DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF THE JOINT APPLICATION FOR APPROVAL TO CHANGE AND ESTABLISH NATURAL GAS DELIVERY SERVICE RATES FOR ENERGY WEST MONTANA, INC. AND CUT BANK GAS COMPANY	UTILITY DIVISION Docket No. D2017.9.80

ENERGY WEST MONTANA'S AND CUT BANK GAS COMPANY'S RESPONSES TO DATA REQUESTS PSC-060 THROUGH PSC-107

Energy West Montana ("EWM") and Cut Bank Gas Company ("CBG") provide the attached responses to the Montana Public Service Commission's Data Requests PSC-060 through PSC-107.

Respectfully submitted this 8th day of February, 2018.

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DATA REQUESTS

PSC-060: RE: PSC-039 - Debt issuance; reacquisition costs
Witness: Henthorne

a. Per your response to PSC-039, the calculated 4.66% and 4.31% cost(s) of debt used in the requested Rate of Return (ROR)/weighted average cost of capital (WACC) calculation for EWM and CBG, respectively, includes the amortization of debt issuance and reacquisition costs. Additionally, the joint applicants are requesting a "return of" and a "return on" these costs by including them in rate base (see JDHEWM- 3/JDH-CBG-3). Please explain the inclusion of these costs in both rate base as well as the cost of debt.

b. Please explain why the debt issuance costs to be included in rate base, represented in JDH-EWM-3, do not agree to the "average" unamortized debt issuance costs represented in Exhibit JDH-EWM-9, Statement A - Balance Sheet, Rule 38.5.121.

c. Please explain why the debt issuance costs, represented in JDH-CBG-3, to be included in rate base are not represented in Exhibit JDH-CBG-6, Statement A - Balance Sheet, Rule 38.5.121.

d. Please provide your calculations of the debt issuance costs to be included in rate base. In your calculations, please be sure to reference the amounts represented in Attachment MCC-013 provided in response to the MCC's data requests.

Response to PSC-060:

a. We include the debt issuance costs in the cost of debt calculation to request a reasonable return of our cost of doing business, including the cost of debt. Because we had to invest that amount up front in order to obtain our debt facility, we included the amounts in rate base so we can get a return on our investment until we fully recover our costs.

b. The unamortized debt issuance costs represented on Statement A include debt issuance costs related to the refinancing of the line of credit arrangement. We did not include these costs in rate base because they are not related to the long term debt included in the rate of return calculation. Additionally, the 2015 balance used in the calculation of the average rate base was recorded on EWM's former parent company EWI's books. See answer to subpart (d) for further detail.

c. The unamortized debt issuance costs are included in the "Other Assets", line 23, of Statement A.

d. The below table shows the calculations for the amount of debt issuance costs included in rate base for EWM and CBGC. For EWM, the outstanding debt issuance cost on the December 31, 2016 balance sheet related to the refinanced $7,579,000 of long term debt is $97,220. The December 31, 2015 balance of $47,363 shown in the table is the portion of debt issuance costs allocable to EWM from its previous debt arrangement with its previous parent company EWI. While the balance was on EWI's balance sheet, the amortization of the debt costs were allocated to EWM monthly. Therefore, we thought it appropriate to include the outstanding December 31, 2015 in the average calculation. The reacquired debt portion included in rate base is calculated by taking the net December 31, 2016 balance per the balance sheet, removing the portion related to the line of credit, and then averaging the result with the 2015 balance, which was zero.

For CBGC, the outstanding net debt issuance cost on the balance sheet related to the $550,000 of long term debt as of December 31, 2016 is $5,361. We used the average of this and the 2015 balance of zero to calculate the $2,681 included in rate base.

There are no amounts from MCC-013 that we can reference in this response as the questions are referring to differing ways of calculating debt issue costs and at different time periods. The answer to this data request involves the average net balances on the balance sheet of the beginning and ending date of the test year, whereas MCC-013 regarding the embedded cost rates of long term debt, asks for the original overall cost of the debt and one year cost to the company.

	12/31/2015	12/31/2016	Average
EMM			
Long term debt	$ 47,363	$ 97,220	$ 72,292
Reacquired debt	-	288,148	144,074
	$ 47,363	$ 385,368	$ 216,366

	Asset	Amortization	Net
Reacquired debt per BS 12/31/16	$ 318,249	$ (7,329)	$ 310,920
Less: Amount related to line of credit	23,971	(1,199)	22,772
Amount to add to rate base	$ 294,278	$ (6,130)	$ 288,148

	12/31/2015	12/31/2016	Average
Cut Bank Gas	$ -	$ 5,361	$ 2,681

PSC-061: RE: MCC-013 & Cost of Debt
Witness: Henthorne

The questions below are based on Joint Applicants' Attachment MCC-013 and relate to the overall cost of debt for the Joint Applicants.

a. Please provide all journal entries made by GNI to record the refinancing of the Long- Term debt identified on line 7 of Attachment MCC-013.

b. What was the outstanding principal balance of the LT Note Payable to Energy West, Inc. at the date of refinancing? Please provide an amortization schedule in support of your response.

Response to PSC-061:

a. See below for journal entries related to the refinance of the $7.579M loan.

Cash	7,579,000.00
New Loan Payable	(7,579,000.00)
Old Loan Payable	7,579,000.00
Cash	(7,579,000.00)
Cash (Make Whole Payment)	(458,576.92)
Accrued Interest	159,988.89
AR EWM	266,235.14
AR EWR	31,987.56
AR MRP	365.33
Debt Issue Costs	(48,102.00)
AR EWM	28,043.47
AR EWR	3,646.13
AR MRP	38.48
Interest Expense	16,373.92

b. The outstanding balance of the LT Note Payable to Energy West, Inc. at the date of refinancing was $7,579,000. This was an interest only loan with no scheduled paydown of the principal. Therefore, we paid down no principal balance on this debt from the date of inception until the date it was refinanced. Our response to MCC-013 shows zero as the amount outstanding on the long term note payable because we understood it to be asking the current amount outstanding (as of the rate case filing) rather than the amount outstanding as of the specific quarter.

PSC-062: RE: MCC-013; Unamortized Loss on Reacquired Debt
Witness: Henthorne

The questions below are based on Joint Applicants' Attachment MCC-013 and relate to the amount represented as Unamortized Loss on Reacquired Debt.

a. Please describe what the $28,043 Loss on Reacquired Debt (represented in cell J21) represents, and please provide a detailed calculation of the $28,043 figure. In support of this calculation please provide supporting documentation for each number used in the calculation.

b. Please provide the journal entry made to record the initial loss.

c. Please provide an amortization schedule of the loss.

Response to PSC-062:

a. The $28,043 loss on reacquired debt represents the unamortized balance of debt issuance costs relating to the prior debt facility at the time of refinance. The original debt facility was for $13,000,000, of which $7,579,000 was allocated to EWM, which is 58.3% of the total. Accordingly, we took the $48,102 outstanding debt issuance cost balance at the time of refinance and allocated 58.3%, or $28,043, to EWM as the loss on reacquired debt. See Attachment PSC-062(a) for support of the $48,102 outstanding debt issue cost balance at September 30, 2016.

b. See below for journal entries moving the debt issue cost from EWI's balance sheet to EWM's unamortized loss on reacquired debt account. See PSC-060 for more detail about moving the balances from EWI to EWM.

EWI

2240100	(28,043.47)	Debt issue cost - long term debt
1460000	28,043.47	Receivable from EWM

EWM

1890100	28,043.47	Unamortized loss on reacquired debt.
1460000	(28,043.47)	Payable to EWI

c. Please see Attachment PSC-062(c) for the amortization schedule of the deferred loss on debt reacquisition. Column B shows the total amount for CBGC. EWM's amortization is broken up into three parts; column D is the amortization on the make whole interest portion, column E is the amortization of the debt issue costs related to long term debt, and column F is the amortization of the debt issue cost related to the line of credit, which is not included in the adjustment to rate base.

PSC-063: RE: MCC-013 - Make Whole Interest Charges
Witness: Henthorne

The questions below are based on Joint Applicants' Attachment MCC-013 and relate amount represented as Make Whole Interest Charges.

a. Please describe what the $266,235 amount represented as Make Whole Interest Charges (represented in cell J22) represents.

b. Please provide a detailed calculation of the $266,235 figure, and provide supporting documentation for each number used in the calculation.

Response to PSC-063:

a. The $266,235 is EWM's portion of the early repayment interest charges related to the $7.579M debt owed at the time of refinance. The original loan had a maturity date of June 29, 2017 and was paid off early on October 19, 2016. According to the provisions of the original loan agreement, the net present value of future interest payments is owed at the time of early extinguishment of the debt.

b. The Attachment PSC-063 is a worksheet which was provided to EWM by the lender to calculate the make-whole payment of $298,588 on row 137. Rows 167-170 show the calculation of the allocation of $266,235 to EWM.

PSC-064: RE: PSC-040 - SAP software
Witness: Henthorne

a. Please provide the total capitalized cost of the software when it was placed in service and please confirm it was placed in service in October of 2015.

b. Please provide the total capitalized cost of the software on December 31, 2015. Additionally, for GNI and the Joint Applicants, please separately identify the per-books GAAP accumulated depreciation recorded related to the software, including the financed portion of the software, and the GAAP accumulated depreciation related to the deferred rent (asset)/loss, as well as separate calculations illustrating the allocation of the deferred rent asset (loss), and associated accumulated depreciation from GNI to both EWM & CBG.

c. Please provide the total capitalized cost of the software on December 31, 2016. Additionally, for GNI and the Joint Applicants, please separately identify the per-books GAAP accumulated depreciation recorded related to the software, including the financed portion of the software and the GAAP accumulated depreciation related to the deferred rent (asset)/loss, as well as separate calculations illustrating the allocation of the deferred rent asset (loss), and associated accumulated depreciation from GNI to both EWM & CBG.

d. Per GNI's GAAP books, for each of the December 31 dates referenced in subpart(s) b & c above, please identify the useful lives over which the following capitalized costs were being depreciated:

   i. The VeriLease financed portion of the total SAP software asset; and

   ii. The deferred rent (loss) portion of the total SAP software asset (the GNI contributed cash).

