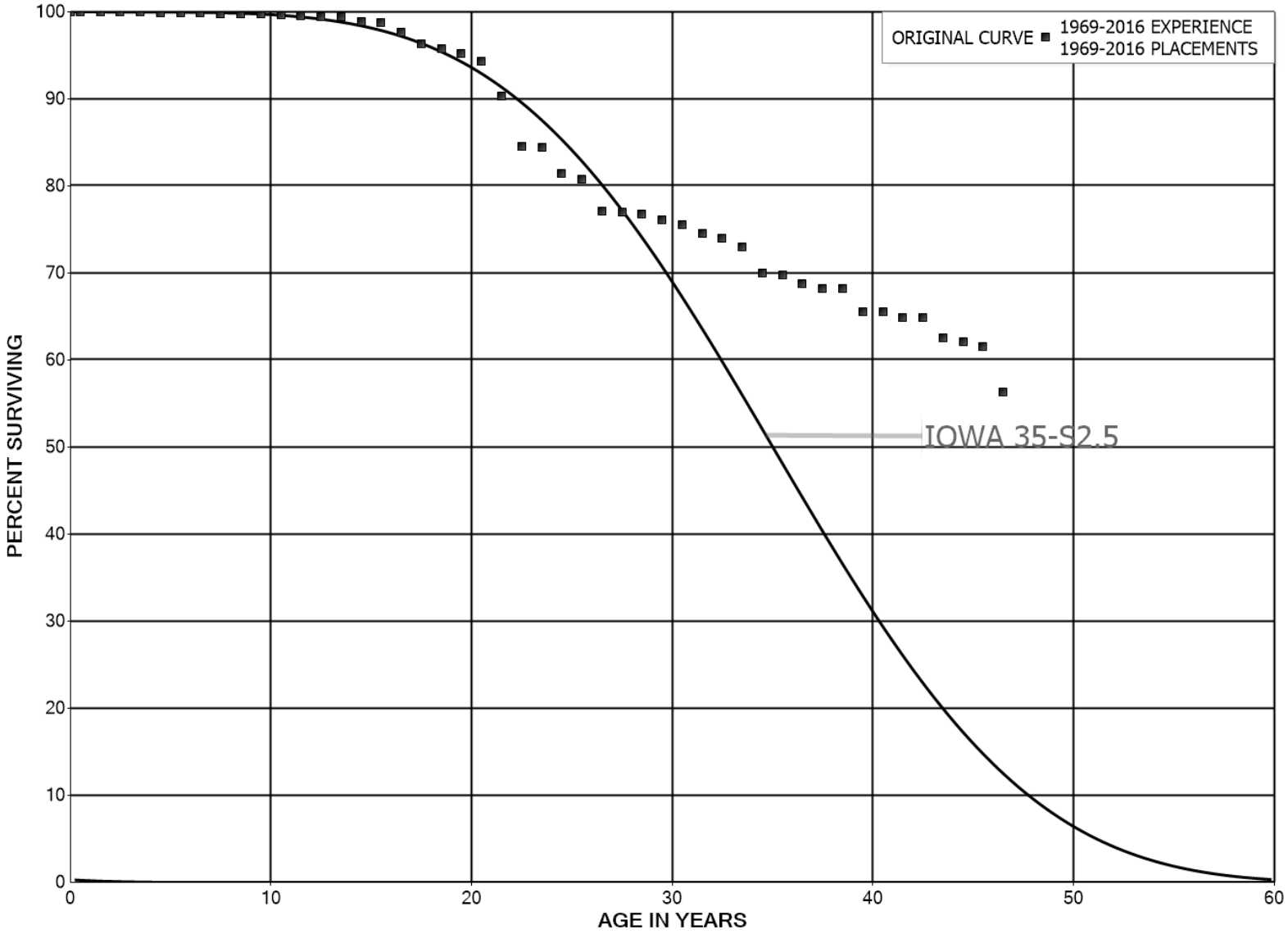
ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	811,772		0.0000	1.0000	92.50
40.5	811,772		0.0000	1.0000	92.50
41.5	805,218		0.0000	1.0000	92.50
42.5	802,301	15,000	0.0187	0.9813	92.50
43.5	782,283	19,900	0.0254	0.9746	90.77
44.5	754,468		0.0000	1.0000	88.46
45.5	746,350	11,133	0.0149	0.9851	88.46
46.5	717,052		0.0000	1.0000	87.15
47.5					87.15

PACIFIC NORTHERN GAS LTD.
ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,405,370	409	0.0000	1.0000	100.00
0.5	18,279,774	5,790	0.0003	0.9997	100.00
1.5	17,677,652	3,504	0.0002	0.9998	99.97
2.5	15,497,262	2,317	0.0001	0.9999	99.95
3.5	14,236,543	7,547	0.0005	0.9995	99.93
4.5	13,217,546	7,227	0.0005	0.9995	99.88
5.5	12,568,681	4,577	0.0004	0.9996	99.82
6.5	12,069,786	2,634	0.0002	0.9998	99.79
7.5	10,783,041	5,953	0.0006	0.9994	99.77
8.5	10,321,293	3,104	0.0003	0.9997	99.71
9.5	9,668,531	6,024	0.0006	0.9994	99.68
10.5	9,505,317	16,135	0.0017	0.9983	99.62
11.5	9,271,863	4,537	0.0005	0.9995	99.45
12.5	8,788,564	4,818	0.0005	0.9995	99.40
13.5	8,641,606	41,625	0.0048	0.9952	99.35
14.5	8,563,612	15,335	0.0018	0.9982	98.87
15.5	8,364,175	93,183	0.0111	0.9889	98.69
16.5	8,143,255	112,728	0.0138	0.9862	97.59
17.5	7,561,985	42,589	0.0056	0.9944	96.24
18.5	7,097,829	39,739	0.0056	0.9944	95.70
19.5	6,653,605	58,518	0.0088	0.9912	95.16
20.5	4,595,931	197,063	0.0429	0.9571	94.33
21.5	4,204,097	270,188	0.0643	0.9357	90.28
22.5	3,567,035	6,347	0.0018	0.9982	84.48
23.5	3,274,527	114,373	0.0349	0.9651	84.33
24.5	2,529,619	22,677	0.0090	0.9910	81.38
25.5	2,406,198	110,259	0.0458	0.9542	80.65
26.5	2,118,710	3,541	0.0017	0.9983	76.96
27.5	2,084,961	3,909	0.0019	0.9981	76.83
28.5	1,407,631	13,126	0.0093	0.9907	76.69
29.5	1,229,417	9,853	0.0080	0.9920	75.97
30.5	1,129,534	14,674	0.0130	0.9870	75.36
31.5	1,021,738	8,208	0.0080	0.9920	74.38
32.5	888,293	12,118	0.0136	0.9864	73.78
33.5	868,112	35,569	0.0410	0.9590	72.78
34.5	791,532	3,046	0.0038	0.9962	69.80
35.5	564,904	8,689	0.0154	0.9846	69.53
36.5	503,150	3,562	0.0071	0.9929	68.46
37.5	497,662	496	0.0010	0.9990	67.97
38.5	484,063	19,341	0.0400	0.9600	67.91

PACIFIC NORTHERN GAS LTD.

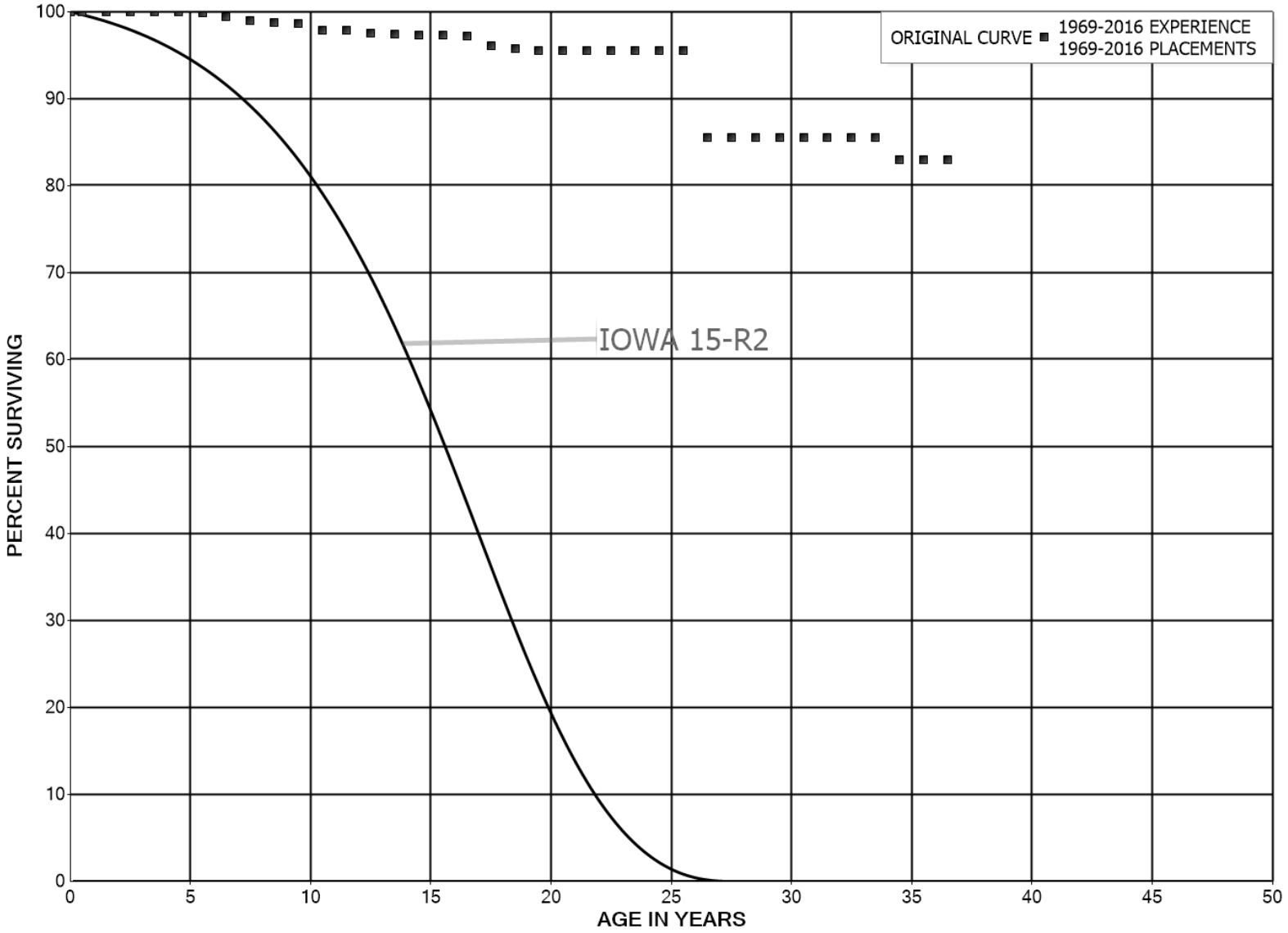
ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	462,677		0.0000	1.0000	65.19
40.5	461,869	5,460	0.0118	0.9882	65.19
41.5	433,444		0.0000	1.0000	64.42
42.5	425,286	15,427	0.0363	0.9637	64.42
43.5	380,995	2,951	0.0077	0.9923	62.08
44.5	338,235	3,033	0.0090	0.9910	61.60
45.5	323,351	28,818	0.0891	0.9109	61.05
46.5	202,901	47,820	0.2357	0.7643	55.61
47.5					42.50

PACIFIC NORTHERN GAS LTD.
ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,630,911		0.0000	1.0000	100.00
0.5	3,596,166		0.0000	1.0000	100.00
1.5	3,590,740	311	0.0001	0.9999	100.00
2.5	3,254,430	1,263	0.0004	0.9996	99.99
3.5	3,251,589	278	0.0001	0.9999	99.95
4.5	3,225,063	3,456	0.0011	0.9989	99.94
5.5	3,221,607	14,044	0.0044	0.9956	99.84
6.5	3,207,563	14,399	0.0045	0.9955	99.40
7.5	3,193,164	7,719	0.0024	0.9976	98.96
8.5	3,180,658	3,194	0.0010	0.9990	98.72
9.5	3,173,285	25,657	0.0081	0.9919	98.62
10.5	3,147,628	645	0.0002	0.9998	97.82
11.5	3,060,978	8,447	0.0028	0.9972	97.80
12.5	2,951,807	4,806	0.0016	0.9984	97.53
13.5	2,898,677	1,167	0.0004	0.9996	97.37
14.5	2,814,860	2,126	0.0008	0.9992	97.33
15.5	2,597,107	2,154	0.0008	0.9992	97.26
16.5	2,480,342	29,739	0.0120	0.9880	97.18
17.5	2,185,136	6,949	0.0032	0.9968	96.01
18.5	2,177,225	5,390	0.0025	0.9975	95.71
19.5	1,251,800		0.0000	1.0000	95.47
20.5	1,211,686		0.0000	1.0000	95.47
21.5	1,197,485		0.0000	1.0000	95.47
22.5	1,135,248		0.0000	1.0000	95.47
23.5	1,135,248		0.0000	1.0000	95.47
24.5	1,109,445		0.0000	1.0000	95.47
25.5	797,103	83,656	0.1050	0.8950	95.47
26.5	555,716		0.0000	1.0000	85.45
27.5	489,919		0.0000	1.0000	85.45
28.5	459,827		0.0000	1.0000	85.45
29.5	445,140		0.0000	1.0000	85.45
30.5	445,140		0.0000	1.0000	85.45
31.5	445,140		0.0000	1.0000	85.45
32.5	433,905		0.0000	1.0000	85.45
33.5	418,930	12,021	0.0287	0.9713	85.45
34.5	64,211		0.0000	1.0000	83.00
35.5	62,621		0.0000	1.0000	83.00
36.5	23,463		0.0000	1.0000	83.00
37.5	23,463		0.0000	1.0000	83.00
38.5	23,463		0.0000	1.0000	83.00

PACIFIC NORTHERN GAS LTD.

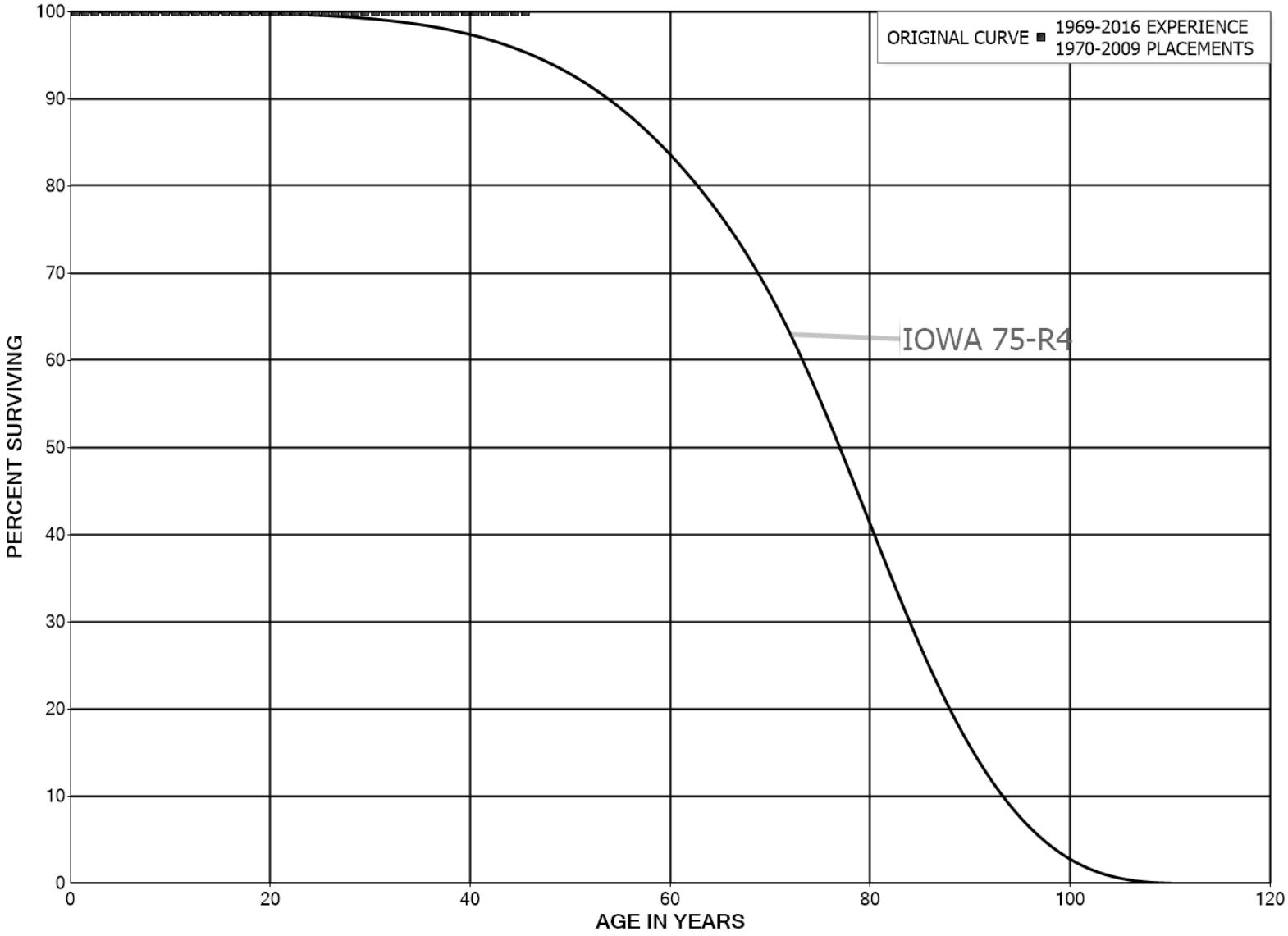
ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,463		0.0000	1.0000	83.00
40.5	23,463		0.0000	1.0000	83.00
41.5	23,463		0.0000	1.0000	83.00
42.5	23,463		0.0000	1.0000	83.00
43.5	9,782		0.0000	1.0000	83.00
44.5	9,782		0.0000	1.0000	83.00
45.5	9,782		0.0000	1.0000	83.00
46.5	2,373		0.0000	1.0000	83.00
47.5					83.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2009 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	257,861		0.0000	1.0000	100.00
0.5	257,861		0.0000	1.0000	100.00
1.5	257,861		0.0000	1.0000	100.00
2.5	257,861		0.0000	1.0000	100.00
3.5	257,861		0.0000	1.0000	100.00
4.5	257,861		0.0000	1.0000	100.00
5.5	257,861		0.0000	1.0000	100.00
6.5	257,861		0.0000	1.0000	100.00
7.5	255,917		0.0000	1.0000	100.00
8.5	255,917		0.0000	1.0000	100.00
9.5	255,917		0.0000	1.0000	100.00
10.5	255,917		0.0000	1.0000	100.00
11.5	255,917		0.0000	1.0000	100.00
12.5	255,917		0.0000	1.0000	100.00
13.5	255,917		0.0000	1.0000	100.00
14.5	255,917		0.0000	1.0000	100.00
15.5	255,917		0.0000	1.0000	100.00
16.5	255,917		0.0000	1.0000	100.00
17.5	255,917		0.0000	1.0000	100.00
18.5	240,794		0.0000	1.0000	100.00
19.5	238,789		0.0000	1.0000	100.00
20.5	99,240		0.0000	1.0000	100.00
21.5	99,240		0.0000	1.0000	100.00
22.5	99,240		0.0000	1.0000	100.00
23.5	99,240		0.0000	1.0000	100.00
24.5	99,240		0.0000	1.0000	100.00
25.5	97,928		0.0000	1.0000	100.00
26.5	92,658		0.0000	1.0000	100.00
27.5	91,057		0.0000	1.0000	100.00
28.5	90,222		0.0000	1.0000	100.00
29.5	85,696		0.0000	1.0000	100.00
30.5	85,427		0.0000	1.0000	100.00
31.5	84,088		0.0000	1.0000	100.00
32.5	82,533		0.0000	1.0000	100.00
33.5	73,346		0.0000	1.0000	100.00
34.5	71,822		0.0000	1.0000	100.00
35.5	71,395		0.0000	1.0000	100.00
36.5	9,309		0.0000	1.0000	100.00
37.5	9,309		0.0000	1.0000	100.00
38.5	7,446		0.0000	1.0000	100.00

PACIFIC NORTHERN GAS LTD.

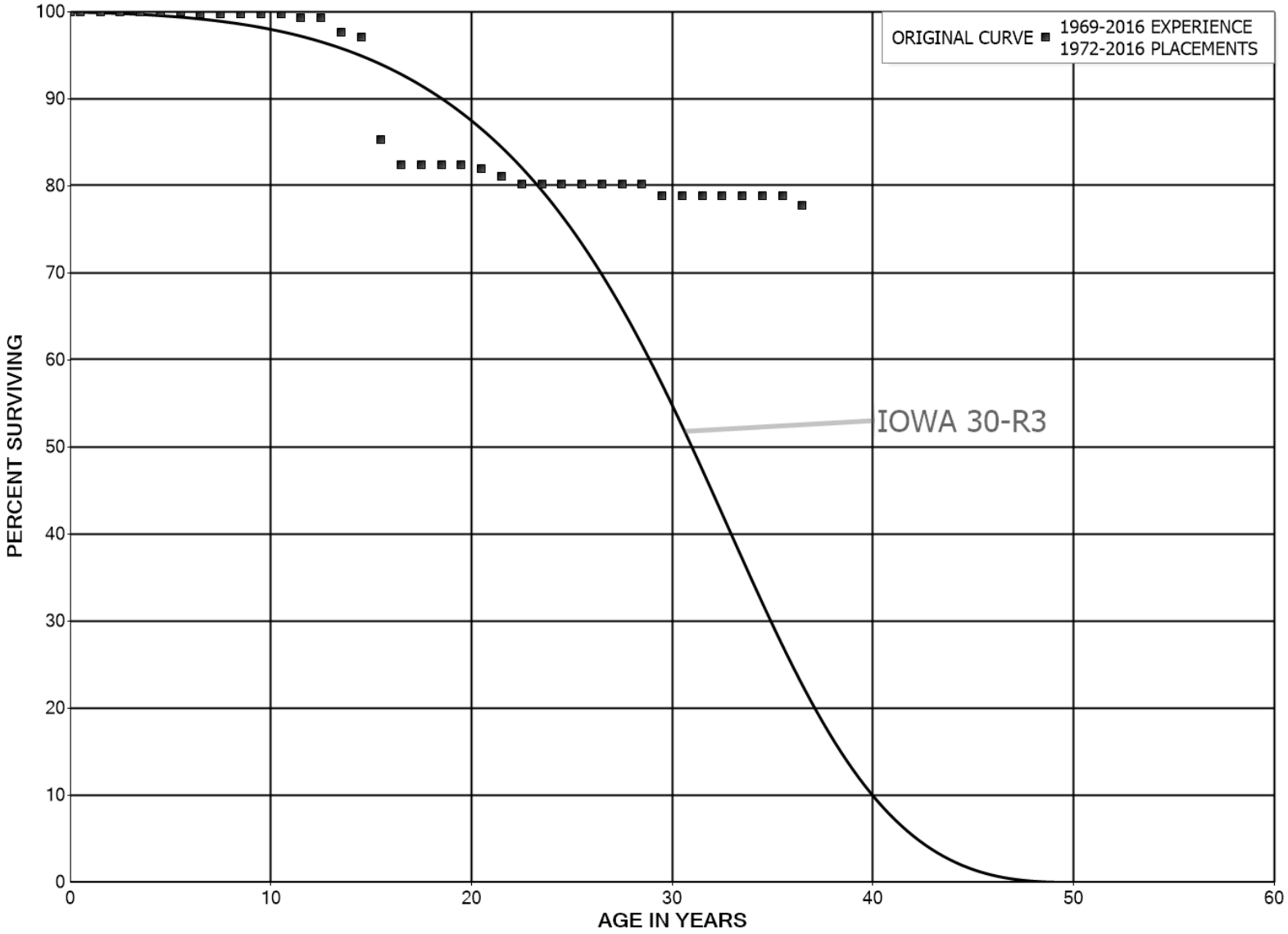
ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2009 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,145		0.0000	1.0000	100.00
40.5	7,145		0.0000	1.0000	100.00
41.5	7,145		0.0000	1.0000	100.00
42.5	4,371		0.0000	1.0000	100.00
43.5	2,667		0.0000	1.0000	100.00
44.5	2,667		0.0000	1.0000	100.00
45.5	2,547		0.0000	1.0000	100.00
46.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,890,030		0.0000	1.0000	100.00
0.5	2,729,276		0.0000	1.0000	100.00
1.5	2,650,119	22	0.0000	1.0000	100.00
2.5	2,586,874	2	0.0000	1.0000	100.00
3.5	2,506,002		0.0000	1.0000	100.00
4.5	2,355,669		0.0000	1.0000	100.00
5.5	2,195,975	6,972	0.0032	0.9968	100.00
6.5	2,009,870		0.0000	1.0000	99.68
7.5	1,818,050		0.0000	1.0000	99.68
8.5	1,631,740		0.0000	1.0000	99.68
9.5	1,529,202		0.0000	1.0000	99.68
10.5	1,463,405	5,287	0.0036	0.9964	99.68
11.5	1,366,605		0.0000	1.0000	99.32
12.5	1,255,596	21,846	0.0174	0.9826	99.32
13.5	1,070,735	6,356	0.0059	0.9941	97.59
14.5	897,674	108,234	0.1206	0.8794	97.01
15.5	688,804	23,458	0.0341	0.9659	85.32
16.5	338,933		0.0000	1.0000	82.41
17.5	338,933		0.0000	1.0000	82.41
18.5	333,982		0.0000	1.0000	82.41
19.5	322,467	2,000	0.0062	0.9938	82.41
20.5	262,521	2,800	0.0107	0.9893	81.90
21.5	259,721	2,856	0.0110	0.9890	81.03
22.5	256,865		0.0000	1.0000	80.14
23.5	251,871		0.0000	1.0000	80.14
24.5	251,871		0.0000	1.0000	80.14
25.5	245,803		0.0000	1.0000	80.14
26.5	204,464		0.0000	1.0000	80.14
27.5	204,464		0.0000	1.0000	80.14
28.5	183,475	3,000	0.0164	0.9836	80.14
29.5	180,475		0.0000	1.0000	78.83
30.5	158,597		0.0000	1.0000	78.83
31.5	147,809		0.0000	1.0000	78.83
32.5	147,809		0.0000	1.0000	78.83
33.5	147,809		0.0000	1.0000	78.83
34.5	144,781		0.0000	1.0000	78.83
35.5	144,781	2,000	0.0138	0.9862	78.83
36.5	14,715		0.0000	1.0000	77.74
37.5	14,299		0.0000	1.0000	77.74
38.5	14,299		0.0000	1.0000	77.74

PACIFIC NORTHERN GAS LTD.

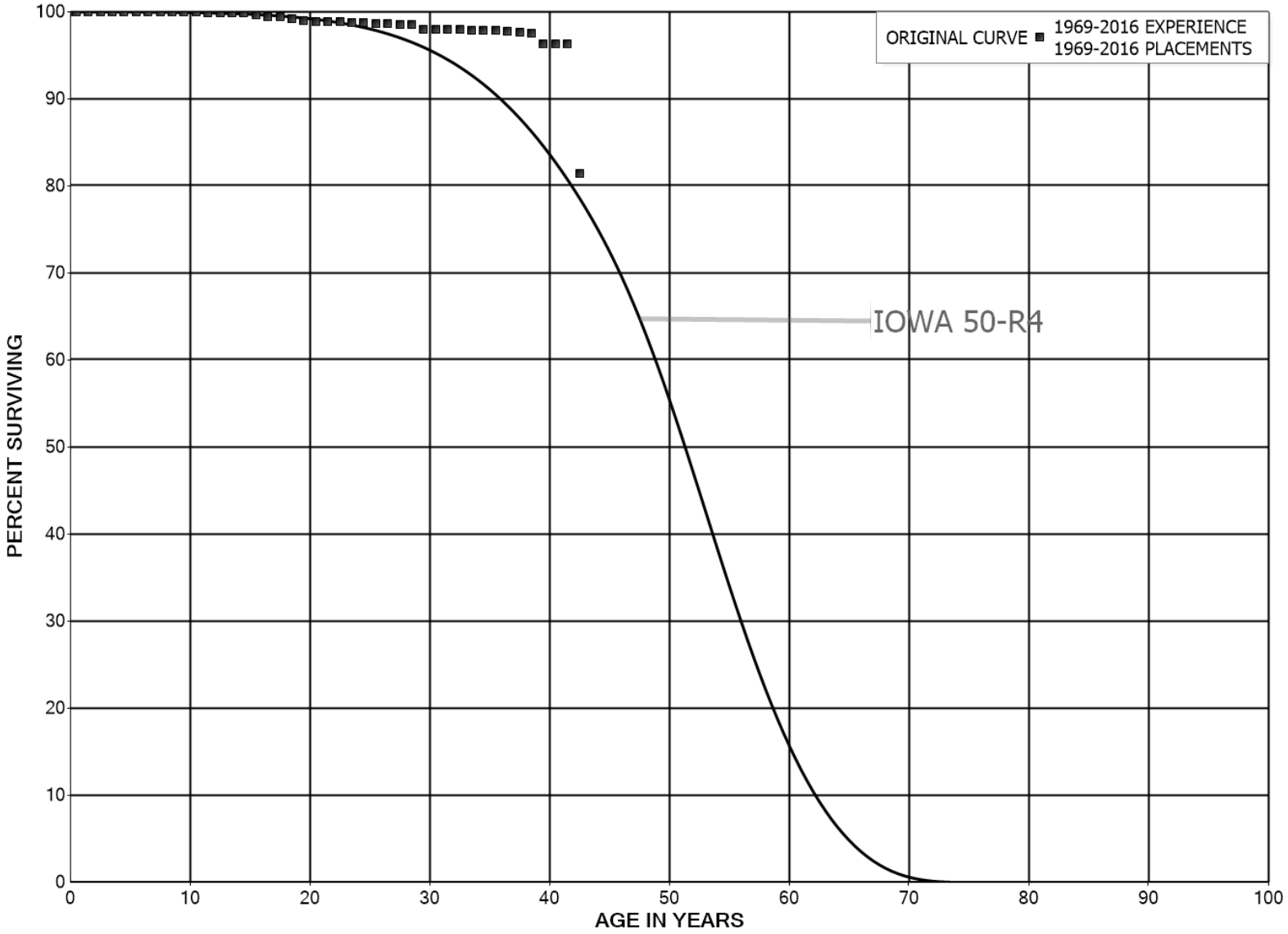
ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1972-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,949		0.0000	1.0000	77.74
40.5	7,074		0.0000	1.0000	77.74
41.5	7,074		0.0000	1.0000	77.74
42.5	908		0.0000	1.0000	77.74
43.5	908		0.0000	1.0000	77.74
44.5					77.74

PACIFIC NORTHERN GAS LTD.
ACCOUNT 473.00 - DISTRIBUTION - SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	52,360,679		0.0000	1.0000	100.00
0.5	51,123,791	1,299	0.0000	1.0000	100.00
1.5	49,445,039	3,779	0.0001	0.9999	100.00
2.5	47,780,747	4,475	0.0001	0.9999	99.99
3.5	46,133,155	6,466	0.0001	0.9999	99.98
4.5	44,613,309	7,586	0.0002	0.9998	99.97
5.5	43,412,314	10,052	0.0002	0.9998	99.95
6.5	41,467,987	8,222	0.0002	0.9998	99.93
7.5	40,280,190	1,206	0.0000	1.0000	99.91
8.5	38,720,995	1,320	0.0000	1.0000	99.90
9.5	37,470,383	1,823	0.0000	1.0000	99.90
10.5	36,425,339	2,859	0.0001	0.9999	99.90
11.5	35,531,067	4,543	0.0001	0.9999	99.89
12.5	34,607,235	6,726	0.0002	0.9998	99.87
13.5	33,750,254	8,689	0.0003	0.9997	99.86
14.5	32,944,948	52,833	0.0016	0.9984	99.83
15.5	32,115,086	72,488	0.0023	0.9977	99.67
16.5	31,187,640	7,540	0.0002	0.9998	99.44
17.5	30,252,112	64,504	0.0021	0.9979	99.42
18.5	28,440,781	64,553	0.0023	0.9977	99.21
19.5	26,434,496	35,135	0.0013	0.9987	98.98
20.5	19,298,435	6,363	0.0003	0.9997	98.85
21.5	18,448,919	7,064	0.0004	0.9996	98.82
22.5	17,264,391	7,334	0.0004	0.9996	98.78
23.5	15,896,544	7,427	0.0005	0.9995	98.74
24.5	14,456,063	7,109	0.0005	0.9995	98.69
25.5	13,278,800	9,413	0.0007	0.9993	98.64
26.5	10,929,159	5,360	0.0005	0.9995	98.57
27.5	10,079,457	4,683	0.0005	0.9995	98.53
28.5	9,272,763	44,674	0.0048	0.9952	98.48
29.5	8,591,163	3,027	0.0004	0.9996	98.01
30.5	8,036,066	2,958	0.0004	0.9996	97.97
31.5	7,170,778	2,581	0.0004	0.9996	97.94
32.5	6,447,565	2,319	0.0004	0.9996	97.90
33.5	5,556,057	2,226	0.0004	0.9996	97.87
34.5	4,797,146	2,067	0.0004	0.9996	97.83
35.5	4,115,051	2,537	0.0006	0.9994	97.78
36.5	2,358,624	2,053	0.0009	0.9991	97.72
37.5	1,876,000	1,737	0.0009	0.9991	97.64
38.5	1,572,426	20,965	0.0133	0.9867	97.55

PACIFIC NORTHERN GAS LTD.

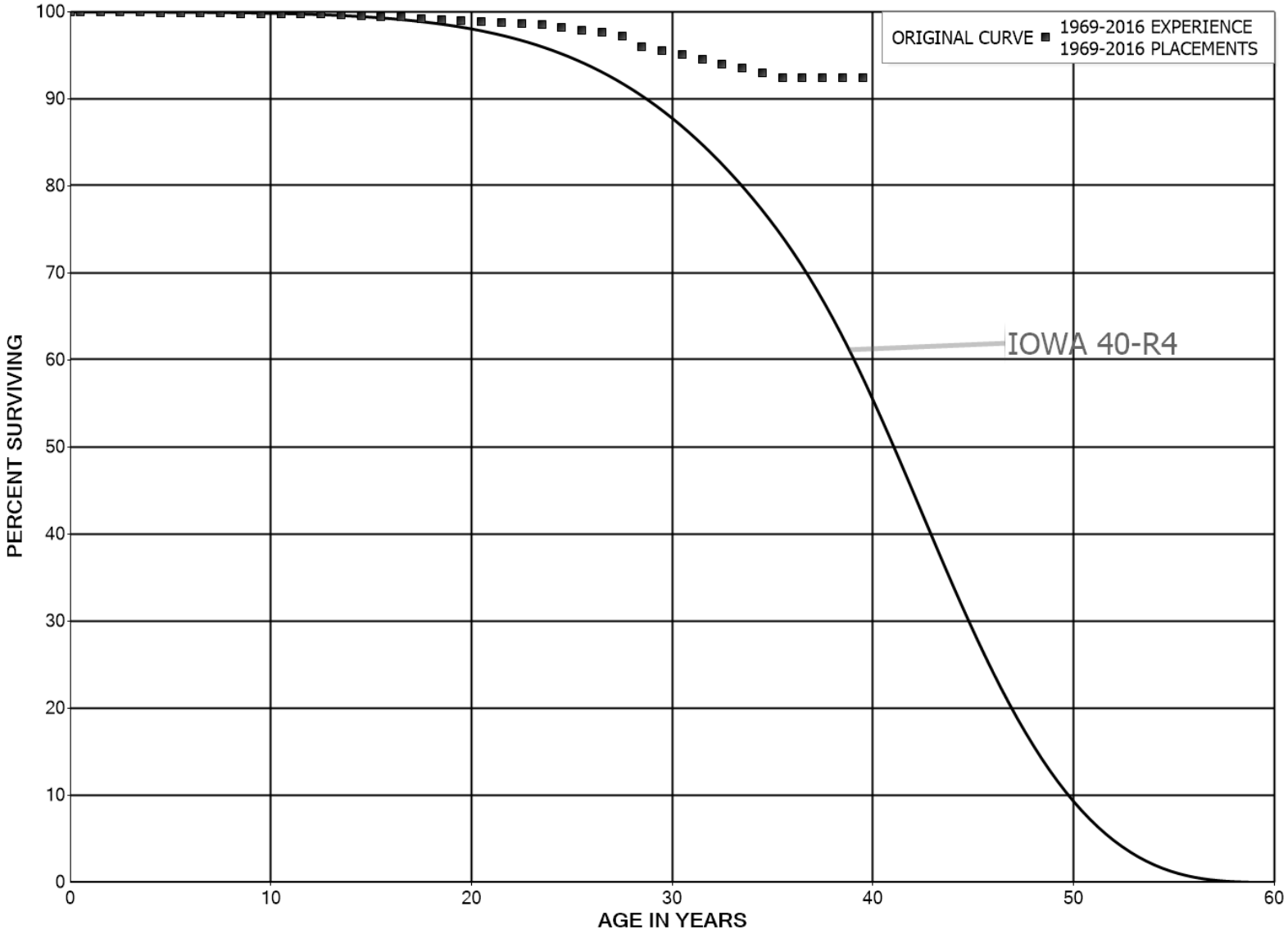
ACCOUNT 473.00 - DISTRIBUTION - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,270,234		0.0000	1.0000	96.25
40.5	1,026,286		0.0000	1.0000	96.25
41.5	863,100	133,000	0.1541	0.8459	96.25
42.5	532,370	223,848	0.4205	0.5795	81.42
43.5	259,141	7,824	0.0302	0.9698	47.18
44.5	251,317	21,527	0.0857	0.9143	45.76
45.5	229,789	20,043	0.0872	0.9128	41.84
46.5					38.19

PACIFIC NORTHERN GAS LTD.
ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,554,232		0.0000	1.0000	100.00
0.5	10,307,986	481	0.0000	1.0000	100.00
1.5	10,052,785	1,197	0.0001	0.9999	100.00
2.5	9,818,684	1,621	0.0002	0.9998	99.98
3.5	9,636,184	8,726	0.0009	0.9991	99.97
4.5	9,436,461	5,183	0.0005	0.9995	99.88
5.5	9,289,481	2,898	0.0003	0.9997	99.82
6.5	9,036,739	521	0.0001	0.9999	99.79
7.5	8,875,626	447	0.0001	0.9999	99.78
8.5	8,634,988	454	0.0001	0.9999	99.78
9.5	8,503,181	450	0.0001	0.9999	99.77
10.5	8,307,457	2,698	0.0003	0.9997	99.77
11.5	8,184,428	4,338	0.0005	0.9995	99.74
12.5	7,769,996	4,097	0.0005	0.9995	99.68
13.5	7,347,085	5,516	0.0008	0.9992	99.63
14.5	6,926,420	7,911	0.0011	0.9989	99.56
15.5	6,474,752	6,308	0.0010	0.9990	99.44
16.5	6,196,561	7,507	0.0012	0.9988	99.35
17.5	6,030,659	7,875	0.0013	0.9987	99.23
18.5	5,752,934	6,493	0.0011	0.9989	99.10
19.5	5,308,548	6,795	0.0013	0.9987	98.98
20.5	4,136,263	5,501	0.0013	0.9987	98.86
21.5	4,005,877	6,505	0.0016	0.9984	98.73
22.5	3,843,945	3,579	0.0009	0.9991	98.57
23.5	3,662,318	11,000	0.0030	0.9970	98.47
24.5	3,530,613	10,600	0.0030	0.9970	98.18
25.5	3,347,092	8,914	0.0027	0.9973	97.88
26.5	2,222,669	9,426	0.0042	0.9958	97.62
27.5	2,107,287	26,928	0.0128	0.9872	97.21
28.5	1,935,310	9,898	0.0051	0.9949	95.97
29.5	1,783,766	7,419	0.0042	0.9958	95.48
30.5	1,674,068	9,484	0.0057	0.9943	95.08
31.5	1,530,456	10,128	0.0066	0.9934	94.54
32.5	1,444,262	6,642	0.0046	0.9954	93.91
33.5	1,364,269	7,124	0.0052	0.9948	93.48
34.5	1,291,005	8,769	0.0068	0.9932	92.99
35.5	1,193,818		0.0000	1.0000	92.36
36.5	559,574		0.0000	1.0000	92.36
37.5	488,282		0.0000	1.0000	92.36
38.5	182,470		0.0000	1.0000	92.36

PACIFIC NORTHERN GAS LTD.

