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IDAHO PUBLIC
UTILITIES COMMISSION

August 12, 2016

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington Street
Boise, ID 83702

RE: Intermountain Gas Company General Rate Case No. INT-G-16-02

Dear Ms. Jewell:

Enclosed for filing with the Commission are an original and nine copies of an Application by Intermountain Gas Company, dated August 12, 2016, for approval of revised natural gas rates. The Company, in its Application, has requested the Commission to suspend this filing for 31 days.

Intermountain Gas Company has also included for filing nine copies of its prepared direct testimony and exhibits in support of its revised rates. Computer-readable copies of the testimony and exhibits are included on the attached compact disc, as required under Rule 231.05.

Please direct any questions related to the transmittal of this filing to Mike McGrath at 208-377-6168, or to Ronald L. Williams at 208-344-6633.

Sincerely,

Ronald L. Williams
Williams Bradbury, P.C.
Attorneys for Intermountain Gas Company

Michal P. McGrath
Intermountain Gas Company
Director, Regulatory Affairs

Ronald L. Williams, ISB No. 3034
Williams Bradbury, P.C.
1015 W. Hays St.
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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR THE AUTHORITY TO CHANGE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE TO NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	Case No. INT-G-16-02 **APPLICATION OF INTERMOUNTAIN GAS COMPANY**

Application is hereby made to the Idaho Public Utilities Commission ("Commission") for an Order granting Intermountain Gas Company ("Applicant", "Intermountain", or "Company") the authority to change its rates and charges for natural gas service to natural gas customers in the State of Idaho, to be effective on and after September 12, 2016.

In support of this Application, Intermountain states as follows:

I.

The name of the Applicant is Intermountain Gas Company, an Idaho corporation whose principle business office is 555 S. Cole Road, Boise, Idaho 83707. Communications in reference to this Application should be addressed to the following:

Michael P. McGrath
Director, Regulatory Affairs
Intermountain Gas Company
555 S. Cole Road
PO Box 7608
Boise, ID 83707
Phone: (208) 377-6168
mike.mcgrath@intergas.com

Ronald L. Williams
Attorney for Intermountain Gas Company
1015 W. Hays Street
Boise, ID 83702
Phone: (208) 344-6633
ron@williamsbradbury.com

II.

Intermountain is a public utility gas corporation within the meaning of the Idaho Public Utilities Law, duly exists under the laws of the State of Idaho, and is engaged in the distribution of natural gas in southern Idaho. The Company is subject to the jurisdiction of this Commission. Applicant's certificate of public convenience and necessity, Certificate No. 219, was issued by the Commission on December 2, 1955. Intermountain provides natural gas service in southern Idaho to 75 communities in Idaho and approximately 334,650 customers. Applicant is a wholly owned subsidiary of MDU Resources Group, Inc. ("MDU") and shares in certain centralized services provided MDU with other utilities also owned by MDU.

III.

Intermountain's existing base rates and charges for natural gas service were approved by the Commission in 1985. The existing rates and charges for natural gas service on file with the Commission were approved by the Commission in Case No. INT-G-15-02, Order No. 33386, and are incorporated herein as though fully attached hereto.

IV.

Attached as Attachment 1 hereto are copies of the Company's tariff schedules showing the proposed changes by striking over the existing rates and underlining the proposed rates. Attachment 1 to this Application is also Exhibit 30 sponsored by Company witness Michael P. McGrath.

V.

Applicant proposes to increase rates by $10.2 Million, or 4.06 %. Applicant alleges that the proposed changes in rates and charges set forth on Attachment 1 are just and reasonable and that the rate of return expected to be provided to the Applicant there under will be 7.42%, which is a fair rate of return on Applicant's investment in property used and useful in rendering gas utility service.

VI.

The revenue realized by Applicant under its presently authorized rates produces a rate of return of 4.852%, based on a test year ending December 31, 2016. Applicant seeks additional revenues to recover increased operating expenses and costs associated with plant additions, and to produce a fair rate of return, thereby enabling it to continue to provide adequate and reliable service to its customers. Unless the increased rates as requested in this filing are approved, Applicant's rates will not be fair, just and reasonable and Intermountain will not have the opportunity to realize a fair rate of return on its investment in the state of Idaho.

VII.

Applicant's evidence in support of its need for increased rates is based on a 12-month test year ending December 31, 2016. The test year is six months actual and six months forecasted, with the forecasted months to be trued-up in January, 2017. Applicant's rate base evidence is presented on a 13 month average basis. A complete justification of the proposed increases in rates is provided in the testimony and exhibits of Company witnesses. A brief summary of Intermountain's witnesses and their testimonies is described in the first portion of the testimony of Mr. Scott Madison, Intermountain's Executive Vice President.

VIII.

This Application has been brought to the attention of Intermountain's customers through a Customer Notice and by a Press Release sent to daily and weekly newspapers, and major radio and television stations in Intermountain's service area. The Press Release and Customer Notice are attached as Attachment 2 hereto and incorporated herein by reference. Copies of this Application have also been provided to those parties regularly intervening in Intermountain's rate proceedings.

X.

Portions of the Company's Application and accompanying testimony and exhibits are based on computer models. Microsoft Excel based computer modeling, used by the Company to calculate revenue requirement and upon which allocations of revenue requirement have been based will be provided to Commission Staff on computer disk.

XI.

The Applicant stands ready for immediate consideration of this Application.

WHEREFORE, Applicant respectfully requests of the Commission:

1. That this Application be heard and acted upon at the earliest possible date,
2. That the Commission find that the Applicant's existing rates are unjust, unreasonable and insufficient to provide Applicant with a fair rate of return and that the revised rates and charges proposed in Attachment A of this Application are just and reasonable and

that Applicant be permitted to charge said rates to its customers, effective September 12, 2016.

3. That the Commission grant such other and further relief as the Commission may determine proper in the circumstances.

DATED at Boise, Idaho, this 12th day of August, 2016.

Respectfully submitted,

/s/ Ronald L. Williams

Ronald L. Williams
Williams Bradbury, P.C.
1015 W. Hays St.
Boise ID, 83702
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ron@williamsbradbury.com
Attorneys for Intermountain Gas Company

ATTACHMENT 01

TO APPLICATION

(PROPOSED TARIFFS IN STRIKE-OUT AND UNDERLINE FORMAT)

I.P.U.C. Gas Tariff
Rate Schedules
Fiftieth Revised Sheet No. 01 (Page 1 of 1)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
June 20, 2016 July 1, 2016
Jean D. Jewell Secretary

Rate Schedule RS-1
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, who does not have both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Per Therm Charge - $0.87267*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Per Therm Charge - $0.76011*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00085)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.22910
Distribution Cost:	April through November	$0.31678
	December through March	$0.20422

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: July 1, 2016

I.P.U.C. Gas Tariff Rate Schedules Fiftieth Revised	Sheet No. 02 (Page 1 of 1)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
June 20, 2016 July 1, 2016
Jean D. Jewell Secretary

Rate Schedule RS-2
RESIDENTIAL SERVICE- SPACE AND WATER HEATING

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, which must include at a minimum, both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Per Therm Charge - $0.71185*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Per Therm Charge - $0.67822*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00968)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19789
Distribution Cost:	April through November	$0.19600
	December through March	$0.16237

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: July 1, 2016

I.P.U.C. Gas Tariff
Rate Schedules
Fifty-~~Second~~ Revised Third Sheet No. 03 (Page 1 of 2)

Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the customer charge.

~~For billing periods ending April through November~~

Customer Charge - $~~2.00~~ per bill $35.00

Block One:	Per Therm Charge -	First	200 therms per bill @ $~~0.72918~~*	$0.62243
Block Two:		Next	1,800 therms per bill @ $~~0.70745~~*	$0.60829
Block Three:	Next 8,000	~~Over~~	~~2,000~~ therms per bill @ $~~0.68643~~*	$0.59464
Block Four:		Over 10,000 therms per bill @ $0.58667		

~~For billing periods ending December through March~~

~~Customer Charge - $9.50 per bill~~

~~Per Therm Charge -~~	~~First~~	~~200 therms per bill @ $0.67833*~~	
	~~Next~~	~~1,800 therms per bill @ $0.65713*~~	
	~~Over~~	~~2,000 therms per bill @ $0.63667*~~	

*****Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726

Distribution Cost:		~~April through November:~~		
Block One:		First 200 therms per bill @	$~~0.21751~~	$0.11076
Block Two:		Next 1,800 therms per bill @	$~~0.19578~~	$0.09662
Block Three:	Next 8,000	~~Over~~ ~~2,000~~ therms per bill @	$~~0.17476~~	$0.08297
Block Four:		Over 10,000 therms per bill @	$0.07500	
		~~December through March~~		
		~~First 200 therms per bill @~~	~~$0.16666~~	
		~~Next 1,800 therms per bill @~~	~~$0.14546~~	
		~~Over 2,000 therms per bill @~~	~~$0.12500~~	

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ September 12 2016

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge - ~~$9.50~~ per bill $35.00

Per Therm Charge - ~~$0.63667~~ *
Block One: First 10,000 therms per bill @ $0.59464*
Block Two: Over 10,000 therms per bill @$0.58667*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726
Distribution Cost:	Block One: First 10,000 therms per bill @$0.08297 Block Two: Over 10,000 therms per bill @ $0.07500	~~$0.12500~~

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

I.P.U.C. Gas Tariff
Rate Schedules
~~Ninth~~ Revised Tenth Sheet No. 4 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS~~-1 or RS-2~~ who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

~~For billing periods ending April through November~~

Customer Charge - $~~2.50~~ per bill $10.00

Per Therm Charge - $~~0.67822~~* $0.63476

~~For billing periods ending December through March~~

~~Customer Charge - $6.50 per bill~~

~~Per Therm Charge - $0.67822*~~

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($~~0.00968~~)	($0.00828)
	2) Weighted average cost of gas	$0.32764	
	3) Gas transportation cost	$~~0.19789~~	$0.20275
Distribution Cost:		$~~0.16237~~	$0.11265

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ 2016 September 12

I.P.U.C. Gas Tariff
Rate Schedules
~~Ninth~~ Revised Tenth Sheet No. 5 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company**.**

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

~~For billing periods ending April through November~~

Customer Charge – $~~2.00~~ per bill $35.00

Block One: Per Therm Charge – First 200 therms per bill @ ~~$0.67833~~* $0.62243
Block Two: Next 1,800 therms per bill @ ~~$0.65713~~* $0.60829
Block Three: Next 8,000 ~~Over~~ ~~2,000~~ therms per bill @ ~~$0.63667~~* $0.59464
Block Four: Over 10,000 therms per bill @ $0.58667

~~For billing periods ending December through March~~

~~Customer Charge – $9.50 per bill~~

~~Per Therm Charge – First 200 therms per bill @ $0.67833*~~
~~Next 1,800 therms per bill @ $0.65713*~~
~~Over 2,000 therms per bill @ $0.63667*~~

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726

Distribution Cost:
Block One: First 200 therms per bill @ $~~0.16666~~ $0.11076
Block Two: Next 1,800 therms per bill @ $~~0.14546~~ $0.09662
Block Three: Next 8,000 ~~Over~~ ~~2,000~~ therms per bill @ $~~0.12500~~ $0.08297
Block Four: Over 10,000 therms per bill @ $0.07500

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ September 12 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Sixtieth~~ Revised Sixty-First Sheet No. 7 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.30000 per MDFQ therm

Per Therm Charge:

Block One:	First	250,000 therms per bill @ ~~$0.49512~~*	$0.45149
Block Two:	Next	500,000 therms per bill @ ~~$0.45663~~*	$0.43889
Block Three:	~~Amount~~ Over	750,000 therms per bill @ ~~$0.33442~~*	$0.32977

*****Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	
	Block One and Two	($0.02707)
	Block Three	$0.00017
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost (Block One and Two only)	$0.12999

Distribution Cost:	Block One:	First	250,000 therms per bill @	~~$0.06456~~	$0.02093
	Block Two:	Next	.500,000 therms per bill @	~~$0.02607~~	$0.00833
	Block Three:	Over	750,000 therms per bill @	~~$0.00661~~	$0.00196

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such excess usage ~~may~~ will be ~~transported and~~ billed under ~~either secondary~~ rate schedule ~~T-3 or T-4.~~ LV-1. ~~The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.~~ Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ September 12, 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Third~~ Revised Fourth Sheet No. 7 (Page 2 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

3.The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those LV-1 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE
(Continued)

~~3.~~ 4. Embedded in this service is the cost of purchased gas per the Company's PGA, firm interstate pipeline reservation charges, and distribution system costs.