Response to PSC-064:

a. The total capitalized cost of the software as of October 2015 was $5,345,710. Of this amount, $4,465,375 was capitalized to net plant as a capital leased asset and $880,335 was capitalized to a deferred rent asset. The $5,345,710 capitalized was less than the total cost outlay of $5,723,495 as shown on PSC-040 for schedule 1 because the $4,843,160 financed through Varilease was capitalized at its net present value as of October 1, 2015.

In October 2015, a portion of the SAP software was placed in service and we began using the software. Parts of the system were still in development when we went live in October. Consultants continued to work on developing the remaining functionality through August 2016. At this time, we felt the software was functioning appropriately in all areas and so released from service most of the development consultant staff. We capitalized costs related to this additional development through July 2016. From August 2016 and thereafter, consultants working on SAP are used for maintenance and small functionality fixes, so their costs are expensed.

b. The total capitalized cost of the software as of December 31, 2015 was $9,558,559. Of this amount, $7,521,863 was capitalized to net plant as a capital lease asset and $2,036,696 was capitalized to a deferred rent asset. The $9,558,559 capitalized was less than the total cost outlay of $10,324,264 as shown on PSC-040 for schedule 1 & schedule 2, because the $8,287,568 financed through Varilease was capitalized at its net present value.

Please see Attachment PSC-064 for a depreciation and amortization schedule. Row 24 shows the total capitalized costs, both for the leased assets and the deferred rent assets, as of December 31, 2015. Row 22 shows the costs, depreciation, accumulated depreciation, and net book value related to the capital leased assets financed through Varilease. Row 23 shows the costs, amortization and net value of the deferred rent assets.

Row 50 shows the total asset costs allocated to EWM at December 31, 2015. Row 48 is the portion related to the capital leased assets and row 49 is the portion related to the deferred rent assets. Row 75 shows the total asset costs allocated to CBGC at December 31, 2015. Row 73 is the portion related to the capital leased assets and row 74 is the portion related to the deferred rent assets. The assets were allocated using the 4-factor formula. The depreciation was not allocated to the subsidiaries from GNI. Because the assets were allocated during the construction phase, each subsidiary capitalized the assets upon completion and calculated depreciation on their own assets.

c. The total capitalized cost of the software as of December 31, 2016 was $13,602,836. Of this amount, $9,193,408 was capitalized to net plant as a capital leased asset, $1,253,811 was capitalized to net plant as a leasehold improvement and $3,155,617 was capitalized to a deferred rent asset. The $13,602,836 capitalized was less than the total cost outlay of $14,500,918 as shown on PSC-040 because the $10,091,490 financed through Varilease was recorded at its net present value.

Please see Attachment PSC-064 for a depreciation and amortization schedule. Row 30 shows the total capitalized costs for the leased assets, deferred rent assets, and leasehold improvement assets as of December 31, 2016. Row 27 shows the costs, depreciation, accumulated depreciation, and net book value related to the capital leased assets financed through Varilease. Row 28 shows the costs, amortization and net value of the deferred rent assets. Row 29 shows the costs, depreciation, accumulated depreciation, and net book value related to the leasehold improvement asset paid for by GNI.

Row 56 shows the total asset costs allocated to EWM at December 31, 2016. Row 53 is the portion related to the capital leased assets, row 54 is the portion related to the deferred rent asset and row 55 is the portion related to the leasehold improvements paid for by GNI. Row 81 shows the total asset costs allocated to CBGC at December 31, 2015. Row 78 is the portion related to the capital leased assets, row 79 is the portion related to the deferred rent assets and row 80 is the portion related to the leasehold improvements paid for by GNI. The assets were allocated using the 4-factor formula. The depreciation was not allocated to the subsidiaries from GNI. Because the assets were allocated during the construction phase, each subsidiary capitalized the assets upon completion and calculated depreciation on their own assets.

d. Depreciation and amortization for schedule 1 and schedule 2 started in 2015 and schedule 3 started in 2016 using the lives listed below:

i. The Varilease portion of the total SAP software asset is depreciated at differing lives per schedule as noted below

Schedule 1 – Depreciation start date 10/1/15 – 10 year useful life

Schedule 2 – Depreciation start date 11/1/15 – 9 year, 11 month useful life

Schedule 3 – Depreciation start date 4/1/16 – 9 year, 6 month useful life

ii. The deferred rent portion of the total SAP software asset is being amortized over the life of each lease schedule as noted below:

Schedule 1 – Amortization start date 1/1/15 – 36 months

Schedule 2 – Amortization start date 11/1/15 – 36 months

Schedule 3 – Amortization start date 4/1/16 – 30 months

PSC-065: RE: PSC-040 - SAP software
Witness: Henthorne

a. Would you say that the journal entry recording “loss” (Deferred Rent) was not necessarily a direct result of the company having to contribute cash towards the software development, but more the result of Varilease not giving consideration to these costs in the price they agreed to purchase the software for in the “sales-leaseback” transaction? Please explain.

b. Would you agree that by requesting the accounting order to include the deferred gain referenced above in rate base, the Joint Applicants are seeking to include the total cost of the SAP software as part of rate base and to amortize the total cost over a 10 year period? Please explain.

Response to PSC-065:

a. No. The recording of a loss as deferred rent was the direct result of applying U.S. GAAP accounting rules to the Varilease transaction. The transaction with Varilease was a lease and there was no “sale” to Varilease. The U.S. GAAP accounting rules required the transaction to be accounted for as a sale-leaseback because GNI stood the risk of completion during construction and implementation. Please see Mr. Henthorne’s direct testimony at pages 13-14 for further explanation.

b. Yes, by requesting an accounting order for the deferred loss as a part of rate base, we are seeking to include the total cost of the SAP software and to amortize the total cost over the 10 year useful life of the SAP software.

PSC-066: RE: PSC-042 - SAP software
Witness: Henthorne

In response to PSC-042 (regarding the deferred rent asset), you state that the requested accounting order seeks to include the average balance of 2015 and 2016 in the rate base. In your testimony (p 14, lines 14-18) you state that in this proceeding, EWM is requesting an accounting order to reclassify the unamortized portion of the deferred rent asset as of January 1, 2016 as a regulatory asset to be included in rate base. Please clarify these seemingly contradictory representations.

Response to PSC-066:

EWM is asking for the entire balance of the unamortized portion of the deferred rent asset as of January 1, 2016 to be treated as a regulatory asset. EWM included the asset in rate base at the beginning and end of year average balances to be consistent with the accounting treatment of our other rate base assets and liabilities.

PSC-067: RE: SAP software
Witness: Henthorne

Please provide:

a. For GNI, EWM, and CBGC, the per books GAAP depreciation expense recorded related to the Software for the periods ending December 31, 2015 and December 31, 2016. Please provide calculation illustrating the allocation of depreciation expense related to this asset from GNI to each of the joint applicants.

b. A description the types of costs (capital outlay) the depreciation expense referenced in subpart "a" is based upon. In your response, please specifically identify the separate "sources" and related dollar amounts that serve as the basis for depreciation (i.e. VeriLease funded costs, the deferred rent asset, outside services employed (as shown in note 5), cash put forth by GNI, etc.).

c. Please explain the treatment of the capital lease obligation as it pertains to the total depreciable basis of the SAP software. In your testimony (page 9, line 7) you treat the capital lease as customer contributed capital. Identify whether the "OC" serving as the basis for depreciation is reduced by the capital lease obligation. Please address any differences between the GAAP treatment of this asset and the accounting treatment requested by the Joint Applicants in this docket.

Response to PSC-067:

a. See Attachment PSC-064 for the depreciation and amortization schedules of the software related assets for 2015 and 2016. The assets were allocated using the 4-factor formula. See PSC-064 for further information regarding the allocation of depreciation.

b. See Attachment PSC-064, rows 21-30 for a summary of depreciation and amortization by type of cost (leased asset financed through Varilease, deferred rent, and leasehold improvements paid for by GNI). The costs all relate to the SAP ERP software and the costs of installing and implementing the software.

c. We have not adjusted the depreciable basis of the SAP software to treat the capital lease as customer contribute capital directly. The SAP software is depreciating based on its original cost over the 10 year estimated life of the asset, and the capital lease obligations is amortizing over the three year life of the lease. We included the capital lease obligation as a reduction to rate base because it is related solely to the SAP asset. Because it is short term (it ends in October 2018) we did not feel it was appropriate to include it in the cost of debt.

PSC-068: RE: PSC-042 & JDH-EWM-3/JDH-CBG-3
Witness: Henthorne

You state that rate base assets and liabilities are presented as an average of 2015 and 2016 balances. However, you also note that additions to plant represented in rate base that adjust for known projects completed within one year of the test year are presented as an average of 2015 and 2017 balances. Please discuss the rationale as to why "plant" related rate base items are treated differently than other rate base assets and liabilities.

Response to PSC-068:

The following clarifies the response to PSC-042 stating that we are averaging 2015 and 2017 balances:

While the additions to CWIP occurred in 2017, because it is within one year following the test year, we are proposing to include them in the normalized December 31, 2016 utility plant balances. The adjusted rate base reflects the average of December 31, 2015 and normalized December 31, 2016, including the CWIP additions that occurred in 2017.

PSC-069: RE: GIRC; PSC-022/JDH-EWM-12
Witness: Henthorne

Please explain the rationale in determining the amounts eligible for the GIRC program (see line 33). Specifically, please explain why the total GIRC program amount (line 15) is adjusted by the annual depreciation in excess of investment in plant (clearings to plant) to arrive at this figure.

Response to PSC-069:

One of the fundamental precepts of our proposed GIRC plan is that only the amount of capital expenditures above our annual depreciation expense amount are eligible for the GIRC program. In EWM-JDH-12, line 25 showing annual depreciation expense is greater than the average of clearings to plant on line 28. Therefore, this amount ($263,558 for year 2019 in column (C) reduces the total cost of the GIRC program on line 15 to arrive at the GIRC eligible amount in line 33.