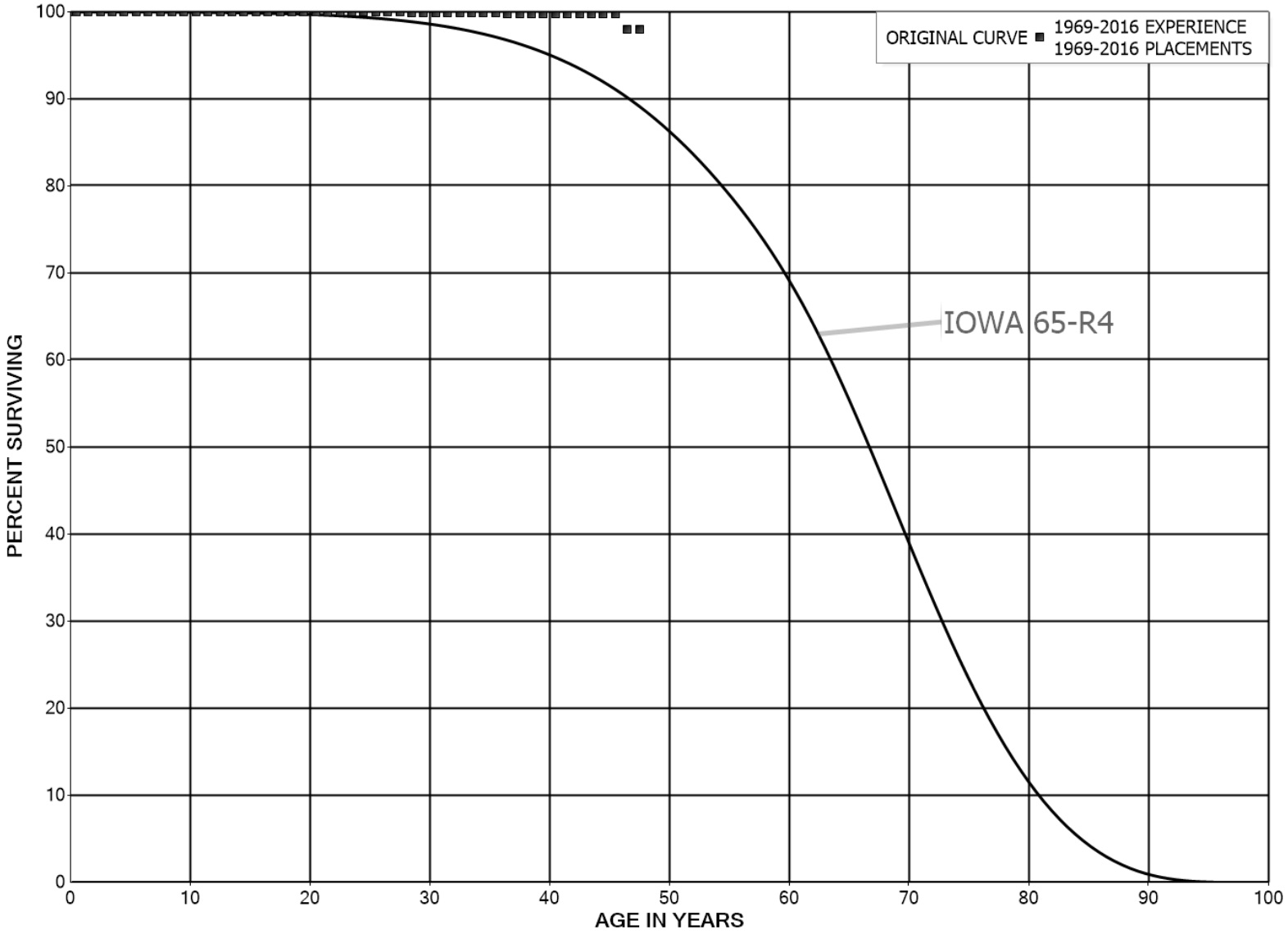
ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	114,233		0.0000	1.0000	92.36
40.5	67,424		0.0000	1.0000	92.36
41.5	26,653		0.0000	1.0000	92.36
42.5	7,200		0.0000	1.0000	92.36
43.5					92.36

PACIFIC NORTHERN GAS LTD.
ACCOUNT 475.00 - DISTRIBUTION - MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 475.00 - DISTRIBUTION - MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	74,584,969	30	0.0000	1.0000	100.00
0.5	71,005,565	56	0.0000	1.0000	100.00
1.5	67,991,169	51	0.0000	1.0000	100.00
2.5	65,156,837	399	0.0000	1.0000	100.00
3.5	62,721,539	2,002	0.0000	1.0000	100.00
4.5	60,604,335	792	0.0000	1.0000	100.00
5.5	59,040,782	1,074	0.0000	1.0000	99.99
6.5	56,451,938	781	0.0000	1.0000	99.99
7.5	53,179,368	764	0.0000	1.0000	99.99
8.5	50,751,813	628	0.0000	1.0000	99.99
9.5	49,607,570	459	0.0000	1.0000	99.99
10.5	48,915,352	1,058	0.0000	1.0000	99.99
11.5	47,664,881	912	0.0000	1.0000	99.99
12.5	46,152,252	593	0.0000	1.0000	99.98
13.5	45,184,606	472	0.0000	1.0000	99.98
14.5	44,468,828	3,619	0.0001	0.9999	99.98
15.5	43,511,278	3,829	0.0001	0.9999	99.97
16.5	42,460,310	1,809	0.0000	1.0000	99.96
17.5	41,369,710	12,071	0.0003	0.9997	99.96
18.5	38,733,276	762	0.0000	1.0000	99.93
19.5	36,156,604	109	0.0000	1.0000	99.93
20.5	24,978,478	246	0.0000	1.0000	99.93
21.5	23,695,748	219	0.0000	1.0000	99.93
22.5	23,412,010	2,810	0.0001	0.9999	99.93
23.5	22,830,913	650	0.0000	1.0000	99.91
24.5	21,643,765	1,102	0.0001	0.9999	99.91
25.5	20,685,724	384	0.0000	1.0000	99.91
26.5	17,548,126	514	0.0000	1.0000	99.91
27.5	16,481,053	5,678	0.0003	0.9997	99.90
28.5	16,021,682	7,025	0.0004	0.9996	99.87
29.5	15,511,515	1,480	0.0001	0.9999	99.82
30.5	14,857,801	254	0.0000	1.0000	99.81
31.5	14,463,835	38	0.0000	1.0000	99.81
32.5	13,538,831	155	0.0000	1.0000	99.81
33.5	12,779,186	39	0.0000	1.0000	99.81
34.5	9,885,377	1,381	0.0001	0.9999	99.81
35.5	8,960,967	3,535	0.0004	0.9996	99.80
36.5	5,278,230	570	0.0001	0.9999	99.76
37.5	4,597,818	873	0.0002	0.9998	99.75
38.5	4,233,462		0.0000	1.0000	99.73

PACIFIC NORTHERN GAS LTD.

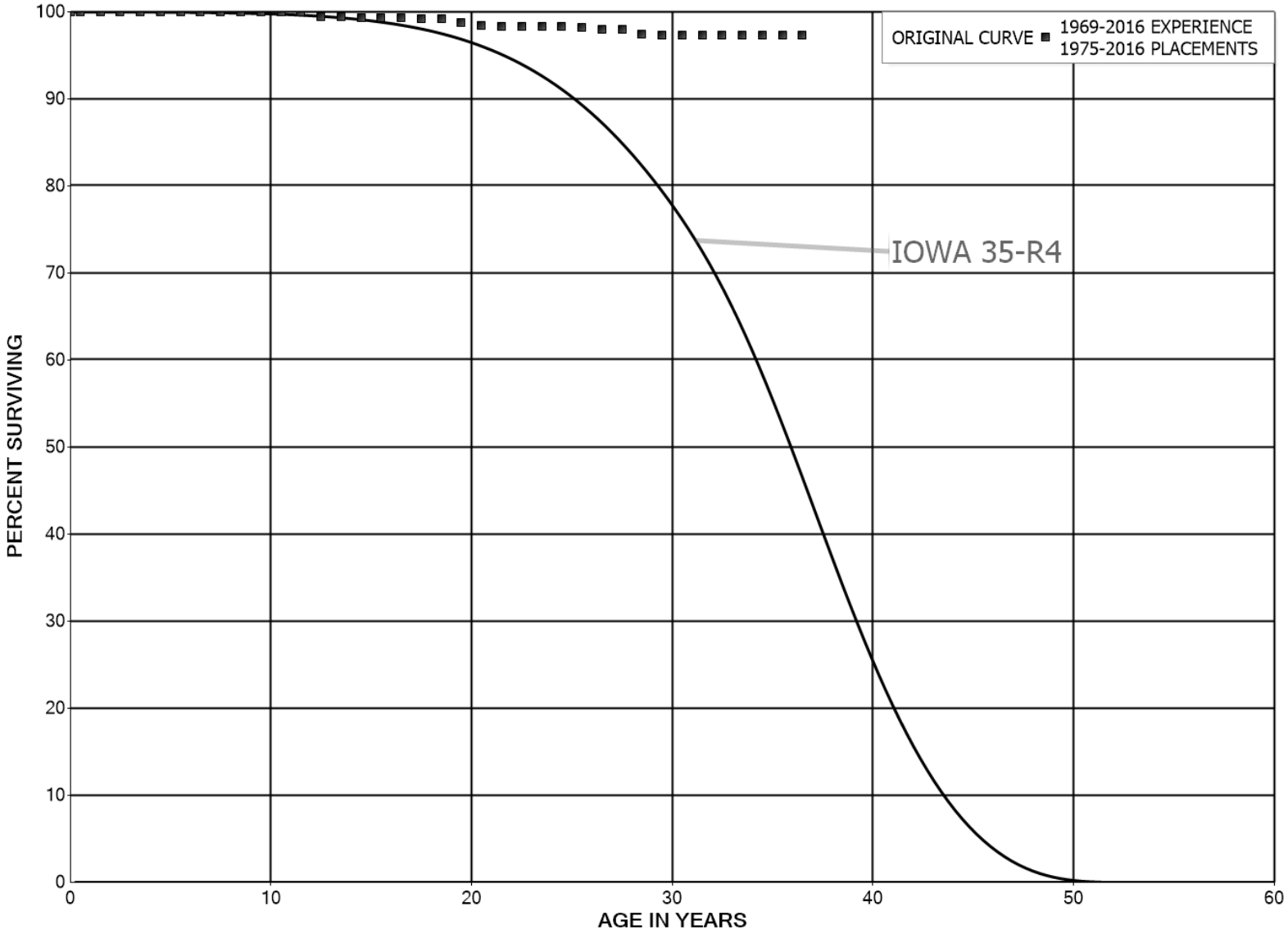
ACCOUNT 475.00 - DISTRIBUTION - MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,671,182		0.0000	1.0000	99.73
40.5	3,375,560		0.0000	1.0000	99.73
41.5	3,093,660		0.0000	1.0000	99.73
42.5	2,833,262		0.0000	1.0000	99.73
43.5	2,437,770		0.0000	1.0000	99.73
44.5	2,014,111		0.0000	1.0000	99.73
45.5	1,743,129	30,104	0.0173	0.9827	99.73
46.5	1,256,817		0.0000	1.0000	98.01
47.5					98.01

PACIFIC NORTHERN GAS LTD.
ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

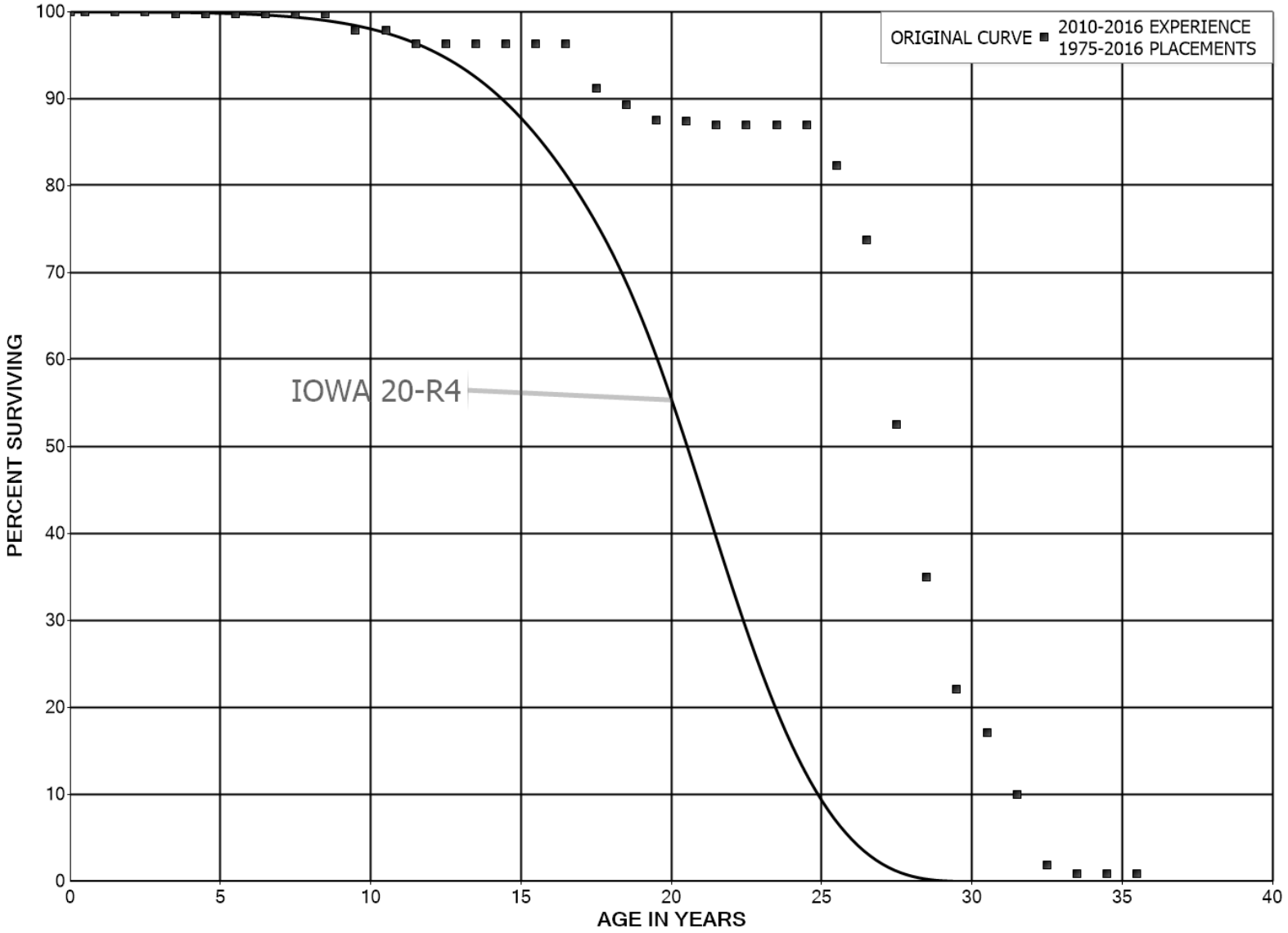
ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,362,396		0.0000	1.0000	100.00
0.5	2,209,066	3	0.0000	1.0000	100.00
1.5	2,209,063	2	0.0000	1.0000	100.00
2.5	2,209,061		0.0000	1.0000	100.00
3.5	2,209,061	12	0.0000	1.0000	100.00
4.5	2,124,992	6	0.0000	1.0000	100.00
5.5	2,082,978		0.0000	1.0000	100.00
6.5	1,924,842		0.0000	1.0000	100.00
7.5	1,878,262		0.0000	1.0000	100.00
8.5	1,878,262		0.0000	1.0000	100.00
9.5	1,838,158		0.0000	1.0000	100.00
10.5	1,792,249	76	0.0000	1.0000	100.00
11.5	1,789,775	10,833	0.0061	0.9939	99.99
12.5	1,710,547	67	0.0000	1.0000	99.39
13.5	1,681,629	1,314	0.0008	0.9992	99.39
14.5	1,019,956	346	0.0003	0.9997	99.31
15.5	947,326	166	0.0002	0.9998	99.27
16.5	897,072	565	0.0006	0.9994	99.26
17.5	896,507	120	0.0001	0.9999	99.19
18.5	896,387	3,839	0.0043	0.9957	99.18
19.5	892,548	3,394	0.0038	0.9962	98.76
20.5	889,154	492	0.0006	0.9994	98.38
21.5	888,115		0.0000	1.0000	98.33
22.5	883,292		0.0000	1.0000	98.33
23.5	883,292	85	0.0001	0.9999	98.33
24.5	878,922	1,107	0.0013	0.9987	98.32
25.5	807,687	1,684	0.0021	0.9979	98.19
26.5	728,359	187	0.0003	0.9997	97.99
27.5	721,700	3,787	0.0052	0.9948	97.96
28.5	667,447	1,178	0.0018	0.9982	97.45
29.5	666,269	78	0.0001	0.9999	97.28
30.5	611,788		0.0000	1.0000	97.27
31.5	567,906		0.0000	1.0000	97.27
32.5	567,906		0.0000	1.0000	97.27
33.5	567,906		0.0000	1.0000	97.27
34.5	567,906		0.0000	1.0000	97.27
35.5	566,852		0.0000	1.0000	97.27
36.5	20,626		0.0000	1.0000	97.27
37.5	20,626		0.0000	1.0000	97.27
38.5					97.27

PACIFIC NORTHERN GAS LTD.
ACCOUNT 478.00 - DISTRIBUTION - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

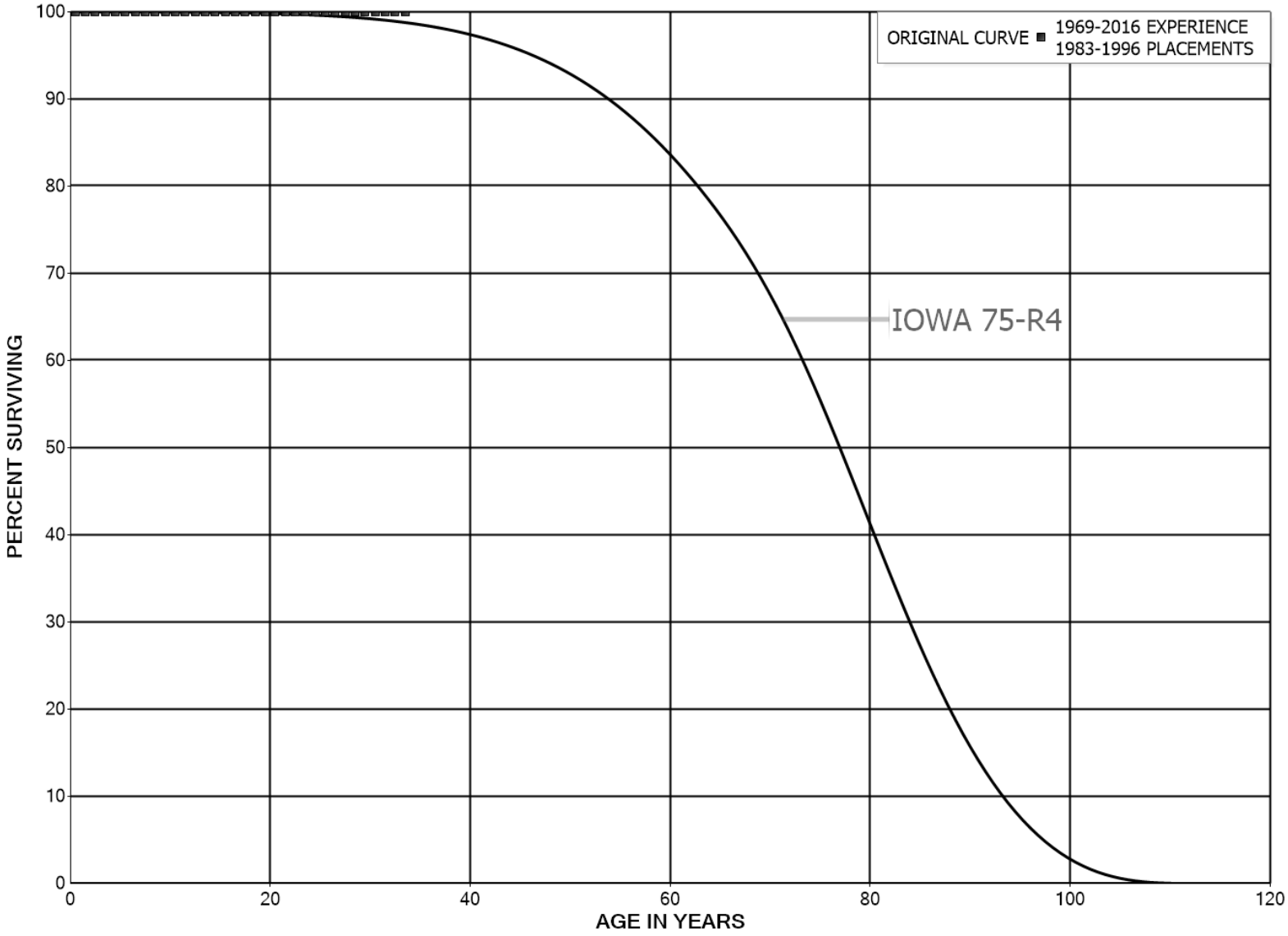
ACCOUNT 478.00 - DISTRIBUTION - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2016 EXPERIENCE BAND 2010-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,604,543		0.0000	1.0000	100.00
0.5	2,417,581	876	0.0004	0.9996	100.00
1.5	2,236,112	1,172	0.0005	0.9995	99.96
2.5	1,992,669	2,711	0.0014	0.9986	99.91
3.5	1,700,050	792	0.0005	0.9995	99.78
4.5	1,348,425		0.0000	1.0000	99.73
5.5	1,164,617		0.0000	1.0000	99.73
6.5	1,147,793		0.0000	1.0000	99.73
7.5	984,674		0.0000	1.0000	99.73
8.5	765,051	14,190	0.0185	0.9815	99.73
9.5	609,753		0.0000	1.0000	97.88
10.5	1,054,819	17,674	0.0168	0.9832	97.88
11.5	1,055,993		0.0000	1.0000	96.24
12.5	1,299,057		0.0000	1.0000	96.24
13.5	1,328,544		0.0000	1.0000	96.24
14.5	1,342,039		0.0000	1.0000	96.24
15.5	1,515,749		0.0000	1.0000	96.24
16.5	1,775,086	94,040	0.0530	0.9470	96.24
17.5	1,504,608	31,413	0.0209	0.9791	91.14
18.5	1,661,267	31,239	0.0188	0.9812	89.24
19.5	1,831,911	3,362	0.0018	0.9982	87.56
20.5	1,816,737	10,085	0.0056	0.9944	87.40
21.5	1,937,515		0.0000	1.0000	86.91
22.5	1,808,923		0.0000	1.0000	86.91
23.5	1,727,804		0.0000	1.0000	86.91
24.5	1,663,272	87,632	0.0527	0.9473	86.91
25.5	1,446,467	151,167	0.1045	0.8955	82.33
26.5	1,106,866	319,254	0.2884	0.7116	73.73
27.5	999,208	333,363	0.3336	0.6664	52.46
28.5	935,246	346,405	0.3704	0.6296	34.96
29.5	1,066,320	240,454	0.2255	0.7745	22.01
30.5	1,000,260	418,040	0.4179	0.5821	17.05
31.5	642,159	521,787	0.8126	0.1874	9.92
32.5	126,723	67,725	0.5344	0.4656	1.86
33.5	59,099		0.0000	1.0000	0.87
34.5	59,157	621	0.0105	0.9895	0.87
35.5	58,537	1,953	0.0334	0.9666	0.86
36.5					0.83

PACIFIC NORTHERN GAS LTD.
ACCOUNT 481.00 - GENERAL - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

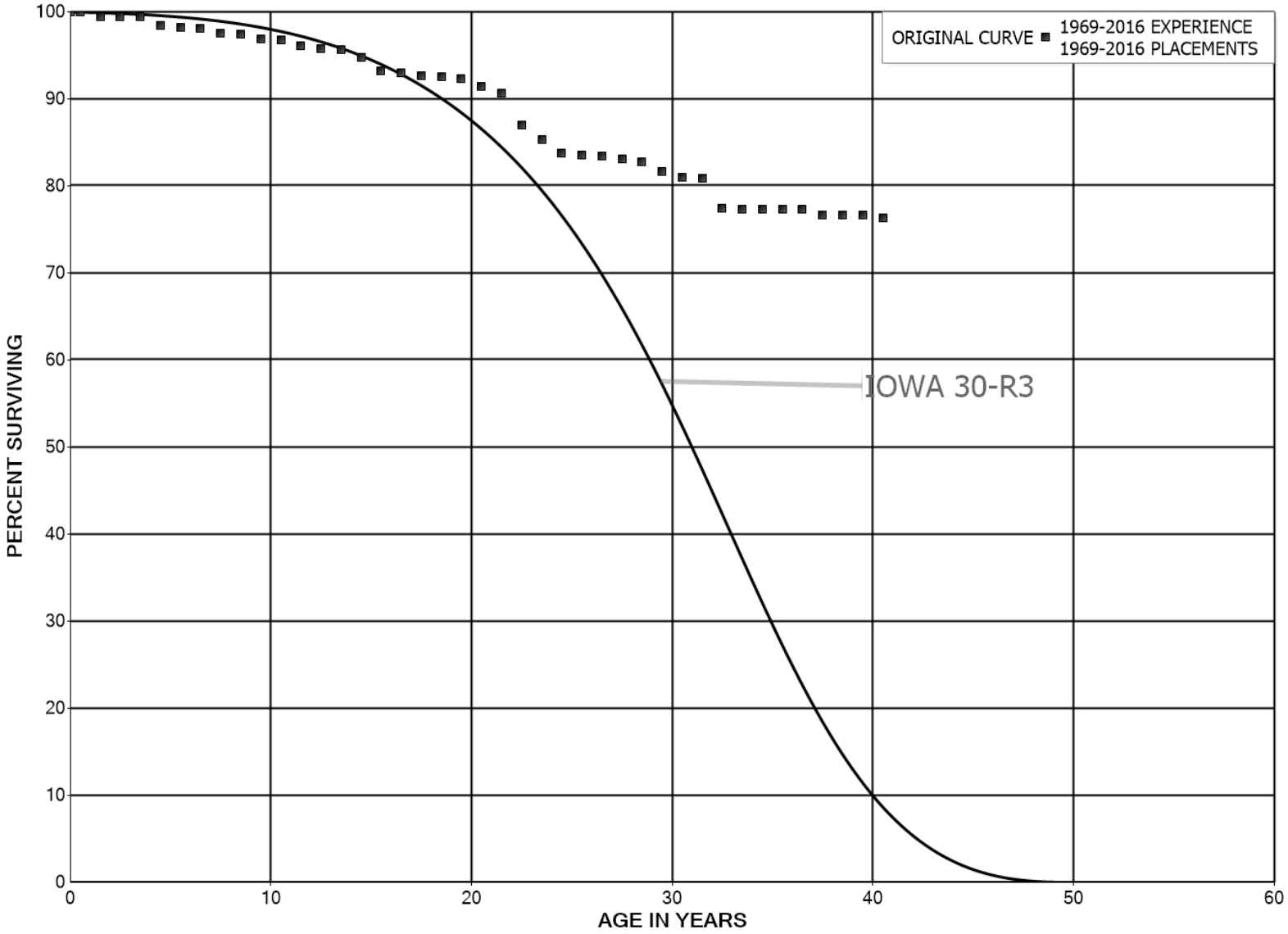
ACCOUNT 481.00 - GENERAL - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-1996 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,729		0.0000	1.0000	100.00
0.5	1,729		0.0000	1.0000	100.00
1.5	1,729		0.0000	1.0000	100.00
2.5	1,729		0.0000	1.0000	100.00
3.5	1,729		0.0000	1.0000	100.00
4.5	1,729		0.0000	1.0000	100.00
5.5	1,729		0.0000	1.0000	100.00
6.5	1,729		0.0000	1.0000	100.00
7.5	1,729		0.0000	1.0000	100.00
8.5	1,729		0.0000	1.0000	100.00
9.5	1,729		0.0000	1.0000	100.00
10.5	1,729		0.0000	1.0000	100.00
11.5	1,729		0.0000	1.0000	100.00
12.5	1,729		0.0000	1.0000	100.00
13.5	1,729		0.0000	1.0000	100.00
14.5	1,729		0.0000	1.0000	100.00
15.5	1,729		0.0000	1.0000	100.00
16.5	1,729		0.0000	1.0000	100.00
17.5	1,729		0.0000	1.0000	100.00
18.5	1,729		0.0000	1.0000	100.00
19.5	1,729		0.0000	1.0000	100.00
20.5	350		0.0000	1.0000	100.00
21.5	350		0.0000	1.0000	100.00
22.5	350		0.0000	1.0000	100.00
23.5	350		0.0000	1.0000	100.00
24.5	350		0.0000	1.0000	100.00
25.5	350		0.0000	1.0000	100.00
26.5	350		0.0000	1.0000	100.00
27.5	350		0.0000	1.0000	100.00
28.5	350		0.0000	1.0000	100.00
29.5	350		0.0000	1.0000	100.00
30.5	350		0.0000	1.0000	100.00
31.5	50		0.0000	1.0000	100.00
32.5	50		0.0000	1.0000	100.00
33.5					100.00

PACIFIC NORTHERN GAS LTD.
ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,833,107	199	0.0000	1.0000	100.00
0.5	9,343,285	53,280	0.0057	0.9943	100.00
1.5	9,083,047	1,452	0.0002	0.9998	99.43
2.5	8,991,785	5,404	0.0006	0.9994	99.41
3.5	7,998,133	79,948	0.0100	0.9900	99.35
4.5	7,798,573	17,362	0.0022	0.9978	98.36
5.5	7,728,701	4,036	0.0005	0.9995	98.14
6.5	7,534,093	48,203	0.0064	0.9936	98.09
7.5	7,286,639	3,562	0.0005	0.9995	97.46
8.5	7,070,226	42,496	0.0060	0.9940	97.41
9.5	7,005,804	9,977	0.0014	0.9986	96.83
10.5	6,941,426	45,578	0.0066	0.9934	96.69
11.5	6,792,588	24,191	0.0036	0.9964	96.06
12.5	6,594,080	8,877	0.0013	0.9987	95.71
13.5	6,538,757	55,264	0.0085	0.9915	95.58
14.5	6,469,660	106,973	0.0165	0.9835	94.78
15.5	6,316,999	17,512	0.0028	0.9972	93.21
16.5	6,225,456	20,216	0.0032	0.9968	92.95
17.5	6,172,530	10,750	0.0017	0.9983	92.65
18.5	6,017,190	10,992	0.0018	0.9982	92.49
19.5	5,125,026	53,111	0.0104	0.9896	92.32
20.5	4,510,870	37,011	0.0082	0.9918	91.36
21.5	3,442,027	137,075	0.0398	0.9602	90.61
22.5	2,660,706	51,356	0.0193	0.9807	87.00
23.5	2,609,350	49,801	0.0191	0.9809	85.32
24.5	2,550,821	6,308	0.0025	0.9975	83.70
25.5	2,527,556	2,356	0.0009	0.9991	83.49
26.5	2,498,063	9,836	0.0039	0.9961	83.41
27.5	2,472,498	11,237	0.0045	0.9955	83.08
28.5	2,174,541	28,476	0.0131	0.9869	82.71
29.5	2,088,225	16,460	0.0079	0.9921	81.62
30.5	1,795,465	2,833	0.0016	0.9984	80.98
31.5	1,729,040	73,556	0.0425	0.9575	80.85
32.5	1,613,429	1,654	0.0010	0.9990	77.41
33.5	1,492,887	143	0.0001	0.9999	77.33
34.5	1,123,141	476	0.0004	0.9996	77.32
35.5	1,109,452	6	0.0000	1.0000	77.29
36.5	694,858	6,470	0.0093	0.9907	77.29
37.5	688,388	10	0.0000	1.0000	76.57
38.5	687,731	38	0.0001	0.9999	76.57

PACIFIC NORTHERN GAS LTD.

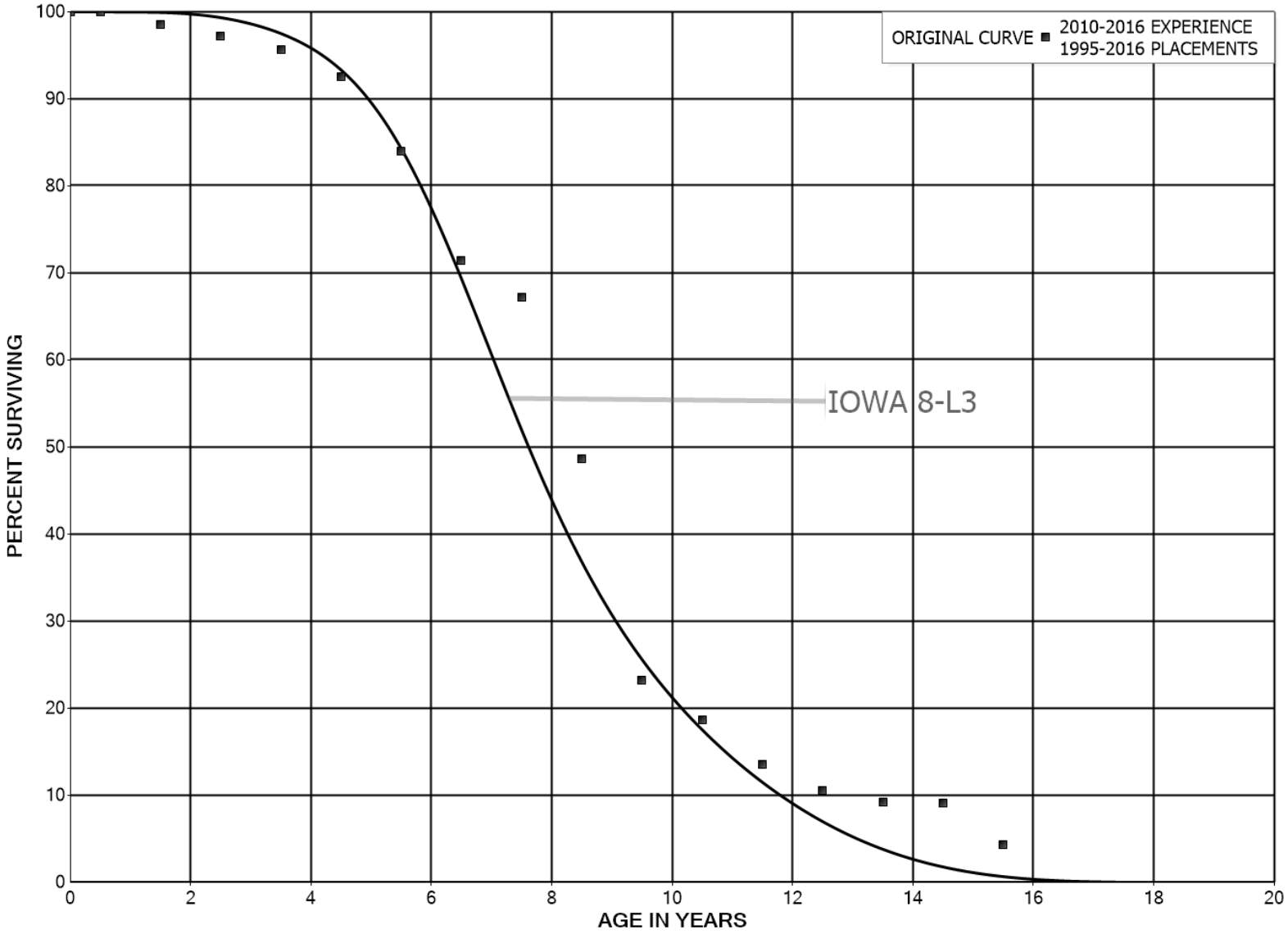
ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2016 EXPERIENCE BAND 1969-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	684,936	2,149	0.0031	0.9969	76.57
40.5	630,810		0.0000	1.0000	76.33
41.5	151,679	89,630	0.5909	0.4091	76.33
42.5	67,291		0.0000	1.0000	31.22
43.5	6,065		0.0000	1.0000	31.22
44.5	6,065		0.0000	1.0000	31.22
45.5					31.22

PACIFIC NORTHERN GAS LTD.
ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

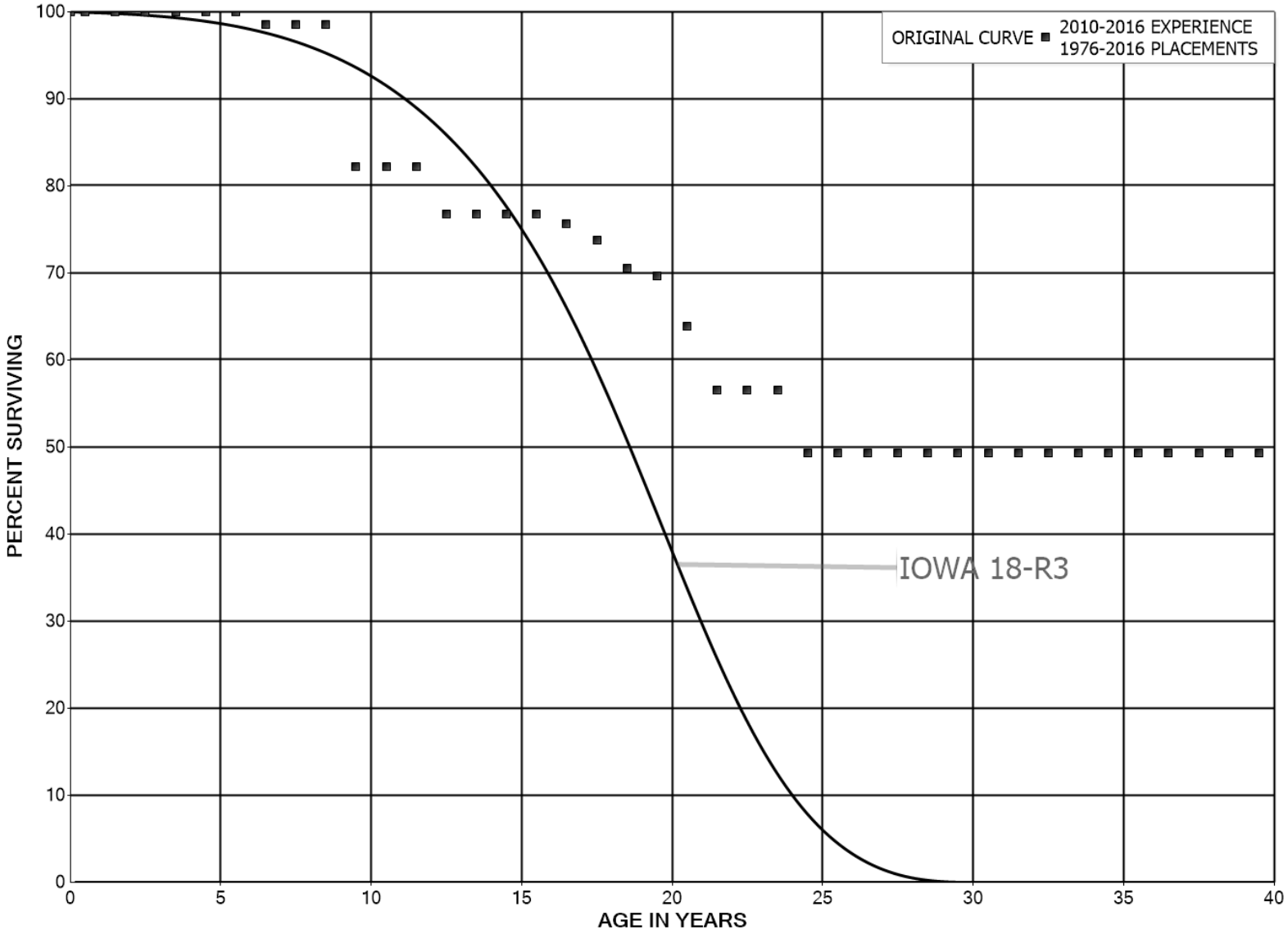
ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2016 EXPERIENCE BAND 2010-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,556,910		0.0000	1.0000	100.00
0.5	3,067,272	45,921	0.0150	0.9850	100.00
1.5	2,755,226	37,813	0.0137	0.9863	98.50
2.5	2,634,826	40,566	0.0154	0.9846	97.15
3.5	2,729,887	91,268	0.0334	0.9666	95.66
4.5	2,593,041	238,457	0.0920	0.9080	92.46
5.5	2,463,168	368,568	0.1496	0.8504	83.95
6.5	2,166,016	128,220	0.0592	0.9408	71.39
7.5	2,278,915	628,835	0.2759	0.7241	67.17
8.5	1,822,092	952,658	0.5228	0.4772	48.63
9.5	951,503	188,065	0.1977	0.8023	23.21
10.5	491,610	134,705	0.2740	0.7260	18.62
11.5	366,323	82,285	0.2246	0.7754	13.52
12.5	350,957	45,479	0.1296	0.8704	10.48
13.5	275,325	1,884	0.0068	0.9932	9.12
14.5	222,478	116,359	0.5230	0.4770	9.06
15.5	70,228	70,228	1.0000		4.32
16.5					

PACIFIC NORTHERN GAS LTD.
ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1976-2016 EXPERIENCE BAND 2010-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,179,827		0.0000	1.0000	100.00
0.5	2,098,291		0.0000	1.0000	100.00
1.5	2,063,860		0.0000	1.0000	100.00
2.5	2,419,295		0.0000	1.0000	100.00
3.5	2,759,725		0.0000	1.0000	100.00
4.5	2,836,066		0.0000	1.0000	100.00
5.5	2,880,635	42,906	0.0149	0.9851	100.00
6.5	2,924,531		0.0000	1.0000	98.51
7.5	2,402,031		0.0000	1.0000	98.51
8.5	2,146,591	355,912	0.1658	0.8342	98.51
9.5	1,174,757		0.0000	1.0000	82.18
10.5	880,772		0.0000	1.0000	82.18
11.5	730,223	48,108	0.0659	0.9341	82.18
12.5	579,257		0.0000	1.0000	76.76
13.5	505,044		0.0000	1.0000	76.76
14.5	568,104		0.0000	1.0000	76.76
15.5	467,216	7,089	0.0152	0.9848	76.76
16.5	422,200	10,350	0.0245	0.9755	75.60
17.5	571,767	25,311	0.0443	0.9557	73.75
18.5	598,231	7,667	0.0128	0.9872	70.48
19.5	615,461	50,492	0.0820	0.9180	69.58
20.5	587,833	67,779	0.1153	0.8847	63.87
21.5	332,438		0.0000	1.0000	56.51
22.5	333,620		0.0000	1.0000	56.51
23.5	333,620	42,423	0.1272	0.8728	56.51
24.5	81,831		0.0000	1.0000	49.32
25.5	85,942		0.0000	1.0000	49.32
26.5	50,242		0.0000	1.0000	49.32
27.5	46,327		0.0000	1.0000	49.32
28.5	47,930		0.0000	1.0000	49.32
29.5	34,107		0.0000	1.0000	49.32
30.5	34,107		0.0000	1.0000	49.32
31.5	25,238		0.0000	1.0000	49.32
32.5	24,761		0.0000	1.0000	49.32
33.5	33,055		0.0000	1.0000	49.32
34.5	18,266		0.0000	1.0000	49.32
35.5	16,663		0.0000	1.0000	49.32
36.5	13,750		0.0000	1.0000	49.32
37.5	13,750		0.0000	1.0000	49.32
38.5	13,750		0.0000	1.0000	49.32
39.5	10,117		0.0000	1.0000	49.32
40.5					49.32

PART VI. NET SALVAGE STATISTICS

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	129,561	169,667	131	0		0		169,667-	131-
2015	126,630	172,774	136	0		0		172,774-	136-
2016	124,004	119,679	97	0		0		119,679-	97-
TOTAL	380,195	462,120	122	0		0		462,120-	122-
THREE-YEAR MOVING AVERAGES									
14-16	126,732	154,040	122	0		0		154,040-	122-

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	458,975		0		0	4,089	1	4,089	1
2015	432,374		0		0	3,827	1	3,827	1
2016	469,288		0		0	2,544	1	2,544	1
TOTAL	1,360,637		0		0	10,460	1	10,460	1
THREE-YEAR MOVING AVERAGES									
14-16	453,546		0		0	3,487	1	3,487	1

PACIFIC NORTHERN GAS LTD.

ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	361,872		0		0	51,050	14	51,050	14
2011	77,034		0		0	10,490	14	10,490	14
2012	240,863		0		0	16,285	7	16,285	7
2013	426,036		0		0	87,413	21	87,413	21
2014	590,698		0		0	75,487	13	75,487	13
2015	456,360		0		0	54,169	12	54,169	12
2016	1,018,448		0		0	227,240	22	227,240	22
TOTAL	3,171,311		0		0	522,133	16	522,133	16
THREE-YEAR MOVING AVERAGES									
10-12	226,589		0		0	25,942	11	25,942	11
11-13	247,978		0		0	38,063	15	38,063	15
12-14	419,199		0		0	59,728	14	59,728	14
13-15	491,031		0		0	72,356	15	72,356	15
14-16	688,502		0		0	118,965	17	118,965	17
FIVE-YEAR AVERAGE									
12-16	546,481		0		0	92,119	17	92,119	17

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2012	54,771		0		0	13,353	24	13,353	24
2013									
2014	200,248		0		0	15,000	7	15,000	7
2015									
2016	342,450		0		0	28,604	8	28,604	8
TOTAL	597,470		0		0	56,957	10	56,957	10
THREE-YEAR MOVING AVERAGES									
12-14	85,006		0		0	9,451	11	9,451	11
13-15	66,749		0		0	5,000	7	5,000	7
14-16	180,900		0		0	14,535	8	14,535	8
FIVE-YEAR AVERAGE									
12-16	119,494		0		0	11,391	10	11,391	10

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	3,893		0		0	125	3	125	3
2011	8,404		0		0		0		0
2012	15,633		0		0	5,125	33	5,125	33
2013	161,332		0		0		0		0
2014	2,500		0		0		0		0
2015	4,500		0		0		0		0
2016	35,749		0		0		0		0
TOTAL	232,012		0		0	5,250	2	5,250	2
THREE-YEAR MOVING AVERAGES									
10-12	9,310		0		0	1,750	19	1,750	19
11-13	61,790		0		0	1,708	3	1,708	3
12-14	59,822		0		0	1,708	3	1,708	3
13-15	56,111		0		0		0		0
14-16	14,250		0		0		0		0
FIVE-YEAR AVERAGE									
12-16	43,943		0		0	1,025	2	1,025	2

PART VII. DETAILED DEPRECIATION CALCULATIONS

PACIFIC NORTHERN GAS LTD.

ACCOUNT 411.00 - GATHERING PLANT - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1980	275.00	131		275	39.32	7
	275.00	131		275		7

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.3 2.55

PACIFIC NORTHERN GAS LTD.

ACCOUNT 412.00 - GATHERING PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -3						
1990	34,442.84	26,146	22,526	12,950	7.89	1,641
	34,442.84	26,146	22,526	12,950		1,641

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.9 4.76

PACIFIC NORTHERN GAS LTD.

ACCOUNT 413.00 - GATHERING PLANT - MEASURING AND REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -15						
1980	75,159.71	76,004	74,217	12,217	3.62	3,375
	75,159.71	76,004	74,217	12,217		3,375

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.6 4.49

PACIFIC NORTHERN GAS LTD.

ACCOUNT 417.00 - GATHERING PLANT - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. -7						
2000	29,701.25	16,780	16,287	15,493	11.80	1,313
	29,701.25	16,780	16,287	15,493		1,313

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.8 4.42

PACIFIC NORTHERN GAS LTD.

ACCOUNT 418.00- GATHERING PLANT - PURIFICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 31-S5						
NET SALVAGE PERCENT.. -25						
1990	2,131,654.03	2,210,738	2,136,728	527,840	5.28	99,970
2000	59,112.21	39,329	38,012	35,878	14.50	2,474
2001	84,502.30	52,814	51,046	54,582	15.50	3,521
2002	41,472.49	24,248	23,436	28,405	16.50	1,722
2003	41,105.45	22,376	21,627	29,755	17.50	1,700
2004	80,184.24	40,416	39,063	61,167	18.50	3,306
2005	112,335.11	52,091	50,347	90,072	19.50	4,619
2006	60,438.84	25,589	24,732	50,817	20.50	2,479
2007	111,076.30	42,549	41,125	97,720	21.50	4,545
2008	97,399.41	33,382	32,264	89,485	22.50	3,977
2009	156,349.01	47,284	45,701	149,735	23.50	6,372
2010	273,285.67	71,628	69,230	272,377	24.50	11,117
2011	197,930.65	43,896	42,427	204,986	25.50	8,039
2012	91,549.12	16,612	16,056	98,380	26.50	3,712
2014	22,737.18	2,292	2,215	26,206	28.50	920
2016	188,463.07	3,800	3,673	231,906	30.50	7,603
	3,749,595.08	2,729,044	2,637,682	2,049,312		166,076

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.3 4.43

PACIFIC NORTHERN GAS LTD.

ACCOUNT 443.00 - PROCESSING PLANT - GAS HOLDERS - STORAGE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	30,000.00	14,625	13,113	16,887	20.50	824
	30,000.00	14,625	13,113	16,887		824

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.5 2.75

PACIFIC NORTHERN GAS LTD.

ACCOUNT 449.00 - PROCESSING PLANT - OTHER LOCAL STORAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-R3						
NET SALVAGE PERCENT.. 0						
1997	3,200.00	1,713	2,111	1,089	15.33	71
	3,200.00	1,713	2,111	1,089		71

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.3 2.22

PACIFIC NORTHERN GAS LTD.

ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1968	296,958.82	182,728	10,527	286,432	28.85	9,928
1970	92,594.85	54,927	3,164	89,430	30.51	2,931
1971	65,680.01	38,226	2,202	63,478	31.35	2,025
1972	29,748.57	16,972	978	28,771	32.21	893
1973	5,886.96	3,291	190	5,697	33.07	172
1974	285.13	156	9	276	33.94	8
1975	320.54	172	10	311	34.81	9
1976	9,698.29	5,082	293	9,406	35.70	263
1977	1,394.00	714	41	1,353	36.59	37
1978	1,478.45	739	43	1,436	37.49	38
1980	120.05	57	3	117	39.32	3
1981	308,028.30	142,762	8,225	299,804	40.24	7,450
1982	49,730.05	22,438	1,293	48,437	41.16	1,177
1983	101,521.35	44,534	2,566	98,956	42.10	2,350
1984	12,479.08	5,318	306	12,173	43.04	283
1985	10,740.05	4,442	256	10,484	43.98	238
1986	39,950.77	16,017	923	39,028	44.93	869
1987	29,691.01	11,528	664	29,027	45.88	633
1988	12,609.72	4,735	273	12,337	46.84	263
1989	50,070.09	18,159	1,046	49,024	47.80	1,026
1990	53,549.00	18,728	1,079	52,470	48.77	1,076
1991	5,240.82	1,766	102	5,139	49.73	103
1992	440.39	143	8	432	50.71	9
1993	13,227.28	4,113	237	12,990	51.68	251
1994	45,315.96	13,498	778	44,538	52.66	846
	1,236,759.54	611,245	35,215	1,201,545		32,881
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1996	70,475.07	19,150	47,894	22,581	54.62	413
2015	214,145.24	4,283	10,712	203,433	73.50	2,768
	284,620.31	23,433	58,606	226,014		3,181

PACIFIC NORTHERN GAS LTD.

ACCOUNT 461.00 - TRANSMISSION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1990	10,967.40	3,836		10,967	48.77	225
2013	78,734.45	3,675		78,734	71.50	1,101
2014	57,887.01	1,929		57,887	72.50	798
2016	27,077.40	181		27,077	74.50	363
	174,666.26	9,621		174,666		2,487
	1,696,046.11	644,299	93,821	1,602,225		38,549

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.6 2.27

PACIFIC NORTHERN GAS LTD.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -3						
1969	299,496.05	298,199	304,359	4,122	1.00	4,122
1970	3,030.96	3,018	3,080	42	1.00	42
1972	1,920.04	1,912	1,951	26	1.00	26
1973	1,817.75	1,810	1,847	25	1.00	25
1974	584.10	582	594	8	1.00	8
1975	726.71	724	739	10	1.00	10
1976	3,136.84	3,108	3,172	59	1.14	52
1977	593.43	583	595	16	1.38	12
1980	3,731.57	3,567	3,641	203	2.16	94
1982	1,272,570.06	1,191,469	1,216,081	94,666	2.73	34,676
1983	15,010.29	13,894	14,181	1,280	3.04	421
1984	114,988.38	105,094	107,265	11,173	3.38	3,306
1985	14,763.72	13,306	13,581	1,626	3.75	434
1986	11,153.66	9,895	10,099	1,389	4.16	334
1987	22,151.27	19,295	19,694	3,122	4.63	674
1988	18,948.43	16,166	16,500	3,017	5.15	586
1989	1,562.63	1,303	1,330	280	5.72	49
1990	25,033.92	20,336	20,756	5,029	6.34	793
1991	141,605.25	111,821	114,131	31,723	7.00	4,532
1992	58,539.28	44,860	45,787	14,509	7.68	1,889
1993	136,204.87	101,056	103,144	37,147	8.39	4,428
1994	91,268.58	65,429	66,781	27,226	9.12	2,985
1995	88,758.62	61,344	62,611	28,810	9.87	2,919
1996	11,746.00	7,803	7,964	4,134	10.65	388
1997	63,633.55	40,505	41,342	24,201	11.46	2,112
1998	35,029.88	21,300	21,740	14,341	12.29	1,167
1999	141,930.30	82,158	83,855	62,333	13.14	4,744
2000	19,737.06	10,835	11,059	9,270	14.01	662
2003	5,387.92	2,451	2,502	3,048	16.75	182
2004	10,778.31	4,555	4,649	6,453	17.69	365
2005	81,767.39	31,892	32,551	51,670	18.64	2,772
2006	99,182.23	35,415	36,147	66,011	19.60	3,368
2007	15,288.00	4,950	5,052	10,694	20.57	520
2008	4,901.11	1,422	1,451	3,597	21.55	167
2009	5,814.84	1,489	1,520	4,470	22.54	198
2011	18,888.43	3,554	3,627	15,828	24.52	646
2013	59,061.55	7,077	7,223	53,610	26.51	2,022
	2,900,742.98	2,344,177	2,392,601	595,165		81,730

PACIFIC NORTHERN GAS LTD.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -3						
1996	15,352.66	10,200	9,597	6,216	10.65	584
1998	382,528.81	232,593	218,845	175,160	12.29	14,252
1999	67,163.42	38,878	36,580	32,598	13.14	2,481
	465,044.89	281,671	265,022	213,974		17,317
	3,365,787.87	2,625,848	2,657,623	809,139		99,047
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.2	2.94

PACIFIC NORTHERN GAS LTD.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 39-R4						
NET SALVAGE PERCENT.. -15						
1969	98,454.43	105,094	113,223			
1970	8,004.87	8,481	9,206			
1971	5,425.16	5,701	6,239			
1972	1,890.17	1,970	2,174			
1973	808.52	835	930			
1975	2,294.22	2,323	2,597	41	4.66	9
1976	3,441.50	3,445	3,851	106	5.05	21
1977	2,838.12	2,805	3,136	128	5.48	23
1978	3,144.89	3,065	3,426	190	5.95	32
1980	23,080.67	21,779	24,347	2,196	7.00	314
1981	27,899.44	25,840	28,887	3,197	7.59	421
1982	147,135.53	133,586	149,338	19,868	8.21	2,420
1983	10,521.06	9,347	10,449	1,650	8.87	186
1984	28,910.06	25,114	28,075	5,171	9.54	542
1985	76,850.03	65,195	72,883	15,495	10.23	1,515
1986	38,259.47	31,656	35,389	8,610	10.94	787
1987	44,362.94	35,751	39,967	11,051	11.67	947
1988	226,989.59	177,908	198,887	62,151	12.42	5,004
1989	56,701.91	43,170	48,261	16,947	13.18	1,286
1990	25,453.68	18,786	21,001	8,271	13.97	592
1991	74,813.14	53,452	59,755	26,280	14.77	1,779
1992	82,398.99	56,855	63,559	31,200	15.60	2,000
1993	20,616.79	13,715	15,332	8,377	16.44	510
1994	20,528.84	13,136	14,685	8,923	17.30	516
1995	28,062.08	17,236	19,268	13,003	18.17	716
1999	8,533.14	4,323	4,833	4,980	21.82	228
2002	1,484.00	627	701	1,006	24.66	41
2003	30,321.43	11,954	13,364	21,506	25.63	839
2004	8,838.20	3,232	3,613	6,551	26.60	246
2005	56,747.66	19,109	21,362	43,898	27.58	1,592
2006	4,339.50	1,336	1,494	3,497	28.56	122
2007	91,366.87	25,486	28,491	76,581	29.54	2,592
2008	4,650.00	1,161	1,298	4,050	30.53	133
2016	16,676.08	246	275	18,902	38.50	491
	1,281,842.98	943,719	1,050,295	423,825		25,904

PACIFIC NORTHERN GAS LTD.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 39-R4						
NET SALVAGE PERCENT.. -15						
1996	83,483.54	49,086	50,113	45,893	19.06	2,408
	83,483.54	49,086	50,113	45,893		2,408
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 39-R4						
NET SALVAGE PERCENT.. -15						
1978	3,568.45	3,478	3,482	622	5.95	105
1990	912.88	674	675	375	13.97	27
2003	30,066.02	11,853	11,866	22,710	25.63	886
2004	28,191.47	10,308	10,320	22,101	26.60	831
2016	63,132.87	931	932	71,671	38.50	1,862
	125,871.69	27,244	27,275	117,478		3,711
	1,491,198.21	1,020,049	1,127,683	587,196		32,023

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.3 2.15

PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1969	17,380,047.36	14,217,365	15,607,290	5,248,767	20.69	253,686
1970	420,941.37	338,361	371,440	133,690	21.46	6,230
1971	53,145.06	41,963	46,065	17,709	22.23	797
1972	519,367.77	402,520	441,871	181,370	23.02	7,879
1973	44,805.00	34,071	37,402	16,364	23.81	687
1974	1,974,935.05	1,472,267	1,616,199	753,723	24.62	30,614
1975	282,899.30	206,614	226,813	112,666	25.44	4,429
1976	114,818.79	82,098	90,124	47,658	26.27	1,814
1977	68,231.88	47,716	52,381	29,497	27.12	1,088
1978	21,867.79	14,949	16,410	9,831	27.97	351
1979	1,051,828.43	702,361	771,026	491,169	28.83	17,037
1980	325,587.76	212,184	232,928	157,778	29.70	5,312
1981	609,567.99	387,349	425,217	306,264	30.58	10,015
1982	24,696,098.92	15,287,379	16,781,911	12,853,407	31.47	408,434
1983	968,064.71	583,162	640,173	521,504	32.37	16,111
1984	807,771.32	473,031	519,276	450,050	33.28	13,523
1985	162,053.53	92,147	101,156	93,309	34.20	2,728
1986	5,375,832.37	2,965,460	3,255,371	3,195,628	35.12	90,992
1987	897,363.88	479,602	526,489	550,348	36.05	15,266
1988	4,245,313.62	2,195,269	2,409,884	2,684,492	36.99	72,573
1989	1,029,044.30	514,267	564,543	670,310	37.93	17,672
1990	8,743,215.53	4,216,153	4,628,335	5,863,524	38.88	150,811
1991	2,006,999.34	932,604	1,023,778	1,384,622	39.83	34,763
1992	3,249,428.77	1,452,339	1,594,323	2,304,991	40.79	56,509
1993	6,298,443.63	2,703,468	2,967,766	4,590,367	41.75	109,949
1994	9,351,457.01	3,846,479	4,222,520	6,999,228	42.72	163,840
1995	8,980,127.01	3,532,962	3,878,353	6,897,799	43.69	157,880
1996	2,381,432.99	894,238	981,661	1,876,059	44.66	42,008
1997	1,442,443.88	515,558	565,960	1,164,972	45.64	25,525
1998	3,178,422.65	1,078,515	1,183,953	2,630,154	46.62	56,417
1999	5,946,251.83	1,910,103	2,096,839	5,038,663	47.60	105,854
2000	3,011,149.35	912,812	1,002,051	2,611,328	48.58	53,753
2001	731,933.38	208,496	228,879	649,441	49.57	13,101
2002	2,150,515.18	573,284	629,330	1,951,289	50.56	38,594
2003	1,372,877.27	340,891	374,217	1,273,235	51.55	24,699
2004	1,359,069.81	312,624	343,187	1,287,697	52.54	24,509
2005	6,921,218.43	1,465,582	1,608,861	6,696,601	53.53	125,100
2006	4,205,571.88	812,920	892,393	4,154,293	54.53	76,184
2007	3,853,629.31	674,462	740,399	3,883,956	55.52	69,956
2008	4,850,373.18	759,336	833,571	4,986,877	56.52	88,232
2009	2,923,042.50	404,187	443,701	3,063,950	57.51	53,277
2010	1,121,505.83	134,379	147,516	1,198,291	58.51	20,480

PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
2011	3,520,212.85	356,781	391,661	3,832,595	59.51	64,403
2012	2,150,153.82	178,239	195,664	2,384,520	60.51	39,407
2013	2,115,297.24	136,691	150,054	2,388,302	61.50	38,834
2014	480,152.44	22,160	24,326	551,857	62.50	8,830
2015	1,257,455.33	34,826	38,231	1,470,716	63.50	23,161
2016	1,029,528.51	9,500	10,429	1,225,005	64.50	18,992
	155,681,495.15	69,169,724	75,931,928	110,885,866		2,662,306
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1996	3,348,547.95	1,257,393	2,268,070	1,750,187	44.66	39,189
1997	105,760.40	37,801	68,185	58,727	45.64	1,287
1998	492,662.93	167,172	301,543	289,653	46.62	6,213
1999	109,864.44	35,292	63,659	68,178	47.60	1,432
2000	78,580.79	23,821	42,968	51,329	48.58	1,057
2003	3,553.94	882	1,591	2,674	51.55	52
2006	22,367.96	4,324	7,800	19,042	54.53	349
2007	87,430.90	15,302	27,602	77,316	55.52	1,393
2008	65,003.79	10,176	18,355	59,649	56.52	1,055
2009	83,763.81	11,583	20,893	79,623	57.51	1,385
2010	4,003.06	480	866	3,938	58.51	67
2011	22,179.04	2,248	4,055	22,560	59.51	379
2012	213,214.77	17,675	31,882	223,976	60.51	3,701
2015	2,103,466.59	58,258	105,085	2,419,075	63.50	38,096
2016	138,418.78	1,277	2,303	163,799	64.50	2,540
	6,878,819.15	1,643,684	2,964,857	5,289,726		98,195
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1970	10,388.55	8,351	9,537	2,929	21.46	136
1980	589,185.56	383,970	438,513	268,509	29.70	9,041
1990	1,043,295.67	503,098	574,564	677,391	38.88	17,423
2000	11,382.63	3,451	3,941	9,718	48.58	200
2001	110,897.25	31,590	36,077	96,999	49.57	1,957
2003	22,383.42	5,558	6,348	20,513	51.55	398

PACIFIC NORTHERN GAS LTD.

ACCOUNT 465.00 - TRANSMISSION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
2004	60,353.98	13,883	15,855	56,570	52.54	1,077
2009	113,856.77	15,744	17,980	118,648	57.51	2,063
2010	59,342.01	7,110	8,120	63,090	58.51	1,078
2012	123,347.96	10,225	11,677	136,340	60.51	2,253
2013	1,391,361.92	89,910	102,682	1,566,952	61.50	25,479
2014	2,024,908.91	93,454	106,729	2,323,161	62.50	37,171
2015	5,324.61	147	168	6,222	63.50	98
2016	261,817.27	2,416	2,759	311,422	64.50	4,828
	5,827,846.51	1,168,907	1,334,951	5,658,464		103,202
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1980	1,670,849.65	1,088,886	1,039,095	965,924	29.70	32,523
1990	45,285.77	21,838	20,839	33,503	38.88	862
2011	24,879.22	2,522	2,407	27,448	59.51	461
	1,741,014.64	1,113,246	1,062,341	1,026,876		33,846
	170,129,175.45	73,095,561	81,294,078	122,860,932		2,897,549
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					42.4	1.70

PACIFIC NORTHERN GAS LTD.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -2						
1969	717,052.22	671,002	731,393			
1970	18,164.36	16,860	18,528			
1971	8,118.03	7,474	8,280			
1972	7,914.94	7,224	8,073			
1973	5,018.51	4,541	5,119			
1974	2,916.92	2,615	2,975			
1975	6,553.50	5,816	6,685			
1982	8,747,857.95	7,061,784	8,351,055	571,760	7.30	78,323
1983	487,922.62	386,768	457,380	40,301	7.80	5,167
1984	1,098,759.23	854,325	1,010,299	110,435	8.32	13,273
1985	1,967,386.33	1,498,167	1,771,688	235,047	8.87	26,499
1986	3,000,929.07	2,234,492	2,642,443	418,504	9.45	44,286
1987	113,912.00	82,827	97,949	18,242	10.05	1,815
1988	44,106.75	31,261	36,968	8,021	10.68	751
1989	1,197,433.48	826,351	977,218	244,164	11.32	21,569
1990	20,693.95	13,877	16,411	4,697	11.99	392
1991	633,943.04	412,357	487,641	158,981	12.68	12,538
1992	88,140.63	55,509	65,643	24,260	13.39	1,812
1993	278,199.63	169,285	200,191	83,572	14.12	5,919
1994	513,257.99	301,251	356,250	167,273	14.86	11,257
1995	450,348.51	254,221	300,634	158,721	15.63	10,155
1996	790,721.05	428,617	506,870	299,666	16.40	18,272
1997	680,182.80	352,839	417,257	276,530	17.20	16,077
1998	56,668.02	28,075	33,201	24,601	18.00	1,367
1999	331,832.97	156,373	184,922	153,548	18.83	8,154
2000	250,003.56	111,766	132,171	122,832	19.66	6,248
2001	425,130.49	179,524	212,300	221,333	20.51	10,791
2002	424,716.18	168,580	199,358	233,853	21.38	10,938
2003	265,586.55	98,686	116,703	154,195	22.25	6,930
2004	519,050.53	179,403	212,157	317,275	23.14	13,711
2005	233,298.34	74,516	88,120	149,844	24.04	6,233
2006	27,761.57	8,131	9,615	18,701	24.95	750
2007	70,844.71	18,850	22,291	49,970	25.87	1,932
2008	12,824.62	3,065	3,625	9,457	26.80	353
2009	16,564.94	3,505	4,145	12,751	27.74	460
2010	34,858.50	6,410	7,580	27,975	28.69	975
2011	30,632.27	4,776	5,648	25,597	29.65	863
2012	161,404.64	20,650	24,420	140,213	30.61	4,581
2013	354,448.63	35,326	41,775	319,762	31.58	10,125

PACIFIC NORTHERN GAS LTD.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -2						
2014	401,868.36	28,693	33,931	375,974	32.55	11,551
2015	510,106.70	21,853	25,843	494,466	33.53	14,747
2016	189,789.77	2,710	3,205	190,381	34.51	5,517
	25,196,924.86	16,830,355	19,837,962	5,862,902		384,331
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -2						
1990	4,412.00	2,959	3,143	1,357	11.99	113
	4,412.00	2,959	3,143	1,357		113
	25,201,336.86	16,833,314	19,841,105	5,864,259		384,444
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.3	1.53

PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1969	155,081.23	145,598	165,937			
1970	91,632.28	85,385	98,047			
1971	11,851.07	10,960	12,681			
1972	39,808.64	36,522	42,595			
1973	28,863.99	26,261	30,884			
1974	8,158.30	7,355	8,729			
1975	22,965.44	20,515	24,573			
1976	808.11	715	865			
1977	2,043.79	1,789	2,187			
1978	504.17	437	539			
1979	1,925.57	1,648	2,060			
1980	10,510.57	8,888	11,246			
1981	223,582.51	186,533	236,070	3,163	7.71	410
1982	41,009.75	33,738	42,698	1,183	8.09	146
1983	8,062.96	6,537	8,273	354	8.48	42
1984	125,237.19	99,928	126,465	7,538	8.90	847
1985	93,121.81	73,050	92,450	7,191	9.34	770
1986	90,029.92	69,331	87,743	8,589	9.81	876
1987	165,087.16	124,659	157,764	18,879	10.30	1,833
1988	673,421.32	498,008	630,262	90,299	10.81	8,353
1989	30,208.49	21,841	27,641	4,682	11.35	413
1990	75,723.67	53,430	67,619	13,405	11.92	1,125
1991	100,743.77	69,266	87,661	20,135	12.51	1,610
1992	630,534.91	421,576	533,532	141,140	13.13	10,749
1993	286,160.57	185,641	234,941	71,251	13.78	5,171
1994	366,874.23	230,375	291,555	101,001	14.46	6,985
1995	194,770.74	118,076	149,433	58,972	15.17	3,887
1996	91,190.75	53,220	67,353	30,221	15.91	1,899
1997	403,330.97	226,014	286,036	145,528	16.67	8,730
1998	421,566.36	226,052	286,084	164,992	17.46	9,450
1999	121,614.16	62,163	78,671	51,456	18.28	2,815
2000	107,510.11	52,193	66,054	48,982	19.12	2,562
2001	29,746.24	13,650	17,275	14,553	19.99	728
2003	110,906.84	44,823	56,726	61,944	21.78	2,844
2004	418,681.21	157,307	199,082	248,906	22.71	10,960
2005	177,509.74	61,594	77,951	111,984	23.65	4,735
2006	92,219.92	29,320	37,106	61,569	24.60	2,503
2007	284,198.13	81,932	103,690	200,402	25.57	7,837
2008	58,116.41	15,031	19,023	43,162	26.54	1,626
2009	781,968.45	178,578	226,002	610,704	27.53	22,183
2010	62,728.27	12,446	15,751	51,368	28.51	1,802
2011	365,132.57	61,284	77,559	313,133	29.51	10,611

PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
2012	350,291.35	48,190	60,988	313,824	30.50	10,289
2013	10,989.37	1,176	1,488	10,270	31.50	326
2014	1,306,426.82	99,850	126,367	1,271,510	32.50	39,123
2015	285,038.90	13,072	16,543	288,448	33.50	8,610
2016	851,507.01	13,020	16,478	894,635	34.50	25,931
	9,809,395.74	3,988,977	5,010,680	5,485,374		218,781
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1996	1,907,965.78	1,113,508	1,440,621	600,902	15.91	37,769
1997	1,153.80	647	837	397	16.67	24
1999	346,928.58	177,332	229,426	141,787	18.28	7,756
2000	8,534.51	4,143	5,360	3,772	19.12	197
2005	39,809.13	13,813	17,871	24,725	23.65	1,045
2006	12,764.60	4,058	5,250	8,408	24.60	342
2007	242,299.56	69,853	90,374	168,887	25.57	6,605
2008	377,229.76	97,563	126,224	277,412	26.54	10,453
2009	219,910.21	50,221	64,974	170,330	27.53	6,187
2010	261,480.52	51,880	67,121	212,663	28.51	7,459
2011	251,586.82	42,226	54,631	214,567	29.51	7,271
2012	607,391.34	83,559	108,106	541,803	30.50	17,764
2013	466,191.38	49,882	64,536	434,289	31.50	13,787
2014	189,207.21	14,461	18,709	183,743	32.50	5,654
2015	265,500.25	12,176	15,753	268,332	33.50	8,010
2016	167,841.73	2,566	3,320	176,271	34.50	5,109
	5,365,795.18	1,787,888	2,313,113	3,428,288		135,432
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1978	12,599.45	10,912	12,358	1,123	6.67	168
1980	42,554.34	35,984	40,753	4,780	7.34	651
1990	74,099.39	52,284	59,214	20,073	11.92	1,684
2000	11,691.73	5,676	6,428	6,082	19.12	318
2001	129,333.66	59,349	67,215	71,172	19.99	3,560
2002	36,369.01	15,699	17,780	21,135	20.88	1,012

PACIFIC NORTHERN GAS LTD.

ACCOUNT 467.00 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
2003	26,449.89	10,690	12,107	16,195	21.78	744
2004	52,991.12	19,910	22,549	34,152	22.71	1,504
2006	52,205.03	16,598	18,798	37,062	24.60	1,507
2007	123,160.53	35,506	40,212	91,570	25.57	3,581
2009	282,232.67	64,454	72,996	228,992	27.53	8,318
2010	170,109.83	33,752	38,225	143,792	28.51	5,044
2011	24,918.14	4,182	4,736	21,926	29.51	743
2012	53,767.49	7,397	8,377	49,154	30.50	1,612
2013	615,250.76	65,832	74,557	583,761	31.50	18,532
2014	536,680.64	41,019	46,456	527,793	32.50	16,240
2015	34,447.17	1,580	1,789	35,069	33.50	1,047
2016	83,744.73	1,280	1,450	88,157	34.50	2,555
	2,362,605.58	482,104	546,000	1,981,988		68,820
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -7						
1990	27,405.79	19,337	21,263	8,061	11.92	676
2001	25,021.93	11,482	12,626	14,148	19.99	708
2003	4,783.52	1,933	2,126	2,993	21.78	137
2004	7,090.20	2,664	2,929	4,657	22.71	205
2008	20,448.59	5,289	5,816	16,064	26.54	605
2013	165,970.26	17,759	19,528	158,060	31.50	5,018
2014	144,571.25	11,050	12,151	142,541	32.50	4,386
2015	11,346.15	520	572	11,569	33.50	345
2016	22,093.67	338	372	23,269	34.50	674
	428,731.36	70,372	77,381	381,361		12,754
	17,966,527.86	6,329,341	7,947,174	11,277,011		435,787
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					25.9	2.43

PACIFIC NORTHERN GAS LTD.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
1969	2,373.06	2,215	2,373			
1970	7,408.99	6,915	7,409			
1973	13,680.72	12,769	13,681			
1980	39,158.21	36,548	39,158			
1981	1,590.51	1,484	1,591			
1982	342,697.47	319,850	342,697			
1983	14,974.60	13,976	14,975			
1984	11,235.20	10,486	11,235			
1987	14,687.37	13,708	14,687			
1988	30,091.84	28,086	30,092			
1989	65,796.51	61,410	65,797			
1990	157,731.52	147,216	157,732			
1991	182,547.48	170,377	182,547			
1992	25,803.87	24,084	25,804			
1994	62,237.04	56,096	62,237			
1995	14,201.00	12,525	14,201			
1996	40,113.57	34,578	40,114			
1997	920,035.48	774,053	905,033	15,003	2.38	6,304
1998	961.44	787	920	41	2.72	15
1999	265,467.55	210,959	246,656	18,812	3.08	6,108
2000	114,610.46	88,021	102,915	11,695	3.48	3,361
2001	215,627.83	159,278	186,230	29,398	3.92	7,499
2002	82,649.82	58,461	68,353	14,296	4.39	3,256
2003	48,323.41	32,506	38,006	10,317	4.91	2,101
2004	100,724.08	64,061	74,901	25,823	5.46	4,729
2005	86,004.94	51,317	60,001	26,004	6.05	4,298
2007	4,179.42	2,132	2,493	1,687	7.35	230
2008	4,786.76	2,221	2,597	2,190	8.04	272
2012	26,248.09	6,807	7,959	18,289	11.11	1,646
2013	1,578.25	322	376	1,202	11.94	101
2014	335,998.55	49,503	57,880	278,119	12.79	21,745
2016	14,620.83	439	513	14,108	14.55	970
	3,248,145.87	2,453,190	2,781,162	466,984		62,635

PACIFIC NORTHERN GAS LTD.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
2016	20,124.11	604		20,124	14.55	1,383
	20,124.11	604		20,124		1,383
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
1991	129,794.00	121,141	129,794			
	129,794.00	121,141	129,794			
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. 0						
2015	5,426.25	485	362	5,064	13.66	371
	5,426.25	485	362	5,064		371
	3,403,490.23	2,575,420	2,911,318	492,172		64,389
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.6	1.89

PACIFIC NORTHERN GAS LTD.

ACCOUNT 469.00 - TRANSMISSION - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	1,943.15	802	141	1,802	23.50	77
2016	484,950.35	6,062	1,069	483,881	39.50	12,250
	486,893.50	6,864	1,210	485,683		12,327
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	18,450.46	6,688	7,017	11,433	25.50	448
	18,450.46	6,688	7,017	11,433		448
	505,343.96	13,552	8,227	497,116		12,775

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.9 2.53

PACIFIC NORTHERN GAS LTD.

ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1970	364.03	216		364	30.51	12
1971	120.60	70		121	31.35	4
1973	1,703.45	952		1,703	33.07	51
1974	2,774.26	1,519		2,774	33.94	82
1977	301.25	154		301	36.59	8
1978	1,862.98	932		1,863	37.49	50
1980	2,332.91	1,110		2,333	39.32	59
1981	427.00	198		427	40.24	11
1982	1,523.96	688		1,524	41.16	37
1983	9,186.62	4,030		9,187	42.10	218
1984	1,555.47	663		1,555	43.04	36
1985	1,338.52	554		1,339	43.98	30
1986	269.50	108		270	44.93	6
1987	4,525.67	1,757		4,526	45.88	99
1988	835.02	314		835	46.84	18
1989	1,600.92	581		1,601	47.80	33
1990	300.00	105		300	48.77	6
1991	1,312.50	442		1,312	49.73	26
2009	1,943.83	194		1,944	67.51	29
	34,278.49	14,587		34,278		815
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1996	139,548.29	37,919	19,666	119,882	54.62	2,195
1997	2,005.35	519	269	1,736	55.60	31
1998	15,123.04	3,712	1,925	13,198	56.59	233
	156,676.68	42,150	21,861	134,816		2,459
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1970	2,182.78	1,295		2,183	30.51	72
1980	58,392.52	27,779		58,393	39.32	1,485
1990	4,319.64	1,511		4,320	48.77	89
	64,894.94	30,585		64,895		1,646

PACIFIC NORTHERN GAS LTD.