BILLING ADJUSTMENTS:

1. Any LV-1 customer who exits the LV-1 service ~~at any time (including, but not limited to, the expiration of the contract term)~~ will pay to Intermountain Gas Company, upon exiting the LV-1 service, all ~~gas and/or interstate transportation~~ related costs ~~to serve the customer during the LV-1 contract period~~ not paid by the customer during the LV-1 contract period. Any LV-1 customer will have refunded to them, upon exiting the LV-1 service, any ~~excess gas and/or interstate transportation related payments made by the~~ customer during the ~~LV-1~~ contract period.

Purchased Gas Cost ("PGA")

incurred on the customer's behalf

who has exited the LV-1 service

PGA related credits attributable to the

said

2. In the event that total deliveries to any existing customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the LV-1 Block 1 rate adjusted for the removal of variable gas costs. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

   In the event that total deliveries to any new customer did not meet the 200,000 therm threshold during the current contract period, an additional amount shall be billed. The additional amount shall be calculated by billing the customer's total usage during that contract period at the Rate Schedule GS-1 Block 3 rate, and then subtracting the amounts previously billed during the annual contract period. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

~~EXIT FEE PROVISIONS:~~

~~1.~~ ~~Any LV-1 customer, upon subsequent execution of a T-3 or T-4 contract, will pay to Intermountain each month for a period of two (2) years, an Interstate Pipeline fixed cost collection rate of $0.015 per therm times the customer's monthly T-3 or T-4 usage, up to and including 750,000 therms, not to exceed the customer's historic high usage for that same month, such usage as measured by the most recent three (3) year period.~~

~~2.~~ ~~In lieu of paying the Exit Fee Provision, as stated in the above paragraph #1, the existing LV-1 customer will provide to Intermountain a one year or more advanced written notice of the customer's intent to contract for T-3 or T-4 service.~~

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1~~, 2016 September 12

I.P.U.C. Gas Tariff
Rate Schedules
~~Eleventh~~ Revised Twelfth Sheet No. 8 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~Sept. 29, 2015~~ ~~Oct. 1, 2015~~
~~Per O.N. 33386~~
Jean D. Jewell Secretary

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Per Therm Charge:

Block One:	First	100,000 therms transported @ $~~0.05465~~*	$0.01414
Block Two:	Next	50,000 therms transported @ $~~0.02205~~*	$0.00519
Block Three:	~~Amount~~ Over	150,000 therms transported @ $~~0.00792~~*	$0.00132

*Includes temporary purchased gas cost adjustment of $(0.00095)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.
2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.
3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.
4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company’s distribution system.
5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.
6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.
7. An existing ~~LV-1,~~ T-4, ~~or T-5~~ customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~October 1, 2015~~September 12, 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Tenth~~ Revised Eleventh Sheet No. 9 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~Sept. 29, 2015~~ ~~Oct. 1, 2015~~
~~Per O.N. 33386~~
Jean D. Jewell Secretary

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.27923 per MDFQ therm*

~~Commodity~~ Charge:

Per Therm	Block One:	First	250,000 therms transported @ ~~$0.05777~~*	$0.01473
	Block Two:	Next	500,000 therms transported @ ~~$0.01928~~*	$0.00520
	Block Three:	~~Amount over~~ Over	750,000 therms transported @ ~~$0.00455~~*	$0.00160

*Includes temporary purchased gas cost adjustment of $(~~0.00206~~) $(0.02077)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

4. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in the contract and in effect throughout the term of the service contract.

5. The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

~~5~~. 6. An existing LV-1~~,~~ or T-3, ~~or T-5~~ customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer's same or contiguous property.

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-4 customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~March 23, 2015~~ ~~April 1, 2015~~
Jean D. Jewell Secretary

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE
(Continued)

In the event that total deliveries to any new T-4 customer did not meet the 200,000 therm threshold during the current contract period, an additional amount shall be billed. The additional amount shall be calculated by billing the customer's total usage during that contract period at the Rate Schedule GS-1 Block 3 rate, adjusted for the cost of gas, and then subtracting the amounts previously billed during the annual contract period. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

~~2.~~ ~~Usage above 750,000 therms in any given month which is in excess of the customer's historical maximum above 750,000 therms for that same month will be billed at the currently effective T-4 Block 2 price. The historical maximum is the maximum usage by the customer during that same month measured over the previous three (3) year contract period.~~

2 ~~3~~. Any T-4 customer who exits the T-4 service will pay to Intermountain Gas Company, upon exiting the T-4 service, all Purchased Gas Cost (“PGA”) related costs incurred on the customers behalf not paid by the customer during the T-4 contract period. Any T-4 customer who has exited the T-4 service will have refunded to them, upon exiting the T-4 service, any PGA related credits attributable to the customer during said contract period.

3. In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm distribution capacity to serve Intermountain's system, all such excess usage will be billed under rate schedule T-4. Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
Sept. 29, 2015 Oct. 1, 2015
Per O.N. 33386
Jean D. Jewell Secretary

Rate Schedule T-5
FIRM DISTRIBUTION SERVICE WITH MAXIMUM DAILY DEMANDS

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing T-5 customer whose daily contract demand on any given day meets or exceeds a predetermined level agreed to by the customer and the Company upon execution of a one-year minimum written service contract for firm distribution service in excess of 200,000 therms per year.

MONTHLY RATE:

Firm Service	Rate Per Therm
Demand Charge:	
Firm Daily Demand	$0.84253
Commodity Charge:	
For Firm Therms Transported	$0.00111*
Over-Run Service	
Commodity Charge:	
For Therms Transported In Excess Of MDFQ:	$0.04370*

*Includes temporary purchased gas cost adjustment of $(0.00135)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in and will be in effect throughout the term of the service contract.

3. The monthly Demand Charge will be equal to the MDFQ times the Firm Daily Demand rate. Firm demand relief will be afforded to those T-5 customers paying both demand and commodity charges for gas when, in the Company's judgment, such relief is warranted.

4. The actual therm usage for the month or the MDFQ times the number of days in the billing month, whichever is less, will be billed at the applicable commodity charge for firm therms.

5. All therms not billed at the commodity charge for firm therms transported rate will be billed at the Overrun Service rate.

Rate Schedule T-5
FIRM DISTRIBUTION SERVICE WITH MAXIMUM DAILY DEMANDS
(Continued)

6. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule.

7. Under the overrun portion of the service contract, the customer expressly agrees to interrupt its operations during periods of curtailment.

8. Embedded in this service is the cost of firm distribution capacity.

9. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and scheduled for delivery by the interstate pipeline.

10. The customer shall negotiate a Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract. The MDFQ shall not exceed the customer's historical maximum daily usage, as agreed to by the Company.

    In the event the Customer requires daily usage in excess of the MDFQ, all such usage may be transported and billed under either secondary rate schedule T-3 or T-4. The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-5 customer within the three most recent contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-5 Rate Schedule will be renegotiated with the Company.

2. Any T-5 customer who exits the T-5 service at any time (including, but not limited to, the expiration of the contract term) will pay to Intermountain Gas Company, upon exiting the T-5 service, all Purchase Gas Cost Adjustment ("PGA") related costs incurred on the customer's behalf not paid by the customer during the T-5 contract period. Any exiting T-5 customer will have refunded to them upon exiting the T-5 service any PGA related credits attributed to the customer during the T-5 contract period.

ATTACHMENT 02

TO APPLICATION

(PRESS RELEASE AND CUSTOMER NOTICE)

NEWS RELEASE

INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

555 S. Cole Rd.
Boise, ID 83709
(208) 377-6000

Intermountain Gas Company files for an overall decrease to its prices

BOISE, IDAHO – ***August 12, 2016*** **–** Intermountain Gas Company made two filings with the Idaho Public Utilities Commission that, if approved, will affect the rate customers pay for natural gas. The company filed its annual Purchase Gas Adjustment (PGA) and an additional application requesting an increase to its general base rates. If both applications are approved, the net effect to its customers is an overall average decrease of 3.05 percent or $7 million less annually as compared to the company's current rates.

"Intermountain Gas prides itself on keeping expenses low and finding the best options possible in acquiring natural gas to ensure our customers have safe and reliable service at the lowest price possible," said Scott Madison, executive vice president of Intermountain Gas. "We are happy to provide a significant discount in our natural gas prices as outlined in our PGA. We also believe our general rate request is reasonable in order to continue to provide a safe and reliable distribution system for our growing customer base. We have been able to hold our underlying rates stable for more than 30 years but our investment in and replacement of infrastructure, combined with costs associated with mandated federal regulations, is driving the need for our requested general rate increase."

The PGA request is an overall decrease in prices of 7.11 percent or $17.2 million in annual revenues. The primary reason for the proposed decrease is a decline in the price of natural gas that Intermountain purchases for its customers. The cost of natural gas makes up the largest segment of a customer's bill and is a straight pass-through cost to customers. Intermountain Gas does not make a return on the cost of gas.

If the PGA is approved residential customers using natural gas for space heating and water heating will save an average of $3.48 or 7.55 percent per month, while customers using natural gas only for space heating will see an average decrease of $2.31 or 6.5 percent per month, based on average weather and usage. Commercial customers, on average, would see a decrease of $14.23 per month or 7.34 percent.

Intermountain's request for a general rate increase is seeking $10.2 million annually over current rates, or 4.06 percent. This is the first general rate case filing by Intermountain Gas since 1985. Over the past 31 years, Intermountain has worked diligently to keep customers' rates at the lowest levels in the region while continuing to provide quality service.

If approved, customers using natural gas for space and water heating will experience an average increase of $2.31 per month, or 4.93 percent; customers using natural gas for space heating only will realize an increase of $1.16 per month, or 3.26 percent. Commercial customers, on average, would see an increase of $12.16 per month or 6.29 percent.

"Since the acquisition by MDU Resources Group, Intermountain has found synergistic savings in a number of areas," said Nicole Kivisto, president and CEO of Intermountain Gas, as well as its three sister utility companies, all of which are under the MDU Resources Group umbrella. "We have found savings in joint senior management, a combined customer service center located in Meridian, as well as joint billing and payment processing, also located in Idaho.

"Even with these savings, however, Intermountain's customer growth and related expenses over the last 31 years necessitates the requested general rate increase."

If both of the company's applications are approved, residential customers using natural gas for space heating and water heating will save an average of $1.17 or 2.62 percent per month, while customers using natural gas only for space heating will save an average of $1.15 or 3.24 percent per month, based on average weather and usage. Commercial customers, on average, would see a decrease of $2.07 per month or 1.05 percent.

Intermountain continues to urge all its customers to use energy wisely. As part of the general rate case application, the company is proposing to implement several "Demand Side Management" (DSM) programs to better enable its customers to conserve energy. Conservation tips and information on government payment energy assistance are provided through bill inserts and on the company's website www.intgas.com. The website also outlines a number of programs and tips to help our customers' level out their energy bills over the year, and stabilize the potential impact that cold weather will have during periods of higher natural gas usage.

A Purchased Gas Cost Adjustment application is filed each year to reflect the gas costs Intermountain incurs on behalf of its customers in its sales prices. A general rate change application is filed as needed to recover changes in the cost of delivering natural gas to the customer's home or business. Both requests are subject to public review and approval by the Idaho Public Utilities Commission. A copy of the applications are available for review at the commission, the company's website at www.intgas.com as well as the commission's homepage at www.puc.idaho.gov . Written comments regarding the application may be filed with the commission. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email.

Intermountain Gas Company is a natural gas distribution company serving approximately 339,000 residential, commercial and industrial customers in 75 communities in southern Idaho. Intermountain is a subsidiary of MDU Resources Group, Inc., a diversified natural resources enterprise traded on the New York Stock Exchange as "MDU." For more information about MDU Resources, visit the company's website at www.mdu.com. For more information about Intermountain, visit www.intgas.com .

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Media Contact: Cheryl Imlach at (208) 377-6179

INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

Customer Notice

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

DIRECT TESTIMONY OF NICOLE A. KIVISTO

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name and business address.

A. My name is Nicole A. Kivisto. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer (CEO) of Intermountain Gas Company ("Intermountain" or "Company") and Cascade Natural Gas Corporation (Cascade), subsidiaries of MDU Resources Group, Inc. ("MDU Resources"). I am also the President and CEO of Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., both divisions of MDU Resources.