PSC-070: RE: GIRC; PSC-022/JDH-EWM-12/ JDH-CBG-8
Witness: Jed D. Henthorne

a. Please provide a GIRC expenditure plan in a more detailed description of the replacements than has been provided in Exhibits JDH-EWM-12 and JDH-CBG-8 and the updated in response to PSC-022? Those exhibits appear to provide an overall scope of the GIRC amounts but does not have details of specific projects. The plan should include, at a minimum, location of the replacements, proposed amount of replacements, and a timeline for each project.

b. Please explain the progress monitoring plan that EWM and CBGC propose to provide the Commission with regarding performance of the GIRC (annual, quarterly). At a minimum, the plan should update the Commission on actual facilities replaced versus those proposed in the plan, and a cost comparison of the proposed expenditure plan with actual expenditures. The progress report should note accelerated expenditures or replacements, as well as delays and the reasoning behind each of those.

Response to PSC-070:

a. The purpose of the GIRC plan is to accelerate the existing infrastructure replacement plans we already have in place. Please also see response to MCC-097. Our plan proposes that capital expenditures above our annual depreciation levels are GIRC plan eligible. Our DIMP plan identifies the portions of our system that are higher risk and this is the basis for the programs we have identified for the GIRC plan.

Specifically, for EWM, we have identified three focus areas:

Replacement of pre-1984 Aldyl-A main: We have identified 42.45 miles, or 224,136 feet, of pre-1984 Aldyl-A main in the distribution system in Great Falls. We currently replace an average of 7,540 feet of this main per year through our on-going replacement program and would replace an additional 11,000 feet per year at a cost of approximately $290,000 per year. We would continue this program each year until all of the Aldyl-A main in our distribution system has been replaced, or approximately 12 years.

Replacement of coupled steel services: We have identified 11,000 steel services with couplings in the distribution system in Great Falls. We currently replace an average of 238 of these services per year through our on-going replacement program and would replace an additional 760 per year at a cost of approximately $1 million per year. We would continue this program each year until all of the coupled steel services have been replaced, or approximately 11 years.

Replacement of couplings on 12 inch header main: The original header main in the Great Falls distribution system has couplings that need to replaced/upgraded which is possible with the back feed provided by the SME Pipeline. We have not yet identified the cost or the time frame involved with repairing each coupling individually. This is an example of GIRC eligible facilities that we propose to include in the GIRC recovery.

Specifically, for CBGC we have identified one focus area.

Replacement of coupled steel services: We have identified 750 steel services with property line meter sets in the distribution system in Cut Bank, which are typically coupled and mixed materials. The homeowner's contractor, with little or no quality control, originally installed the service from the meter set. We currently replace an average of 32 of these services per year through our on-going replacement program and would replace approximately 40 additional services each year at an approximate cost of $42,000 per year. We would continue this program each year until all of the services have been replaced, or approximately 10 years.

The above items are all identified in the first seven categories of Appendix B in our DIMP plan.

b. Our annual GIRC filing would include a listing of all capital additions for the year with the GIRC eligible amounts shown separately. For the focus areas identified above, we would show the feet/number of services replaced and the costs with a comparison to the projected quantities and costs. In addition, we propose to work with the Commission Staff to build the report that meets the needs of the Commission.

<u>Sponsors:</u> Kevin Degenstein / Jed Henthorne

PSC-071: RE: GIRC
Witness: Henthorne

Please provide more information on how "mechanical couplings" and "property line meter sets" contribute to risk in the broader DIMP plan categories, as well as what EWM, CBC, and GNI are doing or propose to do in order to mitigate these risks.

Response to PSC-071:

EWM and CBGC have been executing on their DIMP plans since such plans were required by CFR 49 Part 192 Section §192.1001 on 08/02/2011. See Attachment PSC-071-1 for the EWM and CBGC DIMP Plan. Even prior to the requirement, EWM and CBGC were addressing its high-risk materials. Appendix C, "Summary of Items Removed From the System," of the DIMP Plan identifies the removal of all bare services (possible mix materials) with inside shutoff valve, Marlex black plastic pipe (CBGC only), bare steel mains, and inside meters and regulators. The current EWM and CBGC DIMP plan identifies its higher risk items in Appendix B. The first seven categories, highest risk, include services and main that include mechanical couplings, mixed material associated with property line meter sets, and Aldyl A pipe. There have been several advisory bulletins issued by PHMSA identifying the risks of mechanical fittings. Including, ADB-86-02, ADB-08-02, ADB-09-02 and ADB-12-0. See Attachment PSC-071-2 for a PHMSA presentation discussing ADB-86-02, December 2009. In addition, PHMSA requires mechanical fitting failures be reported on Form PHMSA F 7100.1-2. See Attachment PSC-071-3. There have been several advisory bulletins issued by PHMSA identifying the risks of older plastic pipe, which includes Aldyl A pipe. Including, ADB-99-01, ADB-99-02, ADB-02-07 and ADB-07-01. See Attachment PSC-071-4, Hazard Analysis and Mitigation Report-Aldyl A Polyethylene Gas Pipelines dated June 11, 2014.

EWM and CBGC are systematically replacing the higher risk items identified in its DIMP plan. Since 2009, CBGC replaced approximately 10 miles of main and over 185 services, which included all bare steel and Marlex (PE water pipe) gas main. During the same period, EWM replaced over 1,855 services and 10 miles of main (including all bare steel main) and moved approximately 600 combination regulator/meter sets from inside buildings to outside. EWM and CBGC will continue to replace the higher risk items as they have always done. GNI (now Hearthstone Utilities, Inc.) will continue to support safe and reliable service.

However, based on the life expectancy of these facilities and notices issued by PHMSA, eliminating these items from EWM's and CBGC's natural gas distribution systems over the course of the next 10 to 12 years would be a prudent approach. The GIRC allows us to accelerate the replacement of this higher risk infrastructure and replace the facilities systematically, without requiring more frequent rate cases to recover this accelerated capital investment. If the leak rates increase from today's rate and a GIRC plan is not implemented there is the potential for a large rapid and more risky replacement program.

Sponsor: Kevin Degenstein

PSC-072: RE: Proxy Group; Test. Henthorne p. 17
Witness: Henthorne

a. You indicated that you eliminated any company that was engaged in significant mergers or acquisitions. Do you agree that merger and acquisition activities can distort market factors used on DCF and risk premium analysis? Please explain.

b. Are you aware that on October 16, 2017, South Jersey Industries announced its acquisition of Elizabeth Gas and Elkton Gas? With this new information do you agree South Jersey should be excluded from you proxy group and that an updated ROE recommendation should be provided? Please explain.

Objection:

EWM & CBGC object to this request on the grounds that it is ambiguous, as there is no reference to the proxy group on page 17 of Mr. Henthorne's testimony nor does Mr. Henthorne's testimony address the selection of proxy groups generally.

Response to PSC-072:

For purposes of this response, EWM & CBGC assume the question is intended to reference Mr. Scheig's direct testimony:

a. Mergers and acquisitions could affect a company's composition and outlook, but Mr. Scheig does not see how they would "distort" a DCF and risk premium analysis.

b. The information Mr. Scheig considered was from June 2017, prior to this acquisition. At that time, the information reflected in Mr. Scheig's analysis reflected the market's pricing and risk assessment for South Jersey Industries. If the analysis were updated to a current time, Mr. Scheig would consider the post-merger company, but would also update all of the other companies as well. Mr. Scheig does not believe excluding it would improve the analyses.

Sponsor: Greg Scheig

PSC-073: RE: SME Pipeline
Witness: Henthorne

a. Please provide a cost savings report regarding what upgrades or improvements would have cost EWM if the pipeline had not been purchased.

b. Please provide a cost savings report directly related to the SME pipeline as it relates to any failures the EWM system has suffered since its purchase.

c. Will there be any cost savings to EWM regarding the GIRC plan because of the SME pipeline acquisition? Please explain. If so, these savings should be noted in the updated GIRC plan the Commission is requesting.

Response to PSC-073:

a. As indicated in response to MCC-081, EWM was experiencing system pressure problems prior to the incident in 2007 and was asking key customers not to burn gas during extremely cold weather. EWM recognized the need to extend the 10" loop that terminates just east of the Missouri river, with approximately 14.5 miles of 12" pipe, strengthening the pressures throughout its natural gas distribution system. The estimated cost of running the 12" pipeline extension would be approximately $6,000,000 using the estimated cost per mile identified in the SME construction agreement. See Attachment MCC-060-5. In addition, EWM can now systematically replace the couplings on the 12" header pipe running west to east in the alley north of 9th Avenue North. This would not be possible without the SME Pipeline, a similar pipeline extension, or back feed, even during the summer months. To accomplish this without creating long-term customer interrupts, EWM would have to either replace the entire 12" header pipe (4.5 miles) or bypass each coupling using multiple stopper fittings, valves, and bypass piping. The cost to replace the 12" header pipe, connect all existing laterals and services would be approximately $5,000,000 due to construction conditions in existing alleys. It has also saved operating expenses that would have been required during extremely cold weather to manage the gas distribution system.

b. EWM has had no system failures since the purchase of the SME Pipeline and has avoided the cost of responding to low pressure and outage calls from customers.

c. The SME pipeline allows EWM to address the coupled 12" header main without having to directly replace it for approximately $5 million. Therefore, the GIRC plan already reflects the savings due the SME pipeline acquisition.

Sponsor: Kevin Degenstein

PSC-074: RE: Gas Cost Adjustment; Ex. JDH-EWM-6 and JDH-CBG-4
Witness: Henthorne

Please explain in greater detail the billing or other errors that caused Gas Cost Adjustments to be made to both the EWM and CBG test years.

Response to PSC-074:

These adjustments are a result of corrections made when preparing the gas cost true up filings for EWM and CBGC for the periods ending March 31, 2016 and December 31, 2015, respectively. These corrections were made in order to reflect the correct amount of gas costs and recoveries in our filings and also resulted in correcting entries to the general ledgers of EWM and CBGC. These adjustments are unrelated to our costs of service and so we removed them from the test years of EWM and CBGC.

PSC-075: RE: SME Pipeline
Witness: Henthorne

Where has EWM accounted for the increased property taxes it could incur if the pipeline were to be valued at the requested addition to rate base? Please provide supporting documentation or reference to it if it has been provided already.

Response to PSC-075:

EWM has not accounted for increased property taxes in this rate filing.

PSC-076: RE: PSC-001 Response, Account 146
Witness: Henthorne

Please explain in greater detail what intercompany taxes are, how they are accounted for and where in the rate case filing the workpapers or testimony will address the account.