ACCOUNT 471.00 - DISTRIBUTION - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1980	1,360.63	647		1,361	39.32	35
1990	650.00	227		650	48.77	13
	2,010.63	874		2,011		48
	257,860.74	88,196	21,861	236,000		4,968
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					47.5	1.93

PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1972	908.33	949	876	124	1.50	83
1974	6,165.87	6,326	5,836	946	2.02	468
1976	3,875.21	3,903	3,601	662	2.53	262
1979	416.64	407	375	83	3.33	25
1980	203.82	197	182	42	3.62	12
1982	3,028.03	2,859	2,638	693	4.25	163
1985	10,787.68	9,738	8,984	2,882	5.38	536
1986	21,878.74	19,398	17,896	6,170	5.82	1,060
1988	20,988.08	17,862	16,479	6,608	6.79	973
1991	6,067.59	4,788	4,417	2,257	8.48	266
1993	4,993.94	3,708	3,421	2,072	9.75	213
2000	131,919.83	72,991	67,340	77,772	14.91	5,216
2002	3,168.10	1,562	1,441	2,044	16.55	124
2005	5,947.34	2,368	2,185	4,357	19.14	228
2009	6,081.94	1,610	1,485	5,205	22.78	228
2012	44,686.90	7,177	6,621	42,534	25.62	1,660
2014	23,021.17	2,068	1,908	23,415	27.55	850
2015	39,194.48	2,113	1,949	41,165	28.53	1,443
	333,333.69	160,024	147,635	219,032		13,810
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1996	57,946.45	38,584	34,315	29,426	11.84	2,485
1997	11,514.75	7,355	6,541	6,125	12.58	487
1998	4,951.41	3,025	2,690	2,756	13.34	207
2000	171,817.09	95,066	84,548	104,451	14.91	7,005
2001	93,565.06	48,957	43,541	59,381	15.73	3,775
2002	84,330.77	41,589	36,988	55,776	16.55	3,370
2003	104,898.99	48,463	43,101	72,288	17.40	4,154
2004	65,607.36	28,242	25,117	47,051	18.26	2,577
2005	42,405.46	16,886	15,018	31,628	19.14	1,652
2006	34,107.32	12,468	11,089	26,429	20.03	1,319
2007	42,084.73	13,996	12,448	33,846	20.93	1,617
2008	43,856.84	13,106	11,656	36,587	21.85	1,674
2009	124,470.27	32,952	29,306	107,611	22.78	4,724
2010	100,683.11	23,221	20,652	90,100	23.71	3,800
2011	78,414.76	15,354	13,655	72,601	24.66	2,944
2012	24,891.66	3,998	3,556	23,825	25.62	930

PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
2013	39,880.35	5,001	4,448	39,421	26.58	1,483
2015	16,356.46	882	784	17,208	28.53	603
2016	16,271.50	292	260	17,639	29.51	598
	1,158,054.34	449,437	399,713	874,147		45,404
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1977	3,349.30	3,342	3,060	624	2.79	224
1980	105,346.88	101,898	93,308	22,574	3.62	6,236
1990	41,339.75	33,514	30,689	14,785	7.89	1,874
2000	22,675.72	12,546	11,488	13,455	14.91	902
2001	532.72	279	255	331	15.73	21
2002	79,207.03	39,062	35,769	51,359	16.55	3,103
2003	51,480.36	23,784	21,779	34,849	17.40	2,003
2004	45,401.39	19,544	17,896	32,045	18.26	1,755
2005	28,730.41	11,440	10,476	21,128	19.14	1,104
2006	31,690.30	11,585	10,608	24,251	20.03	1,211
2007	40,017.58	13,308	12,186	31,833	20.93	1,521
2008	15,473.94	4,624	4,234	12,787	21.85	585
2009	41,405.22	10,961	10,037	35,509	22.78	1,559
2010	66,648.28	15,372	14,076	59,237	23.71	2,498
2011	51,889.62	10,160	9,303	47,775	24.66	1,937
2012	48,378.98	7,770	7,115	46,102	25.62	1,799
2013	40,989.33	5,140	4,707	40,382	26.58	1,519
2014	31,041.67	2,789	2,554	31,592	27.55	1,147
2016	127,429.84	2,289	2,096	138,077	29.51	4,679
	873,028.32	329,407	301,637	658,694		35,677
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
1980	22,514.94	21,778	19,369	5,397	3.62	1,491
2001	6,537.72	3,421	3,043	4,149	15.73	264
2003	6,635.51	3,066	2,727	4,572	17.40	263
2005	14,429.58	5,746	5,110	10,762	19.14	562
2007	20,434.77	6,796	6,044	16,434	20.93	785

PACIFIC NORTHERN GAS LTD.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. -10						
2008	126,979.80	37,946	33,749	105,929	21.85	4,848
2009	19,862.00	5,258	4,676	17,172	22.78	754
2010	11,801.66	2,722	2,421	10,561	23.71	445
2011	29,389.97	5,755	5,118	27,211	24.66	1,103
2012	32,375.90	5,200	4,625	30,989	25.62	1,210
2014	9,159.89	823	732	9,344	27.55	339
2015	23,606.33	1,272	1,131	24,836	28.53	871
2016	17,053.13	306	272	18,486	29.51	626
	340,781.20	100,089	89,018	285,841		13,561
	2,705,197.55	1,038,957	938,004	2,037,714		108,452

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.8 4.01

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1973	49,381.72	61,628	48,456	30,555	11.00	2,778
1974	189,938.66	232,971	183,178	120,724	11.67	10,345
1975	163,185.66	196,606	154,585	106,512	12.35	8,624
1976	243,947.91	288,522	226,856	163,461	13.04	12,535
1977	281,227.00	326,313	256,570	193,394	13.74	14,075
1978	301,837.34	343,274	269,905	213,034	14.46	14,733
1979	480,571.00	535,164	420,783	348,131	15.20	22,903
1980	432,449.24	471,197	370,487	321,432	15.95	20,152
1981	680,027.58	724,420	569,589	518,456	16.71	31,027
1982	756,685.41	787,195	618,947	591,750	17.49	33,834
1983	889,188.14	902,277	709,432	713,269	18.29	38,998
1984	720,631.94	712,561	560,264	592,747	19.10	31,034
1985	862,330.71	830,045	652,638	727,091	19.92	36,501
1986	552,069.25	516,560	406,155	477,156	20.76	22,984
1987	636,926.20	578,635	454,962	564,120	21.61	26,105
1988	802,011.44	706,283	555,328	727,890	22.48	32,379
1989	844,341.59	719,784	565,943	785,003	23.36	33,605
1990	1,238,272.16	1,020,336	802,258	1,178,978	24.25	48,618
1991	1,170,154.63	930,507	731,628	1,140,619	25.15	45,353
1992	1,433,053.66	1,097,834	863,192	1,429,694	26.06	54,862
1993	1,360,512.70	1,002,208	788,004	1,388,816	26.98	51,476
1994	1,177,463.99	832,326	654,432	1,229,511	27.91	44,053
1995	843,152.95	570,646	448,681	900,364	28.85	31,208
1996	2,108,160.91	1,363,390	1,071,990	2,301,067	29.79	77,243
1997	1,419,276.04	874,274	687,414	1,583,428	30.75	51,494
1998	886,825.80	519,041	408,106	1,010,816	31.71	31,877
1999	420,298.81	233,081	183,264	489,214	32.67	14,974
2000	378,972.31	198,400	155,996	450,360	33.64	13,388
2001	267,999.03	131,898	103,707	325,091	34.62	9,390
2002	245,109.81	112,947	88,807	303,369	35.60	8,522
2003	345,497.47	148,370	116,659	436,137	36.58	11,923
2004	255,919.51	101,876	80,102	329,369	37.56	8,769
2005	216,249.06	79,234	62,299	283,699	38.55	7,359
2006	281,244.12	94,138	74,018	375,973	39.54	9,509
2007	252,297.35	76,456	60,115	343,561	40.53	8,477
2008	475,950.71	129,154	101,550	659,971	41.52	15,895
2009	225,707.72	54,025	42,478	318,654	42.52	7,494
2010	463,676.54	96,296	75,714	666,168	43.51	15,311
2011	248,663.50	43,685	34,348	363,513	44.51	8,167
2012	249,375.17	35,830	28,172	370,828	45.51	8,148
2013	222,812.25	24,955	19,621	336,878	46.50	7,245

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
2014	325,362.46	26,029	20,466	500,114	47.50	10,529
2015	217,662.20	10,448	8,215	340,045	48.50	7,011
2016	212,110.35	3,394	2,669	336,708	49.50	6,802
	25,828,532.00	18,744,213	14,737,981	26,587,670		1,007,709
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1996	4,992,764.60	3,228,921	2,149,583	5,838,841	29.79	196,000
1997	522,456.43	321,833	214,253	621,677	30.75	20,217
1998	860,001.48	503,342	335,089	1,040,914	31.71	32,826
1999	507,688.90	281,544	187,432	624,871	32.67	19,127
2000	402,534.69	210,735	140,292	503,763	33.64	14,975
2001	362,194.16	178,257	118,671	460,840	34.62	13,311
2002	432,124.84	199,123	132,562	558,838	35.60	15,698
2003	410,451.58	176,264	117,344	539,379	36.58	14,745
2004	486,854.60	193,807	129,023	649,945	37.56	17,304
2005	485,495.49	177,886	118,424	658,369	38.55	17,078
2006	501,312.99	167,799	111,708	690,392	39.54	17,461
2007	700,248.02	212,203	141,269	979,127	40.53	24,158
2008	734,110.23	199,208	132,618	1,041,958	41.52	25,095
2009	422,851.07	101,214	67,381	609,181	42.52	14,327
2010	651,739.34	135,353	90,108	952,675	43.51	21,896
2011	630,890.03	110,835	73,786	935,638	44.51	21,021
2012	761,126.92	109,359	72,803	1,145,000	45.51	25,159
2013	938,826.36	105,149	70,001	1,432,122	46.50	30,798
2014	851,215.27	68,097	45,334	1,316,610	47.50	27,718
2015	902,839.98	43,336	28,850	1,415,694	48.50	29,190
2016	810,054.43	12,961	8,628	1,287,459	49.50	26,009
	17,367,781.41	6,737,226	4,485,159	23,303,291		624,113
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1970	209,746.85	274,248	152,344	183,251	9.14	20,049
1980	923,036.27	1,005,740	558,684	918,174	15.95	57,566
1990	1,058,173.40	871,935	484,356	1,208,721	24.25	49,844

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
2000	73,450.42	38,453	21,360	96,160	33.64	2,859
2001	146,496.77	72,100	40,051	194,344	34.62	5,614
2002	115,052.73	53,016	29,450	154,634	35.60	4,344
2003	78,203.94	33,584	18,656	106,471	36.58	2,911
2004	114,965.36	45,765	25,422	158,522	37.56	4,221
2005	182,058.33	66,706	37,055	254,238	38.55	6,595
2006	240,701.96	80,568	44,755	340,368	39.54	8,608
2007	283,035.34	85,771	47,645	405,211	40.53	9,998
2008	344,537.18	93,494	51,936	499,324	41.52	12,026
2009	522,958.51	125,175	69,534	767,199	42.52	18,043
2010	805,853.05	167,360	92,968	1,196,397	43.51	27,497
2011	259,804.74	45,642	25,354	390,334	44.51	8,770
2012	476,255.65	68,428	38,011	723,998	45.51	15,909
2013	445,724.87	49,921	27,731	685,429	46.50	14,740
2014	475,514.17	38,041	21,132	739,691	47.50	15,572
2015	556,950.84	26,734	14,851	876,271	48.50	18,067
2016	214,723.23	3,436	1,909	341,648	49.50	6,902
	7,527,243.61	3,246,117	1,803,204	10,240,385		310,135
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
1980	398,405.06	434,102	253,481	383,967	15.95	24,073
1990	43,782.09	36,076	21,066	48,986	24.25	2,020
2001	338.72	167	98	444	34.62	13
2002	4,329.17	1,995	1,165	5,762	35.60	162
2003	16,102.55	6,915	4,038	21,726	36.58	594
2004	61,549.72	24,502	14,307	84,172	37.56	2,241
2005	7,610.15	2,788	1,628	10,548	38.55	274
2006	19,961.91	6,682	3,902	28,037	39.54	709
2007	13,711.21	4,155	2,426	19,512	40.53	481
2008	3,390.45	920	537	4,888	41.52	118
2009	8,058.37	1,929	1,126	11,767	42.52	277
2010	13,005.09	2,701	1,577	19,231	43.51	442
2011	54,051.23	9,496	5,545	80,937	44.51	1,818

PACIFIC NORTHERN GAS LTD.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -60						
2012	26,622.70	3,825	2,233	40,363	45.51	887
2013	35,753.14	4,004	2,338	54,867	46.50	1,180
2014	8,421.36	674	394	13,081	47.50	275
	715,092.92	540,931	315,861	828,288		35,564
	51,438,649.94	29,268,487	21,342,205	60,959,634		1,977,521
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					30.8	3.84

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1973	7,200.41	7,681	7,526	1,115	4.44	251
1974	19,452.21	20,536	20,120	3,222	4.81	670
1975	40,771.14	42,565	41,703	7,222	5.20	1,389
1976	46,809.47	48,265	47,288	8,883	5.63	1,578
1977	68,236.47	69,417	68,012	13,872	6.09	2,278
1978	68,021.42	68,157	66,777	14,848	6.60	2,250
1979	71,291.62	70,279	68,856	16,694	7.14	2,338
1980	101,960.40	98,708	96,710	25,643	7.73	3,317
1981	88,418.12	83,953	82,253	23,848	8.35	2,856
1982	59,015.61	54,885	53,774	17,045	9.00	1,894
1983	73,351.16	66,742	65,391	22,630	9.67	2,340
1984	76,066.04	67,638	66,269	25,010	10.36	2,414
1985	134,127.72	116,409	114,052	46,901	11.07	4,237
1986	102,279.33	86,559	84,807	37,928	11.79	3,217
1987	141,646.06	116,731	114,368	55,607	12.53	4,438
1988	145,048.30	116,227	113,874	60,184	13.29	4,529
1989	105,956.54	82,424	80,755	46,392	14.07	3,297
1990	224,029.18	168,896	165,477	103,358	14.87	6,951
1991	172,921.66	126,112	123,559	83,947	15.69	5,350
1992	120,705.26	85,025	83,304	61,543	16.52	3,725
1993	178,047.82	120,823	118,377	95,280	17.38	5,482
1994	155,426.87	101,463	99,409	87,103	18.24	4,775
1995	124,885.09	78,191	76,608	73,254	19.13	3,829
1996	221,649.85	132,790	130,102	135,878	20.03	6,784
1997	282,840.31	161,728	158,454	180,954	20.94	8,642
1998	184,510.95	100,411	98,378	123,035	21.86	5,628
1999	120,326.21	62,088	60,831	83,560	22.80	3,665
2000	92,279.16	45,014	44,103	66,632	23.74	2,807
2001	114,488.01	52,584	51,520	85,866	24.69	3,478
2002	176,497.24	75,982	74,444	137,353	25.65	5,355
2003	111,070.94	44,584	43,681	89,604	26.62	3,366
2004	43,132.26	16,045	15,720	36,039	27.60	1,306
2005	22,035.90	7,556	7,403	19,040	28.57	666
2006	69,116.33	21,647	21,209	61,731	29.56	2,088
2007	9,106.01	2,584	2,532	8,396	30.54	275
2008	50,428.37	12,814	12,555	47,959	31.53	1,521
2009	39,190.85	8,794	8,616	38,413	32.52	1,181
2010	63,416.62	12,328	12,078	64,022	33.52	1,910
2011	33,929.27	5,588	5,475	35,240	34.51	1,021
2012	50,496.43	6,802	6,664	53,931	35.51	1,519
2013	31,075.53	3,254	3,188	34,103	36.51	934

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
2014	41,597.80	3,120	3,057	46,861	37.50	1,250
2015	87,957.09	3,958	3,878	101,671	38.50	2,641
2016	125,919.09	1,889	1,851	149,252	39.50	3,779
	4,296,732.12	2,679,246	2,625,008	2,531,070		133,221
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1996	943,840.01	565,455	687,483	445,125	20.03	22,223
1997	155,053.05	88,659	107,792	78,272	20.94	3,738
1998	85,338.88	46,441	56,463	45,943	21.86	2,102
1999	38,068.61	19,643	23,882	21,800	22.80	956
2000	33,757.81	16,467	20,021	20,489	23.74	863
2001	44,161.11	20,283	24,660	28,333	24.69	1,148
2002	71,139.86	30,626	37,235	48,133	25.65	1,877
2003	33,315.56	13,373	16,259	23,720	26.62	891
2004	53,855.47	20,034	24,357	40,269	27.60	1,459
2005	51,684.21	17,723	21,548	40,473	28.57	1,417
2006	63,303.95	19,827	24,106	51,859	29.56	1,754
2007	79,573.50	22,583	27,457	68,032	30.54	2,228
2008	98,986.96	25,153	30,581	88,203	31.53	2,797
2009	64,598.57	14,496	17,624	59,894	32.52	1,842
2010	69,532.77	13,517	16,434	67,005	33.52	1,999
2011	39,914.22	6,574	7,993	39,904	34.51	1,156
2012	56,666.32	7,633	9,280	58,719	35.51	1,654
2013	52,167.15	5,462	6,641	55,960	36.51	1,533
2014	55,505.68	4,163	5,061	61,545	37.50	1,641
2015	65,881.41	2,965	3,605	75,453	38.50	1,960
2016	65,506.75	983	1,195	77,413	39.50	1,960
	2,221,851.85	962,060	1,169,677	1,496,545		57,198
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1978	237,790.83	238,266	226,971	58,378	6.60	8,845
1980	293,040.64	283,693	270,245	81,404	7.73	10,531
1990	880,509.47	663,816	632,348	424,263	14.87	28,531

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
2000	145,825.92	71,134	67,762	107,229	23.74	4,517
2001	285,108.25	130,950	124,742	217,388	24.69	8,805
2002	166,944.19	71,869	68,462	131,871	25.65	5,141
2003	274,427.91	110,155	104,933	224,380	26.62	8,429
2004	308,918.16	114,918	109,470	261,231	27.60	9,465
2005	45,593.32	15,634	14,893	39,819	28.57	1,394
2006	60,754.62	19,028	18,126	54,780	29.56	1,853
2007	42,050.04	11,934	11,368	39,092	30.54	1,280
2008	87,274.22	22,176	21,125	83,604	31.53	2,652
2009	55,835.03	12,529	11,935	55,067	32.52	1,693
2010	114,602.74	22,279	21,223	116,300	33.52	3,470
2011	64,781.39	10,669	10,163	67,574	34.51	1,958
2012	74,288.67	10,007	9,533	79,614	35.51	2,242
2013	89,730.71	9,395	8,950	98,727	36.51	2,704
2014	135,800.44	10,185	9,702	153,258	37.50	4,087
2015	100,881.53	4,540	4,325	116,733	38.50	3,032
2016	54,820.19	822	783	65,001	39.50	1,646
	3,518,978.27	1,833,999	1,747,059	2,475,715		112,275
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
1980	239,243.74	231,612	223,619	63,473	7.73	8,211
1990	10,969.58	8,270	7,985	5,179	14.87	348
2000	19.64	10	10	14	23.74	1
2002	567.56	244	236	445	25.65	17
2004	4,188.12	1,558	1,504	3,522	27.60	128
2005	1,017.77	349	337	884	28.57	31
2006	2,098.20	657	634	1,884	29.56	64
2007	624.11	177	171	578	30.54	19
2008	3,500.78	890	859	3,342	31.53	106
2009	967.66	217	210	952	32.52	29
2010	2,292.15	446	431	2,320	33.52	69

PACIFIC NORTHERN GAS LTD.

ACCOUNT 474.00 - DISTRIBUTION - HOUSE REGULATOR AND METER INSTALLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -20						
2011	3,172.08	522	504	3,303	34.51	96
2012	9,545.50	1,286	1,242	10,213	35.51	288
2013	7,905.98	828	799	8,688	36.51	238
	286,112.87	247,066	238,540	104,796		9,645
	10,323,675.11	5,722,371	5,780,284	6,608,126		312,339
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.2	3.03

PACIFIC NORTHERN GAS LTD.

ACCOUNT 475.00 - DISTRIBUTION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1969	1,256,817.29	1,070,950	1,084,874	486,147	20.69	23,497
1970	441,367.81	369,563	374,368	177,342	21.46	8,264
1971	270,981.38	222,882	225,780	112,947	22.23	5,081
1972	423,659.77	342,026	346,473	183,102	23.02	7,954
1973	395,492.06	313,274	317,347	177,018	23.81	7,435
1974	260,397.44	202,208	204,837	120,660	24.62	4,901
1975	281,900.64	214,463	217,251	135,124	25.44	5,311
1976	295,621.59	220,183	223,046	146,481	26.27	5,576
1977	562,279.55	409,600	414,926	287,924	27.12	10,617
1978	363,483.33	258,841	262,206	192,148	27.97	6,870
1979	679,842.46	472,881	479,029	370,774	28.83	12,861
1980	834,170.74	566,277	573,640	469,074	29.70	15,794
1981	923,029.78	610,976	618,920	534,867	30.58	17,491
1982	2,893,769.43	1,865,939	1,890,200	1,727,012	31.47	54,878
1983	759,489.87	476,580	482,776	466,586	32.37	14,414
1984	924,966.01	564,229	571,565	584,643	33.28	17,567
1985	393,712.24	233,201	236,233	255,907	34.20	7,483
1986	652,234.33	374,782	379,655	435,638	35.12	12,404
1987	503,141.52	280,111	283,753	345,174	36.05	9,575
1988	453,692.88	244,382	247,559	319,557	36.99	8,639
1989	1,066,559.78	555,224	562,443	770,757	37.93	20,321
1990	1,415,180.20	710,863	720,106	1,048,870	38.88	26,977
1991	956,938.67	463,194	469,216	726,957	39.83	18,251
1992	1,186,498.08	552,404	559,586	923,536	40.79	22,641
1993	578,287.29	258,559	261,921	460,938	41.75	11,040
1994	283,518.38	121,477	123,056	231,342	42.72	5,415
1995	1,282,484.91	525,578	532,411	1,070,695	43.69	24,507
1996	2,353,292.94	920,491	932,459	2,009,157	44.66	44,988
1997	1,790,152.38	666,496	675,162	1,562,529	45.64	34,236
1998	1,696,640.76	599,699	607,496	1,513,305	46.62	32,460
1999	436,832.16	146,170	148,070	397,970	47.60	8,361
2000	484,218.99	152,904	154,892	450,382	48.58	9,271
2001	163,402.86	48,486	49,116	155,137	49.57	3,130
2002	61,786.77	17,157	17,380	59,853	50.56	1,184
2003	250,221.05	64,720	65,561	247,215	51.55	4,796
2004	352,788.98	84,533	85,632	355,354	52.54	6,763
2005	288,298.01	63,591	64,418	295,955	53.53	5,529
2006	168,254.20	33,878	34,318	175,999	54.53	3,228
2007	415,340.71	75,722	76,707	442,469	55.52	7,970
2008	77,302.74	12,606	12,770	83,859	56.52	1,484
2009	362,358.89	52,193	52,872	400,077	57.51	6,957
2010	576,098.00	71,904	72,839	647,284	58.51	11,063

PACIFIC NORTHERN GAS LTD.

ACCOUNT 475.00 - DISTRIBUTION - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
2011	132,438.16	13,982	14,164	151,384	59.51	2,544
2012	382,377.10	33,018	33,447	444,524	60.51	7,346
2013	330,078.86	22,218	22,507	390,092	61.50	6,343
2014	95,516.55	4,592	4,652	114,744	62.50	1,836
2015	696,935.67	20,107	20,368	850,801	63.50	13,398
2016	81,044.85	779	789	100,517	64.50	1,558
	31,534,898.06	15,605,893	15,808,798	23,609,824		600,209
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1996	8,824,723.88	3,451,791	4,919,005	6,111,900	44.66	136,854
1997	785,757.66	292,547	416,897	565,300	45.64	12,386
1998	927,722.17	327,915	467,298	692,355	46.62	14,851
1999	651,958.48	218,153	310,881	504,067	47.60	10,590
2000	553,870.40	174,898	249,240	443,098	48.58	9,121
2001	679,840.92	201,726	287,471	562,330	49.57	11,344
2002	572,743.38	159,044	226,647	489,282	50.56	9,677
2003	556,088.45	143,832	204,969	490,142	51.55	9,508
2004	1,042,854.27	249,881	356,095	947,473	52.54	18,033
2005	788,200.67	173,857	247,756	737,494	53.53	13,777
2006	408,131.73	82,177	117,107	393,058	54.53	7,208
2007	558,669.74	101,852	145,145	553,192	55.52	9,964
2008	1,403,017.66	228,797	326,049	1,427,723	56.52	25,260
2009	826,776.27	119,087	169,706	863,764	57.51	15,019
2010	929,320.32	115,991	165,294	996,356	58.51	17,029
2011	1,002,210.99	105,808	150,783	1,101,981	59.51	18,518
2012	1,300,823.86	112,326	160,071	1,465,959	60.51	24,227
2013	1,222,065.31	82,260	117,225	1,410,356	61.50	22,933
2014	1,946,970.00	93,601	133,387	2,300,326	62.50	36,805
2015	1,860,448.66	53,674	76,489	2,249,072	63.50	35,418
2016	3,082,945.03	29,635	42,232	3,811,450	64.50	59,092
	29,925,139.85	6,518,852	9,289,747	28,116,678		517,614

PACIFIC NORTHERN GAS LTD.

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1961	564,265.19	542,562	476,740	228,591	15.00	15,239
1970	14,840.19	12,426	10,919	7,632	21.46	356
1980	1,901,479.30	1,290,819	1,134,221	1,242,628	29.70	41,839
1990	1,706,038.69	856,965	753,001	1,379,548	38.88	35,482
2000	9,049.87	2,858	2,511	8,801	48.58	181
2001	110,687.48	32,844	28,859	109,500	49.57	2,209
2002	80,775.72	22,430	19,709	81,261	50.56	1,607
2003	160,743.56	41,576	36,532	164,397	51.55	3,189
2004	116,073.10	27,813	24,439	120,653	52.54	2,296
2005	172,914.55	38,141	33,514	182,629	53.53	3,412
2006	115,372.73	23,230	20,412	123,804	54.53	2,270
2007	144,854.01	26,409	23,205	157,862	55.52	2,843
2008	946,470.57	154,346	135,621	1,047,467	56.52	18,533
2009	2,082,654.40	299,980	263,587	2,339,731	57.51	40,684
2010	1,082,351.42	135,091	118,702	1,234,237	58.51	21,094
2011	357,690.29	37,763	33,182	413,931	59.51	6,956
2012	418,826.57	36,166	31,778	491,755	60.51	8,127
2013	850,677.76	57,261	50,314	1,013,033	61.50	16,472
2014	791,794.76	38,066	33,448	956,295	62.50	15,301
2015	456,956.00	13,183	11,584	559,611	63.50	8,813
2016	415,384.12	3,993	3,509	515,722	64.50	7,996
	12,499,900.28	3,693,922	3,245,787	12,379,088		254,899
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -25						
1980	943,551.11	640,530	546,224	633,214	29.70	21,320
1990	15,994.88	8,034	6,851	13,142	38.88	338
2007	24,750.46	4,512	3,848	27,090	55.52	488
2011	70,422.07	7,435	6,340	81,687	59.51	1,373
2012	13,174.10	1,138	970	15,497	60.51	256
2013	32,076.62	2,159	1,841	38,255	61.50	622
	1,099,969.24	663,808	566,075	808,886		24,397
	75,059,907.43	26,482,475	28,910,408	64,914,476		1,397,119
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					46.5	1.86

PACIFIC NORTHERN GAS LTD.

ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1980	25,840.15	24,118	27,649			
1981	1,054.45	970	1,128			
1985	43,881.62	37,522	46,953			
1986	54,403.27	45,455	57,429	782	7.67	102
1988	50,466.00	40,083	50,642	3,356	9.02	372
1989	6,472.14	5,000	6,317	608	9.73	62
1990	3,209.19	2,409	3,044	390	10.45	37
1991	70,127.24	51,025	64,467	10,569	11.20	944
1992	4,285.21	3,017	3,812	773	11.97	65
1994	4,822.89	3,160	3,992	1,168	13.57	86
1995	547.62	345	436	150	14.41	10
2004	11,440.00	4,326	5,466	6,775	22.63	299
	276,549.78	217,430	271,335	24,573		1,977
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
2000	50,087.84	24,745	47,794	5,800	18.84	308
2001	72,283.62	33,655	65,003	12,341	19.77	624
2002	656,175.77	286,664	553,676	148,432	20.71	7,167
2003	28,851.23	11,757	22,708	8,163	21.67	377
2004	24,731.74	9,353	18,065	8,398	22.63	371
2005	2,397.93	836	1,615	951	23.60	40
2006	34,423.37	10,976	21,200	15,633	24.57	636
2007	23,007.99	6,647	12,838	11,780	25.55	461
2009	28,652.01	6,543	12,637	18,020	27.53	655
2010	26,381.50	5,226	10,094	18,134	28.52	636
2011	42,007.30	7,051	13,619	31,329	29.51	1,062
2012	84,057.57	11,539	22,287	67,655	30.51	2,217
2016	153,329.85	2,344	4,527	159,536	34.50	4,624
	1,226,387.72	417,336	806,061	506,173		19,178
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1978	20,626.07	19,712	22,070			
1980	332,360.78	310,209	349,689	5,937	4.47	1,328

PACIFIC NORTHERN GAS LTD.

ACCOUNT 477.00 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1990	74,435.15	55,866	62,976	16,670	10.45	1,595
2002	4,183.56	1,828	2,061	2,416	20.71	117
2004	32,222.95	12,186	13,737	20,742	22.63	917
2006	5,719.36	1,824	2,056	4,064	24.57	165
2007	17,095.83	4,939	5,568	12,725	25.55	498
2009	17,928.10	4,094	4,615	14,568	27.53	529
2010	4,525.73	897	1,011	3,831	28.52	134
	509,097.53	411,555	463,782	80,952		5,283
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. -7						
1980	188,024.57	175,493	198,184	3,002	4.47	672
2006	5,766.32	1,839	2,077	4,093	24.57	167
2010	127,228.83	25,204	28,463	107,672	28.52	3,775
	321,019.72	202,536	228,723	114,768		4,614
	2,333,054.75	1,248,857	1,769,902	726,466		31,052

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.4 1.33

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1990	238,470.97	224,282	169,129	66,957	1.00	66,957
1991	280,384.96	261,898	197,495	80,086	1.13	70,873
1992	254,596.89	234,407	176,765	75,286	1.40	53,776
1993	254,230.11	230,672	173,948	77,740	1.67	46,551
1994	233,800.10	208,663	157,351	74,111	1.97	37,620
1995	82,941.68	72,628	54,768	27,344	2.31	11,837
1996	152,261.81	130,389	98,325	52,414	2.70	19,413
1997	242,746.59	202,229	152,499	87,820	3.17	27,703
1998	95,789.01	77,193	58,211	36,620	3.72	9,844
1999	84,630.50	65,603	49,471	34,313	4.34	7,906
2001	47,216.49	33,399	25,186	21,558	5.71	3,775
2002	36,651.25	24,565	18,524	17,760	6.46	2,749
2003	45,398.50	28,675	21,624	23,321	7.24	3,221
2004	45,155.03	26,710	20,142	24,562	8.05	3,051
2005	50,940.55	27,989	21,106	29,325	8.90	3,295
2006	23,549.20	11,902	8,975	14,338	9.79	1,465
2007	41,870.61	19,275	14,535	26,917	10.70	2,516
2008	197,662.95	81,895	61,756	133,930	11.63	11,516
2009	137,262.29	50,347	37,966	97,923	12.59	7,778
2010	57,930.57	18,496	13,948	43,404	13.55	3,203
2011	94,458.03	25,576	19,287	74,227	14.53	5,109
2012	156,230.96	34,646	26,126	128,542	15.52	8,282
2013	138,622.96	23,948	18,059	119,178	16.51	7,219
2014	120,413.75	14,901	11,237	107,973	17.50	6,170
2015	222,860.24	16,547	12,478	208,154	18.50	11,252
2016	209,705.92	5,190	3,914	203,695	19.50	10,446
	3,545,781.92	2,152,025	1,622,826	1,887,498		443,527
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1997	118,518.44	98,736	72,140	45,193	3.17	14,256
1999	354,428.73	274,743	200,738	150,146	4.34	34,596
2002	41,309.65	27,687	20,229	20,667	6.46	3,199
2003	53,070.21	33,520	24,491	28,048	7.24	3,874
2004	65,646.66	38,832	28,372	36,618	8.05	4,549
2005	15,658.38	8,603	6,286	9,216	8.90	1,036
2006	51,220.91	25,887	18,914	31,795	9.79	3,248
2007	63,735.57	29,341	21,438	41,661	10.70	3,894

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
2008	64,311.24	26,645	19,468	44,200	11.63	3,801
2009	72,599.32	26,629	19,456	52,417	12.59	4,163
2010	84,674.26	27,034	19,752	64,075	13.55	4,729
2011	97,584.83	26,423	19,306	77,303	14.53	5,320
2012	173,813.71	38,545	28,163	143,913	15.52	9,273
2013	138,651.99	23,953	17,501	119,764	16.51	7,254
2014	173,055.08	21,416	15,647	155,677	17.50	8,896
2015	164,070.79	12,182	8,901	153,529	18.50	8,299
2016	154,614.83	3,827	2,796	150,273	19.50	7,706
	1,886,964.60	744,003	543,598	1,324,497		128,093
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1990	106,388.50	100,058	62,332	42,993	1.00	42,993
2001	20,373.73	14,411	8,977	11,193	5.71	1,960
2002	1,081.80	725	452	619	6.46	96
2003	63,801.45	40,298	25,104	38,059	7.24	5,257
2004	7,399.72	4,377	2,727	4,599	8.05	571
2005	10,342.16	5,682	3,540	6,699	8.90	753
2006	14,920.89	7,541	4,698	10,074	9.79	1,029
2007	38,374.96	17,666	11,005	26,986	10.70	2,522
2008	26,569.20	11,008	6,858	19,446	11.63	1,672
2009	32,681.59	11,987	7,467	24,887	12.59	1,977
2010	31,133.09	9,940	6,192	24,630	13.55	1,818
2011	85,400.02	23,123	14,405	70,141	14.53	4,827
2012	65,578.55	14,543	9,060	55,863	15.52	3,599
2013	80,457.74	13,899	8,658	70,995	16.51	4,300
2014	80,440.13	9,954	6,201	73,435	17.50	4,196
2015	59,783.93	4,439	2,765	56,421	18.50	3,050
2016	67,184.63	1,663	1,036	65,477	19.50	3,358
	791,912.09	291,314	181,476	602,517		83,978

PACIFIC NORTHERN GAS LTD.

ACCOUNT 478.00 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. +1						
1980	56,583.41	53,217	50,000	6,018	1.00	6,018
2009	1,925.16	706	663	1,243	12.59	99
2010	5,356.69	1,710	1,607	3,697	13.55	273
2011	37,710.00	10,211	9,594	27,739	14.53	1,909
2012	32,151.19	7,130	6,699	25,131	15.52	1,619
2013	32,418.52	5,600	5,261	26,833	16.51	1,625
2014	12,572.98	1,556	1,462	10,985	17.50	628
2015	22,844.28	1,696	1,593	21,022	18.50	1,136
	201,562.23	81,826	76,879	122,667		13,307
	6,426,220.84	3,269,168	2,424,780	3,937,179		668,905

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.9 10.41

PACIFIC NORTHERN GAS LTD.

ACCOUNT 479.00 - OTHER DISTRIBUTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 35-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	30,514.62	17,001	23,643	6,872	15.50	443
	30,514.62	17,001	23,643	6,872		443
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 35-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	5.31	3	3	2	14.50	
1998	19,611.39	10,366	10,279	9,332	16.50	566
	19,616.70	10,369	10,282	9,334		566
	50,131.32	27,370	33,925	16,206		1,009

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.1 2.01

PACIFIC NORTHERN GAS LTD.

ACCOUNT 481.00 - GENERAL - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1983	50.00	22		50	42.10	1
1985	300.00	124		300	43.98	7
	350.00	146		350		8
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1996	1,378.59	375	234	1,144	54.62	21
	1,378.59	375	234	1,144		21
	1,728.59	521	234	1,494		29

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.5 1.68

PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1971	6,064.80	5,812	6,065			
1973	61,226.06	57,634	61,226			
1975	479,130.81	442,875	479,131			
1976	51,977.61	47,594	51,978			
1977	2,718.84	2,466	2,703	15	2.79	5
1978	647.05	581	637	10	3.06	3
1981	13,212.81	11,486	12,592	621	3.92	158
1982	369,603.15	317,241	347,790	21,813	4.25	5,132
1983	118,887.54	100,659	110,352	8,535	4.60	1,855
1984	42,055.39	35,074	38,451	3,604	4.98	724
1985	63,591.77	52,188	57,214	6,378	5.38	1,186
1986	276,300.53	222,698	244,143	32,158	5.82	5,525
1987	57,840.41	45,713	50,115	7,725	6.29	1,228
1988	286,719.03	221,826	243,187	43,532	6.79	6,411
1989	15,729.69	11,886	13,031	2,699	7.33	368
1990	8,303.94	6,120	6,709	1,595	7.89	202
1991	16,956.98	12,164	13,335	3,622	8.48	427
1992	8,728.30	6,081	6,667	2,062	9.10	227
1994	644,245.65	420,261	460,731	183,515	10.43	17,595
1995	1,031,832.67	649,363	711,894	319,939	11.12	28,771
1996	144,101.52	87,229	95,629	48,473	11.84	4,094
1997	497,134.46	288,671	316,469	180,666	12.58	14,361
1998	95,233.53	52,886	57,979	37,255	13.34	2,793
1999	32,710.54	17,315	18,982	13,728	14.12	972
2000	44,346.64	22,306	24,454	19,893	14.91	1,334
2001	45,687.93	21,732	23,825	21,863	15.73	1,390
2002	13,832.66	6,202	6,799	7,033	16.55	425
2003	46,445.99	19,507	21,385	25,061	17.40	1,440
2004	174,316.77	68,215	74,784	99,533	18.26	5,451
2005	103,260.25	37,380	40,980	62,281	19.14	3,254
2006	48,230.75	16,029	17,573	30,658	20.03	1,531
2007	21,926.74	6,629	7,267	14,659	20.93	700
2008	191,684.66	52,075	57,090	134,595	21.85	6,160
2009	194,526.47	46,817	51,325	143,201	22.78	6,286
2010	190,572.08	39,957	43,805	146,767	23.71	6,190
2011	35,104.03	6,249	6,851	28,253	24.66	1,146
2012	88,357.61	12,900	14,142	74,215	25.62	2,897
2013	7,696.19	877	961	6,735	26.58	253

PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
2014	63,345.99	5,173	5,671	57,675	27.55	2,093
2015	157,558.45	7,720	8,463	149,095	28.53	5,226
2016	434,535.58	7,096	7,779	426,756	29.51	14,461
	6,186,381.87	3,492,687	3,820,164	2,366,218		152,274
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1996	416,942.42	252,388	315,230	101,713	11.84	8,591
1997	384,037.68	222,999	278,523	105,515	12.58	8,388
1998	49,356.50	27,409	34,234	15,123	13.34	1,134
2000	23,187.89	11,664	14,568	8,620	14.91	578
2006	6,170.00	2,050	2,560	3,610	20.03	180
2008	21,166.02	5,750	7,182	13,984	21.85	640
2011	17,406.60	3,098	3,869	13,537	24.66	549
2012	21,848.50	3,190	3,984	17,864	25.62	697
2014	8,808.61	719	898	7,911	27.55	287
	948,924.22	529,267	661,048	287,876		21,044
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1980	22,485.44	19,772	21,281	1,205	3.62	333
1990	8,623.16	6,355	6,840	1,783	7.89	226
2000	6,495.66	3,267	3,516	2,979	14.91	200
2009	4,724.21	1,137	1,224	3,500	22.78	154
2012	9,405.57	1,373	1,478	7,928	25.62	309
2013	980,551.57	111,783	120,312	860,240	26.58	32,364
2014	17,655.00	1,442	1,552	16,103	27.55	585
2015	49,400.00	2,421	2,606	46,794	28.53	1,640
2016	55,087.01	900	969	54,118	29.51	1,834
	1,154,427.62	148,450	159,777	994,651		37,645

PACIFIC NORTHERN GAS LTD.

ACCOUNT 482.00 - GENERAL - STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 30-R5						
NET SALVAGE PERCENT.. 0						
1980	392,102.75	377,724	391,117	986	1.10	896
1990	10,209.53	8,535	8,838	1,372	4.92	279
	402,312.28	386,259	399,954	2,358		1,175
	8,692,045.99	4,556,663	5,040,943	3,651,103		212,138
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					17.2	2.44

PACIFIC NORTHERN GAS LTD.

ACCOUNT 483.00 - GENERAL - OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	62,866.54	58,675	42,537	20,330	1.00	20,330
2003	24,104.74	21,694	15,727	8,378	1.50	5,585
2004	40,762.66	33,969	24,626	16,137	2.50	6,455
2005	53,536.69	41,045	29,756	23,781	3.50	6,795
2006	46,009.70	32,207	23,349	22,661	4.50	5,036
2008	47,521.51	26,929	19,522	27,999	6.50	4,308
2009	51,100.65	25,550	18,523	32,578	7.50	4,344
2010	11,287.55	4,891	3,546	7,742	8.50	911
2011	1,389.69	510	370	1,020	9.50	107
2012	29,113.14	8,734	6,332	22,781	10.50	2,170
2013	34,588.58	8,071	5,851	28,737	11.50	2,499
2014	10,524.90	1,754	1,272	9,253	12.50	740
2015	23,823.64	2,382	1,727	22,097	13.50	1,637
2016	108,768.81	3,625	2,628	106,141	14.50	7,320
	545,398.80	270,036	195,763	349,635		68,237
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	1,841.86	1,289	1,364	478	4.50	106
2008	1,640.28	929	983	657	6.50	101
2013	9,761.75	2,278	2,411	7,351	11.50	639
2014	10,033.79	1,672	1,769	8,264	12.50	661
2015	6,235.02	624	660	5,575	13.50	413
	29,512.70	6,792	7,188	22,325		1,920
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	3,695.86	3,449	2,901	795	1.00	795
2003	3,493.36	3,144	2,645	849	1.50	566
2004	6,025.48	5,021	4,224	1,802	2.50	721
2005	5,851.44	4,486	3,774	2,078	3.50	594
2006	6,523.58	4,567	3,842	2,682	4.50	596
2007	3,242.08	2,053	1,727	1,515	5.50	275
2008	8,812.69	4,994	4,201	4,612	6.50	710
2009	5,615.59	2,808	2,362	3,254	7.50	434

PACIFIC NORTHERN GAS LTD.

ACCOUNT 483.00 - GENERAL - OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	3,012.40	1,305	1,098	1,915	8.50	225
2011	1,676.00	615	517	1,159	9.50	122
2012	3,273.26	982	826	2,447	10.50	233
2013	7,681.61	1,792	1,507	6,174	11.50	537
2014	17,878.66	2,980	2,507	15,372	12.50	1,230
	76,782.01	38,196	32,130	44,652		7,038
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	2,311.20	2,080	1,790	521	1.50	347
2004	1,814.53	1,512	1,301	514	2.50	206
2005	716.47	549	472	244	3.50	70
2006	2,872.10	2,010	1,730	1,143	4.50	254
2010	6,811.03	2,951	2,539	4,272	8.50	503
2013	4,366.00	1,019	877	3,489	11.50	303
2014	5,134.84	856	737	4,398	12.50	352
	24,026.17	10,977	9,445	14,581		2,035
	675,719.68	326,001	244,526	431,193		79,230

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4 11.73

PACIFIC NORTHERN GAS LTD.

ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2002	63,463.37	47,201	48,706	5,238	1.00	5,238
2003	33,131.13	24,148	24,918	3,244	1.14	2,846
2006	277,043.13	179,853	185,587	49,900	1.89	26,402
2008	21,876.62	13,203	13,624	4,971	2.32	2,143
2009	5,981.30	3,502	3,614	1,470	2.49	590
2010	5,245.49	2,932	3,025	1,433	2.74	523
2011	92,237.86	47,335	48,844	29,558	3.17	9,324
2012	297,484.35	132,120	136,332	116,530	3.82	30,505
2013	464,308.10	166,251	171,551	223,111	4.63	48,188
2014	252,820.18	66,081	68,188	146,709	5.54	26,482
2015	421,244.98	67,136	69,276	288,782	6.50	44,428
2016	389,702.36	20,703	21,363	309,884	7.50	41,318
	2,324,538.87	770,465	795,028	1,180,831		237,987
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2011	100,111.42	51,376	50,132	34,962	3.17	11,029
2012	55,666.75	24,723	24,125	23,192	3.82	6,071
2013	117,281.42	41,994	40,977	58,712	4.63	12,681
2014	152,524.75	39,866	38,901	90,745	5.54	16,380
2015	55,818.97	8,896	8,681	38,765	6.50	5,964
2016	62,554.51	3,323	3,243	49,929	7.50	6,657
	543,957.82	170,178	166,059	296,305		58,782
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2001	35,890.70	26,694	28,077	2,430	1.00	2,430
2006	49,030.29	31,830	33,479	8,197	1.89	4,337
2008	8,600.00	5,190	5,459	1,851	2.32	798
2010	30,182.50	16,868	17,742	7,913	2.74	2,888
2011	104,377.58	53,565	56,340	32,381	3.17	10,215
2012	40,123.82	17,820	18,743	15,362	3.82	4,021
2013	91,179.58	32,648	34,339	43,163	4.63	9,322

PACIFIC NORTHERN GAS LTD.