Q. Please describe your educational background and professional experiences.

A. I hold a bachelor's degree in accounting from Minnesota State University Moorhead. I have worked for MDU Resources/Montana-Dakota for twenty years and have been in my current capacity since January, 2015. I was Vice President Operations of Montana-Dakota and Great Plains Natural Gas Co., divisions of MDU Resources, from January 2014, until assuming my present position. Prior to that, I was the Vice President, Controller and Chief Accounting Officer for MDU Resources for nearly four years, and held other finance-related positions prior to that.

Q. Please describe your duties and responsibilities with the Company.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above mentioned companies that, in combination, serve over one million customers in eight states.

Q. What is the purpose of your testimony?

A. I will provide an overview of Intermountain and will summarize the key drivers behind the Company’s need for rate relief. I will also provide an overview of the MDU Resources organizational structure and operations that allows cost savings to flow through to Intermountain and its customers in Idaho. I am also available to answer questions of a general nature, and that relate to MDU Resources’ support provided to Intermountain. Scott Madison, who is the Executive Vice President, Western Region Operations and Business Development, of Intermountain and lives in Boise, reports directly to me. Mr. Madison will introduce the other witnesses in this case and provide more detail on some of the key drivers behind this rate case filing.

Q. Would you briefly explain why the Company is seeking a rate increase at this time?

A. The rate increase of $10.2 million being requested in this filing is necessary for the Company to continue to provide quality service to its 339,000 customers in Idaho and to improve service by investing in new and replacement infrastructure. For these reasons, Intermountain continues to make capital investments in utility plant. Intermountain has spent approximately $551 million in capital additions, primarily natural gas main lines and services, since its last general rate case. The Company’s rate base of approximately $66.4 million as filed in its last rate proceeding in 1985 has increased to about $237 million, as filed in this proceeding. Operating costs, excluding Cost of Gas and income taxes, have also increased since the last rate filing from approximately $26.8 million to approximately $71.7 million, or an increase of $44.9 million. An increase in rates is also necessary to attract sufficient capital dollars from investors, which will be used to maintain and improve quality service to our customers, provide adequate operating and maintenance coverage, and maintain a sound financial position.

Q. What are some of the major areas of operating cost increases?

A. Depreciation expense related to the capital investments made by the Company has significantly increased since the Company's last general rate case. The Company has also experienced significant operating cost increases associated with information and customer support technology systems, medical expenses and the cost of federal regulatory compliance, and pipeline safety. These and other expenses are discussed more fully in the testimony and exhibits of Company witnesses, Hart Gilchrist and Jacob Darrington.

Q. Please discuss how Intermountain is managing costs and the Company's effort to mitigate the impact of increased costs on its customers?

A. Intermountain has a long history of mitigating increasing cost pressures in order to avoid filing rate cases. This is evidenced primarily by the several decades between this general rate case and the Company's last general rate case in 1985. In addition, since the acquisition by MDU Resources, Intermountain has found synergistic savings in the form of joint senior management, a unified customer service center located in Meridian, Idaho, joint billing and payment processing, also located in Idaho, and uniform accounting and customer information system software. Intermountain has also significantly reduced its cost of debt.

Q. Do you have an exhibit that shows how Intermountain fits within the MDU Resources' corporate structure?

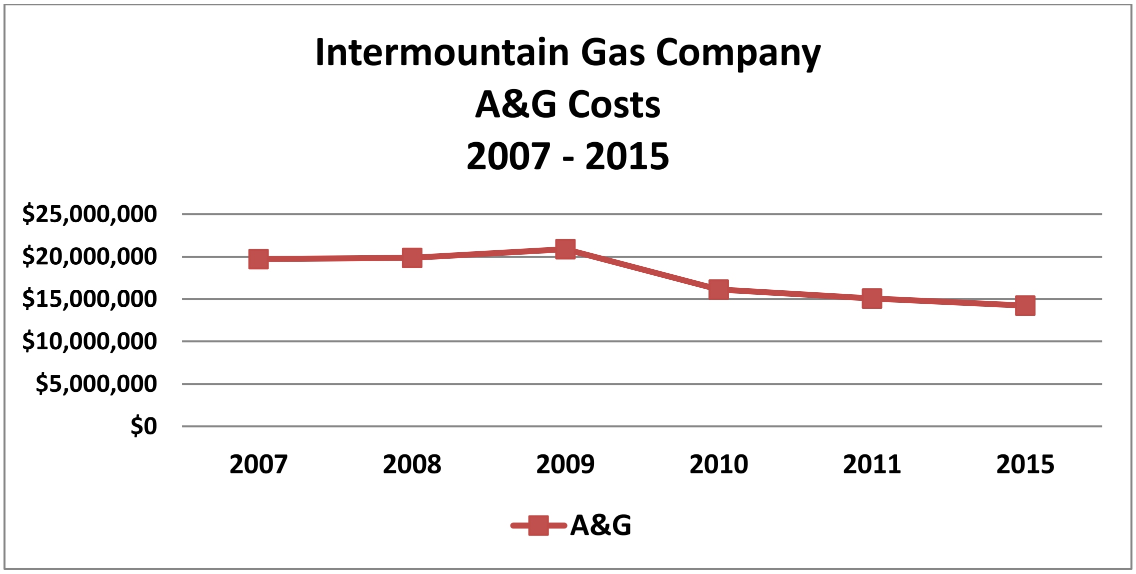
A. Yes. Page 1 of Exhibit No. 1 shows an organizational chart of MDU Resources and its affiliated operating utilities and support companies, including

Intermountain. As shown on this page, there are a number of operating subsidiary companies that are not part of what I will refer to as the "MDU Utilities" that are regulated operating companies and share common administrative and general (A&G) costs. Page 2 of Exhibit No. 1 shows all of MDU Utilities operations and those utilities' respective service territories and the states in which they operate. As you can see from the map, Intermountain is the franchised gas utility serving southern Idaho.

Q. What cost savings have resulted from the MDU Utilities affiliation?

A. There has been meaningful cost savings that have flowed through to Intermountain as a result of MDU Resources' acquisition of Intermountain. Table 1 below is chart showing Intermountain's A&G costs for 2015 and for the pre-acquisition year of 2005

Table K.1



As you can see from Table K.1, A&G costs for the Company have decreased by 19% since 2007, due in large part to the greater scale efficiencies brought by MDU Resources.

Q. What has been the impact on Intermountain's customers related to this A&G cost savings?

A. These A&G cost savings did not come at the expense of the Company's commitment to quality customer service. Rather, Intermountain was able to do both at the same time; increase its customer service quality while reducing A&G costs.

Q. How does Intermountain's customer satisfaction compare to other similarly situated utilities?

A. J.D. Power conducts annual surveys of customer satisfaction for residential gas utilities. In 2013 Intermountain tied for first place in J.D. Power's customer service ranking for midsized gas utilities operating in the west. In 2014 and 2015 Intermountain ranked third and second, respectively, in overall customer satisfaction according to J.D. Power.

Q. Does this conclude your direct testimony?

A. Yes. Thank you.

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Boise, ID 83702
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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 01

Organizational Structure for MDU Utilities Group, Inc.

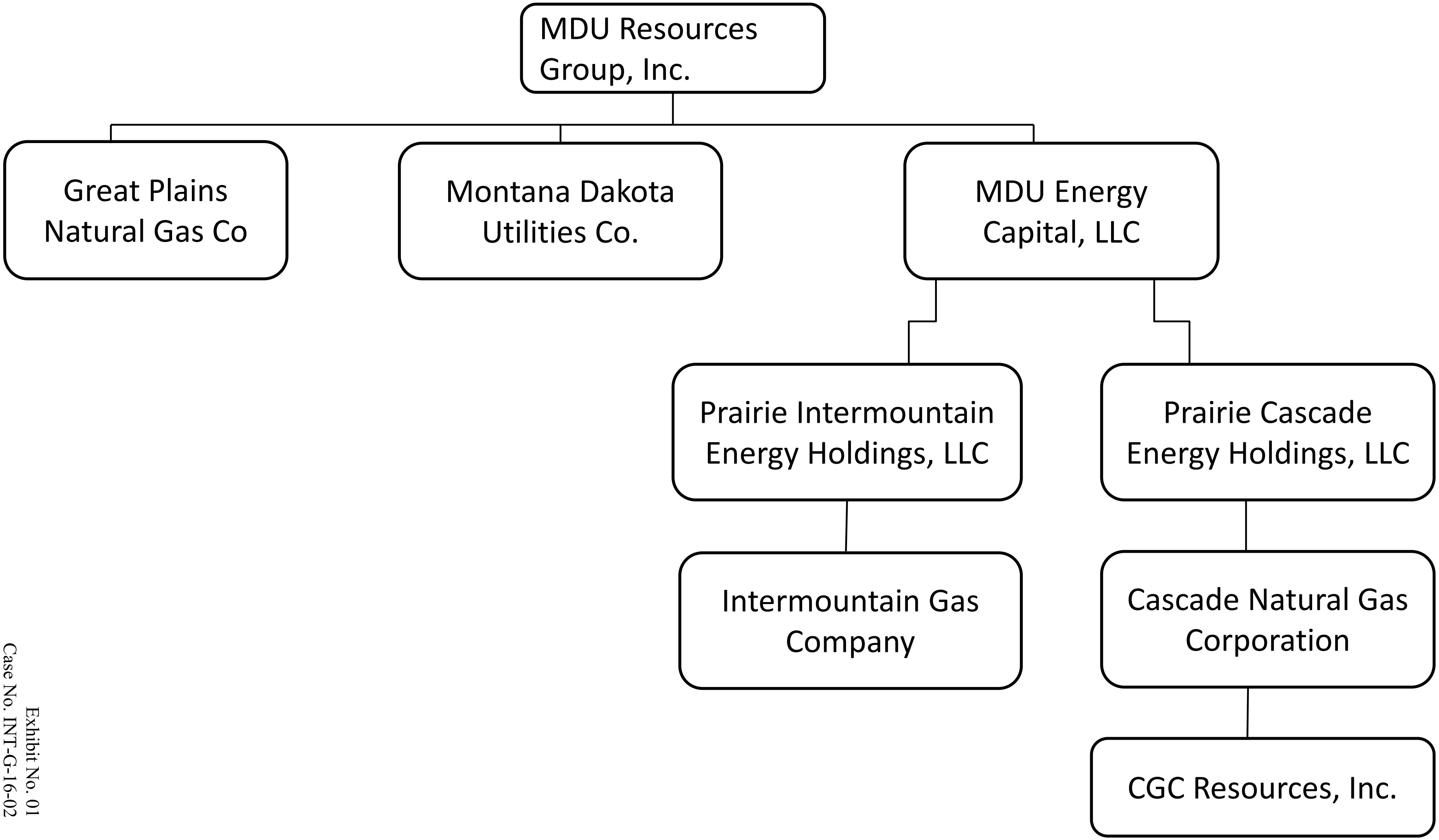
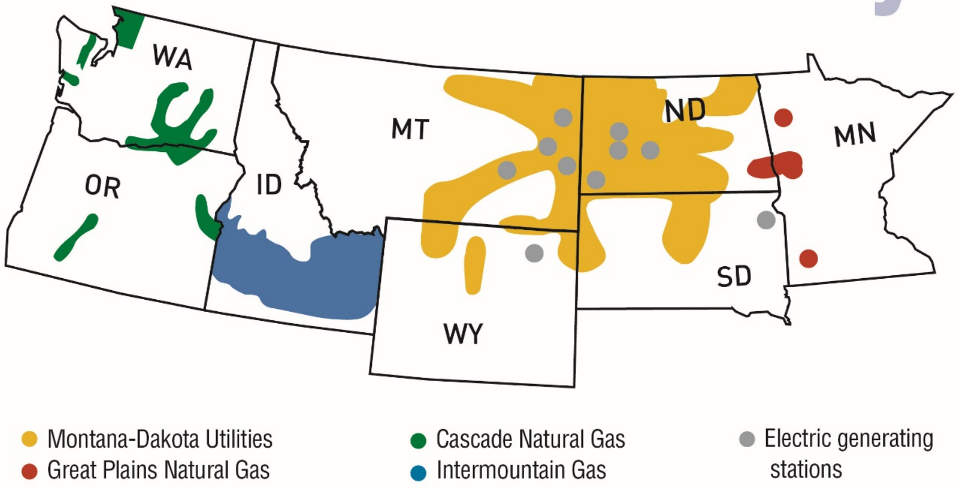


Exhibit No. 01
Case No. INT-G-16-02
N. Kivisto, IGC
p. 1 of 2

Service Territory



INTERMOUNTAIN GAS COMPANY (IGC)

- 74 Communities
- 336,000 natural gas customers
- Idaho
- General Office: Boise, ID

CASCADE NATURAL GAS (CNG)

- 96 Communities
- 260,000 natural gas customers
- Washington and Oregon
- General Office: Kennewick, WA

MONTANA DAKOTA UTILITIES (MDU)

- 259 Communities
- 365,000 customers
  - 245,000 natural gas & 125,000 electric
- North Dakota, South Dakota, Montana & Wyoming
- General Office: Bismarck, ND

GREAT PLAINS NATURAL GAS (GPNG)

- 19 Communities
- 23,000 natural gas customers
- Minnesota and North Dakota
- General Office: Fergus Falls, MN

Exhibit No. 01
Case No. INT-G-16-02
N. Kivisto, IGC
p. 2 of 2

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Attorneys for Intermountain Gas Company

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SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

DIRECT TESTIMONY OF SCOTT MADISON

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name and business address.