Response to PSC-076:

GNI as the parent company of EWM, CBGC and its other subsidiaries files consolidated income tax returns. The intercompany tax accounts facilitate transactions between GNI and its subsidiaries to properly record income tax related items on the books of the subsidiaries. In this case the amounts are related to the Net Operating Losses (NOL)'s that were utilized in the consolidation but that could not have been utilized by EWM yet due to its continuing NOLs. Those NOLs would have been available to EWM had EWM filed its own separate tax returns. These NOLs are also subject to the IRS normalization requirement and must be included in regulatory asset/liability calculations as a part of the required 2017 Tax Act adjustment to comply with the IRS normalization rules.

The intercompany tax account balance is included in the Accounts Receivable-Intercompany line on Statement A, rule 38.5.121 of the ARM based schedules. All income tax related amounts included in rate base or included for recovery in the revenue requirement are stated at the statutory federal and state rates.

PSC-077: RE: PSC-001Response, Account 242
Witness: Henthorne

Please explain in greater detail what budget plan over payments are, how they are accounted for and where in the rate case filing the workpapers or testimony will address the account.

Response to PSC-077:

The budget plan overpayments account is where we record the credit balances related to the levelized billing program. The budget billing program runs from June to May of the following year. A customer's accounts receivable balance typically grows to a credit balance through the summer as they are paying more than their actual bill. In the late fall and winter the customer's accounts receivable balance approaches zero or switches to a debit balance as they are paying less than their actual bill. A true-up of amounts paid versus actual usage related bills occurs for each customer in June of each year. For quarterly financial reporting purposes, when the customer's balance is in a credit state, the amounts are reclassed out of accounts receivable and into budget plan overpayments, a liability account.

The budget plan overpayment account is included in Statement A, rule 38.5.121 of the ARM based schedules.

PSC-078: RE: PSC-002 Response, “Net Utility Plant”
Witness: Henthorne

Please explain in greater detail what adjustment to goodwill is, how it is accounted for and where in the rate case filing the workpapers or testimony will address the account.

Response to PSC-078:

There has been no adjustment to goodwill, it has held the same balance since Cut Bank Gas Company was purchased in 2009. The presentation of the account was just reclassified into a different location on the balance sheet for rate case purposes than what had previously been reported in the 2016 annual PSC report. On the annual report it was recorded in utility net plant. For the rate case, we included the $1,056,771 with other assets, line 22, of Statement A – Balance Sheet of the rule-based schedules.

PSC-079: RE: Discovery Audit
Witness: Henthorne

Please provide electronic and hard copies of documents requested in the Discovery Audit Letter mailed to EWM/CBG from PSC Staff. Include a comprehensive list of documents provided onsite to staff at the audit and what was not provided. The information staff received at the audit was not comprehensive for every item from the discovery audit list, nor was it consistently or clearly labeled, making it difficult for staff to find and review. The flash drives are also different depending on the day the drive was made or updated for staff. This response should include clearly identified documents, by file name, and date when appropriate.

Response to PSC-079:

The folder named Attachment PSC-079 contains electronic copies of the following documents which were requested in the Discovery Audit Letter (hard copies will be provided):

1. Board of Directors' minutes for 2014, 2015, 2016 and year to date 2017 – *Provided.*
2. Internal audit reports from 2014, 2015, 2016 and year to date 2017 – *Provided 2015 & 2016. We did not have an internal audit report for 2014 and there was no internal audit in 2017 since GNI is no longer a public company*.
3. External audit reports from 2014, 2015, 2016 and year to date 2017 – *Provided 2014-2016. There was no external audit in 2017 until the year-end audit which is currently ongoing.*
4. Special project reports prepared in-house for the years 2014, 2015, 2016 and year to date 2017 – *No responsive documents, as we had prepared no special project reports during these years.*
5. List of all clubs and organizations for which dues or memberships were paid by EWM or CBGC to be included in recovery for the rate case – *Provided.*
6. Listing of all outside firms or individuals retained by EWM or CBGC during 2014, 2015, 2016 and year to date 2017 that have provided services and had expenses allocated to the various operating divisions – *Provided.*
7. Outside consultant reports for the years 2014, 2015, 2016 and year to date 2017– *No responsive documents, as we had no outside consultant reports during these years.*
8. Business plans for the years 2014, 2015, 2016 and year to date 2017 – *We were unsure what was meant by business plan but we did provide EWM and CBGC's 5 year forecast in response to MCC-017.*
9. Copies of 2014, 2015 and 2016 MT corporate license tax returns – *These documents will be provided in accordance with the Commission's decision on the Joint Applicants' motion for a protective order filed contemporaneously with these responses.*

10. Copies of 2014, 2015 and 2016 Federal income tax returns- *These documents will be provided in accordance with the Commission's decision on the Joint Applicants' motion for a protective order filed contemporaneously with these responses.*

11. Be prepared to discuss adjustments in JDH-EWM-6 – *No responsive documents.*

12. Be prepared to discuss adjustments in JDH-EWM-3 – *No responsive documents.*

13. Be prepared to discuss adjustments in JDH-CBG-3 – *No responsive documents.*

14. Be prepared to discuss adjustments in JDH-CBG-4 – *No responsive documents.*

15. Be prepared to discuss the 2014-2016 PSC annual reports and JDH-CBG-4 and JDH-EWM-6 – *No responsive documents.*

The following additional items were requested and provided when the staff was on site for the discovery audit:

1. Board of Directors' minutes for GNI

2. GL detail, printed, for all three EWM divisions and CBGC for the years 2015, 2016 and year-to-date 2017

3. The listing from #6 above only for vendors and amounts that were included for recovery in the rate case

4. Listing of all advertising costs included for recovery in the rate case

5. Chart of accounts

PSC-080: RE: SME Pipeline
Witness: Henthorne/Appropriate Witness

a. When EWM was contacted to build the pipeline did SME contact any other potential builders? If so was EWM the lowest bidder? If you are unable to provide this information, please indicate who may.

b. If there was any kind of study or RFP presented, what value was assigned to the pipeline upon completion? Was that value higher or lower than other bidders? Please provide any supporting documentation.

Response to PSC-080:

a. Yes, SME called EWM and indicated they had contacted NorthWestern Energy. They indicated the price quoted was higher than what they had forecasted and budgeted for the project. SME asked if EWM could build a pipeline. EWM indicated it would be able build a pipeline. EWM executed a construction agreement on April 19, 2010, which indicated an estimated price of $8,000,000. See Attachment MCC-60-5. The actual cost to SME was $4,905,867. EWM is not aware of any other potential builders.

b. EWM is not aware of any RFP process. EWM does not know what value SME assigned to the pipeline.

Sponsor: Kevin Degenstein

PSC-081: RE: SME Pipeline
Witness: Henthorne

Since the SME Pipeline has been built and utilized by EWM has the pipeline saved the ratepayers any costs, or has the pipeline increased costs to the ratepayers? Please provide explain and provide supporting documentation, and provide examples if applicable to either scenario.

Response to PSC-081:

The SME Pipeline has saved the ratepayers costs. As indicated in response to PSC-071, EWM would have had to spend significant dollars to continue providing reliable service, which were spent by SME. Without the SME Pipeline, EWM would have been in the position of building its own pipeline and forced to file for a general rate case much sooner than September 30, 2016. The cost of these projects would have been borne by the ratepayer through the ratemaking process. EWM has also saved operating expenses that would have been required during extremely cold weather to manage the gas distribution system. This cost would also have been borne by the ratepayer through the ratemaking process.

Sponsor: Kevin Degenstein

PSC-082: RE: SME Pipeline
Witness: Henthorne

a. Did SME have other options to dispose of the pipeline besides the sale to EWM? If so please list the other options and the costs associated with each option.

b. What options are available to EWM for disposal of the pipeline, including those options that were available SME?

Objection:

EWM objects to this request to the extent is seeks information that is not within EWM's care, custody, or control.

Response to PSC-082:

a. EWM is not aware of any other options that SME may have had.

b. EWM has not option of disposing the SME Pipeline. It is critical to providing reliable service.

Sponsor: Kevin Degenstein

PSC-083: RE: ERP Software
Witness: Henthorne

a. Were overages incurred to finish the ERP software? If so, please provide any cost studies done to estimate the continued overate amount. If no studies were completed, please explain why EWM should be responsible for paying the overage costs

b. What was the original cost and the final cost of the software?

Response to PSC-083:

a. Yes, the total amount paid for the ERP software project was more than originally projected. As seen in the board minutes provided, GNI personnel had several updated cost estimates and negotiations with Capgemini throughout the project timeline. Early on in the project it was concluded that our existing software packages were not at a stage where the standard conversion process could occur, so there would need to be more consultants and internal input than originally planned. It was at this point that the estimated cost was increased to $8 million. The ERP software is by its design and nature inclusive of all GNI subsidiaries including EWM and CBGC. The increase in costs is due to legitimate costs involved with a software conversion of this magnitude and we should be allowed to recover and earn a reasonable return on our actual investment in improving our business software.

b. The original cost estimate from Capgemini for the purchase and implementation of the software was $4 million. The total cost paid for the ERP software project was $14.5 million.

PSC-084: RE: Usage Forecast Model; Loy Testimony
Witness: Loy

In your testimony at 7:26-27, you testify that your usage adjustment model is commonly used to adjust test year billing units for weather impacts. Please support this claim with evidence from other filings.