ACCOUNT 484.00 - GENERAL - TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2014	101,476.60	26,523	27,897	58,358	5.54	10,534
2015	104,540.04	16,661	17,524	71,335	6.50	10,975
2016	218,173.26	11,590	12,190	173,257	7.50	23,101
	783,574.37	239,389	251,791	414,247		78,621
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +15						
2013	40,077.00	14,350	13,741	20,325	4.63	4,390
	40,077.00	14,350	13,741	20,325		4,390
	3,692,148.06	1,194,382	1,226,618	1,911,708		379,780
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.0	10.29

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
1976	10,116.69	8,599	9,105			
1977	3,633.26	3,088	3,270			
1980	2,913.04	2,476	2,622			
1981	1,602.92	1,362	1,443			
1982	14,789.11	12,571	13,310			
1984	4,110.85	3,494	3,700			
1985	7,185.15	6,107	6,467			
1987	16,735.50	14,225	15,062			
1989	18,704.10	15,898	16,834			
1990	6,424.15	5,461	5,782			
1992	217,818.85	180,027	196,037			
1994	15,553.52	12,443	13,998			
1995	187,616.42	147,373	168,855			
1996	5,012.54	3,855	4,511			
1997	12,626.00	9,476	11,363			
1998	4,467.72	3,261	4,021			
1999	77,172.98	54,523	69,456			
2000	37,927.60	25,791	34,135			
2001	113,586.81	74,002	102,228			
2002	30,145.95	18,705	26,225	906	5.59	162
2003	113,176.28	66,434	93,144	8,715	6.26	1,392
2004	53,208.60	29,371	41,180	6,708	6.96	964
2005	180,327.56	92,868	130,206	32,089	7.70	4,167
2006	296,813.92	141,431	198,293	68,839	8.47	8,127
2007	653,989.75	285,467	400,239	188,352	9.27	20,318
2008	260,120.49	102,748	144,058	90,051	10.10	8,916
2009	279,630.62	98,430	138,004	113,664	10.96	10,371
2010	32,765.61	10,092	14,149	15,340	11.84	1,296
2011	3,295.00	867	1,216	1,750	12.74	137
2012	217,720.64	47,137	66,088	129,860	13.67	9,500
2013	15,696.90	2,661	3,731	10,396	14.61	712
2014	374,699.00	45,715	64,095	273,134	15.56	17,554
2015	354,475.21	26,055	36,530	282,497	16.53	17,090
2016	425,281.60	10,419	14,608	368,145	17.51	21,025
	4,049,344.34	1,562,432	2,053,964	1,590,446		121,731

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
1985	1,683.68	1,431	1,515			
1990	15,549.14	13,217	13,994			
1996	3,835.00	2,949	3,452			
1999	18,713.38	13,221	16,842			
2002	8,000.00	4,964	6,788	412	5.59	74
2004	50,703.52	27,988	38,274	7,359	6.96	1,057
2006	81,822.65	38,988	53,317	20,324	8.47	2,400
2007	6,948.38	3,033	4,148	2,106	9.27	227
2009	18,591.70	6,544	8,949	7,784	10.96	710
2012	5,855.32	1,268	1,734	3,536	13.67	259
2014	68,159.00	8,316	11,372	49,971	15.56	3,212
2015	13,123.55	965	1,320	10,492	16.53	635
2016	6,532.35	160	219	5,660	17.51	323
	299,517.67	123,044	161,923	107,643		8,897
PNG - DAWSON CREEK						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
1983	1,822.30	1,549	1,640			
1990	15,549.14	13,217	13,994			
1992	415.58	343	374			
1999	4,854.17	3,429	4,353	15	3.87	4
2001	2,854.17	1,859	2,360	209	4.97	42
2002	10,102.01	6,268	7,958	1,134	5.59	203
2003	20,376.14	11,961	15,185	3,153	6.26	504
2004	11,572.05	6,388	8,110	2,305	6.96	331
2006	26,439.59	12,598	15,994	7,802	8.47	921
2008	153,705.35	60,714	77,081	61,254	10.10	6,065
2009	355,029.61	124,970	158,658	160,869	10.96	14,678
2010	8,842.48	2,723	3,457	4,501	11.84	380
2011	107,328.71	28,227	35,836	60,760	12.74	4,769
2012	49,902.69	10,804	13,716	31,196	13.67	2,282
2013	48,948.62	8,297	10,534	33,520	14.61	2,294
2015	98,098.50	7,211	9,155	79,134	16.53	4,787
2016	292,781.67	7,173	9,107	254,397	17.51	14,529
	1,208,622.78	307,731	387,512	700,249		51,789

PACIFIC NORTHERN GAS LTD.

ACCOUNT 485.00 - GENERAL - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. IOWA 18-R3						
NET SALVAGE PERCENT.. +10						
2002	82,503.75	51,193	73,931	323	5.59	58
2010	5,143.21	1,584	2,288	2,341	11.84	198
2011	12,540.90	3,298	4,763	6,524	12.74	512
2012	7,121.00	1,542	2,227	4,182	13.67	306
2016	10,191.75	250	361	8,812	17.51	503
	117,500.61	57,867	83,569	22,182		1,577
	5,674,985.40	2,051,074	2,686,968	2,420,520		183,994
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					13.2	3.24

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	78,942.60	74,995	61,252	17,690	1.00	17,690
1998	124,786.07	115,427	94,275	30,511	1.50	20,341
1999	198,545.26	173,727	141,892	56,653	2.50	22,661
2000	131,778.11	108,717	88,795	42,983	3.50	12,281
2001	103,936.01	80,550	65,789	38,147	4.50	8,477
2002	180,593.19	130,930	106,937	73,656	5.50	13,392
2003	91,983.23	62,089	50,711	41,272	6.50	6,350
2004	130,906.42	81,817	66,824	64,082	7.50	8,544
2005	100,110.93	57,564	47,016	53,095	8.50	6,246
2006	215,843.12	113,318	92,553	123,290	9.50	12,978
2007	170,594.05	81,032	66,183	104,411	10.50	9,944
2008	110,299.76	46,877	38,287	72,013	11.50	6,262
2009	85,020.84	31,883	26,041	58,980	12.50	4,718
2010	124,331.19	40,408	33,003	91,328	13.50	6,765
2011	89,966.97	24,741	20,207	69,760	14.50	4,811
2012	124,295.34	27,966	22,841	101,454	15.50	6,545
2013	77,927.96	13,637	11,138	66,790	16.50	4,048
2014	233,823.83	29,228	23,872	209,952	17.50	11,997
2015	84,766.95	6,358	5,193	79,574	18.50	4,301
2016	354,850.06	8,871	7,245	347,605	19.50	17,826
	2,813,301.89	1,310,135	1,070,056	1,743,246		206,177
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1997	8,116.29	7,710	7,263	854	1.00	854
1998	31,401.13	29,046	27,361	4,040	1.50	2,693
1999	29,340.27	25,673	24,183	5,157	2.50	2,063
2000	43,537.58	35,919	33,835	9,703	3.50	2,772
2002	19,813.60	14,365	13,532	6,282	5.50	1,142
2003	27,669.37	18,677	17,593	10,076	6.50	1,550
2004	20,725.31	12,953	12,201	8,524	7.50	1,137
2005	24,991.41	14,370	13,536	11,455	8.50	1,348
2006	29,127.87	15,292	14,405	14,723	9.50	1,550
2007	17,802.98	8,456	7,965	9,838	10.50	937
2008	15,866.70	6,743	6,352	9,515	11.50	827
2009	45,471.30	17,052	16,063	29,409	12.50	2,353
2010	42,614.13	13,850	13,046	29,568	13.50	2,190
2012	30,387.47	6,837	6,440	23,947	15.50	1,545

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	33,998.45	5,950	5,605	28,394	16.50	1,721
2014	10,105.90	1,263	1,190	8,916	17.50	509
2015	29,764.36	2,232	2,102	27,662	18.50	1,495
2016	18,597.22	465	438	18,159	19.50	931
	479,331.34	236,853	223,111	256,221		27,617
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	33,744.46	27,839	25,987	7,758	3.50	2,217
2001	54,152.26	41,968	39,175	14,977	4.50	3,328
2002	32,346.57	23,451	21,891	10,456	5.50	1,901
2003	41,311.94	27,886	26,030	15,282	6.50	2,351
2004	78,642.21	49,151	45,880	32,762	7.50	4,368
2005	29,869.04	17,175	16,032	13,837	8.50	1,628
2006	54,115.66	28,411	26,520	27,595	9.50	2,905
2007	22,872.15	10,864	10,141	12,731	10.50	1,212
2008	20,472.51	8,701	8,122	12,350	11.50	1,074
2009	15,886.01	5,957	5,561	10,325	12.50	826
2010	28,294.09	9,196	8,584	19,710	13.50	1,460
2011	24,081.22	6,622	6,181	17,900	14.50	1,234
2012	9,377.85	2,110	1,970	7,408	15.50	478
2013	68,245.90	11,943	11,148	57,098	16.50	3,460
2014	35,597.00	4,450	4,154	31,443	17.50	1,797
2015	24,192.97	1,814	1,693	22,500	18.50	1,216
2016	40,597.37	1,015	947	39,650	19.50	2,033
	613,799.21	278,553	260,018	353,782		33,488
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	268.47	221	204	65	3.50	19
2001	3,550.80	2,752	2,538	1,013	4.50	225
2002	248.62	180	166	83	5.50	15
2003	3,168.74	2,139	1,972	1,196	6.50	184
2004	2,774.67	1,734	1,599	1,176	7.50	157
2005	5,598.10	3,219	2,968	2,630	8.50	309

PACIFIC NORTHERN GAS LTD.

ACCOUNT 486.00 - GENERAL - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	9,241.00	4,852	4,474	4,767	9.50	502
2008	14,980.00	6,366	5,870	9,110	11.50	792
2009	4,193.30	1,572	1,450	2,744	12.50	220
2010	4,472.68	1,454	1,341	3,132	13.50	232
2011	14,968.43	4,116	3,796	11,173	14.50	771
2012	11,678.27	2,628	2,423	9,255	15.50	597
2014	2,507.35	313	289	2,219	17.50	127
2015	5,595.37	420	387	5,208	18.50	282
	83,245.80	31,966	29,477	53,769		4,432
	3,989,678.24	1,857,507	1,582,662	2,407,018		271,714

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.9 6.81

PACIFIC NORTHERN GAS LTD.

ACCOUNT 487.00 - GENERAL - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	290,071.50	232,057	211,889	78,183	1.00	78,183
2013	53,939.54	37,758	34,476	19,463	1.50	12,975
2014	39,275.46	19,638	17,931	21,344	2.50	8,538
2015	40,714.48	12,214	11,152	29,562	3.50	8,446
2016	140,460.21	14,046	12,825	127,635	4.50	28,363
	564,461.19	315,713	288,274	276,187		136,505
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,997.80	2,999	2,225	3,773	2.50	1,509
2015	1,506.76	452	335	1,171	3.50	335
2016	1,885.48	189	140	1,745	4.50	388
	9,390.04	3,640	2,700	6,690		2,232
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	1,942.30	1,554	995	947	1.00	947
2013	3,334.49	2,334	1,494	1,840	1.50	1,227
2015	7,963.60	2,389	1,530	6,434	3.50	1,838
2016	17,618.46	1,762	1,128	16,490	4.50	3,664
	30,858.85	8,039	5,147	25,712		7,676
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	2,675.00	268		2,675	4.50	594
	2,675.00	268		2,675		594
	607,385.08	327,660	296,122	311,264		147,007

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.1 24.20

PACIFIC NORTHERN GAS LTD.

ACCOUNT 488.00 - GENERAL - COMMUNICATION STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - WEST						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	176,126.87	163,546	158,975	17,152	1.00	17,152
2005	23,066.11	18,947	18,417	4,649	2.50	1,860
2006	20,037.74	15,028	14,608	5,430	3.50	1,551
2010	49,469.34	22,968	22,326	27,143	7.50	3,619
2011	4,151.08	1,631	1,585	2,566	8.50	302
2016	114,958.55	4,105	3,990	110,968	13.50	8,220
	387,809.69	226,225	219,902	167,908		32,704
PNG - FORT ST. JOHN						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	19,995.39	9,284	8,083	11,912	7.50	1,588
2016	15,665.78	559	487	15,179	13.50	1,124
	35,661.17	9,843	8,570	27,091		2,712
PNG - DAWSON CREEK						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	10,845.74	10,071	8,572	2,274	1.00	2,274
2013	30,000.00	7,500	6,384	23,616	10.50	2,249
2016	15,665.78	559	476	15,190	13.50	1,125
	56,511.52	18,130	15,431	41,080		5,648
PNG - TUMBLER RIDGE						
SURVIVOR CURVE.. 14-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	1,794.63	1,218	1,065	730	4.50	162
	1,794.63	1,218	1,065	730		162
	481,777.01	255,416	244,967	236,809		41,226

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.7 8.56

PACIFIC NORTHERN GAS LTD.

ACCOUNT 489.00 - OTHER GENERAL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2016

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
2009	2,000.00	675	1,728	272	13.25	21
	2,000.00	675	1,728	272		21

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0 1.05

APPENDIX A – ESTIMATION OF SURVIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

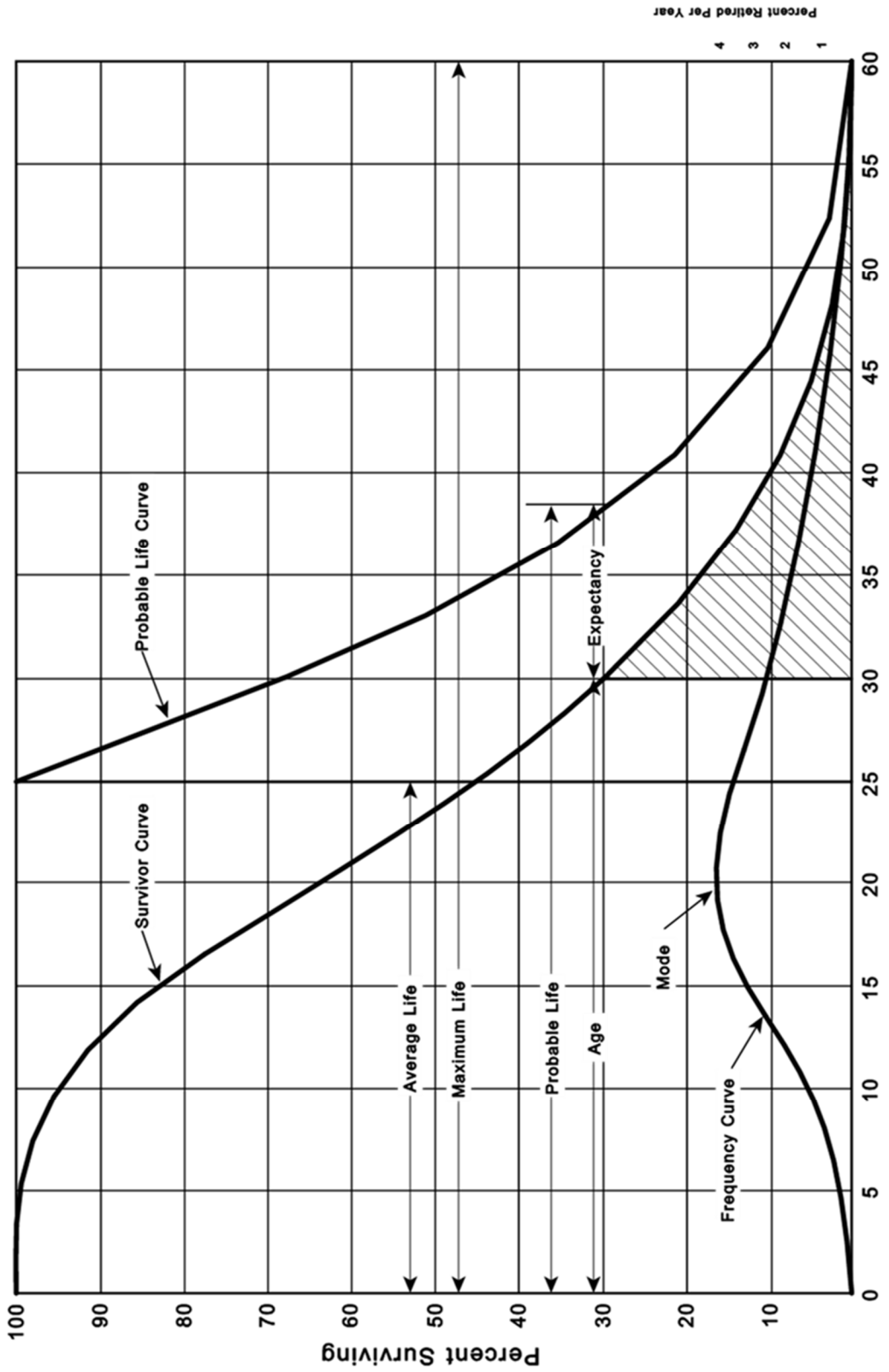


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

[1] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.
[2] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[3] Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

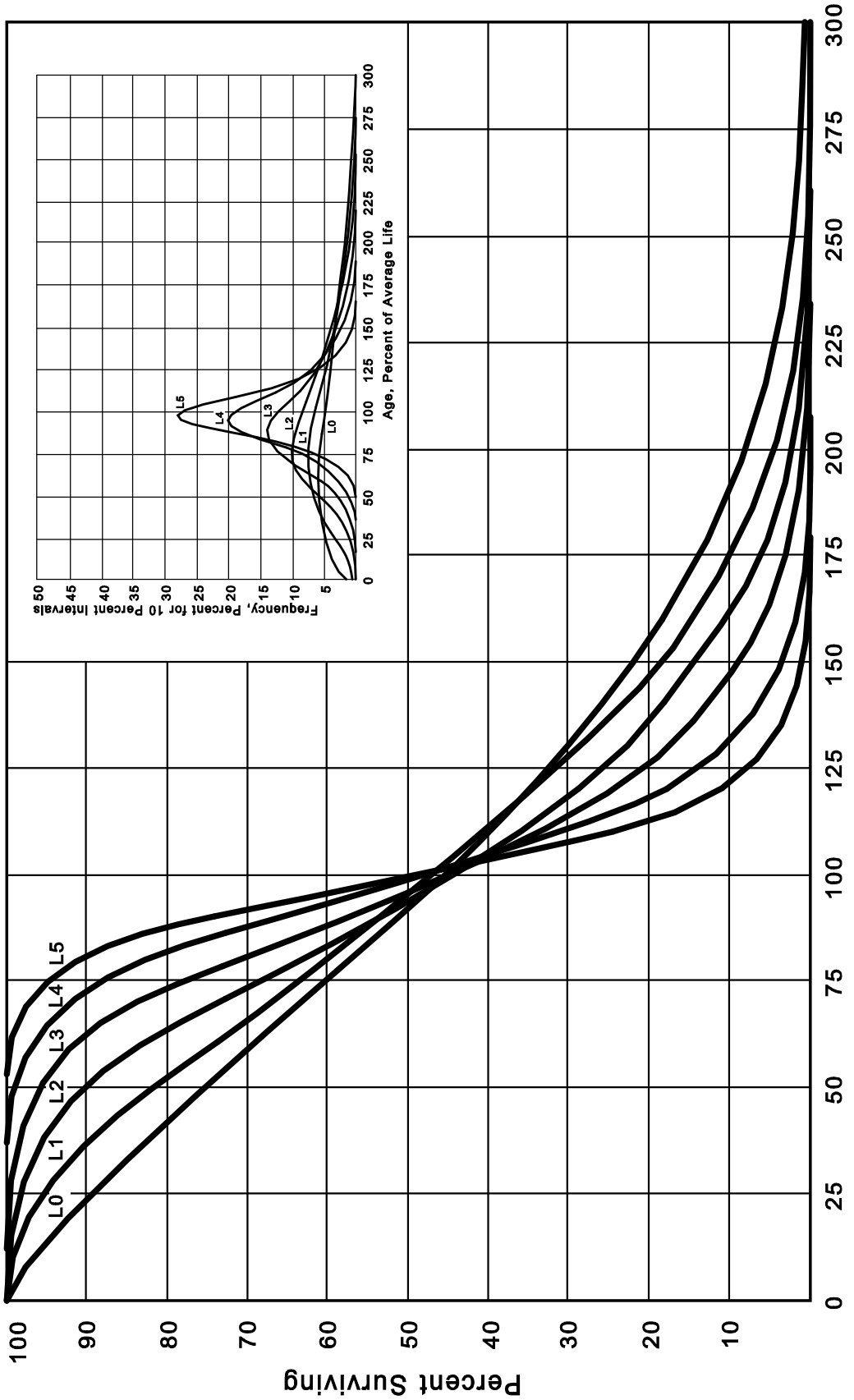


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

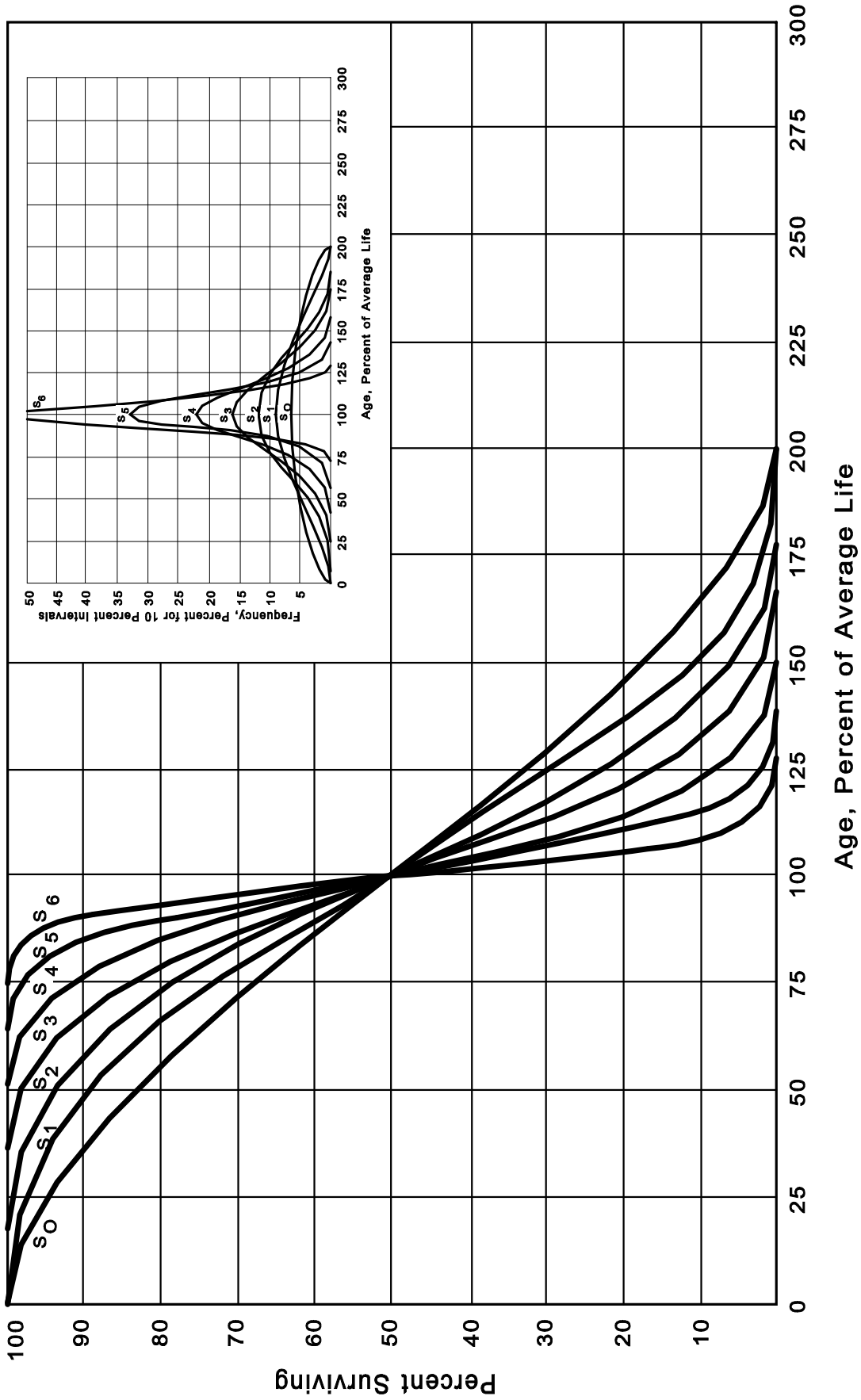


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

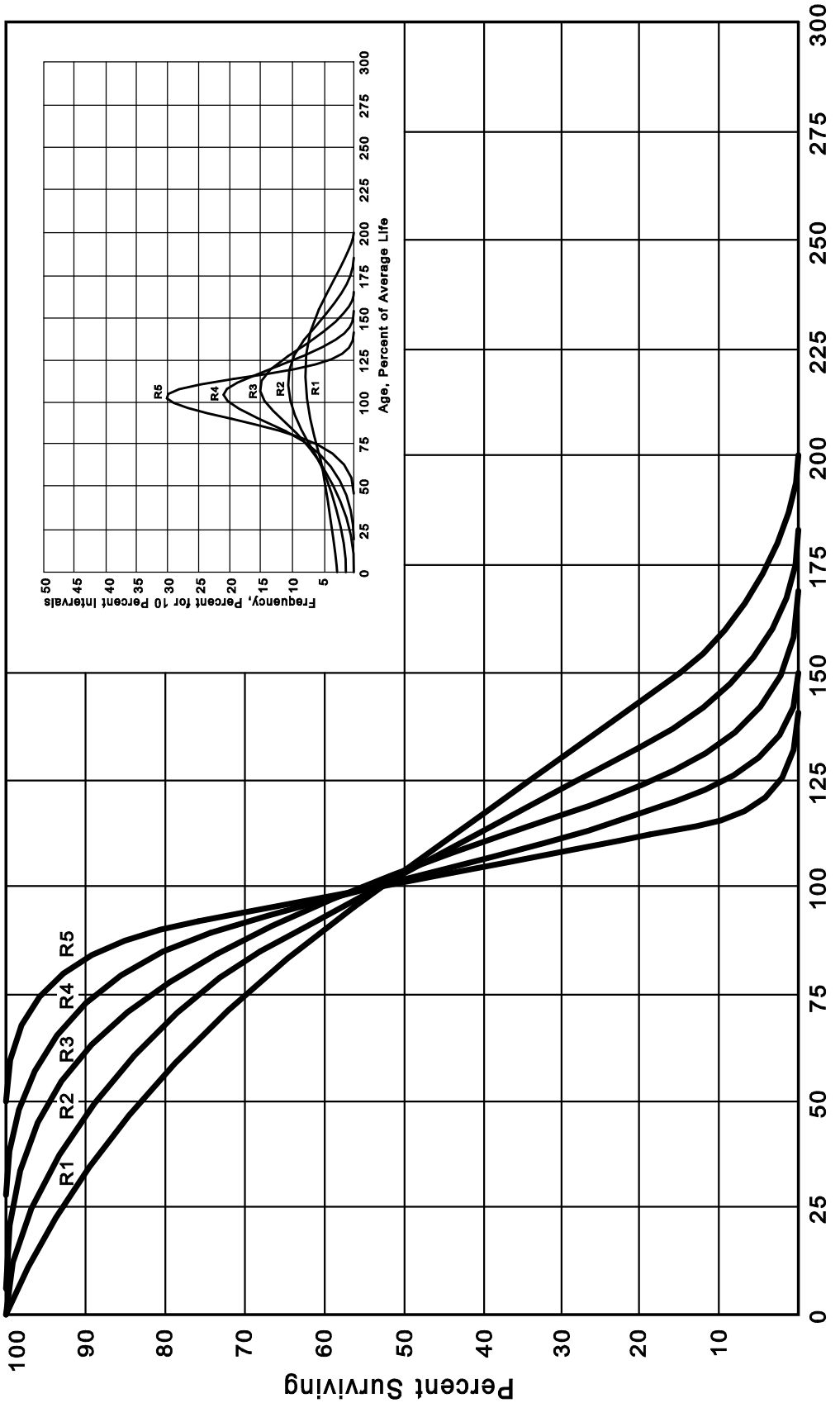


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

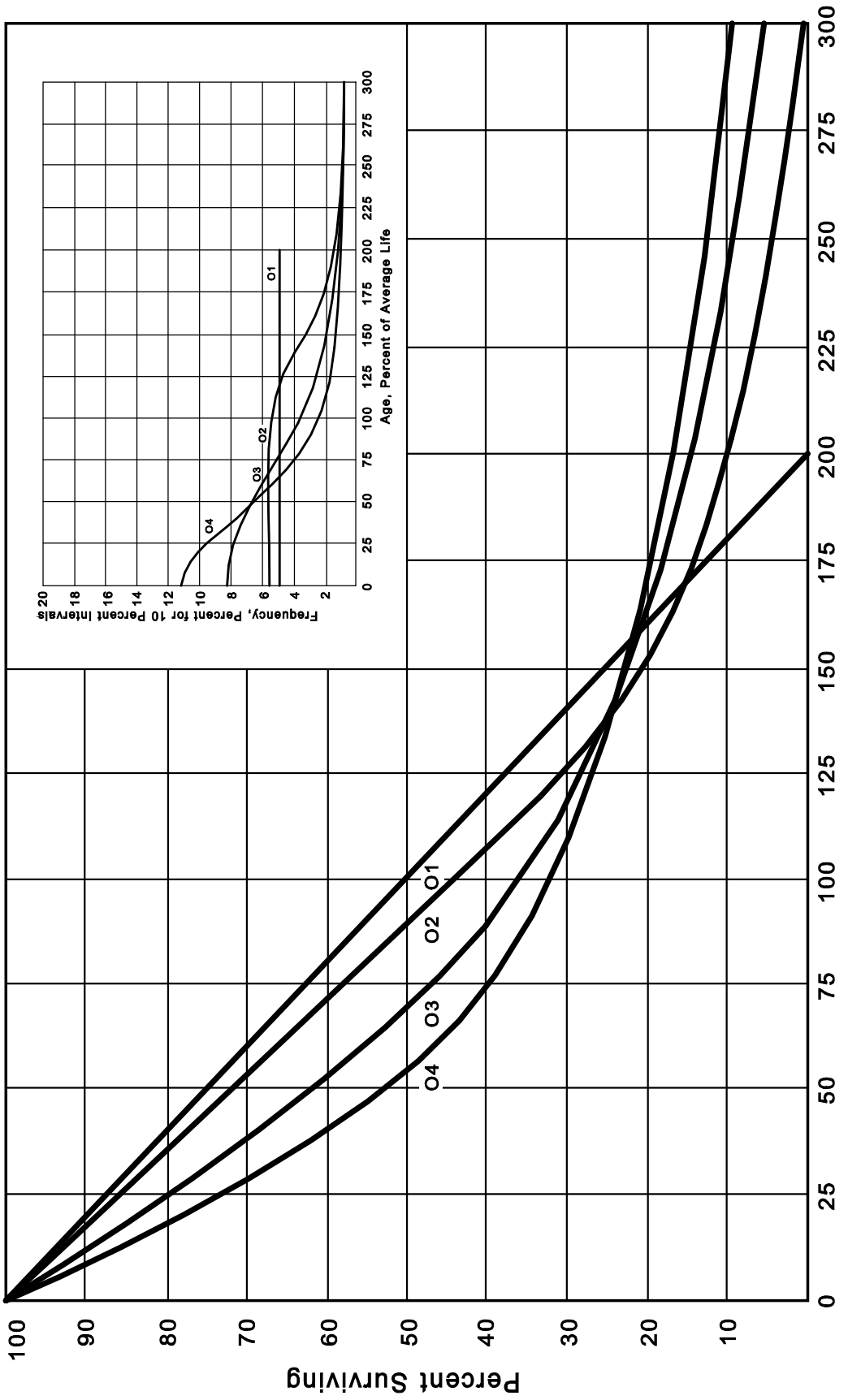


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2007-2016 during which there were placements during the years 2007-2016. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2002 were

[4] Winfrey, Robley, Supra Note 1.
[5] Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[6] Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2002-2016

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2003	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2004	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2005	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2006	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2007	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2008		5	11	12	13	14	15	16	18	20	113	7½-8½
2009			6	12	13	15	16	17	19	19	124	6½-7½
2010				6	13	15	16	17	19	19	131	5½-6½
2011					7	14	16	17	19	20	143	4½-5½
2012						8	18	20	22	23	146	3½-4½
2013							9	20	22	25	150	2½-3½
2014								11	23	25	151	1½-2½
2015									11	24	153	½-1½
2016										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2007-2016

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2003	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2004	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2005	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2006	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2007	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2008		-	-	-	-	-	-	-	-	-	-	7½-8½
2009			-	-	-	-	-	-	-	-	-	6½-7½
2010				-	-	-	-	(12)[b]	-	-	-	5½-6½
2011					-	-	-	-	22[a]	-	-	4½-5½
2012						-	-	(19)[b]	-	-	10	3½-4½
2013							-	-	-	-	-	2½-3½
2014								-	-	(102)[c]	(121)	1½-2½
2015									-	-	-	½-1½
2016												0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

retired in 2007. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2007 retirements of 2002 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on the following page. The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2002-2016

Year Placed	Exposures, Thousands of Dollars, Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2003	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2004	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2005	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2006	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2007	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2008		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2009			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2010				580[a]	574	561	546	530	501	482	3,057	5½-6½
2011					660[a]	653	639	623	628	609	3,789	4½-5½
2012						750[a]	742	724	685	663	4,332	3½-4½
2013							850[a]	841	821	799	4,955	2½-3½
2014								960[a]	949	923	5,719	1½-2½
2015									1,080[a]	1,069	6,579	½-1½
2016										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2006-2015, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on the following page, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the

retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2007-2016 Placement Band 2002-2016

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning o Age Interva (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	3,789,000		
Retirements from age 4½ to 5½	=	143,000		
Retirement Ratio	=	143,000 ÷ 3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year