A. My name is Scott Madison.

Q. By whom are you employed and in what capacity?

A. I am Executive Vice President, Western Region, Operations and Business Development, for Intermountain Gas Company ("Intermountain" or the "Company") and Cascade Natural Gas Corporation (Cascade). Intermountain and Cascade are wholly owned subsidiaries of MDU Resources Group, Inc. (MDU Resources) headquartered in Bismarck, North Dakota. Intermountain is headquartered in Boise, Idaho and Cascade is headquartered in Kennewick, Washington.

Q. Please describe your educational background and professional experiences.

A. I am a graduate of the University of Idaho with a Bachelor of Science degree in Accounting. I have participated in several executive education programs, including attending executive education at the Harvard Business School. I am a Director of the Northwest Gas Association and the Western Energy Institute. I am Chairman Elect and a member of the Executive Committee of the Idaho Association of Commerce and Industry, and the Boise Metro Chamber of Commerce, and am the former President of the Idaho Petroleum Council. I have served as Chairman of the Board for the Better Business Bureau of Idaho.

Q. Please describe your work experience.

A. I served as Vice President, Controller and Chief Accounting Officer for Intermountain Industries and each of its subsidiaries from 1997 to 2008. From 1987 to 1997 I was a Senior Manager with Arthur Andersen LLP. I am a

Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Idaho Society of Certified Public Accountants.

Q. Please describe your duties for Intermountain and Cascade.

A. I oversee the day-to-day operations of both utilities. My office is located here in Boise.

Q. Please provide a brief overview of the Company.

A. Intermountain provides natural gas distribution services to 75 communities in Idaho, with 243 dedicated employees. During 2015, Intermountain had an average of 334,650 customers in Idaho and the Company's headquarters are located in Boise, Idaho. Intermountain was incorporated in Idaho in 1950, and in 2008 became a wholly owned subsidiary company of MDU Resources.

Q. What is the purpose of your testimony?

A. First, I will introduce the other witnesses providing testimony on the Company's behalf. My testimony will then summarize the Company's rate increase request, identifying the primary drivers behind the need for rate relief. Specifically, I will explain how customer growth has helped push Intermountain into needing a general rate increase. I will compare the Company's existing retail rates with other similarly situated utilities. I am also available to answer questions of a general nature.

Q. Would you please introduce and provide a brief description of each of the witnesses filing testimony on behalf of Intermountain in this proceeding?

A. Yes. In addition to me, the following witnesses have, or will, present direct testimony on behalf of Intermountain:

<u>Ms. Nicole A. Kivisto</u>, President and Chief Executive Officer (CEO) of Intermountain, has provided an overview of the Company and its relationship with other MDU Resources' companies and MDU Utilities, and the economies of scale savings this interrelationship brings to Intermountain. Ms. Kivisto summarized the need for rate relief and highlighted the importance of attracting the necessary capital investment needed to build and maintain the Company's infrastructure.

<u>Mr. Hart Gilchrist</u>, Vice President of Operations, will explain how a gas company operates, will present evidence regarding the Company's operations and maintenance expenses and share the results of the A&G cost study and point out how Intermountain's A&G costs compare to other companies as well as compared to pre and post-acquisition by MDU Resources. Mr. Gilchrist will also discuss Intermountain's investment in natural gas infrastructure.

<u>Mr. Steve Gaske</u>, Senior Vice President of Concentric Energy Advisors, will testify as to the Company's cost of capital and present studies that support his recommended fair rate of return on Intermountain's common equity.

<u>Mr. Mark Chiles</u>, Vice President, Regulatory Affairs and Customer Service, will address the company's capital structure, the proposed cost of embedded debt, and the overall rate of return. He will also discuss Intermountain's commitment to outstanding customer service.

<u>Mr. Ted Dedden</u>, Director, Accounting and Finance for the Company, will address Intermountain's unadjusted rate base and earnings as well as the cross charges between affiliate companies.

Mr. Jacob Darrington, Regulatory Analyst, will present Intermountain's regulated rate base and will calculate the Company's regulated current revenue deficiency.

Mr. Branko Terzic, Managing Director, Berkley Research Group, will present testimony in support of the Company's proposal to increase customer charges to the residential and commercial markets, implement a demand charge for the Company's industrial customers and the reasons supporting the implementation of the Company's proposed fixed cost collection mechanism (FCCM).

Ms. Lori Blattner, Senior Regulatory Analyst, will present the Company's Cost of Service study (COS) and will discuss other proposed changes to both residential and general service rates and tariffs.

Mr. Dave Swenson, Manager of Industrial Services for Intermountain, will explain proposed changes for the Company's industrial tariffs that will provide an incentive for economic development and industrial expansion within the Company's service territory.

Mr. Dan Kirchner, Executive Director of the Northwest Gas Association, will discuss the current electric industry shift from coal to natural gas fired power plants, and the comparative benefits of direct use of natural gas versus electricity, for space and water heating.

Ms. Allison Spector, Manager of Conservation Policy for the Company and Company affiliates, will discuss the development of Intermountain's proposed energy efficiency and demand side management programs.

Ms. Cheryl Imlach, Manager of Energy Utilization for the Company, will discuss the implementation of Intermountain's proposed demand side management programs to include the proposed program tariffs.

Mr. Michael McGrath, Director, Regulatory Affairs, will discuss the history of the Company's general rate cases before the Commission and will introduce the Company's proposal to implement a fixed cost collection mechanism (FCCM). Mr. McGrath will also present the proposed tariff changes.

Q. Do you have an initial observation regarding this rate case filing and general rate increase request?

A. Yes. Intermountain faces many challenges in running a natural gas distribution business, which challenges include maintaining a safe and reliable distribution system for a growing customer base, installing new and expensive customer care and billing system, and significant capital spending and associated depreciation expense related to replacing core infrastructure. Despite these expense related challenges, the Company has been able to provide to its customers the lowest natural gas prices in the region, if not the country, and to avoid for several decades having to file a general rate increase.

Q. Would you please summarize Intermountain's requested increase in this filing?

A. Increasing rate base and operating expenses require Intermountain to request a rate increase of $10,165,700, or 4.04%. This increase is based on an overall rate of return of 7.42 % with a capital structure common equity component of 50 % and a return on equity of 9.90 %. The Company is using a 2016 test period that is six months actual and six months forecast. Based on an average annual usage level of 747 therms per year, the average RS-2 residential customer will see a bill increase of $2.31 per month, from $46.83 to $49.14.

Q. When was the Company's last general rate filing?

A. 1985.

Q. What are the Company's current residential and commercial rates, the proposed rates in this case, and the percentage rate increases by class?

A. Table M.1 below shows the Company's percentage rate increase request for Intermountain's different rate schedules.

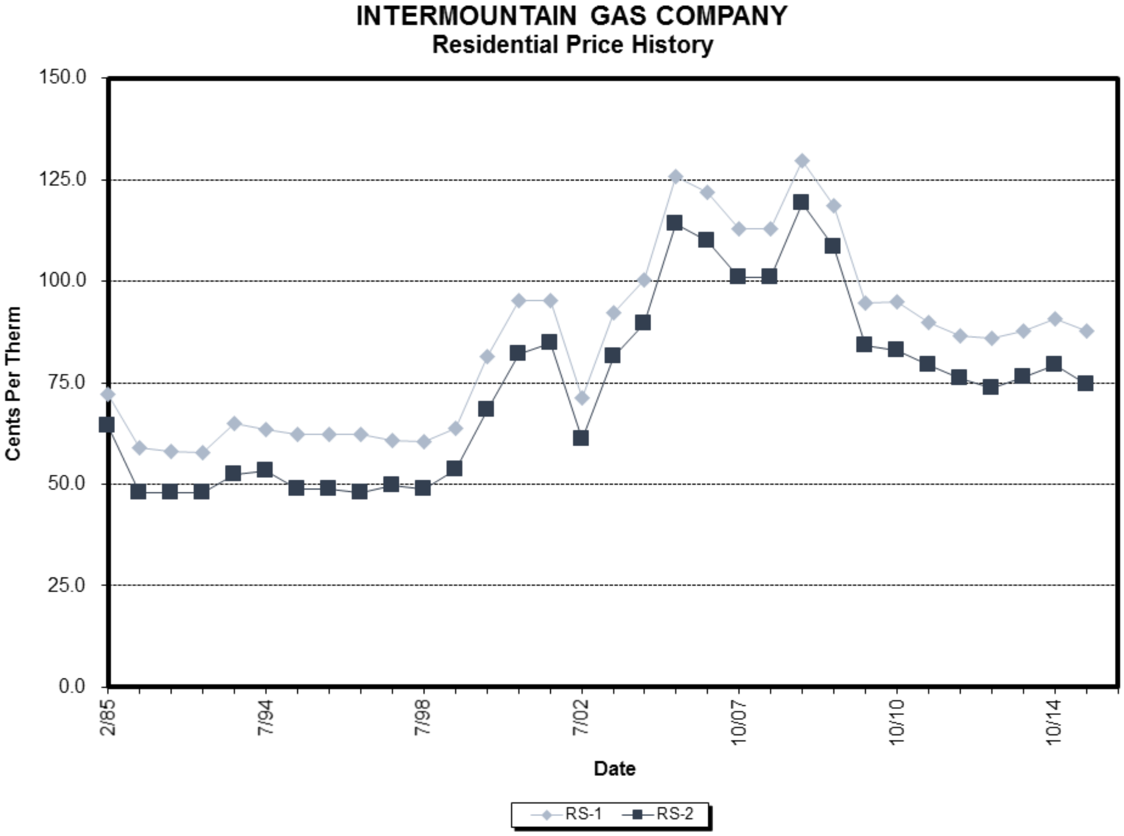
Table M.1

Rate Schedule	**Current Rate**	**Proposed Rate**	**% Increase**	**$ Monthly Increase**
RS-1 Residential	$0.89/Therm	$0.92/Therm	3.26%	$1.16
RS-2 Residential	$0.75/Therm	$0.79/Therm	4.93%	$2.31
GS-1 General Service	$0.69/Therm	$0.73/Therm	6.29%	$12.16

Q. What has been the Company's history of rate changes over the last ten years, and what has been the primary driver of those rate changes?

A. Shown below on Table M.2 are rate histories for Intermountain's residential customers from 1985 through 2016. As the Company has not filed a general rate increase request since 1985, the retail residential rate decreases occurring from 2007 through 2016 are entirely a result of the drop in the wholesale price of gas.