Response to PSC-084:

A quick and non-comprehensive search of filings where weather normalized natural gas volumes were estimated using regression analysis produced the following examples:

1. CenterPoint Energy Oklahoma Gas, Cause No. PUD201700078, Order No. 669205

2. Intermountain Gas Company, Case No. INT-G-16-02; Order No. 33757

3. Washington Gas Light Company, 336 P.U.R.4th 8, Formal Case No. 1137; Order No. 18712

4. Washington Utilities & Transportation Commission v. Cascade Natural Gas Corporation, Docket UG-152286; Order 04

5. Interstate Power & Light Company, Docket No. RPI-I -2012-0002; Docket No. TF-2012-0374

6. CenterPoint Energy Resources Corp. dba CenterPoint Energy Mississippi Gas, Docket No. 12-UN-139; CenterPoint ID No. GC123-0861-OO

7. Interstate Power & Light Company, OAH 4-2500-21392-2; PUC E-001/GR-10-276

8. SourceGas Distribution LLC, Docket No. 08S-108G; Docket No. 08A-127G; Decision No R08-0820

9. CenterPoint Energy Resources Corp., dba CenterPoint Energy Oklahoma, Cause No. PUD 200800062; Orde No. 556393

10. Washington Gas Light Company, 94 Md. P.S.C. 329, Case No. 8959; Order No. 78757

11. Piedmont Natural Gas Company, 223 P.U.R.4th 544, Docket No. 2002-63-G; Order No. 2003-15

Additionally, a benchmarking study conducted by Itron, Inc. (http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg_lftf/meeting_materials/2012-03-26/1_WeatherNorm_McMenamin.pdf) shows that of 159 utility respondents, 60% reported using regression analysis to weather normalize sales, 30% use simulation models that may or may not be based on regression equations, and 10% used some other method.

PSC-085: RE: PSC-011
Witness: Loy

a. Do you believe this analysis provides useful information to the Commission regarding a decision on residential rate design in this proceeding? If so, please describe any useful results.

b. Please describe theoretical flaws and limitations of this analysis.

c. Do you believe this analysis supports the proposed rate design for EWM/CBG in this proceeding? Please explain why or why not.

Response to PSC-085:

a. The response is useful in that it shows three different rate designs for the potential recovery of base costs. A lower customer charge requires more fixed costs to be recovered by volumetric rates and thus increases the likelihood of under- or over-recovery of base revenues.

b. The analysis is limited and/or flawed in that it is designed to achieve pre-determined rate designs for the potential recovery of base costs rather than determining the rate design based on EWM's cost of service. As a result, the analysis merely demonstrates that the lower the customer charge, the greater the revenue volatility and risk of over- or under-recovering base revenues.

c. No. The cost of service studies presented in Mr. Loy's direct testimony and exhibits support the proposed rate design in this proceeding.

PSC-086: RE: GIRC Rates; Loy Testimony
Witness: Loy

In your testimony at 11:8-10, you do not include the Large Commercial class in the list of customer classes to which GIRC rates will be applied. Please explain.

Response to PSC-086:

It is Mr. Loy's understanding that the vast majority of the infrastructure replacements are coupled services and Aldyl A pipe which are not applicable to the Large Commercial or Negotiated classes.

PSC-087: RE: Cost Allocation Model
Witness: Loy

Please provide the results of an alternative analysis in which the DCUS functional allocator is replaced with the DEMD functional allocator, and the CUST functional allocator is replaced with the DCUS allocator. When allocating DCUS demand-classified service, meter, and regulator costs, please allocate these costs to the customer classes using the allocation factors that were used to allocate demand-related distribution mains costs. Please provide amended versions of Table 5, Table 7, Exhibit CEL-EWM-5, and Exhibit CEL-CBG-4 in electronic form.

Response to PSC-087:

Below are the amended Tables 5 and 7. The amended Exhibits CEL-EWM-5 and CEL-CBG-4 are provided as Attachments PSC-087 - EWM and PSC-087 - CBGC. Please note that the proposed revenue increase and rates were not revised.

Amended Version of Table 5

COST OF SERVICE STUDY RESULTS				
Rate Class	**Rate Base**	**Earnings $$$**	**%**	**Increase (Decrease)**
***Residential-** Great Falls/Cascade*	$6,970,244	$396,099	5.68%	$301,950
***Residential-** West Yellowstone*	$479,646	$87,217	18.18%	($77,712)
***Small General-** Great Falls/Cascade*	$1,058,924	$205,059	19.36%	($192,112)
***Small General-** West Yellowstone*	$250,928	$51,056	20.35%	($49,571)
***Large General-** Great Falls/Cascade*	$4,136,358	$511,303	12.36%	($274,573)
***Large General-** West Yellowstone*	$961,465	$182,885	19.02%	($169,008)
***Ext. General-** Great Falls/Cascade*	$1,610,801	$297,268	18.45%	($268,152)
Negotiated Contracts	$4,730,390	($975,370)	-20.62%	$2,248,612
Propane	$56,046	$66	0.12%	$7,551
TOTAL	$20,254,802	$755,582		$1,526,985

Amended Version of Table 7

COST OF SERVICE STUDY RESULTS				
Rate Class	**Rate Base**	**Earnings $$$**	**%**	**Increase (Decrease)**
Residential	$354,220	$120,473	34.01%	($144,945)
General Service	$804,472	($129,825)	-16.14%	$328,229
Total	$1,158,692	($9,352)	-0.81%	$183,284

PSC-088: RE: Fixed Cost Price Signals; Loy Testimony
Witness: Loy

In your testimony at 31:22–32:2, you testify that the fixed cost charge must be reasonable to customers, while the volumetric rate must be at a level that will send an adequate price signal regarding variable use.

a. Please describe how the Commission can ascertain whether volumetric rates adequately signal the variable cost of natural gas distribution.

b. In Table 9, you assert that the base costs of natural gas distribution are typically about 98% fixed. If true in this case, will natural gas conservation reduce distribution system costs? Will incremental increases in usage measurably increase system costs? Please explain why or why not.

c. In your opinion, would straight fixed-variable rates, i.e. rates in which fixed costs are recovered using fixed monthly charges and variable costs are recovered using volumetric rates, provide better price signals for fixed and variable natural gas distribution costs than the rates proposed by the Joint Applicants in this proceeding? Please explain.

Response to PSC-088:

a. The cited passage should be considered in the context of conservation. That is, the volumetric rate (*i.e.*, the combined rate of gas costs and volumetric margin recovery) should be high enough to encourage conservation while the volumetric margin recovery rate should be established at a low enough level to mitigate over- and under-recoveries of non-gas costs.

b. Gas conservation will reduce commodity costs and should slightly reduce base revenue related costs. Incremental usage increases will typically increase gas commodity costs and should only slightly increase base revenue related costs. Most of the non-commodity or base revenue related costs are fixed. However, the EWM and CBGC proposed rate designs rely on the volumetric rates to recover a significant portion of those fixed costs. Therefore, a reduction or increase in usage will have a greater impact on the recovery of base costs than on the level of base costs.

c. The straight fixed-variable rates as described above would most definitely have a higher probability of accurately recovering base costs and minimizing over- and under-recoveries. However, the straight fixed-variable methodology was rejected by this Commission in the last EWM rate case. As such, said methodology was not evaluated or considered in the preparation of this case.

PSC-089: RE: SME Pipeline; Loy Testimony
Witness: Henthorne/Loy

In Loy's testimony at 42:8–9, he discusses the original cost standard. Per CFR, Title 18, part 201, "Original Cost, as applied to gas plant, means the cost of such property to the person first devoting it to public service."

a. Does EWM consider it to be the first person devoting the SME pipeline to public service?

b. If so, please describe the rationale for recording the pipeline at an amount in excess of the $75,000 "cost" to EWM.

c. If not, please discuss how an unregulated entity such as SME (the original owner of the pipeline) effectively devoted the pipeline in its entirety to "public service."

Response to PSC-089:

a. No. EWM considers SME to be the first person who devoted the SME Pipeline to the public service as a result of SME's agreement to provide natural gas distribution facilities at no cost and to provide customers service from the SME Pipeline.

b. Not applicable.

c. Please see Kevin Degenstein's direct testimony at page 12, lines 1-7. SME placed the pipeline into public service by allowing others to be served by the pipeline from its inception. As part of its negotiations with landowners surrounding its power plant site, EWM understands that SME agreed to provide access to natural gas. As part of the construction contract, SME paid EWM build facilities to connect these customers to the SME line. Ultimately, SME relied on EWM to operate the SME pipeline to provide service to customers, but SME committed to providing gas distribution facilities and service to these customers and thus devoted the SME pipeline to public service. EWM believes the entire SME Pipeline was dedicated to the public service because the pipeline became a necessary part of the distribution system required to serve retail customers, regardless of the actual load on the pipeline after it was placed into service.

Sponsors: Kevin Degenstein and Jed Henthorne

PSC-090: RE: SME Pipeline; Loy Testimony
Witness: Loy

In your testimony at 42: 11–14, you state that it would be in the public's best interest to exclude the negative acquisition adjustment from rate base. Please explain how it is "in the public's best interest" to rate base the asset at a level in excess of the bargain purchase amount, thereby depriving ratepayers of windfall gains.

Objection:

EWM objects to this request on the grounds that it is unclear what the PSC is referring to by "windfall gains."

Response to PSC-090:

Please see the discussion on page 43, lines 3-22 of Mr. Loy's direct testimony.

PSC-091: RE: Constant growth DCF Analysis; Ex. GES-2
Witness: Scheig

Please explain why your constant growth DCF results, as seen on Schedule A, do not match the referenced schedules (i.e. Schedule D.1 represents an 8.76% ROE not an 8.82% ROE as is represented in Schedule A). Please provide supporting documentation.

Response to PSC-091:

This was a cell that was linked but did not update properly. The change noted above is not material and does not change Mr. Scheig's conclusions. An updated version of Schedule A is provided as Attachment PSC-091.

PSC-092: RE: Constant growth DCF Analysis; Ex. GES-2
Witness: Scheig

In your calculation of D(1), your notes indicate that you used the following formula, *D(1) = D(0) * (1+g/2)*.

a. Please explain the "g/2" component of this formula.

b. The same source document (Value Line Pages) you used to obtain the "'14-'16 to '20-'22" earnings growth percentage (6%) used in your calculation, also provides projected annual dividend growth rates. Please explain why you chose to use the formula referenced above in your calculation of D(1), as opposed to using the following formula: *D(1) = D(0) * (1+g)*?

Response to PSC-092:

a. This term reflects the assumption that dividends are paid during the year (quarterly) versus only one time at the end of the year.

b. The use of an earnings growth rate is more appropriate as it relates to a company's free cash flow for a longer-term horizon and is not affected by changes in dividend payout ratios.

PSC-093: RE: Non-Constant growth DCF Analysis; Ex. GES-2
Witness: Scheig

Regarding your calculation(s) of "Price" (in final year), please explain why you chose to multiply the 2020–2022 projected EPS by the current P/E ratio, instead of using the projected 2020–2022 P/E ratio provided by Value Line.