average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

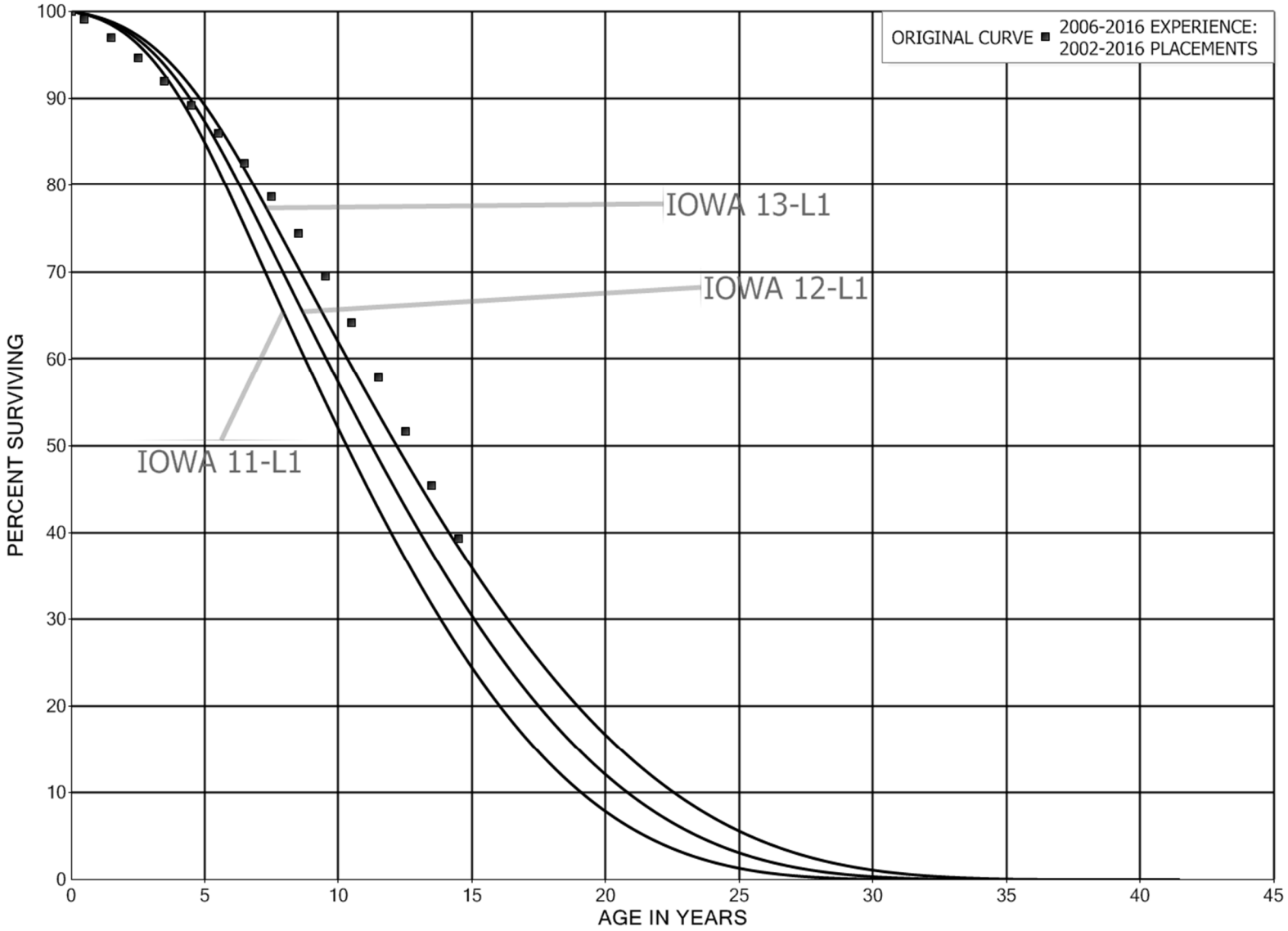


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

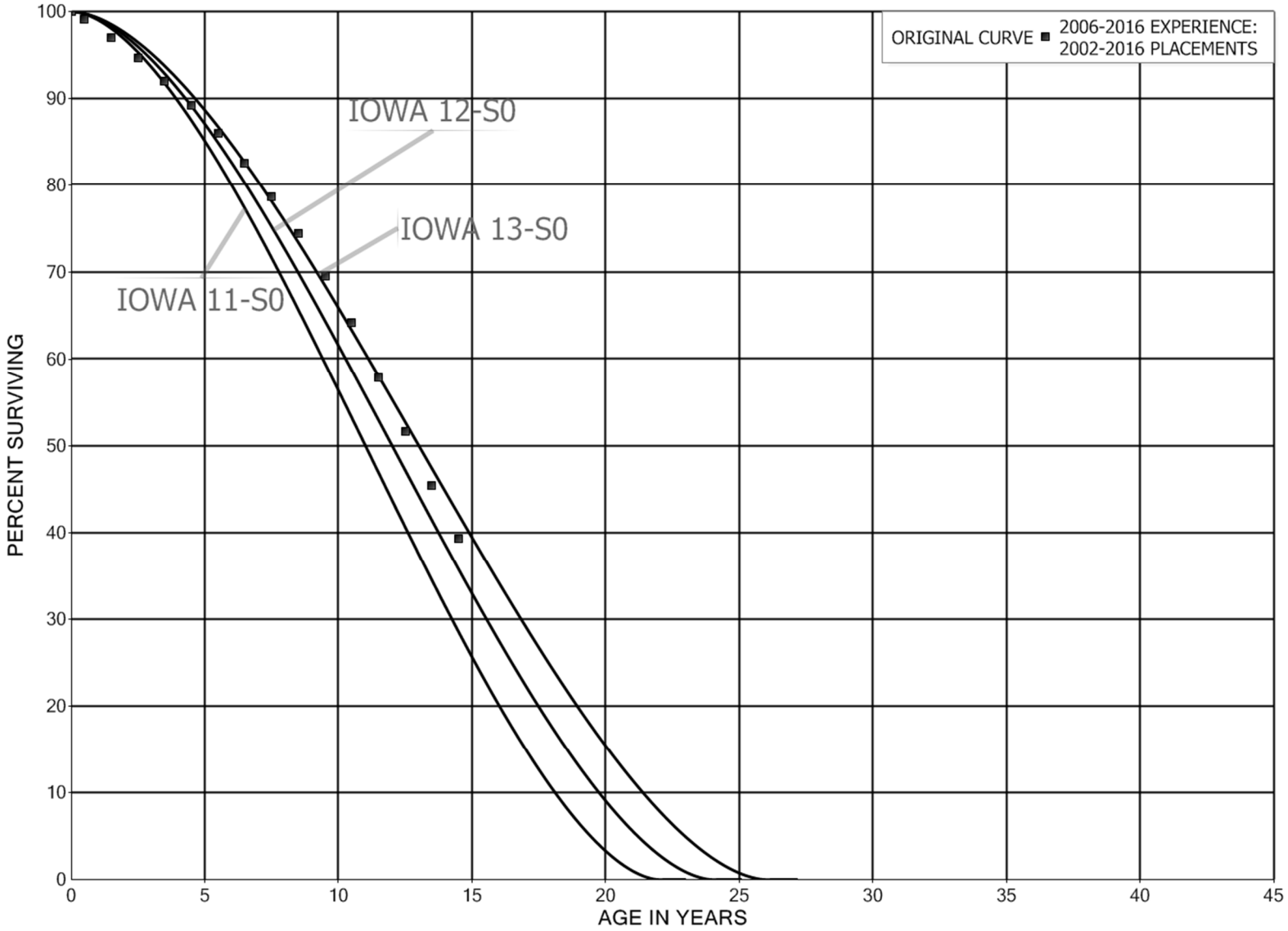


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

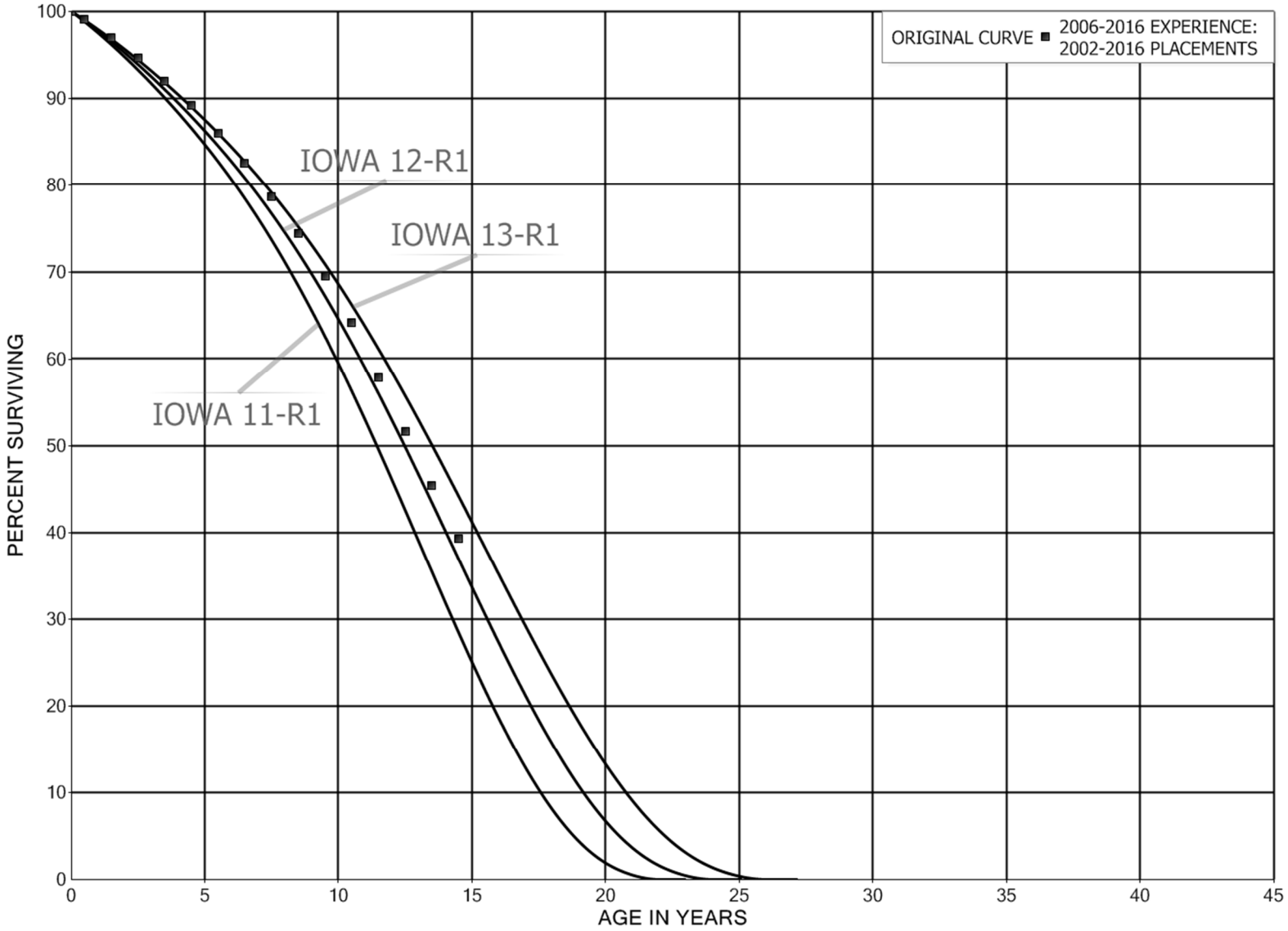
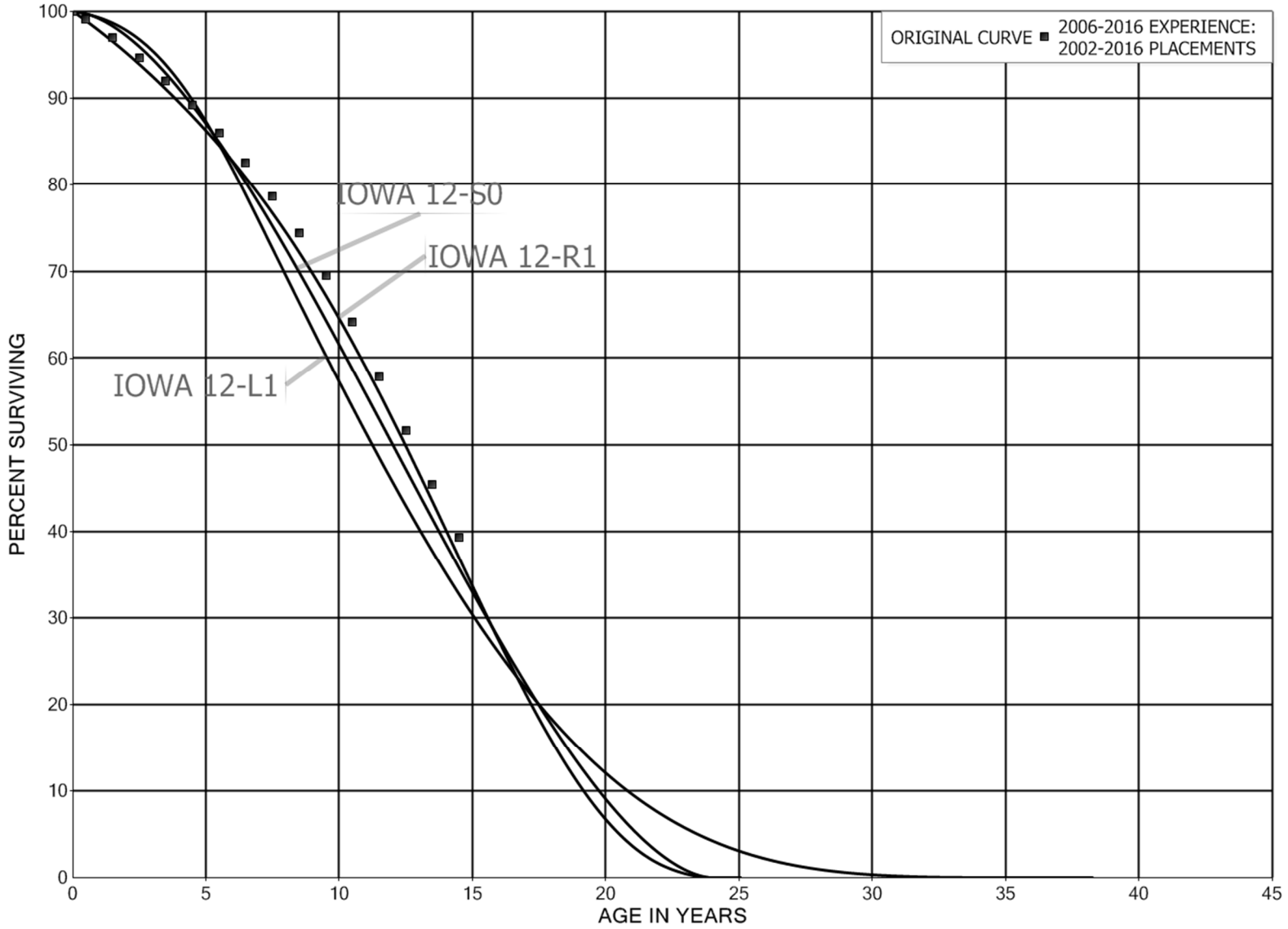


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



APPENDIX B – ESTIMATION OF NET SALVAGE

ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric Advisors, in part on historical data for the years 2010 through 2016, and in part through a comparison to peer gas utility companies. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on both annual and five-year moving average bases.The net salvage percentages estimated in this study have been determined using the "Traditional Approach" for net salvage estimation. The estimates of net salvage were based in part on the database of historic transactions encompassing the period from 2010 through 2016.

When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used a salvage proceed (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the accounts original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage percentage results.

The estimation of the net salvage percentages developed using the traditional approach, included the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period January 1, 2010 through December 31, 2016 were extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) was calculated for each historic year. Additionally, a net salvage amount was also calculated for each historic five-year.
3. The net salvage amount determined above was compared to the original booked costs retired for each period in the manner described, which resulted in a net salvage percentage of original costs retired for each year, in addition to five-year rolling bands.

4. The annual and five-year rolling average net salvage percentages were analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage was based purely upon statistical analysis.
5. Each account was then analyzed based on the statistical analyses, were compared to a group of peer gas utilities, and with the professional judgment of Concentric Advisors. Based on this analysis, a net salvage percentage for each account was determined.
6. The net salvage percentage was then used in the depreciation rate calculations in the depreciation study.

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APPENDIX C – Econolink Extract – January 2018

CANADIAN FORECASTS - 2018

Annual percent change, seasonally adjusted
(except where noted)

2018 FORECAST

	Royal Bank	CIBC	Bank of Montreal	Scotia Bank	TD Bank	FORECAST RANGE	2018 FORECAST AVERAGE
ECONOMIC ACTIVITY							
Real GDP*	1.9	2.1	2.2	2.3	2.4	1.9 - 2.4	2.2
Unemployment Rate	5.9	5.7	5.6	5.9	6.0	5.6 - 6.0	5.8
Consumer Price Index	2.1	2.1	2.0	1.9	1.8	1.8 - 2.1	2.0
THE CONSUMER							
Real Consumer Spending*	2.1	2.4	2.5	2.8	2.9	2.1 - 2.9	2.5
Motor Vehicle Sales *(%chg)*	-5.3	na	-5.8	-2.0	na	-5.8 - -2.0	-4.4
Housing Starts *(million units)*	0.197	0.195	0.205	0.206	0.198	0.195 - 0.206	0.200
% chg	-6.3	-11.8	-7.2	-6.8	-10.4	-11.8 - -6.3	-8.5
BUSINESS							
Business Non-Residential Invst*	3.6	2.9	2.9	3.6	4.1	2.9 - 4.1	3.4
Corporate Profits *(before tax)*	0.2	na	3.1	5.0	4.9	0.2 - 5.0	3.3
Imports*	2.2	2.4	1.7	2.4	1.9	1.7 - 2.4	2.1
Exports*	1.7	2.2	0.8	2.3	1.8	0.8 - 2.3	1.8
FINANCIAL							
Canada-Overnite Rate(%)	1.44	1.50	1.38	1.50	1.38	1.25 - 2.00	1.51
Prime Rate (%)	na	na	na	3.70	na	3.70 - 3.70	na
Exchange Rate *(cents U.S.- annual avg)*	na	na	0.79	na	na	0.79 - 0.79	0.79
(cents U.S.- end of period)	0.81	0.76	na	0.80	0.81	0.76 - 0.81	0.79
90 day T-bills *(annual average)*	2.05	1.21	1.35	1.55	1.44	1.21 - 2.05	1.52
10 yr Gov't Bonds *(annual average)*	2.95	2.19	2.35	2.39	2.35	2.19 - 2.95	2.45

* *indicates chain weighted $2007 dollars, change after subtracting inflation.*

CANADIAN FORECASTS - 2019

Annual percent change, seasonally adjusted
(except where noted)

2019 FORECAST

	Royal Bank	CIBC	Bank of Montreal	Scotia Bank	TD Bank	FORECAST RANGE	2019 FORECAST AVERAGE
ECONOMIC ACTIVITY							
Real GDP*	1.6	1.6	1.8	1.7	1.8	1.6 - 1.8	1.7
Unemployment Rate	5.9	5.6	5.4	5.9	6.0	5.4 - 6.0	5.8
Consumer Price Index	2.0	2.1	2.0	2.1	2.0	2.0 - 2.1	2.0
THE CONSUMER							
Real Consumer Spending*	1.4	1.3	1.8	1.9	1.7	1.3 - 1.9	1.6
Motor Vehicle Sales *(%chg)*	-2.0	na	-2.6	-2.5	na	-2.6 - -2.0	-2.4
Housing Starts *(million units)*	0.193	0.178	0.195	0.196	0.193	0.178 - 0.196	0.191
% chg	-2.0	-8.7	-4.9	-4.9	-2.5	-8.7 - -2.0	-4.6
BUSINESS							
Business Non-Residential Invst*	2.1	2.6	2.4	2.6	3.4	2.1 - 3.4	2.6
Corporate Profits *(before tax)*	-0.7	na	9.6	1.0	5.7	-0.7 - 9.6	3.9
Imports*	2.0	2.5	2.0	2.7	2.8	2.0 - 2.8	2.4
Exports*	2.5	3.7	2.3	3.2	3.1	2.3 - 3.7	3.0
FINANCIAL							
Canada-Overnite Rate(%)	2.3	1.6	2.31	2.25	1.88	1.63 - 2.31	2.06
Prime Rate (%)	na	na	na	4.45	na	4.45 - 4.45	na
Exchange Rate *(cents U.S.- annual avg)*	na	na	0.81	na	na	0.81 - 0.81	0.81
(cents U.S.- end of period)	0.79	0.78	na	0.80	0.80	0.78 - 0.80	0.79
90 day T-bills *(annual average)*	2.15	1.60	2.20	2.29	1.94	1.60 - 2.29	2.04
10 yr Gov't Bonds *(annual average)*	2.80	2.32	2.85	2.74	2.73	2.32 - 2.85	2.69

* *indicates chain weighted $2007 dollars, change after subtracting inflation.*

APPENDIX D – 2017 Pipeline Risk Mitigation Report

(filed confidentially)

APPENDIX E – Business Risk Assessment – 2018 Update

Background

In the Commission's Decision on the 2012 Generic Cost of Capital (2012 GCOC) Proceeding Stage 2, as per Order G-77-13, Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E). Ltd. (collectively, PNG) were directed as follows:

> *"… the Commission Panel directs PNG utilities to include an updated business risk assessment in all future revenue requirements applications."*[1]

The direction given by the Commission was to acknowledge that the PNG utilities face a unique set of circumstances with respect to the level of business risk. Further, the direction given acknowledged that the determinations made in the 2012 GCOC proceeding were based on an assessment of the business risks as they existed at the time of the proceeding with little weight placed on the potential for change to these risks in the future. The example was given that, should the various LNG initiatives contemplated in the region become a reality, the business risk would shift accordingly. Potential developments in the mining industry were also cited as an example.

The Commission's primary interest in this directive was to ensure that PNG's business risk assessment remains contemporary, and that PNG's cost of capital is aligned with the assessment.

In response to this direction, PNG provides the following business risk assessment update at the consolidated entity level as risks of all individual regulated divisions (PNG-West and PNG(NE), consisting of Fort St. John and Dawson Creek (FSJ/DC) and Tumbler Ridge (TR)) are considered somewhat similar.

[1] Section 3.3.7 Commission Cost of Capital Determination, BCUC Decision on the 2012 Generic Cost of Capital Proceeding Stage 2, p. 114

Overview

PNG's business risk profile has been trending higher since the last risk assessment was provided with the 2016-2017 Revenue Requirements Application due to certain events that have arisen since 2016. None of the potential LNG initiatives have proceeded at this time and developments in the mining and other industrial sectors in PNG's service territory have not yet materialized. Other factors that have arisen that have a potential negative effect on PNG include: the impact of the Federal and Provincial governments' climate change initiatives, the trend towards electrification and reduced use of fossil fuels, and the potential changes in access to supply of natural gas for PNG.

PNG reported on seven key risk areas in 2016 and during Stage 2 of the 2012 GCOC. This current business risk analysis uses the same risk categorization to facilitate the Commission's review of how PNG's risks have evolved since the last report. The overall assessment of risk can be summarized as follows:

- For the majority of the risk categories identified, the risk assessment has remained stable or has increased slightly.
- The Western system will continue to be significantly under-utilized keeping pressure on delivery rates and the competitive position of natural gas.
- PNG's filing of two-year revenue requirements applications commencing with the 2016 and 2017 period has resulted in higher regulatory lag and has increased forecasting risk.
- Climate change initiatives may negatively impact the demand for natural gas.

Taking the above into account, PNG entities' overall business risk has been assessed as slightly higher than 2012 and 2016 when this assessment was last updated, with increasing cautionary items of note.

Assessment of Business Risks

Aboriginal Rights

PNG's territory spans virtually the entire Province on an east to west basis, and thus traverses many areas that are currently within existing First Nation territories or within disputed First Nation areas. The PNG-West service area includes 17 different First Nations and PNG-West facilities are located in the traditional territory of "non-treaty" which serves to increase uncertainty. PNG(NE)'s system lies primarily in the "group of eight" First Nations which have a treaty in place with senior governments.

Given PNG's smaller size and resources, the numerous requirements for dealing with various aspects of Aboriginal Rights represent a much more resource intensive effort. The assessment of this risk continues to remain consistent with that made in 2016 and in 2012, but with an increasing trend given recent court cases.

Competitive Position of Natural Gas

This risk relates to the natural gas commodity price risk and price competitiveness of natural gas compared to other energy sources.

Commodity prices continue to be lower than in 2016 and 2012, and market prices have shown less volatility in recent years. In terms of competitiveness, natural gas continues to be a cost effective alternative to electricity for space and water heating but the upfront installation costs are higher and increases in the carbon tax rate have been enacted. PNG notes that the competitive position of natural gas has not improved, therefore this risk continues to be similar to 2012.

Customer Growth

Customer growth is a very significant factor in the operation of a transmission/distribution utility. The safe, reliable and efficient operation of PNG's pipeline infrastructure requires ongoing operating and maintenance costs which need to be covered by its customer base. A slow-down in the customer growth combined with a continuing decline in usage per customer, primarily as a result of more efficient homes and appliances, translates into increasing delivery rates.

PNG-West's customer base suffered a decline during the 2003 to 2012 period and has remained flat over the 2013 to 2017 period. The PNG(NE) Fort St. John/Dawson Creek (FSJ/DC) service area has experienced an average customer growth rate of approximately 2%

per year, though that trend has recently slowed significantly reflecting the effect that the very low commodity prices in the natural gas production sector have had on the economy of the area. The PNG(NE) Tumbler Ridge (TR) service area had experienced small growth of less than 1% over the 2003-2012 period, however the 2013 to 2017 period has seen a slight decrease in the customer base. As a result, this risk continues to be similar to 2012 with a declining trend.

The future for customer growth has become more uncertain under the climate change policies of both the Provincial and Federal Governments. As a fuel which produces carbon dioxide emissions when combusted, natural gas is subject to potential prescriptive policies which favour electrification and which would negatively influence natural gas demand regardless of its price competitiveness.

However, PNG is evaluating various initiatives to add customer growth that entail connecting off-grid customers and also providing renewable natural gas to customers.

Market Demand and Throughput

This risk considers the various elements that influence PNG's ability to attract new customers and retain its existing customer base and throughput.

Due to the loss of several very significant customers, PNG-West saw its total system throughput decline by 87% during the 2003 to 2012 period. There has been some recovery of this loss during the period 2013 to 2016, with throughput increasing by 12%. In the 2016/17 Application, PNG had initially shared that it was in the process of negotiating the final terms for a customer to contract for PNG-West's spare transmission capacity (Douglas Channel LNG). Unfortunately this project was cancelled subsequently and no similar projects to make use of the excess capacity have advanced. Consequently, the PNG-West system continues to be significantly under-utilized.

With respect to other industrial demand, the modernization of the Rio-Tinto Alcan smelter located in Kitimat that was completed in 2015 has helped to stabilize throughput on the PNG-West system, however in the absence of attracting other large industrial customers to the system there is a continued dependency on this customer to maintain throughput volumes.

For the remainder of the PNG-West service area, in terms of the "more stable" residential and small commercial customer counts, PNG continues to experience declines in Usage per Account (UPA) in both the residential and small commercial customers.

For PNG(NE) FSJ/DC, overall throughput has decreased over the 2013 to 2016 period with a declining trend in residential UPA but a relatively stable UPA for its small commercial customers. Demand in the oil and gas sector, representing the vast majority of industrial demand in this area, has generally been falling in response to depressed oil and gas prices.

Due to its smaller size, the PNG(NE) TR service area faces a significantly greater level of volatility, both in terms of customer count and overall throughput. During the 2013 to 2017 period, PNG(NE) TR has experienced significant volatility in demand by CNRL for its natural gas field facilities, due both to operational and market-related pressures on CNRL's service requirements. Further, an anticipated increase in demand from coal mining in the area has not materialized due to very depressed coal prices. In fact, the shut in of some mining operations has further reduced economic activity in the area. In terms of UPA, both the residential and small commercial customers have shown a declining trend since 2012.

Accordingly, given PNG has faced some significant challenges and experienced continued volatility, and given the fact that the Douglas Channel LNG project was cancelled, this risk is assessed to have increased since 2012, but is consistent with the 2016 assessment.

Regulatory Risk

Regulatory risk is the risk that the allowed return does not accord with the Fair Return Standard and that rates are set at a level that does not provide PNG with an opportunity to earn a fair return or that requested capital investments are not approved.

In the 2012 risk assessment, PNG had identified a number of areas where it had either received treatment or decisions that had been inconsistent, or the impact to PNG was much greater due to its small size. Further to the 2012 risk assessment, the implementation of two-year revenue requirements applications commencing the 2016-2017 period has created further regulatory lag and has increased PNG's forecasting risk. In spite of this added forecasting uncertainty, PNG considers this risk to have remained largely consistent during the period from the initial assessment in 2012 to the present date.

Supply Risk

PNG reiterates that this risk continues to be high as PNG only has one access point for all of its gas supply. Compared to 2012, the natural gas transportation infrastructure in PNG's service territory has remained relatively unchanged. However, Enbridge (formerly Spectra) has recently indicated that it may reallocate capacity that was previously designated to

Summit Lake down to Huntingdon. This would potentially hinder economic growth in PNG's service areas as new customers would not be able to access transportation capacity.

Other Risks

Other risks include Operating Risk, Size Specific Risk and Competition Risk. For the Operating Risk, there has been no change to the service areas in which PNG operates, which are characterized by northern, mountainous and generally harsher climate, factors that increase the cost of operating and maintaining a safe, reliable and efficient pipeline system. PNG continues to carry a $2 million deductible on its insurance program in relation to pipeline breaks.

PNG's aging infrastructure requires additional maintenance and refurbishment costs to maintain system reliability and pipeline integrity as PNG faces risks associated with corrosion, geotechnical instability, and obsolete equipment. In addition, pipeline codes, standards, and regulations are becoming more stringent in the face of heightened stakeholder expectations arising from pipeline incidents across North America. The combination of an aging infrastructure, heightened regulations, and low customer growth translates to incremental pressure to maintain service levels while managing customer rates.

For the Size Specific Risk and the Competition Risk, PNG considers both of these risks similar to 2012 and 2016 as no changes have taken place in the environment in which PNG operates.

Conclusion

PNG submits that the business risks for each of its entities have been trending higher since 2012. However, PNG does not propose any changes to its cost of capital to compensate it for these increasing risks as the change has not been overly substantive at this time.

Tab Schedules

1 Utility Income & Return

2 Utility Rate Base

3 Income Taxes

4 Common Equity

5 Return on Capital

6 Rates

Tab 1

Utility Income & Return

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

UTILITY INCOME & RETURN

SCHEDULE 1
(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Energy sales (TJ)	131	133	135	139	117	129	200	211	Tab 6, page 5 & 16
2	Average rate per GJ	$13.65	$11.75	$11.57	$10.77	$10.73	$12.12	$11.44	$8.73	
3										
4	Transportation service (TJ)	450	450	815	463	596	815	629	602	Tab 6, page 5 & 16
5	Average rate per GJ	$0.91	$0.79	$0.57	$1.00	$0.74	$0.48	$0.51	$0.61	
6										
7	Total deliveries (TJ)	581	583	950	602	713	945	829	814	Tab 6, page 5 & 16
8										
9	Utility revenue									
10	Energy sales	$1,614	$1,406	$1,514	$1,492	$1,250	$1,568	$2,288	$1,846	Tab 6, page 4 & 15
11	Interim rates - sales	178	159	43						Tab 6, page 3 & 14
12	Transportation service	356	309	444	462	442	390	324	370	Tab 6, page 4 & 15
13	Interim rates - transportation	53	47	19						Tab 6, page 3 & 14
14										
15	Total Utility Revenue	2,200	1,921	2,020	1,955	1,692	1,959	2,612	2,216	
16	Cost of sales	414	358	497	424	238	497	1,028	605	Tab 6, pages 4 & 7, pages 15 & 18
17										
18	Gross margin	1,786	1,563	1,523	1,531	1,454	1,461	1,584	1,611	
19										
20	Operating expenses	783	754	712	699	708	620	636	620	Tab 1, page 2, line 6
21	Maintenance expenses	84	82	80	56	138	70	124	164	Tab 1, page 2, line 10
22	Admin. & general expenses	243	234	252	246	272	303	252	284	Tab 1, page 2, line 16
23	Property taxes	83	78	94	94	93	88	85	76	Tab 1, page 7, line 4
24	Depreciation	159	125	152	146	140	150	144	134	Tab 2, page 9 & 10, line 55
25	Amortization on gross deferrals	14	139	(9)	(9)	(12)	(19)	35	(88)	Tab 2, page 14 & 15, line 38 less line 23
26	Investment income, other revenue	(17)	(17)	(19)	(14)	(18)	(14)	(30)	(18)	Tab 1, page 8, line 7
27	2018/19 Rate smoothing deferral	89	(85)							Tab 2, page 14 & 15, line 23
28	Interim to permanent rate adjustment		0						-	
29		1,437	1,309	1,263	1,218	1,320	1,199	1,246	1,172	
30										
31	Earned return before income taxes	349	254	260	312	135	262	338	440	
32	Future Income taxes on deferrals	(1)	(60)	(4)	(4)	(4)	(5)	(11)	25	Tab 2, page 14 & 15, line 39
33	Income taxes	49	51	28	46	5	40	69	15	Tab 3, page 1, line 14
34										
35	Earned return	$300	$263	$236	270	134	227	280	399	
36										
37	Utility rate base	$4,478	$3,828	$3,569	3,202	3,069	$3,042	$3,092	$2,632	Tab 2, page 1, line 20
38										
39	Return on rate base	6.71%	6.87%	6.61%	8.44%	4.37%	7.47%	9.05%	15.16%	Tab 5, page 1, line 18

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF OPERATING, MAINTENANCE
& ADMINISTRATIVE & GENERAL EXPENSES

(000s)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	OPERATING EXPENSES								
2	- wages	305	299	281	292	350	248	246	224
3	- gas	60	53	52	70	49	54	90	81
4	- transferred to capital	(23)	(26)	(19)	(26)	(18)	(13)	(23)	(9)
5	- other	441	429	399	363	326	332	324	323
6	Total Operating	783	754	712	699	708	620	636	620
7	MAINTENANCE EXPENSES								
8	- wages	37	36	35	3	6	35	48	36
9	- other	47	46	45	53	132	35	77	129
10	Total Maintenance	84	82	80	56	138	70	124	164
11	ADMINISTRATIVE AND GENERAL EXPENSES								
12	- wages	0	0	0	0	0	0	0	0
13	- benefits	106	106	139	142	146	152	130	138
14	- transferred to capital	(12)	(17)	(40)	(65)	(21)	(9)	(11)	(18)
15	- other	150	144	153	169	147	160	133	163
16	Total Admin & General	243	234	252	246	272	303	252	284
17	TOTAL EXPENSES	$1,110	$1,070	$1,044	$1,001	$1,117	$994	$1,013	$1,068
18	Net of Transfers & Gas	$1,085	$1,060	$1,052	$1,022	$1,107	$962	$957	$1,013

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

OPERATING EXPENSES

(000s)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	621 Processing	258	253	235	332	327	238	218	233
2	Process plant - gas	60	53	52	66	46	49	85	75
3		318	305	287	398	373	287	302	308
4	664 Communications	1	1	1	0	0	0	0	1
5	665 Pipelines	25	25	24	2	10	4	17	16
6	Pipelines - Gas	0	0	0	4	3	4	5	6
7	667 Regulating Stations	22	21	21	6	16	22	19	14
8	Total transmission	47	46	46	13	30	31	41	37
9	670 Supervision	19	18	18	5	14	16	32	16
10	673 Removing & resetting meters	27	27	26	12	15	15	10	19
11	674 Service on customer premises	2	2	2	0	0	1	2	1
12	675 Mains and services	8	8	8	5	19	5	7	4
13	677 Regulating stations	0	0	0	0	0	0	0	0
14	679 Other	1	1	1	0	0	0	0	0
15	Total distribution	58	57	55	21	48	37	50	41
16	684 Communications	0	0	0	0	0	0	1	0
17	685 General systems operations	106	101	82	82	46	53	64	46
18	Shared Services from Parent	49	48	43	43	43	42	39	39
19	688 Other general operations	95	93	88	45	72	66	49	44
20	689 Transferred to capital	(23)	(26)	(19)	(26)	(18)	(13)	(23)	(9)
21	Total general	227	216	194	143	143	148	129	120
22	701 Advertising	1	1	1	0	0	0	0	0
23	702 Demonstration and selling	0	0	0	0	0	0	0	0
24	709 Other	0	0	0	0	0	0	0	0
25	Total sales	1	1	1	0	0	0	0	0
26	710 Customer Accounting	0	0	0	0	0	0	0	0
27	711 Customer contracts	0	0	0	0	0	0	0	0
28	Shared Services from Parent	18	18	18	18	17	18	19	21
29	712 Meter reading	17	17	16	5	7	6	12	18
30	713 Customer billing	56	55	57	48	49	55	50	42
31	Shared Services from Parent	30	29	31	31	31	31	31	30
32	714 Credit and collections	0	0	0	1	1	0	0	0
33	Shared Services from Parent	2	2	2	2	2	2	2	3
34	718 Uncollectible accounts	8	8	6	19	6	5	0	0
35	Total customer accounting	131	128	130	124	113	118	114	114
36	Total operating	$783	$754	$712	$699	$708	$620	$636	$620

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

MAINTENANCE EXPENSES

(000s)

Line No.	Account and Description	Test Year 2019		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	821 Process plant	64	63	62	50	123	38	30	123
2	864 Communications	0	0	0	0	0	0	0	0
3	865 Pipe lines	2	2	2	0	4	9	56	5
4	866 Compressors	0	0	0	0	0	0	0	0
5	867 Regulating stations	7	7	7	4	8	5	20	12
6	Total transmission	9	9	9	4	11	15	76	17
7	872 Structures	6	6	6	0	0	14	17	22
8	874 Customer premises	0	0	0	0	0	0	1	0
9	875 Mains and services	3	2	2	0	3	1	0	0
10	877 Regulating stations	0	0	0	1	0	0	0	0
11	878 Meters	2	2	2	0	1	3	1	2
12	879 Other	0	0	0	0	0	0	0	0
13	Total distribution	11	10	10	1	4	18	19	25
14	884 Communications	0	0	0	0	0	0	0	0
15	885 General	0	0	0	0	0	0	0	0
16	Total general	0	0	0	0	0	0	0	0
17	Total maintenance	$84	$82	$80	$56	$138	$70	$124	$164

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

ADMINISTRATIVE AND GENERAL EXPENSES
NET OF COST ADJUSTMENTS
(000s)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	721 Administration	2	2	7	7	7	7	1	23
2	Shared Services from Parent	98	94	98	98	93	93	83	79
3	722 Audit, legal & consulting fees	6	6	7	24	8	21	9	25
4	723 Insurance	8	8	6	6	7	7	8	8
5	724 Reserve for damages	0	0	0	0	0	0	0	0
6	725 Employee benefits	107	108	140	142	146	152	130	138
7	728 Shared Services from Parent	21	20	19	19	19	19	19	16
8	Regulation	13	13	14	14	14	13	13	12
9	Donations	0	0	0	0	0	0	0	1
10	729 Transferred to capital	(12)	(17)	(40)	(65)	(21)	(9)	(11)	(18)
11	Subtotal general and administrative	$243	$234	$252	$246	$272	$303	$252	$284

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

ADMINISTRATIVE AND GENERAL EXPENSES

(000s)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	721 Administration	2	2	7	7	7	7	1	23
2	Shared Services from Parent	98	94	98	98	93	93	83	79
3	722 Audit, legal & consulting fees	6	6	7	24	8	21	9	25
4	723 Insurance	8	8	6	6	7	7	8	8
5	724 Reserve for damages	0	0	0	0	0	0	0	0
6	725 Employee benefits	107	108	140	143	146	152	130	138
7	728 Shared Services from Parent	21	20	19	19	19	19	19	16
8	Regulation	13	13	14	14	14	13	13	12
9	Donations	1	1	1	0	0	0	0	1
10	729 Transferred to capital	(12)	(17)	(40)	(65)	(21)	(9)	(11)	(18)
11	Subtotal general and administrative	244	234	253	246	272	303	252	284
12	Cost adjustments								
13	728 - 50% of donations	(0)	(0)	(0)	0				
14	725 - 1% portion of employee savings plan	(0)	(0)	(0)	(0)				
15	Subtotal cost adjustments	(1)	(1)	(0)	(0)				
16	Total administrative and general	$243	$234	$252	$246	$272	$303	$252	$284

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

TAXES OTHER THAN INCOME TAXES

(000s)

Line No.	Account and Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**PROPERTY TAXES**								
2	Regular	$63	$62	$69	$69	$68	$66	$64	$61
3	Other 1% in lieu	20	16	25	25	25	22	21	15
4	TOTAL	$83	$78	$94	$94	$93	$88	$85	$76

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

MISCELLANEOUS OPERATING REVENUE

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Penalty charges	$6	$6	$10	$6	$6	$7	$9	$10
2	Connection Fees	9	9	9	9	10	7	7	9
3	Rents	0	0	0	0	0	0	0	0
4	Overheads recovered	1	1	(0)	0	2	0	0	(1)
5	Automotive surcharges	0	0	0	0	0	0	0	0
6	Other	0	0	0	0	0	0	13	0
7		$17	$17	$19	$14	$18	$14	$30	$18

Tab 2

Utility Rate Base

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

UTILITY RATE BASE

SCHEDULE 2
(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Plant in service beginning of year	$11,565	$10,150	$10,134	$9,947	$9,731	9,741	9,535	$9,290	Tab 2, page 4 & 5, line 55
2	Additions	221	1,415	868	306	240	69	207	319	Tab 2, page 4 & 5, line 55
3	Disposals	-	-	-	(102)	(24)	(79)	(1)	(74)	Tab 2, page 4 & 5, line 55
4										
5	Plant in service end of year	11,786	11,565	11,002	10,150	9,947	9,731	9,741	9,535	
6	Accumulated depreciation	6,600	6,412	6,381	6,253	6,159	5,997	5,850	5,659	Tab 2, page 9 & 10, line 39
7										
8	Net plant in service end of year	5,186	5,153	4,621	3,898	3,788	3,734	3,892	3,877	
9										
10	Net plant beginning of year	5,153	3,898	3,951	3,788	3,734	3,892	3,877	3,754	Tab 2, pages 6 & 11 net of lines 1 & 1
11										
12	Net plant in service midyear	5,170	4,525	4,286	3,843	3,761	3,813	3,884	3,815	
13	Contributions for construction	(915)	(943)	(940)	(939)	(979)	(1,020)	(1,058)	(1,084)	Tab 2, page 30, line 13
14	Unamortized deferred charges	20	25	46	36	47	41	30	17	Tab 2, page 14 & 15, line 11
15	Deferred income taxes	-	-	-	-	-	-	-	(307)	Tab 2, page 33, line 9
16	Reserve for damages	-	-	-	-	-	-	-	-	
17	Pension funding in excess of expense	96	110	65	128	136	144	116	72	Tab 2, page 31, line 14
18	Non-pension post retirement	-	-	-	-	-	-	-	-	Tab 2, page 32, line 20
19	Cash working capital	107	109	111	134	104	64	121	119	Tab 2, page 16 & 23, line 10
20	Other working capital	-	-	-	-	-	-	-	-	Tab 2, page 22 & 29, line 15
19										
20	Utility rate base, midyear	$4,478	$3,828	$3,569	$3,202	$3,069	$3,042	$3,092	$2,632	

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE
ACTUAL 2016
($000s)

Line No.	Description	Jan/16 Beginning Balance	Actual				Dec/16 Ending Balance
			Additions	Overheads	Transfers	Retirements	
1	**Processing plant**						
2	410 Land	3					3
3	411 Land Rights						
4	412 Compressor Structures	34					34
5	413 Regulating Structures	75					75
6	417 Regulating Equipment	30					30
7	418 Purification Equipment	3,581	188			(20)	3,750
8							
9		3,724	188			(20)	3,892
10	**Transmission plant**						
11	460 Land						
12	461 Land rights						
13	462 Compressor structures						
14	463 Regulating structures						
15	465 Mains	1,741					1,741
16	466 Compressor equipment	4					4
17	467 Regulating equipment	407	22				429
18	468 Communications	5					5
19	469 Other						
20							
21		2,157	22				2,180
22	**Distribution plant**						
23	471 Land rights	2					2
24	472 Structures	326	17			(2)	341
25	473 Services	716				()	715
26	474 House installations	286					286
27	475 Mains	1,100					1,100
28	476 Compressor equipment						
29	477 Regulating equipment	321					321
30	478 Meters	204				(2)	202
31	479 Other						
32							
33		2,954	17			(4)	2,967
34	**General plant**						
35	480 Land	23					23
36	481 Land rights						
37	482 Structures	402					402
38	483 Office equipment	47					47
39	484 Transportation equipment	40					40
40	485 Heavy work equipment	107	10				118
41	486 Tools	130					130
42	487 Computer equipment	28	3				31
43	488 Communications	117					117
44	489 Other						
45							
46		896	13				908
47	**Construction overheads**						
48							
49	System operations transfers						
50	Administrative transfers						
51	Depreciation						
52							
53							
54							
55		9,731	240			(24)	9,947

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE
ACTUAL 2017
($000s)

Line No.	Description	Jan/17 Beginning Balance	Actual Additions	Overheads	Transfers	Retirements	Dec/17 Ending Balance
1	**Processing plant**						
2	410 Land	3					3
3	411 Land Rights						
4	412 Compressor Structures	34					34
5	413 Regulating Structures	75					75
6	417 Regulating Equipment	30					30
7	418 Purification Equipment	3,750					3,750
8							
9		3,892					3,892
10	**Transmission plant**						
11	460 Land						
12	461 Land rights						
13	462 Compressor structures						
14	463 Regulating structures						
15	465 Mains	1,741					1,741
16	466 Compressor equipment	4					4
17	467 Regulating equipment	429	166			(20)	575
18	468 Communications	5					5
19	469 Other						
20							
21		2,180	166			(20)	2,326
22	**Distribution plant**						
23	471 Land rights	2					2
24	472 Structures	341					341
25	473 Services	715					715
26	474 House installations	286					286
27	475 Mains	1,100	140				1,240
28	476 Compressor equipment						
29	477 Regulating equipment	321					321
30	478 Meters	202				(2)	200
31	479 Other						
32							
33		2,967	140			(2)	3,105
34	**General plant**						
35	480 Land	23					23
36	481 Land rights						
37	482 Structures	402					402
38	483 Office equipment	47				(19)	28
39	484 Transportation equipment	40					40
40	485 Heavy work equipment	118					118
41	486 Tools	130				(47)	83
42	487 Computer equipment	31				(15)	16
43	488 Communications	117					117
44	489 Other						
45							
46		908				(81)	828
47	**Construction overheads**						
48							
49	System operations transfers						
50	Administrative transfers						
51	Depreciation						
52							
53							
54							
55		9,947	306			(102)	10,150

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE
TEST YEAR 2018
($000s)

Line No.	Description	Jan/18 Beginning Balance	Decision				Dec/18 Ending Balance
			Additions	Overheads	Transfers	Retirements	
1	**Processing plant**						
2	410 Land	3					3
3	411 Land Rights						
4	412 Compressor Structures	34					34
5	413 Regulating Structures	75					75
6	417 Regulating Equipment	30					30
7	418 Purification Equipment	3,750	9				3,758
8							
9		3,892	9				3,901
10	**Transmission plant**						
11	460 Land						
12	461 Land rights						
13	462 Compressor structures						
14	463 Regulating structures						
15	465 Mains	1,741	1,249	44			3,034
16	466 Compressor equipment	4					4
17	467 Regulating equipment	575					575
18	468 Communications	5					5
19	469 Other						
20							
21		2,326	1,249	44			3,619
22	**Distribution plant**						
23	471 Land rights	2					2
24	472 Structures	341					341
25	473 Services	715					715
26	474 House installations	286					286
27	475 Mains	1,240					1,240
28	476 Compressor equipment						
29	477 Regulating equipment	321					321
30	478 Meters	200					200
31	479 Other						
32							
33		3,105					3,105
34	**General plant**						
35	480 Land	23					23
36	481 Land rights						
37	482 Structures	402	54				456
38	483 Office equipment	28					28
39	484 Transportation equipment	40	59				99
40	485 Heavy work equipment	118					118
41	486 Tools	83					83
42	487 Computer equipment	16	()				16
43	488 Communications	117					117
44	489 Other						
45							
46		828	113				940
47	**Construction overheads**						
48							
49	System operations transfers		26	(26)			
50	Administrative transfers		17	(17)			
51	Depreciation		1	(1)			
52	Less: Overheads allocated to WIP						
53			44	(44)			
54							
55		10,150	1,415				11,565

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE
TEST YEAR 2019
($000s)