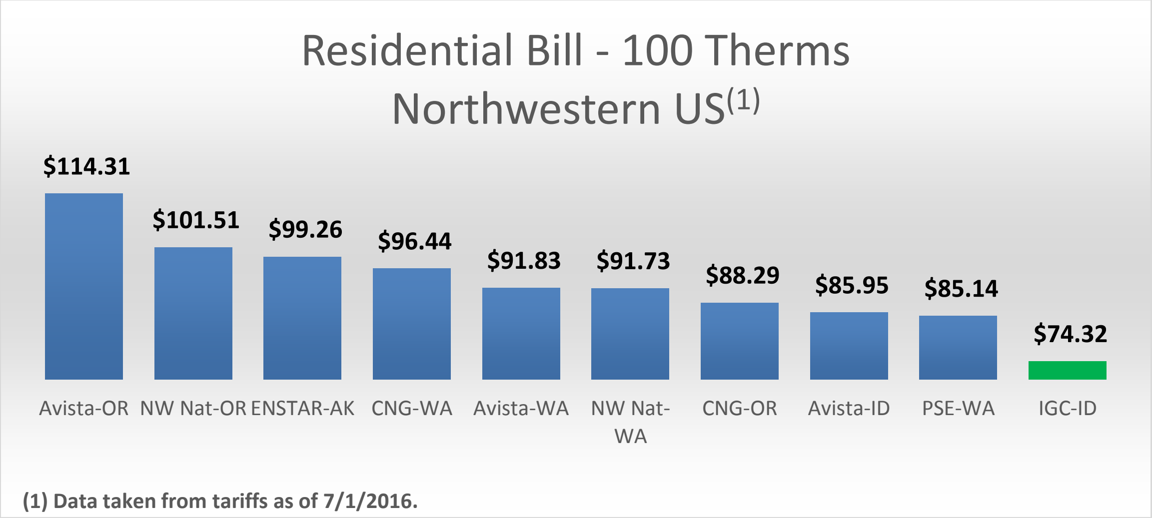
Table M.2



Q. How do Intermountain's retail rates compare to other natural gas utilities?

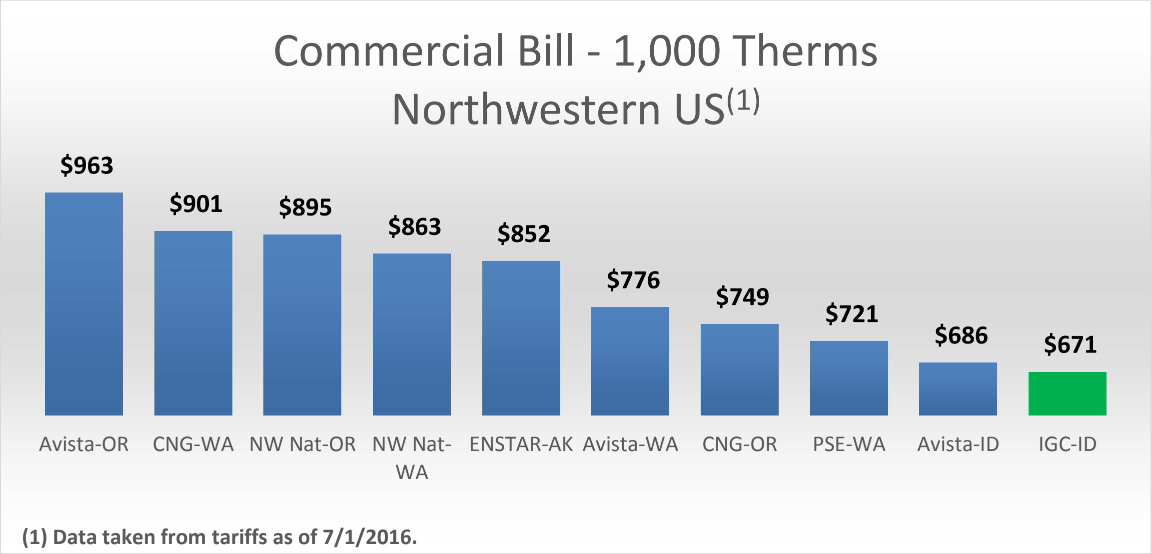
A. The company has worked hard to manage its business for the benefit of its customers since its last general rate case, which was over thirty years ago. This hard work has resulted in some of the most affordable residential prices in the Western U.S. Tables M.3.1 and M.3.2 below, which were prepared at my direction and are based on tariff reviews as of July 2016, compare Intermountain's residential and commercial rates to residential and commercial rates of other gas utilities in the Northwest.

Table M.3.1– Comparison of IGC Residential Rates to other Northwest LDC Rates



(1) Data taken from tariffs as of 7/1/2016.

Table M.3.2– Comparison of IGC Commercial Rates to other Northwest LDC Rates



(1) Data taken from tariffs as of 7/1/2016.

As shown on Table M.3.1, comparing residential bills for 100 therms consumed, Intermountain had the lowest bill out of ten different gas utility bills surveyed for utilities in the Northwestern U.S. (Alaska, Idaho, Oregon, and Washington). Table M.3.2 shows the same results regarding commercial gas utility rates, where the Company had the lowest bill out of ten for 1,000 therms consumed. The metrics shown on Tables M.3.1 and M.3.2 validate the Company's commitment to managing its business for the benefit of its customers.

Q. How do Intermountain's A&G expenses compare to other natural gas utilities?

As shown on Tables M.4.1, M.4.2 and M.4.3 Intermountain's A&G expenses, on a per customer basis, are consistently well below the average expense level of all gas utilities, regional gas utilities, and like sized gas utilities included in the SNL data base.

Table M.4.1

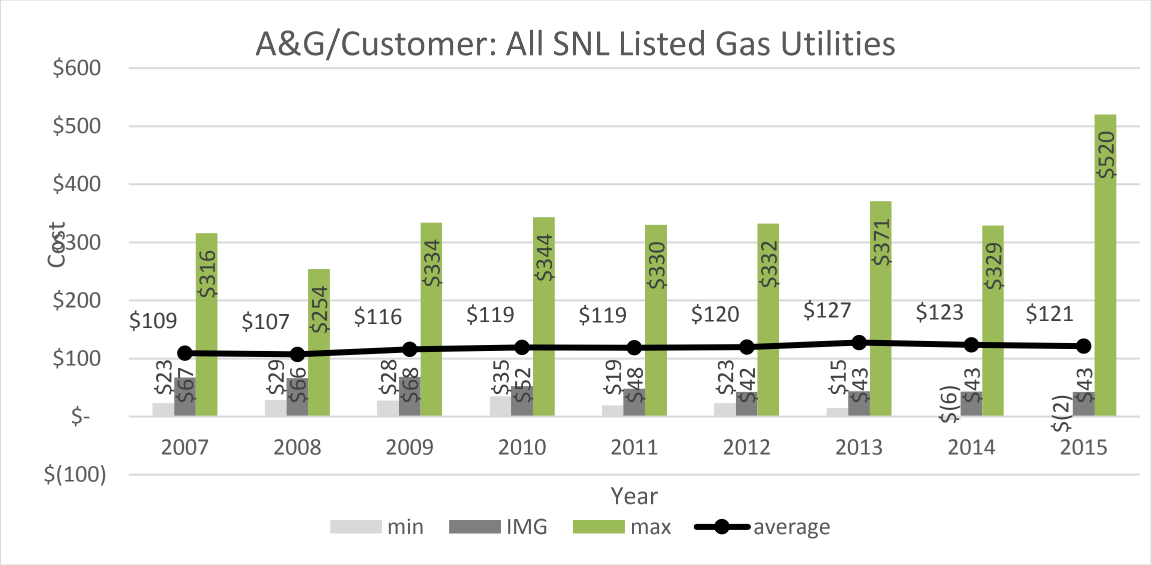


Table M.4.2

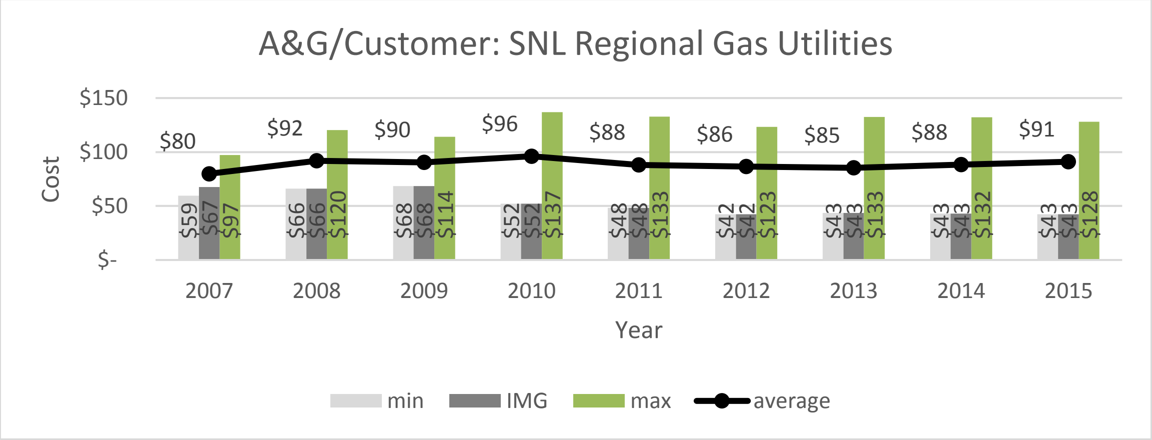
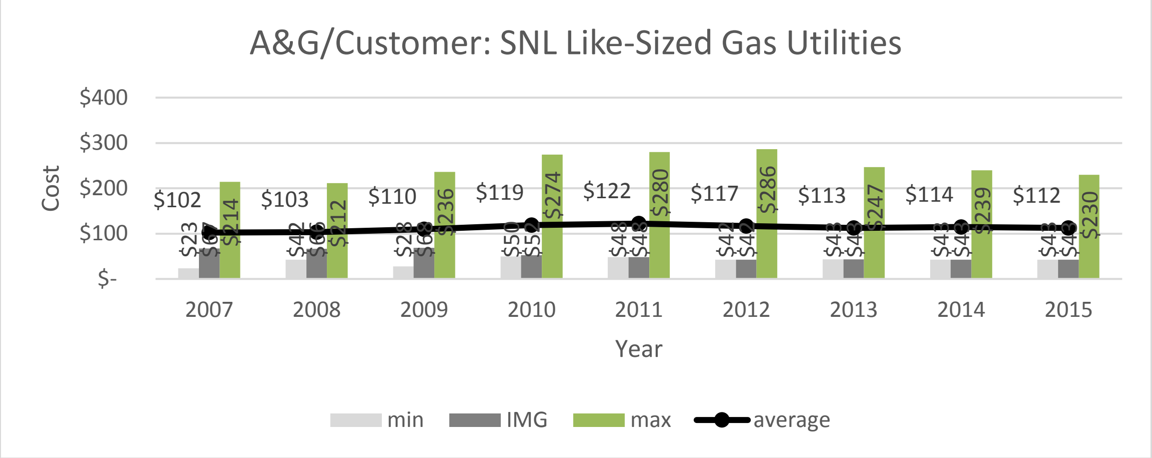


Table M.4.3



Q. Is the Company proposing any rate changes in this case related to the wholesale cost of natural gas?

A. No, Intermountain is not proposing changes in this filing related to the commodity cost of natural gas or upstream pipeline transportation costs. Changes in the commodity/wholesale cost of natural gas and transportation costs included in customers' rates are addressed in the Company's annual Purchased Gas Cost Adjustment (PGA) filing, which is occurring simultaneously with the filing of this case. The concurrent PGA filing, if approved, will result in about a 6 % rate reduction for Idaho customers. In other words, the PGA downward rate adjustment is greater than the base rate increase proposed in this case, and the net rate effect of the two filings, on their face, is an approximate 2 % rate reduction for our customers.

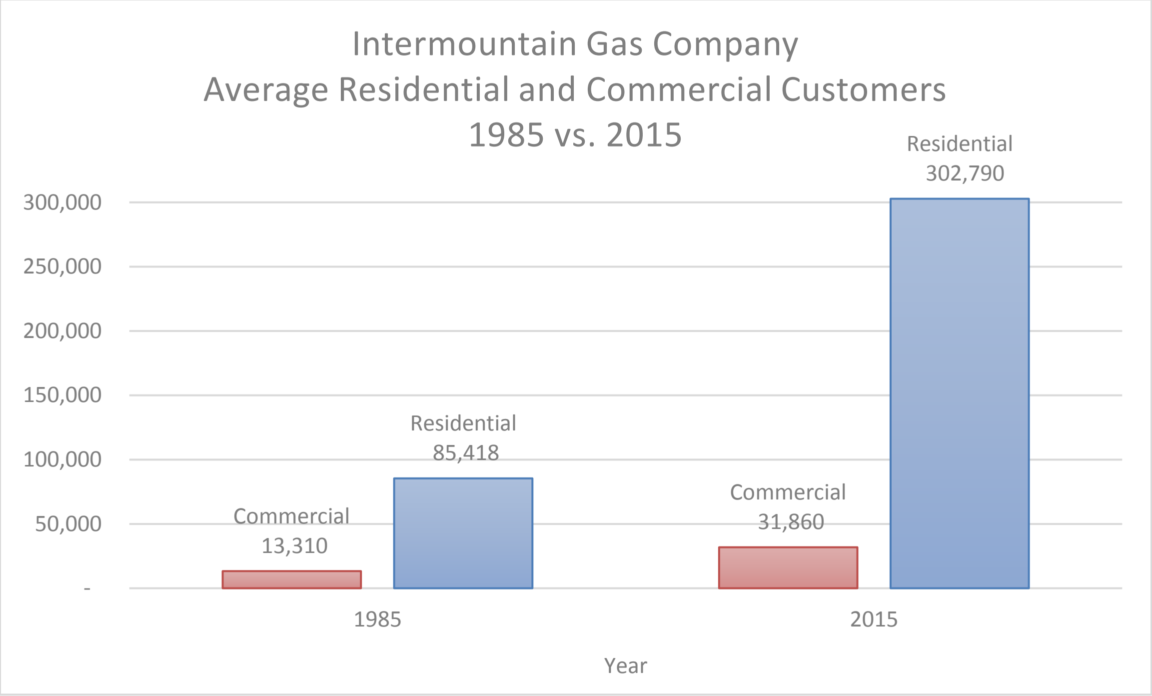
Q. What are the factors causing Intermountain's request for a base rate increase in this filing?