Response to PSC-093:

In Mr. Scheig's opinion, while reasonable forecasts for future earnings may be developed, forecasts of specific future prices are difficult and for this reason he relied on a current P/E ratio as set by the market.

PSC-094: RE: Risk-Free Rate
Witness: Scheig

In determining an appropriate proxy for the risk-free rate, the Duff & Phelps Valuation Handbook 2017 (p. 3-1) states that spot yields on U.S. government bonds are typically the rates that analysts use. Furthermore, the Handbook represents that the two most commonly used government securities for this purpose are the 10-and 20-year U.S. Treasury bonds.

a. Please explain your decision to use 30-year Treasury bond Yields as the risk-free rate in your various analyses, as opposed to the yields on 10- or 20-year Treasury Bonds.

b. Please re-perform all of your CAPM (as well as your modified versions of the true CAPM) and Risk Premium analyses summarized on “Schedule A” using 10-year Treasury yields as the risk free rate and ceteris paribus. Please summarize your results in the same format as “Schedule A.” Additionally, please provide the resulting correlation coefficients associated with your Risk Premium Analyses.

c. Please re-perform all of your CAPM (as well as your modified versions of the true CAPM) and Risk Premium analyses summarized on “Schedule A” using 20-year Treasury yields as the risk free rate and ceteris paribus. Please summarize your results in the same format as “Schedule A.” Additionally, please provide the resulting correlation coefficients associated with your Risk Premium Analyses.

Objection:

EWM and CBGC object to subparts (b) and (c) of this request on the grounds that the burden or expense of preparing the requested analyses outweighs the likely benefit. Furthermore, the requested analyses do not currently exist and therefore are not properly discoverable under MRCP 26(b)(1).

Response to PSC-094:

a. Given the longer-term investments required for utilities, in my experience the 30-year yield is more appropriate.

b. The 10-year rate is 60 basis points below the 30-year yield, so these model results would be approximately 60 basis points lower, ceteris paribus.

c. The 20-year rate is 25 basis points below the 30-year yield, so these model results would be approximately 25 basis points lower, ceteris paribus.

PSC-095: RE: Private Equity Discussion; Scheig Testimony; MCC-054
Witness: Scheig (subparts a-d) / Most Appropriate Witness (subpart e)

a. Pursuant to the private equity discussion, do you conclude that the Joint Applicants cost of equity should include a risk premium simply due to the illiquid nature of investments in private and irrespective of their theoretical market capitalization/size?

b. Would you agree with the representations of Rolf W. Banz in his publication "The Relationship between Return and Market Value of Common Stocks" (1981) that it is not necessarily clear whether or not a size-risk premium, such as that identified by Duff & Phelps, is actually due to the size of the company, or whether it is due to some other factor (or combination of factors) closely correlated with size, such as liquidity? Please explain.

c. If your answer to subpart (b) is "yes," would you agree that the size premia identified by Duff & Phelps (and Schedule G.1 in your testimony) could potentially already account for any additional risk assumed by the investor related to the liquidity of their private equity ownership interest?

d. In response to MCC-054, subpart (a), you state that the private equity study referenced in your testimony was a consideration of small companies like EWM and CBG, and didn't relate to the "ownership" of the Joint Applicants. If this consideration was indeed more related to the risk premium associated with the size of the Joint Applicants (thus accounted for in the Size Premium identified in Schedule(s) G.1 & G.2 of your testimony), and was not intended to imply any additional risk premium related to the "ownership" of the Joint Applicants, please explain the applicability of the "Additional SSRP indicators" (identified on Schedule G.2 of your testimony) used in the determination of the concluded SSRP premium identified on Schedule G.2.

e. In response to subpart (a), if the witness answered "yes," was this risk premium, which potentially increases the ROE to be requested in future rate cases, clearly identified before the Commission in the application for GNI and its subsidiaries to be acquired by First Reserve (Docket D2016.11.91)? Please explain and provide supporting documentation.

Objection:

EWM and CBGC object to this request to the extent it misinterprets or misrepresents Mr. Scheig's responses to MCC-054.

Response to PSC-095:

a. No, private equity investments are typically less liquid than publicly traded securities and are also typically smaller than publicly traded equities. The additional risk premia in this article relates to both of these factors.

b. Agreed, smaller companies like the joint applicants are less liquid than large publicly traded securities and also are perceived by the market to have more risk, given their size.

c. Mr. Scheig agrees that could potentially be the case. As discussed in his direct testimony, Mr. Scheig did not mechanically rely on the Duff & Phelps measure, but considered it and other factors in his concluded SSRP.

d. Mr. Scheig was trying to communicate that the SSRP is related to the company, and not to the composition of its shareholders.

e. Mr. Scheig did not reply “yes” to subpart (a).

PSC-096: RE: Proxy Group
Witness: Scheig

a. Is UGI Corporation primarily involved in propane sales and marketing, or natural gas? Please support your answer.

b. Do you agree that UGI Corporation should be removed from the proxy group? Please explain.

c. Please update your analysis after removing the UGI Utility Company.

d. Regarding Spire Inc., did changing names from The Laclede Group to Spire cause changes in growth, beta or other financial measures? Please explain.

e. When NiSource introduced its Columbia Pipeline Spinoff, could that transaction distort the Company's financial metrics? Could it? If not, please explain why the spinoff could not distort the financial metrics of the company.

Response to PSC-096:

a. Propane accounted for approximately 40% of 2017 revenue, midstream sales accounted for 18.3% of revenue, and natural gas utility services accounted for 14.5% of revenue. See below:

UGI Corporation (NYSE:UGI) Financials > Segments

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Business Segments

For the Fiscal Period Ending	Reclassified 12 months Sep-30-2014	12 months Sep-30-2015	12 months Sep-30-2016	12 months Sep-30-2017
Currency	*USD*	*USD*	*USD*	*USD*
Revenues				
Amerigas Propane	3,712.9	2,885.3	2,311.8	2,453.5
UGI International	-	1,808.5	1,868.8	1,877.5
Midstream & Marketing	-	1,163.6	866.6	1,121.2
UGI Utilities	1,086.9	1,041.6	768.5	887.6
Corporate & Other	(318.6)	5.7	3.9	3.6
Eliminations	-	(213.6)	(133.9)	(222.7)
Midstream & Marketing - Energy Services	1,388.6	-	-	-
Midstream & Marketing - Electric Generation	85.1	-	-	-
UGI International - UGI France	1,295.5	-	-	-
UGI International - Flaga & Other	1,026.9	-	-	-
Total Revenues	**8,277.3**	**6,691.1**	**5,685.7**	**6,120.7**

b. UGI was included in the ValueLine group as a comparable and therefore Mr. Scheig relied upon it also. Many investors and experts routinely rely on this group as an indicator of market utility returns.

c. Removing UGI from the group reduced the CAPM results by approximately 10 basis points.

d. Name changes do not typically impact market risk; I believe the data relied upon reflects this change.

e. Mr. Scheig has not researched this spinoff, but ValueLine's data considered this historical transaction.

PSC-097: RE: Small Risk Premium
Witness: Scheig

a. Do you have access to a modeling software such as the Duff and Phelps Risk Premium Toolkit? If so, did you run the small premium analysis through the Toolkit using the appropriate Industry SIC Code? If so, please provide that model.

b. If you had access to such modeling software but did not use it or chose not to provide the information in this filing, please explain why.

Response to PSC-097:

a. No, Mr. Scheig does not have access to this software.

b. Not applicable.

PSC-098: RE: Small Risk Premium
Witness: Scheig

a. Can additional information on company size such as book value of equity, five year average net income, market value of invested capital, total assets, five year average EBITDA, volume of sales, and number of employees materially improve estimates of small risk premium? Please explain.

b. If you have the above referenced Toolkit or other such software, please add those to the model as an updated exhibit.

Response to PSC-098:

a. All of the factors noted generally can describe the size of a company, "small companies have small assets, few employees, etc." Most studies however, consider the market value of equity as the key measure.

b. Not applicable. See response to PSC-097(a).

PSC-099: RE: Small Risk Premium
Witness: Scheig

a. Have you made an adjustment to small risk premium incorporating the Company's GIRC? If not would the small risk premium not deteriorate if the GIRC is approved? Please explain.

b. How many of the proxy group utilities have infrastructure recovery riders in place? Please identify those utilities.

Response to PSC-099:

a. No adjustment was made. See response to subpart (b), showing that similar riders were also in the guideline public utilities.

b. Proxy utilities with riders in at least one state:[1]

1. Atmos
2. Chesapeake
3. New Jersey
4. NiSource
5. Northwest
6. ONE Gas
7. South Jersey Industries
8. Southwest Gas
9. Spire
10. UGI
11. WGL

[1] Direct Testimony and Exhibits of Charles E. Loy, CPA on Behalf of Energy West Montana, Inc. and Cut Bank Gas Company, Exhibit CEL-EWM-1, pp. 1-2.

PSC-100: RE: Capital Structure
Witness: Scheig

a. Do you agree there is a direct relationship between the authorized equity ratio and the authorized ROE, in that equity ratio is a primary indicator of financial risk?

b. Please explain why the capital structure suggested by the Joint Applicants does not already embed a small risk premium in the capital structure.

Response to PSC-100:

a. There is typically a relationship between equity ratios and rates of return. The leverage of a company can impact its financial risk.

b. A small stock risk premium is included in the required return on equity, not in the capital structure.

PSC-101: RE: Capital Structure
Witness: Scheig

Please confirm that the Joint Applicants are not including flotation cost adjustments in any part of the ROE, small risk premium, or ROR.

Response to PSC-101:

Flotation cost adjustments were not included as a separate component of the cost of equity.

PSC-102: RE: Board, shareholder, and annual meetings
Witness: Appropriate witness

Please provide a chronological list of all board meetings, shareholder meeting, and annual meeting agendas for GNI, EWM, and CBG, by each company since 2013. Please provide a copy of the agenda and minutes for each meeting a copy of the GNI board meeting agenda and minutes for May 28, 2014 (as referenced on page 4 of the minutes of the July 30, 2014 annual meeting of the shareholders). Please provide documents electronically by year, in easily identifiable file names and document names.