Line No.	Description	Jan/19 Beginning Balance	Decision			Dec/19 Ending Balance
			Additions	Allocations	Retirements	
1	**Processing plant**					
2	410 Land	3				3
3	411 Land Rights					
4	412 Compressor Structures	34				34
5	413 Regulating Structures	75				75
6	417 Regulating Equipment	30				30
7	418 Purification Equipment	3,758	179	37		3,974
8						
9		3,901	179	37		4,116
10	**Transmission plant**					
11	460 Land					
12	461 Land rights					
13	462 Compressor structures					
14	463 Regulating structures					
15	465 Mains	3,034				3,034
16	466 Compressor equipment	4				4
17	467 Regulating equipment	575				575
18	468 Communications	5				5
19	469 Other					
20						
21		3,619				3,619
22	**Distribution plant**					
23	471 Land rights	2				2
24	472 Structures	341				341
25	473 Services	715				715
26	474 House installations	286				286
27	475 Mains	1,240				1,240
28	476 Compressor equipment					
29	477 Regulating equipment	321				321
30	478 Meters	200				200
31	479 Other					
32						
33		3,105				3,105
34	**General plant**					
35	480 Land	23				23
36	481 Land rights					
37	482 Structures	456	6			462
38	483 Office equipment	28				28
39	484 Transportation equipment	99				99
40	485 Heavy work equipment	118				118
41	486 Tools	83				83
42	487 Computer equipment	16				16
43	488 Communications	117				117
44	489 Other					
45						
46		940	6			946
47	**Construction overheads**					
48						
49	System operations transfers		23	(23)		
50	Administrative transfers		12	(12)		
51	Depreciation		1	(1)		
52	Less: Overheads allocated to WIP					
53			37	(37)		
54						
55		11,565	221			11,786

Pacific Northern Gas (NE) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE - CONTINUITY OF PLANT COST

($000s)

Line	Description	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016
1	Balance, Beginning of Year	11,565	10,150	9,947	9,731
2	CIAC Balance, Beginning of Year	(4,503)	(4,500)	(4,460)	(4,460)
3	Plant Cost, net of CIAC, Beginning of Year	7,063	5,650	5,487	5,271
4	Additions during year:				
5	Plant Cost	184	1,371	306	240
6	Allocation of overheads	37	44		
7	Total Plant Additions	221	1,415	306	240
8	Contributions in Aid of Construction	(3)	(3)	(1)	
9	Total Additions	218	1,412	305	240
10	Plant Retirements:				
11	Normal Course			(102)	(24)
12	Deactivated Assets				
13	CIAC Retirements				
14	Total Retirements			(102)	(24)
15	Balance, End of Year	7,281	7,063	5,689	5,487
16	Closing balance consists of:				
17	Plant Cost	11,786	11,565	10,150	9,947
18	CIAC	(4,505)	(4,503)	(4,461)	(4,460)
19	Balance, End of Year	7,281	7,063	5,689	5,487

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION

ACTUAL 2016

($000s)

Line No.	Description	Jan/16 Beginning Balance	Actual Provision	Transfers	Retirements	Recoveries	Dec/16 Ending Balance
1	**Processing plant**						
2	412 Compressor Structures	(21)	(2)				(23)
3	413 Regulating Structures	(70)	(4)				(74)
4	417 Regulating Equipment	(15)	(1)				(16)
5	418 Purification Equipment	(2,604)	(54)		20		(2,638)
6							
7		(2,710)	(60)		20		(2,751)
8	**Transmission plant**						
9	462 Compressor structures						
10	463 Regulating structures						
11	465 Mains	(1,038)	(25)				(1,062)
12	466 Compressor equipment	(3)	()				(3)
13	467 Regulating equipment	(61)	(17)				(77)
14	468 Communications		()				()
13	469 Other						
14							
15		(1,101)	(42)				(1,143)
16	**Distribution plant**						
17	472 Structures	(80)	(11)		2		(89)
18	473 Services	(302)	(14)				(316)
19	474 House installations	(231)	(8)				(239)
20	475 Mains	(549)	(17)				(566)
21	476 Compressor equipment						
22	477 Regulating equipment	(222)	(7)				(229)
23	478 Meters	(73)	(6)		2		(77)
24	479 Other						
25							
26		(1,456)	(63)		4		(1,515)
27							
28	**General plant**						
29	482 Structures	(399)	(1)				(400)
30	483 Office equipment	(31)	(2)				(33)
31	484 Transportation equipment	(9)	(5)				(14)
32	485 Heavy work equipment	(75)	(9)				(84)
33	486 Tools	(72)	(4)				(76)
34	487 Computer equipment	(27)	()				(27)
35	488 Communications	(117)	()				(117)
36	489 Other						
37		(730)	(20)				(750)
38							
39		(5,997)	(186)		24		(6,159)
40							
41							
42	**Amortization of Contributions**						
43	Processing	2,322					2,322
44	Transmission	893	26				919
45	Distribution	245	15				260
46	General	1					1
47	Total Amortization of Contributions	3,461	41				3,502
48							
49	Accum Depn/Amort (incl contrib)	(2,536)					(2,658)
50							
51							
52	Amortization of CIAC		41				
53							
54	Depreciation capitalized		6				
55	Net depreciation expense		(140)				

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION

ACTUAL 2017

($000s)

Line No.	Description	Jan/17 Beginning Balance	Actual Provision	Actual Transfers	Actual Retirements	Actual Recoveries	Dec/17 Ending Balance
1	**Processing plant**						
2	412 Compressor Structures	(23)	(2)				(24)
3	413 Regulating Structures	(74)	(1)				(75)
4	417 Regulating Equipment	(16)	(1)				(18)
5	418 Purification Equipment	(2,638)	(61)				(2,699)
6							
7		(2,751)	(65)				(2,816)
8	**Transmission plant**						
9	462 Compressor structures						
10	463 Regulating structures						
11	465 Mains	(1,062)	(25)				(1,087)
12	466 Compressor equipment	(3)	()				(3)
13	467 Regulating equipment	(77)	(18)		17		(78)
14	468 Communications	()	()				(1)
13	469 Other						
14							
15		(1,143)	(43)		17		(1,169)
16	**Distribution plant**						
17	472 Structures	(89)	(11)				(100)
18	473 Services	(316)	(14)				(330)
19	474 House installations	(239)	(8)				(246)
20	475 Mains	(566)	(17)				(584)
21	476 Compressor equipment						
22	477 Regulating equipment	(229)	(7)				(235)
23	478 Meters	(77)	(6)		2		(81)
24	479 Other						
25							
26		(1,515)	(63)		2		(1,577)
27							
28	**General plant**						
29	482 Structures	(400)	(1)				(401)
30	483 Office equipment	(33)	(2)		19		(15)
31	484 Transportation equipment	(14)	(5)				(18)
32	485 Heavy work equipment	(84)	(9)				(93)
33	486 Tools	(76)	(4)		47		(34)
34	487 Computer equipment	(27)	(1)		15		(13)
35	488 Communications	(117)	()				(117)
36	489 Other						
37		(750)	(21)		81		(691)
38							
39		(6,159)	(193)		99		(6,253)
40							
41							
42	**Amortization of Contributions**						
43	Processing	2,322					2,322
44	Transmission	919	26				945
45	Distribution	260	14				274
46	General	1	()				1
47	Total Amortization of Contributions	3,502	40				3,542
48							
49	Accum Depn/Amort (incl contrib)	(2,658)					(2,711)
50							
51							
52	Amortization of CIAC		40				
53							
54	Depreciation capitalized		6				
55	Net depreciation expense		(146)				

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION

TEST YEAR 2018

($000s)

Line No.	Description	Jan/18 Beginning Balance	Decision				Dec/18 Ending Balance
			Provision	Transfers	Retirements	Recoveries	
1	**Processing plant**						
2	412 Compressor Structures	(24)	(1)				(26)
3	413 Regulating Structures	(75)					(75)
4	417 Regulating Equipment	(18)	(1)				(19)
5	418 Purification Equipment	(2,699)	(47)				(2,745)
6							
7		(2,816)	(49)				(2,865)
8	**Transmission plant**						
9	462 Compressor structures						
10	463 Regulating structures						
11	465 Mains	(1,087)	(22)				(1,109)
12	466 Compressor equipment	(3)	()				(3)
13	467 Regulating equipment	(78)	(16)				(94)
14	468 Communications	(1)	()				(1)
13	469 Other						
14							
15		(1,169)	(38)				(1,208)
16	**Distribution plant**						
17	472 Structures	(100)	(11)				(111)
18	473 Services	(330)	(16)				(346)
19	474 House installations	(246)	(2)				(249)
20	475 Mains	(584)	(18)				(601)
21	476 Compressor equipment						
22	477 Regulating equipment	(235)	(3)				(239)
23	478 Meters	(81)	(8)				(89)
24	479 Other						
25							
26		(1,577)	(58)				(1,634)
27							
28	**General plant**						
29	482 Structures	(401)	()				(401)
30	483 Office equipment	(15)	(2)				(17)
31	484 Transportation equipment	(18)	(4)				(23)
32	485 Heavy work equipment	(93)	(2)				(95)
33	486 Tools	(34)	(4)				(38)
34	487 Computer equipment	(13)	(1)				(14)
35	488 Communications	(117)	()				(117)
36	489 Other						
37		(691)	(14)				(705)
38							
39		(6,253)	(160)				(6,412)
40							
41							
42	**Amortization of Contributions**						
43	Processing	2,322					2,322
44	Transmission	945	20				965
45	Distribution	274	13				288
46	General	1	()				1
47	Total Amortization of Contributions	3,542	34				3,575
48							
49	Accum Depn/Amort (incl contrib)	(2,711)					(2,837)
50							
51							
52	Amortization of CIAC		34				
53							
54	Depreciation capitalized		1				
55	Net depreciation expense		(125)				

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION

TEST YEAR 2019

($000s)

Line No.	Description	Jan/19 Beginning Balance	Decision			Dec/19 Ending Balance
			Provision	Retirements	Recoveries	
1	**Processing plant**					
2	412 Compressor Structures	(26)	(1)			(27)
3	413 Regulating Structures	(75)				(75)
4	417 Regulating Equipment	(19)	(1)			(20)
5	418 Purification Equipment	(2,745)	(47)			(2,792)
6						
7		(2,865)	(49)			(2,915)
8	**Transmission plant**					
9	462 Compressor structures					
10	463 Regulating structures					
11	465 Mains	(1,109)	(42)			(1,151)
12	466 Compressor equipment	(3)	()			(4)
13	467 Regulating equipment	(94)	(16)			(110)
14	468 Communications	(1)	()			(1)
13	469 Other					
14						
15		(1,208)	(58)			(1,266)
16	**Distribution plant**					
17	472 Structures	(111)	(11)			(121)
18	473 Services	(346)	(16)			(361)
19	474 House installations	(249)	(2)			(251)
20	475 Mains	(601)	(18)			(619)
21	476 Compressor equipment					
22	477 Regulating equipment	(239)	(3)			(242)
23	478 Meters	(89)	(8)			(97)
24	479 Other					
25						
26		(1,634)	(58)			(1,692)
27						
28	**General plant**					
29	482 Structures	(401)	(2)			(403)
30	483 Office equipment	(17)	(2)			(19)
31	484 Transportation equipment	(23)	(11)			(33)
32	485 Heavy work equipment	(95)	(2)			(97)
33	486 Tools	(38)	(4)			(42)
34	487 Computer equipment	(14)	(1)			(15)
35	488 Communications	(117)	()			(117)
36	489 Other					
37		(705)	(22)			(727)
38						
39		(6,412)	(188)			(6,600)
40						
41						
42	**Amortization of Contributions**					
43	Processing	2,322				2,322
44	Transmission	965	14			979
45	Distribution	288	14			301
46	General	1	()			1
47	Total Amortization of Contributions	3,575	28			3,603
48						
49	Accum Depn/Amort (incl contrib)	(2,837)				(2,997)
50						
51						
52	Amortization of CIAC		28			
53						
54	Depreciation capitalized		1			
55	Net depreciation expense		(159)			

Pacific Northern Gas (NE) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE - CONTINUITY OF ACCUMULATED DEPRECIATION

($000s)

Line	Description	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016
1	Balance, Beginning of Year	(6,412)	(6,253)	(6,159)	(5,997)
2	CIAC Accumulated Balance, Beginning of Year	3,575	3,542	3,502	3,461
3	Utility Accumulated Depreciation, Beginning of Year	(2,837)	(2,711)	(2,658)	(2,536)
4	Depreciation Provision:				
5	Plant	(188)	(160)	(193)	(186)
6	Contributions in Aid of Construction	28	34	40	41
7	Depreciation Adjustment Deferral				
8	Total Additions	(160)	(126)	(152)	(146)
9	Plant Retirements:				
10	Normal Course			99	24
11	Deactivated Assets				
12	CIAC Retirements				
13	Removal Costs				
14	Proceeds on Disposals				
15	Total Retirements			99	24
16	Balance, End of Year	(2,997)	(2,837)	(2,711)	(2,658)
17	Closing Balance Consists of:				
18	Accumulated Depreciation - Plant	(6,600)	(6,412)	(6,253)	(6,159)
19	Accumulated Amortization - CIAC	3,603	3,575	3,542	3,502
20	Balance, End of Year	(2,997)	(2,837)	(2,711)	(2,658)

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTINUITY OF DEFERRED CHARGES

ACTUAL 2016
($000s)

Line No.	Description	Interest Rate	Amortization Period	Actual Balance '15	Additions	Imputed Interest	Amortization	Actual Balance '16
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	1 yr	(3)			(3)	()
3	Plant Gains and Losses - ordinary	n/a	2-5 yrs	43			11	32
4	Plant Gains and Losses - salvage value	n/a	2-5 yrs	(2)			()	(1)
5	Plant Gains and Losses - retirement costs	n/a	2-5 yrs	16			5	11
6	Demand Side Management	n/a	5 yrs	4	1		1	4
7	Sub-total Gross rate base deferrals			58	1		14	45
8	Related Future Income Taxes (FIT)			(5)	()		(1)	(4)
9	Rate Base deferrals, net of FIT			**53**	**1**		**13**	**42**
10								
11	**Average rate base for the year**							**47**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr	(1)			(1)	
15	Investigative Digs	STI	1 yr					
16	GCVA	STI	n/a	(195)	129	(4)		(70)
17	Short term Interest	STI	1 yr		()		()	
18	Long term Interest	STI	1 yr	(5)	1		(4)	()
19	Industrial Customer Deliveries	STI	1 yr	13	104	1	13	104
20	BCUC Hearing & CAP/ROE	STI	1 yr	(5)	(6)		(5)	(6)
21	Property Tax	STI	1 yr		(2)		(2)	
	Old Revolving Debt Issue Costs							
22	GCOC - 2013	STI	1 yr					
23	2018/19 Rate Smoothing	STI	1 yr					
24	Pension / NPPRB	WACD	3 yrs					
25	Permanent to Interim Rate Adjustment	STI	1 yr					
	Revenue Adjustment							
26	Studies	WACD	3 yrs	22		1	8	15
27	RSAM	WACD	n/a	181	(9)	9		181
28	Resource Plans	STI	1 yr		1		1	
29	Legacy Deferred Income Taxes - Offset to NPPRB	WACD	3 yrs	(23)		(1)	(7)	
	Regulatory Asset							(17)
30	Legacy Deferred Income Taxes	WACD	5 yrs	(174)		(7)	(43)	(138)
	Future income taxes - tax rate adjustment		5 yrs					
31	Sub-total gross interest bearing deferrals			(188)	217	(1)	(40)	69
32	Related Future Income Taxes (FIT)			(3)	(57)	(2)	(3)	(58)
33	Interest Bearing deferrals, net of FIT			**(190)**	**161**	**(3)**	**(43)**	**11**
34								
35	NPPRB Regulatory Asset (Non-return bearing)	n/a	3 yrs	32			11	21
36	NPPRB Transitional Obligations (Non-return bearing)	n/a	3 yrs	9			3	6
37								
38	Total gross deferrals (excl. debt issue)			(89)	219	(1)	(12)	141
39	Future Income Taxes on deferrals (excl. debt issue			(7)	(57)	(2)	(4)	(62)
40								
41	**Total deferrals, net of FIT (excl. debt issue)**			**(96)**	**162**	**(3)**	**(16)**	**79**
42								
43	**Debt/equity issue costs**	n/a	varies with debt	**4**			**1**	**3**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTINUITY OF DEFERRED CHARGES

ACTUAL 2017
($000s)

Line No.	Description	Interest Rate	Amortization Period	Actual Balance '16	Additions	Imputed Interest	Amortization	Actual Balance '17
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	1 yr	()			()	
3	Plant Gains and Losses - ordinary	n/a	2-5 yrs	32	3		11	24
4	Plant Gains and Losses - salvage value	n/a	2-5 yrs	(1)			()	(1)
5	Plant Gains and Losses - retirement costs	n/a	2-5 yrs	11			5	6
6	Demand Side Management	n/a	5 yrs	4	1		2	3
7	Sub-total Gross rate base deferrals			45	5		18	32
8	Related Future Income Taxes (FIT)			(4)	()		(2)	(2)
9	Rate Base deferrals, net of FIT			**42**	**4**		**16**	**29**
10								
11	**Average rate base for the year**							**36**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr		(1)			(1)
15	Investigative Digs	STI	1 yr					
16	GCVA	STI	n/a	(70)	(59)	(2)		(131)
17	Short term Interest	STI	1 yr		()		()	
18	Long term Interest	STI	1 yr	()	(1)			(1)
19	Industrial Customer Deliveries	STI	1 yr	104	129	5		238
20	BCUC Hearing & CAP/ROE	STI	1 yr	(6)	(7)	()		(14)
21	Property Tax	STI	1 yr		(15)	()		(15)
22	GCOC - 2013	STI	1 yr					
23	2018/19 Rate Smoothing	STI	1 yr					
24	Pension / NPPRB	WACD	3 yrs		12			12
25	Permanent to Interim Rate Adjustment Revenue Adjustment	STI	1 yr					
26	Studies	WACD	3 yrs	15		1	8	7
27	RSAM	WACD	n/a	181	(145)	5		42
28	Resource Plans	STI	1 yr		()		()	
29	Legacy Deferred Income Taxes - Offset to NPPRB Regulatory Asset	WACD	3 yrs	(17)		()	(8)	(9)
30	Legacy Deferred Income Taxes	WACD	5 yrs	(138)		(5)	(40)	(103)
31	Sub-total gross interest bearing deferrals			69	(87)	3	(41)	26
32	Related Future Income Taxes (FIT)			(58)	26	(2)	(2)	(33)
33	Interest Bearing deferrals, net of FIT			**11**	**(61)**	**1**	**(43)**	**(7)**
34								
35	NPPRB Regulatory Asset (Non-return bearing)	n/a	3 yrs	21			11	11
36	NPPRB Transitional Obligations (Non-return bearing)	n/a	3 yrs	6			3	3
37								
38	Total gross deferrals (excl. debt issue)			141	(82)	3	(9)	71
39	Future Income Taxes on deferrals (excl. debt issue			(62)	25	(2)	(4)	(35)
40								
41	**Total deferrals, net of FIT (excl. debt issue)**			**79**	**(57)**	**1**	**(13)**	**36**
42								
43	**Debt/equity issue costs**	n/a	varies with debt	**3**			**2**	**1**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTINUITY OF DEFERRED CHARGES

TEST YEAR 2018
($000s)

Line No.	Description	Interest Rate	Amortization Period	Actual Balance '17	Additions	Imputed Interest	Amortization	Test Year Balance '18
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	1 yr					
3	Plant Gains and Losses - ordinary	n/a	2-5 yrs	24			10	15
4	Plant Gains and Losses - salvage value	n/a	2-5 yrs	(1)			()	(1)
5	Plant Gains and Losses - retirement costs	n/a	2-5 yrs	6			5	1
6	Demand Side Management	n/a	5 yrs	3	8		1	9
7	Sub-total Gross rate base deferrals			32	8		15	24
8	Related Future Income Taxes (FIT)			(2)	(2)		(2)	(3)
9	Rate Base deferrals, net of FIT			**29**	**6**		**14**	**21**
10								
11	**Average rate base for the year**							**25**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr	(1)		()	(1)	
15	Investigative Digs	STI	1 yr					
16	GCVA	STI	n/a	(131)	84	(4)		(50)
17	Short term Interest	STI	1 yr					
18	Long term Interest	STI	1 yr	(1)		()	(1)	
19	Industrial Customer Deliveries	STI	1 yr	238		5	243	
20	BCUC Hearing & CAP/ROE	STI	1 yr	(14)		()	(14)	
21	Property Tax	STI	1 yr	(15)		()	(15)	
22	GCOC - 2013	STI	1 yr					
23	2018/19 Rate Smoothing	STI	1 yr		85	2		87
24	Pension / NPPRB	WACD	3 yrs	12			4	8
25	Permanent to Interim Rate Adjustment	STI	1 yr					
26	Studies	WACD	3 yrs	7			8	
27	RSAM	WACD	n/a	42	(37)	1		6
28	Resource Plans	STI	1 yr					
29	Legacy Deferred Income Taxes - Offset to NPPRB Regulatory Asset	WACD	3 yrs	(9)		()	(9)	
30	Legacy Deferred Income Taxes	WACD	5 yrs	(103)		(3)	(106)	
31	Sub-total gross interest bearing deferrals			26	134	1	110	50
32	Related Future Income Taxes (FIT)			(33)	(13)	()	(58)	12
33	Interest Bearing deferrals, net of FIT			**(7)**	**121**		**52**	**62**
34								
35	NPPRB Regulatory Asset (Non-return bearing)	n/a	3 yrs	11			11	
36	NPPRB Transitional Obligations (Non-return bearing)	n/a	3 yrs	3			3	
37								
38	Total gross deferrals (excl. debt issue)			71	142	1	139	74
39	Future Income Taxes on deferrals (excl. debt issue			(35)	(15)	()	(60)	9
40								
41	**Total deferrals, net of FIT (excl. debt issue)**			**36**	**126**		**79**	**84**
42								
43	**Debt/equity issue costs**	n/a	varies with debt	**1**	**3**		**1**	**3**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTINUITY OF DEFERRED CHARGES

TEST YEAR 2019
($000s)

Line No.	Description	Interest Rate	Amortization Period	Test Year Balance '18	Additions	Imputed Interest	Amortization	Test Year Balance '19
1	**Rate base items**							
2	Plant Gains and Losses - extraordinary	n/a	n/a					
3	Plant Gains and Losses - ordinary	n/a	1-5 yrs	15			7	8
4	Plant Gains and Losses - salvage value	n/a	1-5 yrs	(1)			()	()
5	Plant Gains and Losses - retirement costs	n/a	1-5 yrs	1			1	
6	Demand Side Management	n/a	4-5 yrs	9	8		3	15
7	Sub-total Gross rate base deferrals			24	8		10	22
8	Related Future Income Taxes (FIT)			(3)	(2)		(1)	(4)
9	Rate Base deferrals, net of FIT			**21**	**6**		**9**	**18**
10								
11	**Average rate base for the year**							**20**
12								
13	**Interest bearing deferrals**							
14	BCUC Fees	STI	1 yr					
15	Investigative Digs	STI	1 yr					
16	GCVA	STI	n/a	(50)	83	()		32
17	Short term Interest	STI	1 yr					
18	Long term Interest	STI	1 yr					
19	Industrial Customer Deliveries	STI	1 yr					
20	BCUC Hearing & CAP/ROE	STI	1 yr					
21	Property Tax	STI	1 yr					
22	GCOC - 2013	STI	1 yr					
23	2018/19 Rate Smoothing	STI	1 yr	87		2	89	
24	Pension / NPPRB	WACD	3 yrs	8			4	4
25	Permanent to Interim Rate Adjustment	STI	1 yr					
26	Studies	WACD	2 yrs					()
27	RSAM	WACD	n/a	6	(6)			1
28	Resource Plans	STI	1 yr					
29	Legacy Deferred Income Taxes - Offset to NPPRB Regulatory Asset	WACD	2 yrs			()	()	
30	Legacy Deferred Income Taxes - other	WACD	4 yrs					()
31	Sub-total gross interest bearing deferrals			50	77	2	93	37
32	Related Future Income Taxes (FIT)			12	(21)		()	(9)
33	Interest Bearing deferrals, net of FIT			**62**	**57**	**2**	**93**	**28**
34								
35	NPPRB Regulatory Asset (Non-return bearing)	n/a	2 yrs					
36	NPPRB Transitional Obligations (Non-return bearing)	n/a	2 yrs					
37								
38	Total gross deferrals (excl. debt issue)			74	85	2	103	59
39	Future Income Taxes on deferrals (excl. debt issue)			9	(23)		(1)	(13)
40								
41	**Total deferrals, net of FIT (excl. debt issue)**			**84**	**62**	**2**	**102**	**46**
42								
43	**Debt/equity issue costs**	n/a	varies with debt	**3**			**1**	**2**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Lag/(Lead) Days	Expense	Working Capital
1	Revenue	55.9		
2	Expense	(24.8)		
3	Operating working capital	31.1	$1,556	$133
4	Adjustments:			
5	Allowance for Doubtful Accounts			(3)
6	Equal Billing Plan adjustment			(28)
7	Carbon Tax			0
8	GST			7
9	PST & ICEF Levy			0
10	Cash working capital required			$109

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Revenues	Revenue Lag days	Normalized Revenue	Extended Revenue
1	Residential - monthly	47.39	$210	$9,958
2	- bimonthly	59.88	735	43,995
3	Small commercial - monthly	42.24	321	13,576
4	- bimonthly	64.90	13	826
5	Large Commercial	41.38	127	5,253
6	Small industrial	72.2	309	22,310
7	Rate increase	55.9	206	11,527
8	Other operating revenue	55.9	9	519
9	Average revenue lag days	55.9	$1,930	$107,964

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

EXPENSE LEAD DAYS

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Expenses	Expense (Lead) Days	Normalized Expenses	Extended Expenses
1	Gas Purchases	(40.2)	$410	($16,497)
2	Operating payroll	(5.0)	335	(1,676)
3	Employee benefits	(20.9)	106	(2,225)
4	Employee expenses	(4.9)	4	(21)
5	Uncollectible accounts	(55.9)	8	(447)
6	Other operating expenses	(31.4)	598	(18,788)
7	Expenses credited/capitalized	(10.6)	(43)	456
8	Insurance	182.5	8	1,422
9	Property taxes	(1.0)	78	(78)
10	Income taxes payable	(15.2)	51	(776)
11		(24.8)	$1,556	($38,630)

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - GOODS AND SERVICES TAX

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Taxable Amount	G.S.TAX @ 5%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential and commercial	$1,506	$75.29	15.2	(30.4)	(15.2)	($3.1)
3	Industrial Transport	356	18	57.0	(60.8)	(3.8)	(0.2)
4	Carbon Tax	218	11	15.3	(30.4)	(15.1)	(0.5)
5							
6			$104			(13.2)	($3.8)
7							
8							
9							
10				Credit	Payment	Net	Working
11				Lag Days	Lag Days	Lag/(Lead)	Capital
12	Purchases						
13	Capital expenditures	$1,022	$51	30.4	8.2	38.6	$5.4
14	Gas supply	410	21	60.8	(25.0)	35.8	2.0
15	Operating costs	606	30	30.4	8.2	38.6	3.2
16							
17			$102			38.0	$10.6
18							
19							$6.9

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - PROVINCIAL SALES TAX

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Taxable Amount	P.S.T. @ 7%	Receipt Lag Days	Payment Lag Days	Net Lag/(Lead)	Working Capital
	Revenues						
1	Commercial sales	$484	$33.85	16.0	(15.0)	1.0	$0.1
2	PST Subtotal	$484	$34				$0.1
3							
4			ICEF Levy				
5			@ 0.4%				
6	Residential sales	$1,022	$4.09	14.9	(15.0)	(0.1)	($0.0)
7	Commercial sales	484	2	16.0	(15.0)	1.0	0.0
8	ICEF Levy Subtotal	$1,506	$6				$0.0
9							
10	PST & ICEF Levy Total	$1,989	$40				$0.1

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - CARBON TAX

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	Taxable GJs	Carbon Tax	Receipt Lag Days	Payment Lag Days	Net Lag/(Lead)	Working Capital
	Gas sales subject to Carbon Tax						
1	Residential sales - January to March	30 824	$46	14.9	(15.0)	(0.1)	($0.0)
2	- April to Decembe	50 197	87	14.9	(15.0)	(0.1)	(0.0)
3	Commercial sales - January to March	22 936	34	16.0	(15.0)	1.0	0.1
4	- April to Decembe	29 288	51	16.0	(15.0)	1.0	0.1
5	Carbon Tax Total	133 245	$218	15.3	(15.0)	0.3	$0.2

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

OTHER WORKING CAPITAL ITEMS

FOR THE YEAR ENDED DECEMBER 31, 2018
($000s)

Line No.	Description	
1	MONTH END BALANCES	
2	January	0
3	February	0
4	March	0
5	April	0
6	May	0
7	June	0
8	July	0
9	August	0
10	September	0
11	October	0
12	November	0
13	December	0
14	Total	$0
15	Average balance	$0

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Lag/(Lead) Days	Expense	Working Capital
1	Revenue	56.0		
2	Expense	(25.2)		
3	Operating working capital	30.8	$1,657	$140
4	Adjustments:			
5	Allowance for Doubtful Accounts			(5)
6	Equal Billing Plan adjustment			(31)
7	Carbon Tax			0
8	GST			2
9	PST & ICEF Levy			0
10	Cash working capital required			$107

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Revenues	Revenue Lag days	Normalized Revenue	Extended Revenue
1	Residential - monthly	47.39	$242	$11,459
2	bimonthly	59.88	845	50,623
3	Small commercial - monthly	42.24	364	15,373
4	- bimonthly	64.90	14	936
5	Large Commercial	41.38	148	6,136
6	Small industrial	72.2	356	25,700
7	Rate increase	56	230	12,899
8	Other operating revenue	56.0	9	511
9	Average revenue lag days	56.0	$2,209	$123,637

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

EXPENSE LEAD DAYS

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Expenses	Expense (Lead) Days	Normalized Expenses	Extended Expenses
1	Gas Purchases	(40.2)	$474	($19,073)
2	Operating payroll	(5.0)	342	(1,711)
3	Employee benefits	(20.9)	106	(2,206)
4	Employee expenses	(4.9)	4	(21)
5	Uncollectible accounts	(56.0)	8	(457)
6	Other operating expenses	(31.4)	617	(19,372)
7	Expenses credited/capitalized	(10.6)	(36)	377
8	Insurance	182.5	8	1,482
9	Property taxes	(1.0)	83	(83)
10	Income taxes payable	(15.2)	49	(750)
11		(25.2)	$1,657	($41,814)

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - GOODS AND SERVICES TAX

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Taxable Amount	G.S.TAX @ 5%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential and commercial	$1,703	$85	15.3	(30.4)	(15.1)	($3.5)
3	Industrial Transport	408	20	57.0	(60.8)	(3.8)	(0.2)
4	Carbon Tax	242	12	15.3	(30.4)	(15.1)	(0.5)
5							
6			$118			(13.2)	($4.2)
7							
8							
9							
10				Credit	Payment	Net	Working
11				Lag Days	Lag Days	Lag/(Lead)	Capital
12	Purchases						
13	Capital expenditures	$198	$10	30.4	8.2	38.6	$1.0
14	Gas supply	474	24	60.8	(25.0)	35.8	2.3
15	Operating costs	625	31	30.4	8.2	38.6	3.3
16							
17			$65			37.6	$6.7
18							
19							$2.4

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - PROVINCIAL SALES TAX

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Taxable Amount	P.S.T. @ 7%	Receipt Lag Days	Payment Lag Days	Net Lag/(Lead)	Working Capital
	Revenues						
1	Commercial sales	$546	$38	16.1	(15.0)	1.1	$0.1
2	PST Subtotal	$546	$38				$0.1
3							
4			ICEF Levy				
5			@ 0.4%				
6	Residential sales	$1,157	$5	14.9	(15.0)	(0.1)	($0.0)
7	Commercial sales	546	2	16.1	(15.0)	1.1	0.0
8	ICEF Levy Subtotal	$1,703	$7				$0.0
9							
10	PST & ICEF Levy Total	$2,248	$45				$0.1

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - CARBON TAX

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Taxable GJs	Carbon Tax	Receipt Lag Days	Payment Lag Days	Net Lag/(Lead)	Working Capital
	Gas sales subject to Carbon Tax						
1	Residential sales - January to March	44 197	$77	14.9	(15.0)	(0.1)	($0.0)
2	- April to Decembe	35 866	71	14.9	(15.0)	(0.1)	(0.0)
3	Commercial sales - January to March	29 550	51	16.1	(15.0)	1.1	0.2
4	- April to Decembe	21 606	43	16.1	(15.0)	1.1	0.1
5	Carbon Tax Total	131 219	$242	15.3	(15.0)	0.3	$0.2

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

OTHER WORKING CAPITAL ITEMS

FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	
1	MONTH END BALANCES	
2	January	0
3	February	0
4	March	0
5	April	0
6	May	0
7	June	0
8	July	0
9	August	0
10	September	0
11	October	0
12	November	0
13	December	0
14	Total	$0
15	Average balance	$0

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTRIBUTIONS IN AID OF CONSTRUCTION

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**Gas Plant In Service**								
2	Beginning balance	$4,503	$4,500	$4,461	$4,460	$4,460	$4,460	$4,455	$4,428
3	Additions	3	3	1	1			5	27
4	Ending balance	$4,505	$4,503	$4,463	$4,461	$4,460	$4,460	$4,460	$4,455
5	**Accumulated Amortization**								
6	Beginning balance	($3,575)	($3,542)	($3,501)	($3,502)	($3,461)	($3,420)	($3,379)	($3,337)
7	Additions	(28)	(34)	(40)	(40)	(41)	(41)	(41)	(42)
8	Ending balance	($3,603)	($3,575)	($3,542)	($3,542)	($3,502)	($3,461)	($3,420)	($3,379)
9	**Net Total**								
10	Beginning balance	$927	$958	$960	$958	$999	$1,040	$1,076	$1,091
11	Additions	(25)	(31)	(39)	(39)	(41)	(41)	(36)	(15)
12	Ending balance	$902	$927	$921	$919	$958	$999	$1,040	$1,076
13	Average balance	$915	$943	$940	$939	$979	$1,020	$1,058	$1,084

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

PENSION CONTRIBUTIONS & EXPENSE

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Cash contributions to plan	$47	$47	$17	$49	$16	$20	$84	$87
2	Expense including amortization of losses	(66)	(68)	(72)	(78)	(74)	(80)	(70)	(72)
3	Additions/(reductions) in B/S asset	($18)	($21)	($55)	($29)	($58)	($60)	$14	$15
4									
5									
6	**Rate Base debit/(credit)**								
7	Prior year closing balance	$103	$118	$86	$114	$122	$121	$77	$66
8	Inter-divisional opening adjustment				25	35	46	33	
9	Current year opening balance	$103	$118	$86	$139	$157	$166	$111	$66
10	Pre-tax additions	(18)	(21)	(55)	(29)	(58)	(60)	14	15
11	Current income taxes	5	6	14	8	15	16	(4)	(4)
12	Closing Balance	$89	$103	$45	$117	$114	$122	$121	$77
13									
14	Average rate base balance	$96	$110	$65	$128	$136	$144	$116	$72
15									
16									
17	**Financial statement components (US GAAP)**								
18	Funding status								
19	Opening balance	($107)	($103)	($111)	($95)	($67)	($65)	($72)	($182)
20	Annual Expense	(50)	(51)	(59)	(64)	(61)	(64)	(58)	(57)
21	Contributions & benefit payments	47	47	17	49	16	66	117	87
22	Actuarial gains / (losses)				7	17	(4)	(52)	80
23	Ending balance	($110)	($107)	($152)	($104)	($95)	($67)	($65)	($72)
24									
25	Unamortized actuarial net loss								
26	Opening balance	$283	$300	$231	$261	$244	$260	$209	$276
27	Amortization included in expense	(15)	(17)	(13)	(14)	(13)	(16)	(12)	(15)
28	Actuarial (gains) / losses				17	28	4	52	(80)
29	Rebalancing of actuarial losses between divisions				36	2	(4)	11	28
30	Ending balance	$268	$283	$218	$300	$261	$244	$260	$209
31									
32	Net pre-tax pension asset/(liability) - closing balance	$158	$176	$66	$196	$166	$177	$195	$137

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Non-Pension Post Retirement Benefits

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Cash contributions to RCA/tax account	$4	$17	$53	$60	$54	$54	$44	$46
2	Cash cost of retiree benefits	1	1	2	1	1	1	2	2
3	Expense (recovered in rates)	(4)	(4)	(42)	(48)	(42)	(42)	(34)	(43)
4	Amortization of regulatory assets (recovered in rates)		(14)	(14)	(14)	(14)	(14)	(14)	(14)
5	Change in unfunded status of NPPRB plans	()			()	(1)		(1)	(9)
6	Current income taxes								2
7	Related future income taxes	()				()		()	(2)
8									
9									
10	**Rate Base debit/(credit)**								
11	Opening Balances:								
12	- historical unrecovered NPPRB expense net of tax								
13	- stranded NPPRB transitional obligation net of tax								
14	- NPPRB liabilities net of tax								
15	Jan 1, 2012 amortization of historical unrecovered NPPRB expense & transitional obligations								
16	Pre-tax additions								
17	Current income taxes								
18	Closing Balance	$0	$0	$0	$0	$0	$0	$0	$0
19									
20	Average rate base balance	$0	$0	$0	$0	$0	$0	$0	$0
21									
22									
23	**Financial statement components (US GAAP)**								
24	Funding status								
25	Opening balance	$10	($4)	($88)	($108)	($102)	($121)	($106)	($175)
26	Annual Expense	(1)	(4)	(41)	(45)	(41)	(40)	(33)	(38)
27	Contributions & benefit payments	4	18	56	61	55	49	40	48
28	Actuarial losses				89	(20)	10	(22)	59
29	Ending balance	$13	$10	($73)	($3)	($108)	($102)	($121)	($106)
30									
31	Unamortized actuarial net loss								
32	Opening balance	$23	$23	$38	$54	$39	$51	$30	$94
33	Amount recognized in expense	(3)		(1)	(3)	(1)	(2)	(1)	(5)
34	Change in actuarial net losses				(28)	16	(10)	22	(59)
35	Ending balance	$20	$23	$37	$23	$54	$39	$51	$30
36									
37	Net after-tax NPPRB position - closing	$24	$24	($27)	$15	($40)	($42)	($52)	($57)

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

DEFERRED INCOME TAX BALANCES

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	Rate Base debit/(credit)								
2	Opening Balances:								
3	- historical recovered deferred income tax expense	$0	$0	$0	$0	$0	$0	($282)	($332)
4	Jan 1, 2012 amortization of historical recovered deferred income tax expense								
5	Current year amortization	0	0	0	0	0	0	0	49
6	Reclassified to deferred charges					0	0	282	
7	Closing Balance	0	0	0	0	0	0	0	(282)
8									
9	Average rate base balance	$0	$0	$0	$0	$0	$0	$0	($307)

Tab 3

Income Taxes

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

INCOME TAXES

SCHEDULE 3
(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	**Calculation of Taxable Income**									
2	Earned return before income taxes	$349	$254	$260	$312	$135	$262	$338	$440	Tab 1, page 1, line 30
3	Interest	(103)	(94)	(78)	(63)	(65)	(72)	(83)	(81)	Tab 5, page 1, lines 1x3 plus lines 6x8
4	Permanent differences	1	1	1	1	2	1	1	1	
5	Timing differences	(64)	28	(75)	(73)	(53)	(39)	11	(109)	Tab 3, page 1, line 25
6										
7	Taxable income	$183	$189	$108	$177	$18	$152	$267	$251	
8										
9	**Calculation of Income Tax Expense**									
10	Income taxes payable	$49	$51	$28	$46	$5	$40	$69	$65	
11	Income Tax Rate Deferral									
12	Deferred income tax								(49)	
13										
14	Income tax expense	$49	$51	$28	$46	$5	$40	$69	$15	
15										
16	**Particulars of Timing Differences**									
17	A. Tax Effects Subject To Flowthrough									
18	Depreciation	$159	$125	$152	$146	$140	$150	$144	$134	Tab 1, page 1, line 24
19	Amortization	14	139	(9)	(9)	(12)	(19)	35	(88)	Tab 1, page 1, line 25
20	Capital cost allowance	(237)	(223)	(204)	(197)	(168)	(157)	(155)	(141)	
21	Deferred charges									
22	Overheads capitalized									
23	Other (Incl. RCA Contributions of NPPRB Obligation Amortization)		(14)	(14)	(14)	(14)	(14)	(14)	(14)	
24										
25	Timing differences	(64)	28	(75)	(73)	(53)	(39)	11	(109)	
26										
27	Tax rate	27.00%	27.00%	26.00%	26.00%	26.00%	26.00%	26.00%	25.75%	
28	Surtax rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Deferred tax rate	27.00%	27.00%	26.00%	26.00%	26.00%	26.00%	26.00%	25.75%	

Tab 4

Common Equity

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

COMMON EQUITY

SCHEDULE 4
(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Opening balance									
2	Share capital	$230	$230	$230	$230	$230	$230	$230	$230	
3	Contributed surplus									
4	Retained earnings	1,441	1,658	1,016	1,441	1,430	1,278	1,082	790	
5										
6		1,671	1,888	1,246	1,671	1,660	1,508	1,312	1,020	
7										
8	Net income	198	169	158	217	61	152	196	291	
9	Shares issued	617		669						
10	Preferred dividends									
11	Common dividends		(386)	()						
12										
13	Closing balance	$2,486	$1,671	$2,073	$1,888	$1,721	$1,660	$1,508	$1,312	
14										
15										
16	Midyear common equity	$2,079	$1,780	$1,659	$1,780	$1,690	$1,584	$1,410	$1,166	Tab 5, page 1, line 11
17	Investment in Non Utility									
18										
19		$2,079	$1,780							
20										
21	Deemed utility common equity	$2,082	$1,780							