A. Primarily, customer growth. Because of this growth, the Company's rate base and depreciation expenses are growing, along with concurrent increases in operating costs necessary to serve this growing customer base. In addition to growth stimulated investment and expenses, Intermountain is also needing to replace information and technology systems that are primarily customer service related. Another reason for the Company's increasing operating expenses relates to the regulatory demands associated with pipeline safety regulations and compliance.

Q. You mentioned that growth is a significant cost driver for this rate increase filing. Could you explain that reason in greater detail?

A. Absolutely. Below is a table that charts customer growth in the Company's service territory that has occurred between 1985 and 2015.

Table M.5– 1985 – 2015 Customer Growth



Q. Is Customer growth important for the Company and the state of Idaho?

A. Yes. From a Company perspective, customer growth is important in allowing Intermountain to spread its fixed costs more broadly and lower the per-customer fixed cost component of rates. I also consider customer growth for the Company to be a key indicator of a growing, healthy and diversified state economy. Company witness Dave Swenson has additional testimony on this topic, on how Intermountain could play a role in helping expand the Company's customer base and contribute to growing the state's economy.

Q. You mentioned that growth allows the Company to spread fixed costs more broadly among customers. If that is true, why is growth also a driver of this rate increase request?

A. Primarily because of Intermountain's investment in non-revenue generating infrastructure, such as pipeline expansion and replacement. There are little or no additional revenues associated with the Company having to replace pipe that is at or nearing the end of its useful life, or where we have to replace a four-inch pipe with an eight-inch pipe, because the smaller diameter can no longer meet the transportation demand at that point in the system. Similarly, there is no additional revenue generated as a result of Intermountain's heavy investment in customer care systems and information technology.

Q. Please summarize the Company's proposal in this filing for a fixed cost collection mechanism?

A. As discussed in much greater detail by Company witness Mike McGrath and Intermountain's consultant on this topic, Mr. Branko Terzic, the Company is proposing a fixed cost collection mechanism (FCCM) that would break the link between therm sales and revenues. The FCCM removes both the financial disincentive to promote energy efficiency, as well as the incentive for the Company to increase earnings by promoting gas usage. The FCCM would allow

Intermountain to partner more effectively with customers and other stakeholders to support conservation efforts, without the conservation efforts having a negative impact on the Company's recovery of utility fixed costs. The Company is proposing that these mechanisms become effective March 1, 2017.

Q. Does this conclude your direct testimony?

A. Yes. Thank you.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

DIRECT TESTIMONY OF HART GILCHRIST

FOR INTERMONTAIN GAS COMPANY

August 12, 2016

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is Hart Gilchrist. I am Vice President, Operations, for Intermountain Gas Company. My business address is 555 South Cole Road, Boise, Idaho 83709.

Q. Mr. Gilchrist, would you please summarize your educational and professional experience.

A. I have been working in the natural gas industry and at Intermountain Gas for 22 years, where I started as an Engineering Technician in the Boise District office. I was named Vice President, Operations in July 2015. Prior to this role I have held numerous positions in the operations department. In my current assignment, I am responsible for corporate and field operations and engineering functions for the Company. These activities include transmission and distribution integrity management, corrosion, leak survey, damage prevention, gas measurement, public awareness and installation and maintenance of natural gas facilities in our distribution system.

I have bachelor's degrees in finance and marketing from the University of Idaho and an MBA from Boise State University. I serve on the United Way of Treasure Valley board of directors, Boise State University College of Business and Economics Advisory Board, College of Western Idaho Foundation Board, American Gas Association Managing Committee, Northwest Gas Association Board and Boise Chamber of Commerce Advisory Board.

Q. What is the purpose of your testimony in this docket?

A. My testimony will cover several areas.

First, I will discuss the delivery chain involved in bringing natural gas from the well-head to the consumer, and the role Intermountain plays in the last part, or local distribution, of that delivery chain. Second, I will provide some detail on certain operations and maintenance expenses of the Company operating as a local gas distribution company ("LDC"). Third, I will explain the Company's focus on building and maintaining a safe and reliable natural gas distribution system and the costs incurred in that endeavor. Fourth, I will explain Intermountain's infrastructure replacement program and spending and lay out a proposal for a future program and regulatory case that would allow the Company to identify parts of its distribution system that has aged or has been identified as needing replacement per federal pipeline safety programs to the point where it needs to be replaced in the near-term, and how Intermountain can recover our replacement costs more quickly for a portion of this pipeline replacement.

II. GAS SUPPLY CHAIN

Q. Please describe Intermountain's delivery chain. Where does Intermountain acquire its natural gas and how is the cost of that wholesale commodity passed through to customers of the Company?

A. First, it is important to distinguish the role Intermountain plays as an LDC, and that it is not a vertically integrated utility. By that, I mean it does not own any producing gas wells that are ultimately used to supply its retail customers in Idaho. Instead, the Company contracts with a wholesale supplier to acquire the gas needed to meet its regulatory obligation to provide service to its Idaho

Customers. Currently, Intermountain has contracted with IGI Resources, Inc., a wholly owned subsidiary of BP Energy ("IGI/BP") to acquire wholesale gas on behalf of Intermountain, and arrange, or contract, for transportation of that gas to the Company's various distribution systems in southern Idaho. That contacted-for delivery occurs over an interstate pipeline system that is not owned by Intermountain, but in the Company's case, is owned by Williams-Northwest Pipeline Company ("NW Pipeline"). Prices for wholesale gas acquired by IGI/BP on behalf of Intermountain are market driven, while transportation costs paid to NW Pipeline are at rate-of-return regulated prices set by FERC. Both gas commodity costs and transportation costs are then passed through, dollar for dollar, to Intermountain's customers pursuant to the Company's annual Purchased Gas Adjustment (PGA) cost recovery filing.

Q. Please describe Intermountain's gas supply chain.

A. Page 1 of Exhibit 3 is a simplified diagram of the gas supply chain from the gas wellhead to the end consumer. As shown on this diagram, gas comes out of the ground at the gas wellhead, which is independently owned, with the various wells connected via a gathering system to a gas compressor station and gas processing station. IGI/BP will acquire a gas supply on behalf of Intermountain from producers/wholesalers who represent a wellhead owner. It does not matter to Intermountain where the gas originates; it's just a commodity to us. IGI then contracts with one or more interstate pipeline owners to move the contracted-for gas to a city gate or a farm tap, where Intermountain takes delivery of the wholesale gas and distributes it to our customers.

Q. Please describe what happens once Intermountain takes delivery of the wholesale gas.

A. The Company takes delivery of gas at a variety of points on the NW Pipeline system that roughly correspond with the various Idaho cities, towns and farms served by Intermountain. Those multiple delivery points are the "Gas Station" box as shown on Exhibit 3, Page 1. Downstream from the "Gas Station" box on Page 1 of Exhibit 3 is the portion of the diagram showing storage facilities, compressor stations, distribution pipelines, and industrial, commercial and residential consumers. All of these facilities and infrastructure are designed and built to deliver gas supply to core market and non-interruptible industrial customers on the coldest peak-day period. The storage facilities, or liquid natural gas (LNG) facilities are an additional failsafe necessary to provide deliverability and reliability on the coldest peak-day period. Peak-day is defined as the maximum daily quantity of gas distributed through the Company's system. In order to meet peak-day demand, the Company has to design and build the distribution system with enough capacity (or using correct pipe size and pressure blends) to meet this demand, regardless of what the demand is on non-peak days. The Company receives the gas at pressures between 500-800 psig and through a series of pressure cuts (via regulators at city gates, district regulator stations and domestic regulators) delivers gas to our customers between 20 psig and 4 oz.

Q. Where does Intermountain provide retail gas service in Idaho, and what is the Company's customer base.

A Page 2 of Exhibit 3 shows a map of the Company's service area in southern Idaho. The Company's current customer base consists of 302,790 residential customers and 31,860 commercial customers.

III. OPERATIONS AND MAIINTENANCE OF PLANT AND FACILITIES

Q. Please describe the Company's operation centers in Idaho and elsewhere that support customers in Idaho.

A. The Company has a general office, five (5) major operations centers with two (2) satellite service centers serving Intermountain customers, as well as a customer service center in Meridian. The general office, located in Boise, is made up of Intermountain's administrative staff. This staff includes Intermountain's executive team and employees that lead Intermountain's safety, training, operations, engineering, accounting, regulatory, human resources, cash processing, marketing/public relations, information technology and geographic information systems. Each of the five operations centers is made up of our operations and service groups. These groups provide all field service activities, operations and maintenance (pipeline safety compliance) activities, customer acquisition activities and emergency response activities. These five operations centers are located in Nampa, Boise, Twin Falls, Pocatello and Idaho Falls. The two satellite service centers, located in Hailey and Soda Springs, respectively, provide field service activities and emergency response activities in our more remote areas. The MDU Resources' customer service center, located in Meridian, serves over a million customers in eight (8) states across 4 brands: Intermountain, Cascade Natural Gas, Montana-Dakota Utilities and Great Plains Natural Gas. The 2010 addition of the customer service center has been an asset to Idaho's economy and Intermountain is fortunate that MDU Resources selected Idaho and Meridian in particular to make this significant capital investment for its customer service center.

Q. Could you please describe the effort and investment the Company has made in information and technology systems?

A. Yes, but first let me set the stage for you. In 1985, Intermountain served less than 100,000 customers with approximately 425 employees, compared to serving approximately 330,000 customers today with 241 employees, plus shared services employees. We have been able to achieve this significant reduction in customer-to-employee ratio through several avenues: transformation of the personal computer; operations mobile field solutions, including electronic field order completion and leak survey; implementation of encoder receiver transmitters (ERT's) on customer meters; integrated geographic information system (GIS); electronic pipeline safety compliance system that interfaces with GIS and; electronic work management system. Each of these technology implementations has allowed Intermountain to streamline work processes, reduce paperwork and back-office activities and continue to maintain a safe, reliable distribution system.

Q. How have O&M costs historically been maintained, reduced or deferred in the past?

A. One example, as referenced above related to ERT's, pertains to the 2001-2002 implementation of the company's automated meter reading (AMR) system. The

AMR system included the installation of approximately 280,000 ERT's on customer meters and the implementation of three mobile collectors installed in vehicles to capture monthly meter reads. Prior to the implementation of the AMR system, Intermountain collected monthly customer meter reads manually, on foot, using 27 meter reader staff. Upon completion of the AMR implementation, the company is able to read the same amount of customer meters with 7 employees. Intermountain continues to read 330,000 customer meters today with the same number of employees, thus deferring additional O&M costs of additional employees since 2001.

IV. SAFETY

Q. Many of Intermountain's operating expenses relate to the Company's commitment to both customer safety and employee safety. Please give us an idea of the safety systems the Company has in place regarding customer safety, and how that impact's system operations.