Response to PSC-102:

The following documents are provided in the folder named Attachment PSC-102 (unless there are none, as noted below):

Cut Bank Gas Company

1. Board Minutes
    a. none
2. Board Written Consents
    a. Undated Consent Resolution
    b. July 13, 2016
    c. September 21, 2017
3. Shareholder Consents/ Minutes
    a. October 28, 2014 (Consent)
4. Agendas
    a. None

Energy West Montana

1. Board Minutes
    a. 2013
        i. None
    b. 2014
        i. October 9, 2014
    c. 2015
        i. April 14, 2015
        ii. May 22, 2015
        iii. August 28, 2015
    d. 2016
        i. March 14, 2016
        ii. September 30, 2016
        iii. December 15, 2016
    e. 2017
        i. March 22, 2017
        ii. June 23, 2017

2. Board Written Consents
    a. 2013
        i. January 13, 2013
        ii. February 13, 2013
        iii. March 13, 2013
    b. 2014
        i. September 12, 2014
    c. 2015
        i. June 26, 2015
    d. 2016
        i. June 30, 2016
        ii. June 30, 2016
    e. 2017
        i. September 21, 2017
3. Shareholder Minutes/Consents
    a. October 28, 2014 (Consent)
4. Agendas
    a. None

<u>Hearthstone Utilities, Inc. (formerly known as Gas Natural Inc.)</u>

I. 2013
    1. Board Minutes
        a. January 30, 2013
        b. February 27, 2013
        c. March 17, 2013
        d. April 24, 2013
        e. May 29, 2013
        f. June 26, 2013
        g. July 31, 2013
        h. August 28, 2013
        i. September 25, 2013
        j. October 30, 2013
        k. November 20, 2013
        l. December 18, 2013
    2. Board Written Consents
        a. May 2013 (Undated)
        b. May 2013 (Undated)
        c. September 20, 2013
        d. September 25, 2013
    3. Shareholder Minutes/Consents
        a. June 26, 2013 (minutes)

4. Agendas
    a. January 30, 2013
    b. February 27, 2013
    c. March 27, 2013
    d. April 24, 2013
    e. May 29, 2013
    f. June 26, 2013
    g. July 31, 2013
    h. August 28, 2013
    i. September 25, 2013
    j. October 30, 2013
    k. November 20, 2013
    l. December 18, 2013

II. 2014

1. Board Minutes
    a. January 29, 2014
    b. February 4, 2014 - Independent Director Meeting
    c. February 20, 2014 – Independent Director Meeting
    d. February 26, 2014 - Independent Director Meeting
    e. February 26, 2014
    f. March 26, 2014
    g. May 1, 2014
    h. May 14, 2014
    i. May 28, 2014
    j. June 9, 2014 - Independent Director Meeting
    k. June 25, 2014
    l. July 16, 2014
    m. July 30, 2014
    n. August 4, 2014
    o. August 27, 2014
    p. September 24, 2014
    q. October 30, 2014
    r. November 19, 2014
    s. December 9, 2014 – Special Board Meeting
    t. December 29, 2014
2. Board Written Consents
    a. March 7, 2014
    b. April 2, 2014
    c. September 24, 2014
    d. October 10, 2014
    e. October 30, 2014
    f. December 15, 2014

3. Shareholder Minutes/Consents
    a. July 30, 2014 (minutes)
4. Agendas
    a. January 29, 2014
    b. February 26, 2014
    c. March 26, 2014
    d. May 1, 2014
    e. May 28, 2014
    f. June 25, 2014
    g. July 16, 2014
    h. July 30, 2014
    i. August 27, 2014
    j. September 24, 2014
    k. October 30, 2014
    l. November 19, 2014
    m. December 29, 2014

III. 2015

1. Board Minutes
    a. January 14, 2015
    b. January 28, 2015
    c. February 9, 2015 - Special Board Meeting
    d. February 23, 2015 - Special Board Meeting
    e. February 25, 2015
    f. March 13, 2015 - Special Board Meeting
    g. March 25, 2015
    h. April 9, 2015 - Special Board Meeting
    i. April 29, 2015
    j. May 27, 2015
    k. June 8, 2015
    l. June 24, 2015
    m. July 29, 2015
    n. August 18, 2015 - Special Board Meeting
    o. September 9, 2015
    p. September 23, 2015 - Special Board Meeting
    q. September 29, 2015
    r. October 2, 2015 - Special Board Meeting
    s. October 9, 2015 - Special Board Meeting
    t. October 20, 2015 - Special Board Meeting
    u. October 28, 2015
    v. November 9, 2015 - Special Board Meeting
    w. November 18, 2015
    x. December 9, 2015 - Special Board Meeting

        y. December 16, 2015
    2. Board Written Consents
        a. June 11, 2015
        b. October 8, 2015
        c. October 12, 2015
        d. November 3, 2015
        e. November 30, 2015
        f. December 1, 2015
    3. Shareholder Minutes/Consents
        a. July 29, 2015 (minutes)
    4. Agendas
        a. January 28, 2015
        b. February 25, 2015
        c. March 25, 2015
        d. April 29, 2015
        e. May 27, 2015
        f. June 24, 2015
        g. July 29, 2015
        h. September 9, 2015
        i. September 29, 2015
        j. October 28, 2015
        k. November 18, 2015
        l. December 16, 2015

IV. 2016

    1. Board Minutes
        a. January 27, 2016
        b. February 22, 2016
        c. March 23, 2016
        d. April 26, 2016
        e. May 25, 2016
        f. June 9, 2016 – Special Board Meeting
        g. June 29, 2016
        h. July 27, 2016
        i. August 4, 2016 - Special Board Meeting
        j. September 28, 2016
        k. October 17, 2016 - Special Board Meeting
        l. November 7, 2016
        m. December 12, 2016
        n. December 28, 2016 - Special Board Meeting
    2. Board Written Consents
        a. March 2, 2016
        b. May 2016 (Undated)

3. Shareholder Minutes/Consents
    a. July 27, 2016 (minutes)
4. Agendas
    a. January 27, 2016
    b. March 23, 2016
    c. April 26, 2016
    d. May 25, 2016
    e. June 29, 2016
    f. July 27, 2016
    g. September 28, 2016

V. 2017

1. Board Minutes
    a. January 25, 2017
    b. March 8, 2017
    c. May 16, 2017
2. Board Written Consents
    a. January 2017 (Undated)
    b. March 5, 2017
    c. July 10, 2017
    d. July 11, 2017
    e. July 25, 2017
    f. August 4, 2017
    g. August 16, 2017
    h. October 19, 2017
3. Shareholder Minutes/Consents
    a. August 4, 2017
    b. August 16, 2017 (Behrens)
    c. August 16, 2017 (Mehta)
4. Agendas
    a. None

Sponsors: Kevin Degenstein and Jed Henthorne

PSC-103: RE: GNI insurance; 2015 10K SEC form
Witness: Appropriate witness

Page 17 of GNI's 2015 10K SEC form indicates that insurance has a $250,000 deductible and that this deductible was met, and that, although "insurance proceeds are available," GNI may incur costs and expenses related to lawsuits "that are not covered by insurance which may be substantial," and any unfavorable outcome "could adversely impact our business and results of operations."

a. Please indicate how these type of insurance costs are allocated for GNI, EWM, and CBG, and provide supporting documentation in excel readable format.

b. Please identify if any of these costs are included in the rate base and please provide support as to why they should be recovered by ratepayers.

Response to PSC-103:

a. All costs related to these insurance deductibles were paid for by GNI and none have been allocated to EWM or CBGC.

b. None of the costs of the insurance deductibles are sought to be recovered in this docket.

Sponsors: Kevin Degenstein and Jed Henthorne

PSC-104: RE: GNI litigation
Witness: Appropriate witness

The Commission is aware that GNI reached a settlement over at least nine different lawsuits with Richard M. Osborne. (*See* News-Herald 7/20/16, http://www.newsherald.com/general-news/20160720/mentor-developer-reaches-settlement-over-gasnatural-firing).

a. Please list the name, case number, and forum of each lawsuit settled by GNI, EWM, and CBG with Richard M. Osborne from 2014 to present.

b. Please indicate where these costs and any other costs from lawsuits or settlements with Richard M. Osborne have been allocated with GNI, EWM, CBG, or other, and what amounts (including but not limited to those cases identified below).

c. Please confirm or deny that the costs of these settlements are sought to be recovered by ratepayers in this docket. If so, please explain how these costs were prudently incurred.

Response to PSC-104:

a. On July 14, 2016, Gas Natural Inc. ("GNI") entered into a settlement agreement with Richard M. Osborne. Pursuant to the settlement agreement, the following litigation and regulatory proceedings between the Company, including its subsidiaries and certain of its then current and former directors, and Mr. Osborne, including companies affiliated with Mr. Osborne, were settled:

Richard M. Osborne and Richard M. Osborne Trust, Under Restated and Amended Trust Agreement of February 24, 2012 v. Gas Natural, Inc. et al., Case No. 14CV001210, filed in the Court of Common Pleas in Lake County, Ohio, and refiled as *Richard M. Osborne and Richard M. Osborne Trust, Under Restated and Amended Trust Agreement of January 13, 1995 v. Gas Natural Inc., et al.*, Case No. 15CV844836, filed in the Court of Common Pleas in Cuyahoga County, Ohio on April 28, 2015;

Richard M. Osborne, Richard M. Osborne Trust, Under Restated and Amended Trust Agreement of February 24, 2012 and John D. Oil and Gas Marketing Company, LLC v. Gas Natural, Inc. et al., Case No. 14CV001512, filed in the Court of Common Pleas in Lake County, Ohio on July 28, 2014;

8500 Station Street LLC v. OsAir Inc., et al., Case No. 14CV002124, transferred from the Mentor Municipal Court, Case No. CVG1400880 (filed October 2, 2014), to the Court of Common Pleas in Lake County, Ohio on November 3, 2014;

Orwell National Gas Company v. Osborne Sr., Richard M., Case No. 15CV001877, filed in the Court of Common Pleas in Lake County, Ohio on October 29, 2015;

Orwell Natural Gas Company v. Ohio Rural Natural Gas Co-Op, et al., Case No. 15CV002063, filed in the Court of Common Pleas in Lake County, Ohio on November 30, 2015;