Tab 5

Return on Capital

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

RETURN ON CAPITAL

SCHEDULE 5
(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013	Source
1	Short term borrowings	$242	$202	$194	($142)	$23	$42	$169	$228	
2	proportion	5.40%	5.29%	5.44%	-4.44%	0.76%	1.37%	5.47%	8.65%	
3	rate of return	4.91%	4.31%	3.93%	2.66%	9.53%	2.05%	4.11%	4.26%	Tab 5, page 2, line 12
4	return component	0.26%	0.23%	0.21%	-0.12%	0.07%	0.03%	0.22%	0.37%	
5										
6	Long term debt	$2,154	$1,845	$1,715	$1,565	$1,355	$1,417	$1,514	$1,238	Tab 5, page 3, line 36
7	proportion	48.10%	48.21%	48.06%	48.88%	44.16%	46.57%	48.95%	47.05%	
8	rate of return	4.22%	4.61%	4.11%	4.27%	4.63%	5.00%	5.02%	5.72%	Tab 5, page 3, line 38
9	return component	2.03%	2.22%	1.98%	2.09%	2.04%	2.33%	2.46%	2.69%	
10										
11	Common equity	$2,082	$1,780	$1,659	$1,780	$1,690	$1,584	$1,410	$1,166	
12	proportion	46.50%	46.50%	46.50%	55.59%	55.08%	52.06%	45.58%	44.30%	
13	rate of return	9.50%	9.50%	9.50%	11.58%	4.10%	9.83%	13.96%	27.31%	
14	return component	4.42%	4.42%	4.42%	6.44%	2.26%	5.12%	6.36%	12.10%	
15										
16	Total capitalization	$4,478	$3,828	$3,569	$3,202	$3,069	$3,042	$3,092	$2,632	
17										
18	Return on rate base	6.71%	6.87%	6.61%	8.44%	4.37%	7.47%	9.05%	15.16%	
19										
20	Utility rate base	$4,478	$3,828	$3,569	$3,202	$3,069	$3,042	$3,092	$2,632	Tab 2, page 1, line 20

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SHORT TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

		Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**Customer Security Deposits**								
2	Average annual balance	$43	$43	$43	$49	$42	$41	$56	$65
3	Interest rate applicable to deposits	2.25%	1.73%	1.04%	1.01%	0.70%	1.08%	1.06%	1.04%
4	Annual Interest Expense	$1	$1	$0	$0	$0	$0	$1	$1
5									
6	**Operating Line / Other**								
7	Average annual draw	$199	$160	$151	($192)	($19)	($0)	$113	$162
8	Interest rate	4.45%	3.93%	3.54%	3.39%	2.22%	3.54%	3.68%	3.74%
9	Annual Interest Expense	$9	$6	$5	($6)	($0)	($0)	$4	$6
10	Other expenses*	$2	$2	$2	$2	$2	$1	$2	$3
11									
12	Average short term interest rate	4.91%	4.31%	3.93%	2.66%	9.53%	2.05%	4.11%	4.26%

* service fees, standby fees, renewal expenses

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	**Secured Debentures Series 2018**								
2	Liability beginning of year	$0	$280	$320	$320	$360	$400	$440	$464
3	Sinking fund payments		(280)	(40)	(40)	(40)	(40)	(40)	(24)
4	Average Capitalization		244	315	315	355	395	435	461
5	Annual Interest Expense		21	28	28	31	35	38	40
6	Issue costs beginning of year			1	1	1	2	2	2
7	Amortization of Issue Costs				1				
8									
9	Effective Cost Rate	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
10									
11	**10-year Term Intercompany Loan**								
12	Liability beginning of year	$1,210	$0	$0	$0	$0	$0	$0	$434
13	Issue during year		1,210						302
14	Sinking fund payments								(736)
15	Average Capitalization	1,210	908						217
16	Annual Interest Expense	51	38						8
17	Stand-by Fees								
18	Issue costs beginning of year								
19	Amortization of Issue Costs								
20									
21	Effective Cost Rate	4.20%	4.20%	0.00%	0.00%	0.00%	0.00%	0.00%	4.24%
22									
23	**5-year Revolving Loan**								
24	Liability beginning of year	$775	$1,250	$1,300	$1,250	$1,000	$1,060	$1,100	$0
25	Issue during year	325		200		250	(60)	(40)	1,100
26	Sinking fund payments		(475)						
27	Average Capitalization	944	694	1,400	1,250	1,000	1,022	1,078	560
28	Annual Interest Expense	21	23	38	37	29	34	35	18
29	Stand-by Fees	1	1			1	1	2	1
30	Issue costs beginning of year	3	1	2	2	3	4	5	6
31	Amortization of Issue Costs		1	1	1	1	1	1	1
32									
33	Effective Cost Rate	4.23%	3.63%	3.03%	3.10%	3.11%	3.49%	3.46%	3.68%
34									
35	**Total Actual Debt**								
36	Total Average Capitalization	2,154	1,845	1,715	1,565	1,355	1,417	1,514	1,238
37									
38	Effective Cost Rate	4.22%	4.61%	4.11%	4.27%	4.63%	5.00%	5.02%	5.72%

Tab 6

Rates

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Summary of Proposed / Indicative Rates Effective January 1, 2018
($/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2017	Proposed 2018 Revenue Requirement	Indicative 2018 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2018	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	$8.50			$8.50	$0.00
Delivery Charge	7.152	1.364		8.516	1.364
Company Use	0.385		0.010	0.395	0.010
GCVA Co. Use Rider	(0.034)		(0.046)	(0.080)	(0.046)
RSAM	1.256		(0.944)	0.312	(0.944)
Subtotal Delivery	8.759	1.364	(0.980)	9.143	0.384
Gas Supply Commodity	3.236		(0.551)	2.685	(0.551)
GCVA Commodity Rider	(0.180)		(0.461)	(0.641)	(0.461)
Subtotal Commodity	3.056	0.000	(1.012)	2.044	(1.012)
Total	11.815	1.364	(1.992)	11.187	(0.628)
Small Commercial (RS2)					
Monthly Fixed Charge	$8.50			$8.50	$0.00
Delivery Charge	5.854	0.994		6.848	0.994
Company Use	0.385		0.010	0.395	0.010
GCVA Co. Use Rider	(0.034)		(0.046)	(0.080)	(0.046)
RSAM	1.256		(0.944)	0.312	(0.944)
Subtotal Delivery	7.461	0.994	(0.980)	7.475	0.014
Gas Supply Commodity	3.236		(0.551)	2.685	(0.551)
GCVA Commodity Rider	(0.180)		(0.461)	(0.641)	(0.461)
Subtotal Commodity	3.056	0.000	(1.012)	2.044	(1.012)
Total	10.517	0.994	(1.992)	9.519	(0.998)
Large Commercial (RS3)					
Monthly Fixed Charge	$8.50			$8.50	$0.00
Delivery Charge	4.842	0.798		5.640	0.798
Company Use	0.385		0.010	0.395	0.010
GCVA Co. Use Rider	(0.034)		(0.046)	(0.080)	(0.046)
Subtotal Delivery	5.193	0.798	(0.036)	5.955	0.762
Gas Supply Commodity	3.236		(0.551)	2.685	(0.551)
GCVA Commodity Rider	(0.180)		(0.461)	(0.641)	(0.461)
Subtotal Commodity	3.056	0.000	(1.012)	2.044	(1.012)
Total	8.249	0.798	(1.048)	7.999	(0.250)
Industrial Transport (CNRL)					
Monthly Fixed Charge	$10,000.00			$10,000.00	$0.00
Delivery Charge	0.420	0.104		0.524	0.104

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Bill Comparison
October 2017 to January 2018

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2017 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	71.2 GJ						
Monthly Fixed Charge @ 8.50 / mo.		1.433	102.00	1.433	102.00	0.00	
Delivery Charge		7.537	536.63	8.911	634.46	97.83	18.2%
GCVA Co. Use Rider		(0.034)	(2.4208)	(0.080)	(5.6960)	(3.28)	
RSAM Rider		1.256	89.43	0.312	22.21	(67.22)	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			725.64		752.97	27.33	3.8%
Gas Supply Charge		3.236	230.40	2.685	191.17	(39.23)	
GCVA Rider		(0.180)	(12.82)	(0.641)	(45.64)	(32.82)	
			217.59		145.53	(72.06)	(33.1%)
Carbon Tax		1.4898	106.07	1.4898	106.07	(0.00)	
		$14.737 /GJ	$1,049.30	$14.109 /GJ	$1,004.57	($44.73)	-4.3%
Small Commercial:	351.7 GJ						
Monthly Fixed Charge @ 8.50 / mo.		0.290	102.00	0.290	102.00	0.00	
Delivery Charge		6.239	2,194.26	7.243	2,547.21	352.95	16.1%
GCVA Co. Use Rider		(0.034)	(11.96)	(0.080)	(28.14)	(16.18)	
RSAM Rider		1.256	441.74	0.312	109.73	(332.00)	
			2,726.03		2,730.80	4.77	0.2%
Gas Supply Charge		3.236	1,138.10	2.685	944.31	(193.79)	
GCVA Rider		(0.180)	(63.31)	(0.641)	(225.44)	(162.13)	
			1,074.80		718.87	(355.92)	-33.1%
Carbon Tax		1.4898	523.96	1.4898	523.96		
		$12.297 /GJ	$4,324.79	$11.298 /GJ	$3,973.64	($351.15)	-8.1%

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
EFFECTIVE JANUARY 1, 2018

Customer Classification	2018 Test Year Gas Deliveries (GJ)	2018 Test Year Marginable Deliveries (GJ)	2018 Gross Margin ($)	Allocation of Revenue Deficiency ($)	Rate Changes for Revenue Deficiency ($/GJ)
Residential Sales (RS1)	81,021	81,021	727,317	110,510	1.364
Small Commercial Sales (RS2)	36,224	36,224	236,869	35,990	0.994
Large Commercial Sales (RS3)	16,000	16,000	83,996	12,763	0.798
Total Sales	133,245	133,245	1,048,181	159,264	
Industrial Transport (CNRL)	450,000	450,000	309,000	46,950	0.104
TOTAL	583,245	583,245	1,357,181	206,214	
Summary					
Sales	133,245	133,245	1,048,181	159,264	0
Transportation	450,000	450,000	309,000	46,950	0
Total	**583,245**	**583,245**	**1,357,181**	**206,214**	**0**

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	**2018 Test Year Gas Deliveries** (GJ)	**Revenue** ($)	**Cost of Gas** ($)	**Gross Margin** ($)
Residential Sales (RS1)	81,021	944,858	217,541	727,317
Small Commercial Sales (RS2)	36,224	334,130	97,261	236,869
Large Commercial Sales (RS3)	16,000	126,956	42,960	83,996
Industrial Transport (CNRL)	450,000	309,000	0	309,000
Total	**583,245**	**1,714,944**	**357,763**	**1,357,181**
Summary				
Sales	133,245	1,405,944	357,763	1,048,181
Transportation	450,000	309,000	0	309,000
Total	**583 245**	**1,714,944**	**357,763**	**1,357,181**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gas Deliveries

Customer Classification	Actual Customer Count At Dec. 31st, 2017	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2018	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2018 Test Year Deliveries (GJ)
Sales:										
Residential (Rate 1)	1,139		1		1,140	1,138		71.2		81,021
Commercial										
Small Commercial (Rate 2)	106		(3)		103	103		351.7		36,224
Large Commercial Firm (Rate 3)	2		0		2					16,000
Total Commercial										
Subtotal Sales	1,247		(2)		1,245					133,245

	2018 Test Year Deliveries (GJ)
Transport	
CNRL	450,000
Total	**583,245**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gross Margin

Customer Classification	2018 Test Year Deliveries (GJ)	Current Delivery Charge ($ / GJ)	Delivery Margin ($)	Average Customer Count	Current Fixed Charge ($ / Month)	Fixed Charge Margin ($)	Total Delivery & Fixed Charge Margin ($)	2018 Test Year Gross Margin ($)
Sales:								
Residential (Rate 1)	81,021	7.547	611,465	1,136	8.50	115,872	727,337	727,337
Commercial								
Small Commercial (Rate 2)	36,224	6.249	226,364	103	8.50	10,506	236,870	236,870
Large Commercial (Rate 3)	16,000	5.237	83,792	2	8.50	204	83,996	83,996
Total Commercial	52,224		310,156	105		10,710	320,866	320,866
Subtotal Sales	133,245		921,621	1,241		126,582	1,048,203	1,048,203

	2018 Test Year Deliveries (GJ)	Current Delivery Charge ($ / GJ)	Delivery Margin ($)	Average Customer Count	Current Fixed Charge ($ / Month)	Fixed Charge Margin ($)	Total Delivery & Fixed Charge Margin ($)	2018 Test Year Gross Margin ($)
Transportation:								
CNRL	450,000	0.420	189,000	1	10,000	120,000	309,000	309,000
Subtotal Transportation	450,000		189,000	1		120,000	309,000	309,000
TOTAL	**583,245**		**1,110,621**	**1,242**		**246,582**	**1,357,203**	**1,357,203**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

Customer Classification	2018 Test Year Deliveries (GJ)	Indicative Gas Cost Charge ($ / GJ)	Indicative Gas Cost ($)
Residential (Rate 1)	81,021	2.685	217,541
Commercial			
Small Commercial (Rate 2)	36,224	2.685	97,261
Large Commercial (Rate 3)	16,000	2.685	42,960
Total Commercial	52,224		140,221
Total Tumbler Ridge	**133,245**		**357,763**

Pacific Northern Gas (N.E.) Ltd.

(Tumbler Ridge Division)

Determination of Indicative Gas Supply Cost Rate Changes Effective January 1, 2018

Using Average of 5 Day Forward Strip ending November 21, 2017

Customer Classification	Gas Supply Costs Rates Rates Effective October 1, 2017		Gas Supply Costs Proposed Rates Indicative Rates Effective January 1, 2018		Indicative Gas Supply Cost Rate Changes Effective January 1, 2018	
	Commodity ($/GJ)	Company Use Gas ($/GJ)	Commodity [1] ($/GJ)	Company Use Gas [2] ($/GJ)	Gas Supply Commodity ($/GJ)	Company Use Gas ($/GJ)
Residential (RS1)	3.236	0.385	2.685	0.395	(0.551)	0.010
Small Commercial (RS2)	3.236	0.385	2.685	0.395	(0.551)	0.010
Large Commercial (RS3)	3.236	0.385	2.685	0.395	(0.551)	0.010
Industrial Sales (RS4)	3.236	0.385	2.685	0.395	(0.551)	0.010

Notes:

1) The commodity charges are payable for each GJ of gas purchased by PNG(N.E.). The commodity charges represent PNG(N.E.)'s projection of its commodity costs based on its projected gas supply purchases.

2) The unit company use gas cost is determined by dividing the projected cost of company use gas by gas sales.

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Determination of Indicative 2018 Unit Company Use Gas Cost Rate

Using Average of 5 Day Forward Strip ending November 21, 2017

Demand Cost	$0
Commodity Cost	$30,992
B.C.S.S. Tax	$2,169
Ice Levy	$125
Carbon Tax	$19,330
Total Company Use Gas Cost	$52,616
Total Company use gas requirement	11 543 GJ
Deliveries	133 245 GJ

2018 Unit Company Use Gas Cost Rate

$0.395 /GJ = $52,616 / 133 245

Commodity Cost of Company Use Gas per GJ Purchased

$2.685 /GJ = $30,992 / 11 543

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Determination of Indicative 2018 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	2015 RSAM Pool	2016 RSAM Pool	2017 RSAM Pool	2018 RSAM Pool	Total
Residential - balance at end of 2015	$153,492	$0	$0	$0	$153,492
Residential - 2016 rate riders	($74,904)				($74,904)
Residential - 2016 additions		$82,716			$82,716
Residential - 2016 imputed interest		$8,039			$8,039
Residential - balance at end of 2016	$78,588	$90,755	$0	$0	$169,343
Residential - 2017 rate riders	($78,588)	($27,548)			($106,136)
Residential - 2017 additions			($4,277)		($4,277)
Residential - 2017 imputed interest			$5,163		$5,163
Residential - balance at end of 2017	$0	$63,207	$886	$0	$64,093
Residential - 2018 imputed interest				$2,442	$2,442
Residential - RSAM pool	**$0**	**$63,207**	**$886**	**$2,442**	**$66,535**
Small Commercial - balance at end of 2015	$27,217	$0	$0	$0	$27,217
Small Commercial - 2016 rate riders	($35,692)				($35,692)
Small Commercial - 2016 additions		$19,181			$19,181
Small Commercial - 2016 imputed interest		$1,404			$1,404
Small Commercial - balance at end of 2016	($8,475)	$20,585	$0	$0	$12,111
Small Commercial - 2017 rate riders	$8,475	($53,359)			($44,884)
Small Commercial - 2017 additions			$10,225		$10,225
Small Commercial - 2017 imputed interest			$0		$0
Small Commercial - balance at end of 2017	$0	($32,774)	$10,225	$0	($22,548)
Small Commercial - 2018 imputed interest				($1,314)	($1,314)
Small Commercial - RSAM pool	**$0**	**($32,774)**	**$10,225**	**($1,314)**	**($23,862)**
RSAM pools - amounts to be recovered / (credited)	**$0**	**$30,433**	**$11,111**	**$1,128**	**$42,673**
Years of amortization remaining	1	1	2	2	
RSAM amounts to be recovered in current year	**$0**	**$30,433**	**$5,556**	**$564**	**$36,553**
Residential - forecast 2018 deliveries (GJ)					81,021
Small Commercial - forecast 2018 deliveries (GJ)					36,224
Forecast 2018 total deliveries (GJ)					**117,245**
RSAM rate rider ($/GJ)					**$0.312**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Forward Gas Price Strip
Average of 5 Day Forward Strip ending November 21, 2017

	STATION #2 CDN$/GJ	AECO CDN$/GJ
Jan-18	1.3833	2.0133
Feb-18	1.3841	2.0141
Mar-18	1.3410	1.9710
Apr-18	1.0209	1.6709
May-18	1.0016	1.6516
Jun-18	1.0347	1.6847
Jul-18	1.0717	1.7217
Aug-18	1.0756	1.7256
Sep-18	1.0565	1.7065
Oct-18	1.0867	1.7367
Nov-18	1.9004	2.1904
Dec-18	2.0634	2.3534
Average	**1.2850**	**1.8700**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Summary of Proposed / Indicative Rates Effective January 1, 2019
($/GJ unless otherwise specified)

Customer Class	Rates Effective Jan 1, 2018	Proposed 2019 Revenue Requirement	Indicative 2019 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2019	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	$8.50			$8.50	$0.00
Delivery Charge	8.516	1.543		10.059	1.543
Company Use	0.395		0.065	0.460	0.065
GCVA Co. Use Rider	(0.080)		0.000	(0.080)	0.000
RSAM	0.312		(0.263)	0.049	(0.263)
Subtotal Delivery	9.143	1.543	(0.198)	10.488	1.345
Gas Supply Commodity	2.685		0.471	3.156	0.471
GCVA Commodity Rider	(0.641)		-	(0.641)	-
Subtotal Commodity	2.044	0.000	0.471	2.515	0.471
Total	11.187	1.543	0.273	13.003	1.816
Small Commercial (RS2)					
Monthly Fixed Charge	$8.50			$8.50	$0.00
Delivery Charge	6.848	1.126		7.974	1.126
Company Use	0.395		0.065	0.460	0.065
GCVA Co. Use Rider	(0.080)		-	(0.080)	0.000
RSAM	0.312		(0.263)	0.049	(0.263)
Subtotal Delivery	7.475	1.126	(0.198)	8.403	0.928
Gas Supply Commodity	2.685		0.471	3.156	0.471
GCVA Commodity Rider	(0.641)		-	(0.641)	-
Subtotal Commodity	2.044	0.000	0.471	2.515	0.471
Total	9.519	1.126	0.273	10.918	1.399
Large Commercial (RS3)					
Monthly Fixed Charge	$8.50			$8.50	$0.00
Delivery Charge	5.640	0.905		6.545	0.905
Company Use	0.395		0.065	0.460	0.065
GCVA Co. Use Rider	(0.080)		-	(0.080)	0.000
Subtotal Delivery	5.955	0.905	0.065	6.925	0.970
Gas Supply Commodity	2.685		0.471	3.156	0.471
GCVA Commodity Rider	(0.641)		-	(0.641)	-
Subtotal Commodity	2.044	0.000	0.471	2.515	0.471
Total	7.999	0.905	0.536	9.440	1.441
Industrial Transport (CNRL)					
Monthly Fixed Charge	$10,000.00			$10,000.00	$0.00
Delivery Charge	0.524	0.117		0.641	0.117

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Bill Comparison
January 2018 to January 2019

Customer Classification	Annual Use	Proposed Rates Jan. 1, 2018 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2019 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	70.3 GJ						
Monthly Fixed Charge @ 8.50 / mo.		1.451	102.00	1.451	102.00	0.00	
Delivery Charge		8.911	626.44	10.519	739.51	113.07	18.0%
GCVA Co. Use Rider		(0.080)	(5.6240)	(0.080)	(5.6240)	0.00	
RSAM Rider		0.312	21.93	0.049	3.44	(18.49)	
			744.75		839.33	94.57	12.7%
Gas Supply Charge		2.685	188.76	3.156	221.87	33.11	
GCVA Rider		(0.641)	(45.06)	(0.641)	(45.06)	0.00	
			143.69		176.81	33.11	23.0%
Carbon Tax		1.4898	104.73	1.7381	122.19	17.46	
		$14.128 /GJ	$993.18	$16.192 /GJ	$1,138.32	$145.15	14.6%
Small Commercial:	341.3 GJ						
Monthly Fixed Charge @ 8.50 / mo.		0.299	102.00	0.299	102.00	0.00	
Delivery Charge		7.243	2,471.88	8.434	2,878.45	406.56	16.4%
GCVA Co. Use Rider		(0.080)	(27.30)	(0.080)	(27.30)	0.00	
RSAM Rider		0.312	106.49	0.049	16.72	(89.76)	
			2,653.06		2,969.87	316.80	11.9%
Gas Supply Charge		2.685	916.39	3.156	1,077.14	160.75	
GCVA Rider		(0.641)	(218.77)	(0.641)	(218.77)	0.00	
			697.62		858.37	160.75	23.0%
Carbon Tax		1.4898	508.47	1.7381	593.21		
		$11.307 /GJ	$3,859.15	$12.955 /GJ	$4,421.45	$477.55	12.4%

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
EFFECTIVE JANUARY 1, 2019

Customer Classification	2019 Test Year Gas Deliveries (GJ)	2019 Test Year Marginable Deliveries (GJ)	2019 Gross Margin ($)	Allocation of Revenue Deficiency ($)	Rate Changes for Revenue Deficiency ($/GJ)
Residential Sales (RS1)	80,063	80,063	834,530	123,563	1.543
Small Commercial Sales (RS2)	35,156	35,156	267,410	39,593	1.126
Large Commercial Sales (RS3)	16,000	16,000	97,799	14,480	0.905
Total Sales	131,219	131,219	1,199,739	177,636	
Industrial Transport (CNRL)	450,000	450,000	355,950	52,703	0.117
TOTAL	581,219	581,219	1,555,689	230,339	
Summary					
Sales	131,219	131,219	1,199,739	177,636	0
Transportation	450,000	450,000	355,950	52,703	0
Total	**581,219**	**581,219**	**1,555,689**	**230,339**	**0**

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	**2019 Test Year Gas Deliveries** (GJ)	**Revenue** ($)	**Cost of Gas** ($)	**Gross Margin** ($)
Residential Sales (RS1)	80,063	1,087,209	252,679	834,530
Small Commercial Sales (RS2)	35,156	378,362	110,952	267,410
Large Commercial Sales (RS3)	16,000	148,295	50,496	97,799
Industrial Transport (CNRL)	450,000	355,950	0	355,950
Total	**581,219**	**1,969,816**	**414,127**	**1,555,689**
Summary				
Sales	131,219	1,613,866	414,127	1,199,739
Transportation	450,000	355,950	0	355,950
Total	**581,219**	**1,969,816**	**414,127**	**1,555,689**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gas Deliveries

Customer Classification	Forecast Customer Count At Dec. 31st, 2018	+	Test Year Customer Additions/(Losses)	=	Forecast Customer Count At Dec. 31st, 2019	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2019 Test Year Deliveries (GJ)
Sales:										
Residential (Rate 1)	1,140		(2)		1,138	1,139		70.3		80,063
Commercial										
Small Commercial (Rate 2)	106		(3)		103	103		341.3		35,156
Large Commercial Firm (Rate 3)	2		0		2					16,000
Total Commercial										
Subtotal Sales	1,248		(5)		1,243					131,219

	2019 Test Year Deliveries (GJ)
Transport	
CNRL	450,000
Total	**581,219**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gross Margin

Customer Classification	2019 Test Year Deliveries (GJ)	Current Delivery Charge ($ / GJ)	Delivery Margin ($)	Average Customer Count	Current Fixed Charge ($ / Month)	Fixed Charge Margin ($)	Total Delivery & Fixed Charge Margin ($)	2019 Test Year Gross Margin ($)
Sales:								
Residential (Rate 1)	80,063	8.976	718,643	1,136	8.50	115,872	834,515	834,515
Commercial								
Small Commercial (Rate 2)	35,156	7.308	256,904	103	8.50	10,506	267,410	267,410
Large Commercial (Rate 3)	16,000	6.100	97,595	2	8.50	204	97,799	97,799
Total Commercial	51,156		354,499	105		10,710	365,209	365,209
Subtotal Sales	131,219		1,073,142	1,241		126,582	1,199,724	1,199,724

	2019 Test Year Deliveries (GJ)	Current Delivery Charge ($ / GJ)	Delivery Margin ($)	Average Customer Count	Current Fixed Charge ($ / Month)	Fixed Charge Margin ($)	Total Delivery & Fixed Charge Margin ($)	2019 Test Year Gross Margin ($)
Transportation:								
CNRL	450,000	0.524	235,950	1	10,000	120,000	355,950	355,950
Subtotal Transportation	450,000		235,950	1		120,000	355,950	355,950
TOTAL	**581,219**		**1,309,093**	**1,242**		**246,582**	**1,555,675**	**1,555,675**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

Customer Classification	2019 Test Year Deliveries (GJ)	Indicative Gas Cost Charge ($ / GJ)	Indicative Gas Cost ($)
Residential (Rate 1)	80,063	3.156	252,679
Commercial			
Small Commercial (Rate 2)	35,156	3.156	110,952
Large Commercial (Rate 3)	16,000	3.156	50,496
Total Commercial	51,156		161,448
Total Tumbler Ridge	**131,219**		**414,127**

Pacific Northern Gas (N.E.) Ltd.

(Tumbler Ridge Division)

Determination of Indicative Gas Supply Cost Rate Changes Effective January 1, 2018

Using Average of 5 Day Forward Strip ending November 21, 2017

Customer Classification	Gas Supply Costs Rates Rates Effective January 1, 2018		Gas Supply Costs Proposed Rates Indicative Rates Effective January 1, 2019		Indicative Gas Supply Cost Rate Changes Effective January 1, 2019	
	Commodity ($/GJ)	Company Use Gas ($/GJ)	Commodity [1] ($/GJ)	Company Use Gas [2] ($/GJ)	Gas Supply Commodity ($/GJ)	Company Use Gas ($/GJ)
Residential (RS1)	2.685	0.395	3.156	0.460	0.471	0.065
Small Commercial (RS2)	2.685	0.395	3.156	0.460	0.471	0.065
Large Commercial (RS3)	2.685	0.395	3.156	0.460	0.471	0.065
Industrial Sales (RS4)	2.685	0.395	3.156	0.460	0.471	0.065

Notes:

1) The commodity charges are payable for each GJ of gas purchased by PNG(N.E.). The commodity charges represent PNG(N.E.)'s projection of its commodity costs based on its projected gas supply purchases.

2) The unit company use gas cost is determined by dividing the projected cost of company use gas by gas sales.

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Determination of Indicative 2018 Unit Company Use Gas Cost Rate

Using Average of 5 Day Forward Strip ending November 21, 2017

Demand Cost	$0	
Commodity Cost	$35,837	
B.C.S.S. Tax	$2,509	
Ice Levy	$144	
Carbon Tax	$21,835	
Total Company Use Gas Cost	$60,325	
Total Company use gas requirement	11,355	GJ
Deliveries	131,219	GJ

2018 Unit Company Use Gas Cost Rate

$0.460 /GJ = $60,325 / 131,219

Commodity Cost of Company Use Gas per GJ Purchased

$3.156 /GJ = $35,837 / 11,355

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Determination of Indicative 2019 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	2016 RSAM Pool	2017 RSAM Pool	2018 RSAM Pool	2019 RSAM Pool	Total
Residential - balance at end of 2016	$169,343	$0	$0	$0	$169,343
Residential - 2017 rate riders	($106,136)				($106,136)
Residential - 2017 additions		($4,277)			($4,277)
Residential - 2017 imputed interest		$5,163			$5,163
Residential - balance at end of 2017	$63,207	$886	$0	$0	$64,093
Residential - 2018 rate riders	($63,207)	$37,928			($25,279)
Residential - 2018 additions			$0		$0
Residential - 2018 imputed interest			$2,442		$2,442
Residential - balance at end of 2018	$0	$38,814	$2,442	$0	$41,257
Residential - 2019 imputed interest				$1,723	$1,723
Residential - RSAM pool	**$0**	**$38,814**	**$2,442**	**$1,723**	**$42,979**
Small Commercial - balance at end of 2016	$12,111	$0	$0	$0	$12,111
Small Commercial - 2017 rate riders	($44,884)				($44,884)
Small Commercial - 2017 additions		$10,225			$10,225
Small Commercial - 2017 imputed interest		$0			$0
Small Commercial - balance at end of 2017	($32,773)	$10,225	$0	$0	($22,548)
Small Commercial - 2018 rate riders	$32,773	($44,075)			($11,302)
Small Commercial - 2018 additions			$0		$0
Small Commercial - 2018 imputed interest			($1,314)		($1,314)
Small Commercial - balance at end of 2018	$0	($33,850)	($1,314)	$0	($35,164)
Small Commercial - 2019 imputed interest				($1,574)	($1,574)
Small Commercial - RSAM pool	**$0**	**($33,850)**	**($1,314)**	**($1,574)**	**($36,738)**
RSAM pools - amounts to be recovered / (credited)	**$0**	**$4,965**	**$1,128**	**$149**	**$6,241**
Years of amortization remaining	1	1	2	2	
RSAM amounts to be recovered in current year	**$0**	**$4,965**	**$564**	**$74**	**$5,603**
Residential - forecast 2019 deliveries (GJ)					80,063
Small Commercial - forecast 2019 deliveries (GJ)					35,156
Forecast 2019 total deliveries (GJ)					**115,219**
RSAM rate rider ($/GJ)					**$0.049**

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Forward Gas Price Strip
Average of 5 Day Forward Strip ending November 21, 2017

	STATION #2 CDN$/GJ	AECO CDN$/GJ
Jan-19	2.1640	2.4540
Feb-19	2.1255	2.4155
Mar-19	2.0336	2.3236
Apr-19	1.4251	1.9051
May-19	1.3669	1.8469
Jun-19	1.3911	1.8711
Jul-19	1.4210	1.9010
Aug-19	1.4210	1.9010
Sep-19	1.3952	1.8752
Oct-19	1.4297	1.9097
Nov-19	2.1029	2.3204
Dec-19	2.2884	2.5059
Average	**1.7137**	**2.1025**

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
2018-2019 Revenue Requirements Application
For the PNG (N.E.) Service Area

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On November 30, 2017, PNG (N.E.) filed its 2018-2019 RRA with the Commission for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions pursuant to sections 58 to 61 of the *Utilities Commission Act* (the UCA), seeking, among other things, approval to increase 2018 delivery rates (Application);

B. PNG (N.E.) also seeks relief pursuant to sections 58 to 61, 89 and 90 of the UCA to allow PNG (N.E.) to amend its rates on an interim and refundable basis, effective January 1, 2018, pending the regulatory process for the review of the Application and orders subsequent to this process;

C. PNG (N.E.) forecasts a 2018 revenue deficiency of approximately $1.141 million for the FSJ/DC Division comprised of a net increase in cost of service of $0.642 million and a decrease in margin of $0.499 million. PNG (N.E.) forecasts a 2018 revenue deficiency for the TR Division of approximately $0.291 million comprised of a net increase in cost of service of $0.142 million and a decrease in margin of $0.149 million;

D. PNG (N.E.) is seeking approval to increase the delivery rates on an interim and refundable basis for the FSJ/DC Division to cover the forecast 2018 revenue deficiency for the following rate classes, among other rate classes:

    1. a 8.8 percent increase from $4.060/GJ to $4.419/GJ for FSJ Residential service and a 9.3 percent increase from $3.862/GJ to $4.221/GJ for DC Residential service; and

    2. a 7.4 percent increase from $3.227/GJ to $3.465/GJ for FSJ Small Commercial service and a 8.9 percent increase from $2.690/GJ to $2.928/GJ for DC Small Commercial service;

PNG (N.E.) is also seeking approval to increase in the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider on an interim and refundable basis for the FSJ/DC Division applicable to Residential and Small Commercial customers of $0.068/GJ from $0.472GJ to $0.540/GJ;

E. PNG (N.E.) is seeking approval to increase the delivery rates on an interim and refundable basis for the TR Division to cover the forecast 2018 revenue deficiency for the following rate classes, among other rate classes:

   1. a 26.7 percent increase from $7.152/GJ to $9.064/GJ for TR Residential service; and
   2. a 23.7 percent increase from $5.854/GJ to $7.239/GJ for TR Small Commercial service;

   PNG (N.E.) is also seeking approval to decrease the RSAM rate rider on an interim and refundable basis for the TR Division applicable to Residential and Small Commercial customers of $0.883 /GJ from $1.256/GJ to $0.373/GJ;

F. With respect to the two year RRA, PNG (N.E.) submits in its Application that it will seek approval of permanent 2018 rates and permanent 2019 rates in the Amended Application, to be filed at the end of February 2018;

G. PNG (N.E.) proposes a written hearing process as the appropriate regulatory process for the review of the Application;

H. The Commission has commenced review of the Application and finds that establishment of interim rates and a preliminary Regulatory Timetable is warranted.

NOW THEREFORE pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act*, the Commission orders as follows:

1. The British Columbia Utilities Commission approves the delivery rates and the Rate Stabilization Adjustment Mechanism rider set forth in the Application on an interim basis, effective January 1, 2018. Any differences between the interim and permanent rates that are determined by the Commission following final disposition of the Application are subject to refund/recovery, with interest, at the average prime rate of Pacific Northern Gas (N.E.) Ltd.'s principal bank for its most recent year, in the manner as set out by a Commission order that establishes permanent rates.

2. The preliminary Regulatory Timetable for the review of the Application is established, as set out in Appendix A to this order.

3. Interveners and interested parties who wish to participate in the regulatory proceeding are to register with the Commission through the Commission's website at www.bcuc.com or in writing by the date established in the preliminary Regulatory Timetable attached as Appendix A to this order. Those requesting intervener status are to specifically state the nature of their interest in the Application and identify generally the issues that they intend to pursue and the extent of their anticipated involvement in the proceeding.

4. Pacific Northern Gas (N.E.) Ltd. is to provide a copy, electronically where possible, of this order including the preliminary Regulatory Timetable attached as Appendix A to this order, to all parties who registered and/or participated in the Pacific Northern Gas (N.E.) Ltd. 2016-2017 Revenue Requirements Application proceeding.

5. The Application and supporting material are to be made available for inspection at the following locations: Public libraries in Fort St. John, Dawson Creek and Tumbler Ridge; the head office of Pacific Northern Gas Ltd. at Suite 2550, 1066 West Hastings Street, Vancouver, BC, V6E 3X2; and the British Columbia Utilities Commission office at Suite 410, 900 Howe Street, Vancouver, BC, V6Z 2N3. Pacific Northern Gas Ltd. is to also make the Application available on its website at www.png.ca.

6. Pacific Northern Gas (N.E.) Ltd. is to publish in display-ad format, as soon as reasonably possible but no later than Friday, December 29, 2017, the Notice of Application attached as Appendix B to this order, in such appropriate news publications as may properly provide adequate notice to the public in the affected service area.

7. Pacific Northern Gas (N.E.) Ltd. is to provide its customers with a bill message notice of the interim rates with its next customer mailing.

8. Pursuant to section 61 of the *Utilities Commission Act*, Pacific Northern Gas (N.E.) Ltd. is to file amended tariff rate schedules, in accordance with the terms of this order, within 15 business days of the date of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of December 2017.

BY ORDER

(X. X. last name)
Commissioner

APPENDIX A

Pacific Northern Gas (N.E.) Ltd.
2018-2019 Revenue Requirements Application
for the PNG (N.E.) Service Area

REGULATORY TIMETABLE

ACTION	DATE (2018)
Intervener and Interested Party Registration	Friday, January 12
Submission of Updated Application	Wednesday, February 28
Further Process to be Determined	

APPENDIX B

PACIFIC NORTHERN GAS (NE) LTD.
APPLICATION FOR APPROVAL OF 2018-2019 REVENUE REQUIREMENTS
FOR THE PNG (N.E.) SERVICE AREA

On November 30, 2017, Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.)] filed its 2018-2019 Revenue Requirements Application for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions (Application) with the British Columbia Utilities Commission (Commission), pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (UCA) seeking Commission approval to, among other things, increase the 2018 delivery rates. The Application also seeks relief to allow PNG (N.E.) to amend its rates on an interim and refundable basis, effective January 1, 2018, pending the regulatory process for the review of the Application and orders subsequent to that process.

Fort St. John and Dawson Creek Division

PNG (N.E.) is requesting a delivery rate increase on an interim and refundable basis of 8.8 percent from $4.060/GJ to $4.419/GJ for FSJ Residential service, a 9.3 percent increase from $3.862/GJ to $4.221/GJ for DC Residential service, a 7.4 percent increase from $3.227/GJ to $3.465/GJ for FSJ Small Commercial service, and a 8.9 percent increase from $2.690/GJ to $2.928/GJ for DC Small Commercial service.

PNG (N.E.) is also requesting an increase in the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider on an interim and refundable basis applicable to residential and small commercial customers of $0.068/GJ from $0.472/GJ to $0.540/GJ.

Based on the gas cost recovery and Gas Cost Variance Account (GCVA) rate riders effective January 1, 2018, the overall bundled rate change for a typical residential customer consuming 97.8 GJ per year, is a decrease of $9 per year or 1.0 percent. Similarly, the overall bundled rate change for a typical small commercial customer consuming 509.4 GJ per year is a decrease pf $112 per year or 3.2 percent.

Tumbler Ridge Division

PNG (N.E.) is requesting a delivery rate increase on an interim and refundable basis of 26.7 percent from $7.152/GJ to $9.064/GJ for residential service, and a 23.7 percent increase from $5.854/GJ to $7.239/GJ for small commercial service.

PNG (N.E.) is also requesting a decrease in the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider on an interim and refundable basis applicable to residential and small commercial customers of $0.883/GJ from $1.256/GJ to $0.373/GJ.

Based on the gas cost recovery and GCVA rate riders effective January 1, 2018, the overall bundled rate will not change for a typical residential customer consuming 79.8 GJ per year as the proposed delivery rate increases are offset by the decrease in the RSAM rider and the cost of the commodity of natural gas. For a typical small

commercial customer consuming 359.8 GJ per year, the overall bundled rate decrease is $192 per year or 4.3 percent.

REGULATORY PROCESS

The Commission wishes to hear from affected parties before determining the public process necessary for the disposition of the Application. Commission Order G-xx-17 establishes a preliminary Regulatory Timetable.

HOW TO GET INVOLVED

Persons wishing to actively participate in the proceeding must register as an intervener through the Commission's website at www.bcuc.com or in writing by Friday, January 12, 2018. Registrants must identify the issues they intend to pursue and indicate the extent of their anticipated involvement in the review process. Interveners will each receive a copy of all non-confidential correspondence and filed documentation, and must provide an email address if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as an interested party through the Commission's website or in writing, by Friday, January 12, 2018, identifying their interest in the proceeding. Interested parties receive a copy of the decision when it is released. Please note that only those parties who register on the Commission's website will receive electronic notice of submissions.

Letters of comment may also be submitted. All submissions and/or correspondence received relating to the Application are provided to the panel and all participants in the proceeding. Submissions are placed on the public record and posted to the Commission's website. By participating and/or providing comment on the application, you agree that all submissions will be placed on the public record and posted on the Commission's website.

VIEW THE APPLICATION

The Application and all supporting documentation are available on the Commission's website on the "Current Applications" page. If you would like to review the material in hard copy, it is available to be viewed at the locations below:

British Columbia Utilities Commission Suite 410, 900 Howe Street Vancouver, BC V6Z 2N3 Phone: 604-660-4700 Toll Free: 1-800-663-1385 www.bcuc.com	**Pacific Northern Gas Ltd.** Suite 2550, 1066 West Hastings Street Vancouver, BC V6E 3X2 Phone: 604-691-5680 Toll Free: 1-800-667-2297 www.png.ca
Public Libraries Fort St. John, Dawson Creek and Tumbler Ridge	

FOR MORE INFORMATION OR TO REGISTER

For more information or to register please visit www.bcuc.com or contact the Commission Secretary at commission.secretary@bcuc.com .