A. Intermountain is committed to customer safety. As part of this commitment, Intermountain has an extensive pipeline safety program, which will be discussed later in this testimony as well as a dedicated staff of employees to address customer needs and concerns as well as natural gas emergencies. The company's first responders are trained to assess, make safe and repair any abnormal operating conditions on the distribution system. This group of employees is made up of service technicians and construction crews. The company keeps employees in these positions on stand-by 24 hours per day, seven days per week to allow for quick response to customer needs, facility damages and outages. This is accomplished by investing in safety and ensuring a qualified workforce. All of our operations employees go through a series of training modules covering all aspects of their jobs and have to display competency through testing and hands-on evaluations. This program is called Operator Qualification. Additionally, our service technicians go through an extensive service technician apprentice program which consists of classroom training as well as ride-a long's with seasoned employees. Service technicians cannot be on-call or respond to emergencies on their own until the successful completion of the apprentice program which takes one full year. All of these programs help ensure that the company provides a qualified workforce that prudently operates the distribution system and provides a safe system for our customers.

Q. You also mentioned employee safety as the second part of Intermountain's safety commitment. Please elaborate?

A. Intermountain's employee safety goal is "Commitment to Zero", evidencing a drive towards zero vehicle accidents and zero employee injuries. As such, the Company views safety as in investment, although in reality it is an operating expense. As part of Intermountain's *Commitment to Zero* the Company provides all necessary Personal Protective Equipment (PPE) to its employees. This includes the likes of hard hats, safety glasses, high visibility clothing, gloves, safety toe footwear, etc. The Company also provides its employees with regular safety training as well as defensive driving training specifically geared toward zero accidents. Intermountain's belief is that a serious commitment to and investment in safety will help to ensure that Intermountain's employees go home in the same condition they came to work in.

Q. What are some of the federal safety requirements that are driving the Company's maintenance costs?

A. Intermountain has several processes or systems in place that help ensure the safe operation of our distribution system. Most of these are derived from federal pipeline safety requirements that can be found in the Code of Federal Regulations, Title 49, Part 192. Specifically, I will discuss the following areas: Leak Survey, Corrosion, Atmospheric Corrosion, Public Awareness, Damage Prevention, Regulator Station inspection and testing, Valve maintenance, Transmission Integrity Management and Distribution Integrity Management. Intermountain applies these processes to approximately 6,216 miles (32 million feet) of gas mainline and approximately 350,000 service lines.

Q. Please explain the federal Leak Survey, Corrosion and Atmospheric Corrosion requirements?

A. *Leak Survey:* Intermountain is required to leak survey all natural gas distribution pipelines of its non-business districts every four (4) years and those in business districts annually. The Company is required to survey all natural gas transmission lines annually and if they fall in a Class 3 location (46 or more buildings intended for human occupancy within 220 yards of the pipeline of any continuous mile) have to be surveyed twice annually.

Corrosion: For all steel natural gas pipelines, Intermountain must protect them against external corrosion using the following means: (1) install pipelines with an external protective coating; (2) have a cathodic protection system installed which is designed to protect the pipe; typically this "system" is a combination of anodes and rectifiers. These systems have to be annually inspected to insure they are functioning properly to protect the steel pipelines against external corrosion. This is done by measuring the "pipe-to-soil" interface of cathodically protected and isolated pipe districts, regardless of the use of anodes or rectifiers. In addition, rectifiers are inspected every two (2) months to ensure they are properly protecting the steel pipe.

Atmospheric Corrosion: All pipe and components related to the natural gas pipeline system that are above ground and exposed to the atmosphere are inspected every three (3) years to ensure the atmosphere is not causing any deterioration to our system.

Q. Please explain the federal Public Awareness, Damage Prevention, Regulator Station inspection and testing requirements.

A. *Public Awareness:* Intermountain follows the American Petroleum Institute (API) Recommended Practice (RP) 1162 which is incorporated by reference into Part 192. Activities surrounding public awareness include educating the public, appropriate government organizations and persons engaged in excavation activities on the following: (1) use of the Idaho one call (Digline) system prior to excavation; (2) possible hazards associated with unintended releases from a gas pipeline facility; (3) physical indications that such a release may have occurred; (4) steps that should be taken for public safety in the event of a gas pipeline release; and (5) procedures for reporting such an event.

Damage Prevention: The Company engages in location of gas facilities prior to excavation work (when notified by the excavator) through its contractual relationship with Digline of Idaho. Excavators can call Digline at no charge to the excavator. Digline then contacts a Company representative who locates Intermountain gas facilities within 48 hours of the request. Additionally, Company representatives regularly meet with excavators to educate them about the importance of safe excavation.

Regulator Station inspection and testing: The Company inspects each regulator station and its equipment on an annual basis to ensure it is in good mechanical condition, has adequate capacity and reliability, is set to control, increase or relieve pressure, and is properly installed and protected from dirt, liquids, and other conditions that could prevent proper operations. Across Intermountain's distribution system, the Company has 664 regulator stations that receive this annual maintenance.

Valve Maintenance: Each Company valve that is either on a transmission class pipeline or which may be used for the safe isolation of Intermountain's system is required to be and is inspected annually. For transmission class valves this includes partially operating the valve; for the remaining valves this includes checking and servicing the valves. The Company has 5,115 valves that receive this annual maintenance.

Q. **Finally, what are the federal safety requirements related to Transmission Integrity Management and Distribution Integrity Management**?

A. *Transmission Integrity Management Plan (TIMP):* The Company implements the TIMP on any segment of transmission pipeline that falls in a High Consequence Area (HCA). An HCA is an area or circle along the transmission pipeline containing either 20 or more buildings intended for human occupancy, or an otherwise identified site. The company has 290 miles of transmission pipeline and 14 of those miles are in an HCA. There are 42 specific pipe segments that fall under the TIMP. Federal TIMP requirements subjects covered pipelines in TIMP areas to a process of threat identification, risk assessment, baseline assessment, repair/maintenance, preventative and mitigative measures, quality control, performance management and management of change, followed by reassessment of each segment of covered pipeline every seven years.

Distribution Integrity Management Plan (DIMP): The federal DIMP safety requirements consists of seven elements: 1) Demonstrate knowledge of distribution system; 2) Identify threats; 3) Evaluate and prioritize risk; 4) Identify and implement measures to address risk; 5) Measure performance, monitor results and evaluate effectiveness; 6) Perform periodic evaluation and improvement; and 7) Report results. The Company implements the DIMP on any segment of distribution line in the company territory; in other words, the entire distribution system that is within the company’s jurisdiction.

Q. Please describe the O&M costs related to these safety processes and programs in 2015, as well as how they have trended historically and how the company expects them to trend in the future.

A. Intermountain's O&M costs related to District Operations each year can be attributed to the safety and maintenance of our pipeline system. These are costs associated with our field employees, tools and equipment, which are responsible for carrying out the safety programs and processes previously discussed. In 2015, the District Operations O&M cost were $17.825 million. While these costs have certainly increased over the last 30 years due to salary increases, cost of living increases, etc., the company has been able to control these costs remarkably well. For example, in 2011, these same O&M costs were$16.333 million. In the future, the expectation is that O&M costs will continue to rise, but at a more accelerated rate due to recent and upcoming pipeline safety regulations, notably DIMP and associated aging infrastructure replacements as referenced above, as well as pending transmission pipeline regulation, quality assurance regulation and pipeline safety management system regulation, to name a few.

V. PIPELINE REPLACEMENT

Q. The fourth point you wished to discuss was the Company's investment in gas pipeline infrastructure. Could you give an overview of the Company's commitment to and spending on infrastructure replacement?

A. Intermountain's annual capital requirements has steadily increased from approximately $ 17 million in 2008, to approximately $42 million in 2015. Capital spending of $43.5 million and $42 million is planned for the years 2016 and 2017 respectively. A significant portion of this capital spending relates to infrastructure replacement

Q Please describe Intermountain's ongoing program for managing and replacing its natural gas pipe?

A. The Company is continuing its pipeline integrity management program to systematically replace select portions of pipe in its natural gas distribution system in Idaho. The pipeline integrity management program is a risk based replacement program that assesses risk based on a pipe segments age, material, operating pressure, leak history, damage history, etc. Intermountain began replacing infrastructure in 2015 under the Distribution Pipeline Integrity rule that became effective in 2013. Since 2005, Intermountain has been conducting pipeline assessments on our transmission pipelines, but have only had to make minor repairs. In 2015 under the company's DIMP, approximately 30,000 feet of plastic pipe was removed and replaced. The company plans to remove another 22,000 in 2016 and 25,000 in 2017. The company will continue to model the distribution system and schedule replacement of pipe as determined by the risk model and available monetary resources.

Q. Please describe Intermountain's protocol for pipeline replacement?

A**.** Intermountain uses its TIMP and DIMP as drivers for pipeline replacement. These two plans both use a risk-based approach to assessing pipelines and determining which segments of pipe need repair or replacement. Once pipe segments have been identified for replacement, the company assesses the capital requirements for replacement compared to capital available in a given year. This then determines how much replacement can be achieved in a given year.

Q. Do you believe the current pace for pipeline replacement and the system for rate basing that investment is adequate, or is there a potentially better regulatory model for more expeditiously replacing pipe that is at or near the end of its useful life?

A. I believe a better way to more quickly fund and replace pipeline infrastructure would be through a pipeline infrastructure cost recovery mechanism (ICRM) that would allow Intermountain to accelerate its spending in this area, and to more timely recover those costs that are incurred to promote the safety and reliability of Intermountain's distribution system.

Q. Is Intermountain proposing a pipeline ICRM in this case?

A. No. However, the Company intends to follow this case with an ICRM case filing.

Q. Why is the eventual establishment of a pipeline ICRM important to Intermountain?

A. There are many portions of Intermountain's system that need to considered for replacement based on material, age, leak history, excavation activity, etc. Intermountain is obligated to provide safe, reliable service to its customers, and to that end, Intermountain is using a systematic approach to identify the elevated risk pipe segments and replace those segments first. A potential problem for the Company is that the costs incurred for replacing pipe has no new revenue associated with those costs. In other words, performing these system improvements increases costs and reduces earnings.

Q. How has Intermountain been able to incur these costs without rate recovery to date?

A. Over the past few years Intermountain has primarily funded its pipeline improvement program through operating efficiency improvements, many of them resulting from the MDU Resources' acquisition of Intermountain. However, rate base and other cost increases have reached the point that Intermountain can no longer fund this large a capital investment from additional operating efficiencies.

Q. What are the benefits to customers and the Company if a pipeline cost recovery mechanism were established and approved by the Commission?

A. In addition to updating the pipeline system to continue operating a safe and reliable system, the mechanism will potentially reduce the need for future rate cases. Without an ICRM, Intermountain will likely be in a position where it will need to file subsequent rate cases for cost recovery of this single and significant capital spending program, until such time as the Company's modeling indicates an acceptable level of risk profile is attained. An ICRM will provide an incentive for the Company to control other costs between rate cases and reduce the need for incurring additional rate case costs.

Q. Can you please describe how such a mechanism would work?

A. Yes. Intermountain would annually file for recovery of pipeline replacement investment incurred over a set period of time, likely a 12 month period. It would also seem that the timing of the filing might best coincide with Intermountain's annual PGA filings in August, with an effective date of October 1. The period of recovery for the prior year's investment would be a matter for determination by the Commission.

Q. Do other MDU Resources' Companies and other gas utilities in the northwest currently have a similar mechanism in place in other states?

A. Yes. Cascade Natural Gas is operating under similar programs in both Oregon and Washington where it files for recovery of pipeline replacement costs under a pipeline CRM. In addition, Northwest Natural Gas currently has a System Integrity Program, which was adopted to encourage Northwest Natural to replace bare steel and cast iron pipe. Cascade's Washington cost recovery mechanism was based on Northwest Natural mechanism in place in Oregon.

Q. Do you anticipate that there would be O&M savings associated with the replacement of some of the aging infrastructure?

A. As a general rule, there will be less O&M costs associated with new infrastructure, as opposed to aging or obsolete pipelines. On a net basis however, Intermountain will continue to see overall increased O&M costs to maintain a system, some of which is now approaching 60 years in age. It is important for the Company to systematically reinvest and upgrade a portion of its pipeline system every year, in addition to making the investments needed or required to meet reliability requirements. While such systematic reinvestment works to slow the growth of annual O&M costs, it does not result in a year to year reduction in overall O&M costs.