In the Matter of Orwell Natural Gas Company, Brainard Gas Corporation and Northeast Ohio Natural Gas Corporations' Request for Injunctive Relief, Case No. 15-2015-GA-UNC, filed with the Public Utilities Commission of Ohio (PUCO) on November 30, 2015;

Cobra Pipeline Co., Ltd. v. Gas Natural, Inc., et al., Case No. 1:15-CV-00481, filed in the United States District Court for the Northern District of Ohio on March 12, 2015, on appeal to the Sixth Circuit Court of Appeals (Case No. 15-4134);

In the Matter of the Complaint of Orwell Natural Gas Company v. Orwell-Trumbull Pipeline Company LLC, Case No. 14-1654-GA-CSS, filed with the PUCO on September 9, 2014;

Orwell-Trumbull Pipeline Company, LLC v. Orwell Natural Gas Company, Case No. 01-15-0002-9137, filed with the American Arbitration Association on March 12, 2015;

Orwell Natural Gas Company v. Orwell-Trumbull Pipeline Company, LLC, Case No. 15-0475-GA-CSS, filed with the PUCO on March 9, 2015;

Orwell Natural Gas Company v. Orwell-Trumbull Pipeline Company LLC, Case No. 15-0637-GA-CSS, filed with the PUCO on March 31, 2015, consolidated with case Case No. 15-0475-GA-CSS; and

Gas Natural Resources LLC v. Orwell-Trumbull Pipeline Company LLC, Case No. 16-0663-GA-CSS, filed with the PUCO on March 28, 2016.

b. All costs related to these lawsuits were paid for by GNI and none have been allocated to EWM or CBGC with the exception of $26,001 related to the lawsuits in Lake County. The amount allocated in error to EWM and CBGC was $6,909 and $621, respectively.

c. None of the costs of these settlements are sought to be recovered in this docket and do not appear in any rate case schedule. The $26,001 allocated in error mentioned in subpart (b) above was specifically removed with the normalizing adjustments. See the spreadsheet in response to MCC-076.

Sponsors: Kevin Degenstein and Jed Henthorne

PSC-105: RE: GNI litigation; 2014–2016 10K SEC forms
Witness: Appropriate witness

GNI's 2014 through 2016 SEC 10K forms indicate legal proceedings with GNI, including a number of settlements made in addition to the settlements with Richard M. Osborne.

a. Please list the name, case number, and forum of each lawsuit settled by GNI, EWM, and CBG with parties other than Richard M. Osborne from 2014 to present.

b. Please indicate where these costs and any other costs from the lawsuits or settlements listed below have been allocated with GNI, EWM, CBG, or other, and what amounts.

c. Please confirm or deny that the costs of these settlements are sought to be recovered by ratepayers in this docket. If so, please explain how these costs were prudently incurred.

d. Has GNI or either of the Joint Applicants recovered costs of litigation from settlement or court decisions since 2014? If so, please explain how the recoveries were allocated and if they are included in the rate base, where they are located.

Response to PSC-105:

a. *Alison D. "Sunny" Masters vs. Michael B. Bender et al.*, Case Number CV16871400, filed in the Cuyahoga County Court of Common Pleas on November 3, 2016, removed to the United States District Court for the Northern District of Ohio, Case Number 1:16-CV-02880, on November 28, 2016. Settled and dismissed effective July 5, 2017.

Beginning on December 10, 2013, five putative shareholder derivative lawsuits were filed by five different individuals, in their capacity as GNI shareholders, in the United States District Court for the Northern District of Ohio, captioned as follows: (1) *Richard J. Wickham v. Richard M. Osborne, et al.*, (Case No. 1:13-cv-02718-LW); (2) *John Durgerian v. Richard M. Osborne, et al.*, (Case No. 1:13-cv-02805-LW); (3) *Joseph Ferrigno v. Richard M. Osborne, et al.*, (Case No. 1:13-cv-02822-LW); (4) *Kyle Warner v. Richard M. Osborne, et al.*, (Case No. 1:14-cv-00007-LW) and (5) *Gary F. Peters v. Richard M. Osborne*, (Case No. 1:14-cv-0026-CAB). On February 6, 2014, the five lawsuits were consolidated as *John Durgerian v. Richard M. Osborne, et al.* (Case No. 1:13-CV-02805-LW). Settled and dismissed effective May 16, 2017.

William Francis Pritchard, Administrator of the Estate of Jeffrey Lee Williams and Jeannie Lloyd Williams v. Best Western International, Inc., AJD Investments, Inc., Appalachian Hospitality Management, Inc., all d/b/a Best Western Blue Ridge Plaza Hotel, Independence Oil, LLC, Gas Natural, Inc., Dale Thomas Winkler, Jr. d/b/a DJ's Heating Services, *Barry Damon Mallatere, Thomas Daniel Miller, Expert Air, Inc. and Patrick Nolan*, Case No. 16 CVS 264, filed in the General Court of Justice, Superior Court Division, Watauga County, North Carolina on June 5, 2015. Settled by insurance carrier.

On December 3, 2013, Jennifer Castner, a former employee, filed a complaint with the United States Department of Labor Occupational Safety and Health Administration against GNI. Settled August 11, 2014.

Robert Half International, Inc. v. Gas Natural, Inc., Case No. 14CV01655, filed in the Lake County Court of Common Pleas. Settled November 2014.

b. All costs related to these lawsuits were paid for by GNI and none have been allocated to EWM or CBGC.

c. None of the costs of these settlements are sought to be recovered in this docket and do not appear in any rate case schedule.

d. No.

<u>Sponsors:</u> Kevin Degenstein and Jed Henthorne

PSC-106: RE: GNI litigation
Witness: Appropriate witness

Please list the case names and numbers, by jurisdiction, for any remaining lawsuits and settlements for GNI, EWM, and CBG made in 2012 thorough 2017. Please indicate where the settlement amounts are allocated as costs and the total amount spent on settlements each year. Indicate whether or not these costs and any recovery are included in the rate base. If so, please explain how the costs have been prudently incurred and reasoning for any allocation of recovery.

Response to PSC-106:

All costs related to the lawsuits identified below were paid for by GNI and none have been allocated to EWM or CBGC. None of the costs of these settlements are sought to be recovered in this docket and do not appear in any rate case schedule

Ohio:

RBS Citizens N.A., dba Charter One v. Richard M. Osborne, Gas Natural Inc. (f/k/a Energy, Inc.) and the Richard M. Osborne Trust, Case No. CV-12-784656, which was filed in the Cuyahoga County Court of Common Pleas in Ohio on June 20, 2012 [Dismissed]

Richard M. Osborne, Richard M. Osborne Trust, Under Restated and Amended Trust Agreement of February 24, 2012 and John D. Oil and Gas Marketing Company, LLC v. Gas Natural, Inc. et al., Case No. 14CV001290, filed in the Court of Common Pleas in Lake County, Ohio on June 26, 2014 [Dismissed]

Gas Natural Inc. v. Richard M. Osborne, Case No. 1:14-cv-2181, filed in the United States District Court Northern District of Ohio on October 2, 2014 [Dismissed on appeal]

Orwell-Trumbull Pipeline Co., LLC v. Orwell Natural Gas Company, Case No. 16CV001776, filed in the Court of Common Pleas in Lake County, Ohio on October 20, 2016 [Dismissed]

Orwell Natural Gas Company v. Orwell-Trumbull Pipeline Co., LLC, Case No. 16-2419-GA-CSS, filed with the PUCO on December 20, 2016

Richard M. Osborne and Richard M. Osborne Trust, Under Restated and Amended Trust Agreement of February 24, 2012 v. Gas Natural, Inc., Case No. CV-17-877354, filed in the Court of Common Pleas in Cuyahoga County, Ohio on March 14, 2017

Cobra Pipeline Company, Ltd. v. Orwell Natural Gas Company, et al., Case No. 17-CV-001419, filed in the Court of Common Pleas in Lake County, Ohio, on August 31, 2017 [Dismissed]

Montana:

Jonathan Harrington v. Energy West, Inc. and Does 1-4, Case No. DDV-13-159, filed in the Montana Eighth Judicial District Court, Cascade County February 25, 2013 [Dismissed]

Dean Ward v. Energy West, Inc. and Does 1-4, Case No. DDV-13-200, filed in the Montana Eighth Judicial District Court, Cascade County [Dismissed]

All costs related to the lawsuit identified below were paid for by EWM. All of the costs related to this lawsuit occurred in 2017 and are not included in the test year 2016 expenses. None of the costs of the settlement are sought to be recovered in this docket and do not appear in any rate case schedule.

Pedro Estrada, et al. v. Energy West Montana, Inc., Eighth Judicial District Court, Cascade County, Montana

Sponsors: Kevin Degenstein and Jed Henthorne

PSC-107: RE: MCC-019 Responses
Witness: Appropriate witness

a. Referencing MCC-019-EWM, revenues increase from CY 2016, $21,930,971, to a projected CY2017 of $25,921,406. Please explain the increase.

b. Referencing MCC-019-CBG, revenues increase from CY 2016, $1,539,524, to a projected CY2017 of $2,023,798. Please explain the increase.

Response to PSC-107:

a. The CY2016 column is an estimate consisting of 6 months actual and 6 months budget. Actual revenue before normalization for 2016 as reported in our application on Exhibit JDH-EWM-2 was $23,180,284. In addition, total revenue is heavily dependent on the price of natural gas passed through to our customers in rates. For 2016, gas costs were about 60% of total revenue. In CY2017, we used 63%.

b. The CY2016 column is an estimate consisting of 6 months actual and 6 months budget. Actual revenue before normalization for 2016 as reported in our application on Exhibit JDH-CBG-2 was $1,339,361. As explained above for EWM, total revenue is heavily dependent on the price of natural gas passed through to our customers in rates. For actual 2016, gas costs were about 50% of total revenue. In CY2017, we used 62%.

Sponsor: Jed Henthorne

CERTIFICATE OF SERVICE

I certify that on this, the 8th day of February, 2018, **ENERGY WEST MONTANA'S AND CUT BANK GAS COMPANY'S RESPONSES TO DATA REQUESTS PSC-060 THROUGH PSC-107** was e-filed with the Commission and served via U.S. mail and e-mail, unless otherwise noted, to the following:

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