Q. Does this conclude your direct testimony?

A. Yes. Thank you.

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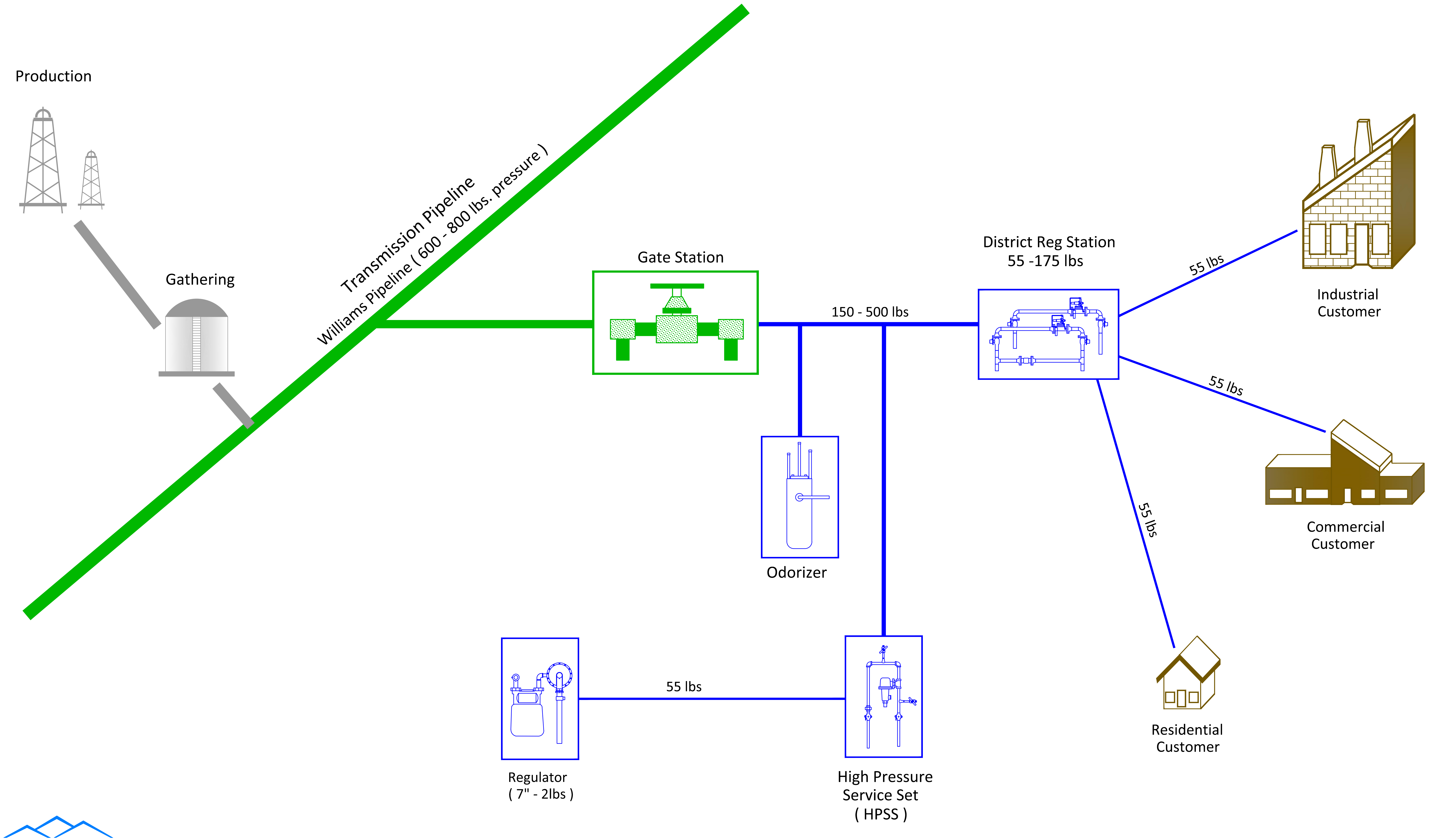
IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

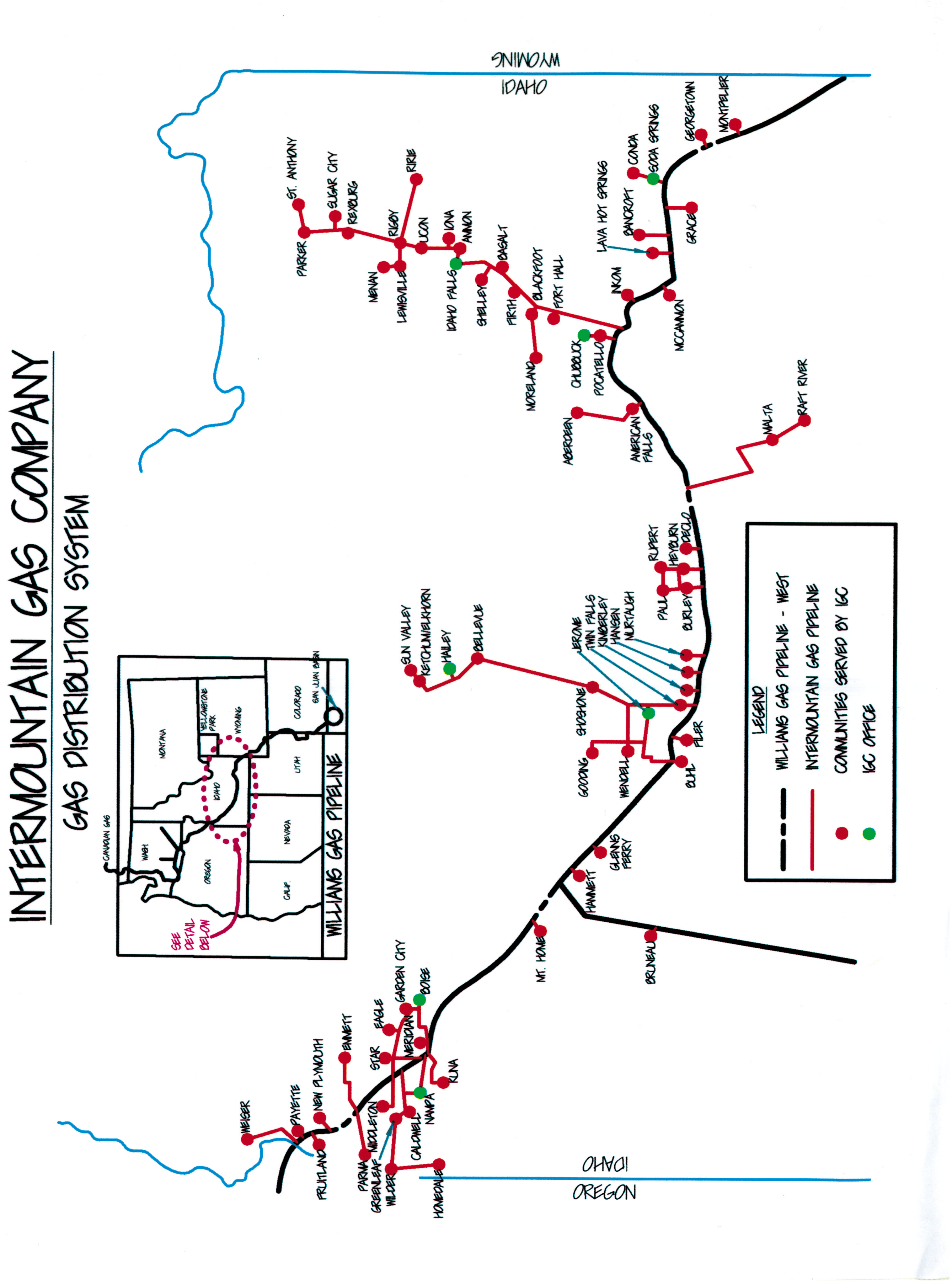
EXHIBIT 02

Delivering Natural Gas to Homes and Businesses



INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

Exhibit No. 02
Case No. INT-G-16-02
H. Gilchrist, IGC
p. 1 of 2



INTERMOUNTAIN GAS COMPANY

GAS DISTRIBUTION SYSTEM

Exhibit No. 02
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H. Gilchrist, IGC
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)

DIRECT TESTIMONY OF MARK A. CHILES

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name, title and business address.

A. My name is Mark A. Chiles. I am the Vice President of Regulatory Affairs for Intermountain Gas Company (IGC, Intermountain, or Company) and Cascade Natural Gas Corporation and the Vice President of Customer Service for the MDU Utilities Group (MDUG). My business address is 555 South Cole Road, Boise, ID 83707.

Q. Mr. Chiles, would you please summarize your educational and professional experience.

A. I am a graduate of Boise State University with a Bachelor of Business Administration degree in Accounting. I am a certified public accountant and a member of the American Institute of Certified Public Accountants and the Idaho Society of Certified Public Accountants. I have over 20 years of experience in the energy industry including time spent in the utility, gas marketing, and exploration and production industries. During my utility career, I have held the positions of Accounting Manager, Director of Accounting and Finance, and Vice President and Controller. I was appointed to my current position in March 2016. I am responsible for providing executive leadership and management for regulatory affairs and customer service including the scheduling and credit and collections functions.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to explain and support the capital structure and return on rate base requested in this proceeding and provide some insight into the customer service center structure, methodology of sharing customer service costs, results of operations, and efficiencies gained in this area since the purchase of IGC by MDU Resources, Inc. (MDUR).

Q. Please summarize your testimony.

A. In brief, I will provide information that shows:

- Intermountain's proposed return on rate base (ROR) provides a reasonable return for our investors at a fair cost to our customers. The ROR is based on a 50/50% common equity ratio with a Return on Equity (ROE) of 9.9% and a debt cost of 4.94%.
- The structure of the customer service function, how the customer service function is charged out to the MDUG brands, efficiencies gained through the organizational structure and implementation of customer focused technology, and how these changes have provided significant savings to Intermountain's customers.

Q. What is the return on rate base and capital structure that Intermountain is requesting in this case?

A. The Company is requesting a return on rate base of 7.42% with a capital structure of 50% equity and 50% debt. The components and calculation of the proposed rate of return are shown in Table C.1.

Table C.1 - Proposed Return on Rate Base

	Capital Structure	Cost	Component
Total Debt	50%	4.94%	2.47%
Common Equity	50%	9.90%	4.95%
	100%		7.42%

Q. The Company is proposing a capital structure of 50% equity and 50% debt. Why does the Company feel this is the appropriate capital structure?

A. Intermountain is proposing a capital structure consisting of 50% common equity and 50% long-term debt, consistent with the Company's target capital structure and in line with the Company's average actual capital structure for the last three years and projected structure for 2016. Intermountain's parent company, MDU Resources, makes equity infusions in order to maintain the target capital structure. Intermountain is committed to maintaining a healthy balance of equity and debt, as discussed in the direct testimony of Company witness, Dr. J. Stephen Gaske. Table C.2 below provides a summary of the four-year history of Intermountain's capital structure.

Table C.2 - Capital Structure

	12/31/2013	12/31/2014	12/31/2015	6/30/2016
Total Debt	45.73%	47.60%	52.05%	48.15%
Common Equity	54.27%	52.40%	47.95%	51.85%

Q. How does Intermountain's proposed capital structure compare to that of other gas distribution companies?

A. As discussed in Dr. Gaske's testimony, the median equity ratio for the companies in his proxy group of gas distribution companies was approximately 53.80% as of March 31, 2016. As such, Intermountain's proposed capital structure is in line with other gas distribution companies.

Q. Why is the Company proposing a 9.90% return on equity?

A. The Company's request for a 9.90 % ROE is based on the testimony and exhibits presented by Dr. Gaske. It is Intermountain's opinion and belief that a 9.90% ROE represents a fair return on investment for Intermountain's shareholders, and is also fair to Intermountain's customers.

Q. How did you calculate the cost of debt proposed in this filing?

A. The 4.94% cost of debt is calculated based on the weighted average debt of the Company that is outstanding at June 30, 2016, as shown on page 1 of Exhibit 3, and the projected weighted average cost of debt for expected new long-term debt, as shown on page 1 of Exhibit 3.

Q. Will any of the debt included in this filing come due within the next five years?

A. Yes, page 1 of Exhibit 3 also shows a schedule of current outstanding debt with maturity dates.

Q. Does Intermountain plan to issue any equity or debt offerings in the near future?

A. Yes, Intermountain plans to issue both equity and long-term debt in 2016. The equity and debt issuances planned for the next five years are shown on page 2 of Exhibit 3. The goal in issuing the new long-term debt is to match a funding mechanism with the lives of the assets that Intermountain is investing in to serve its customers. In this case the Company intends on issuing long-term debt with a term of 30 years to coincide with the life of natural gas distribution system assets.

Q. Please describe the current structure of the customer service function of Intermountain Gas Company.

A. In 2010 the MDUG went through the process of combining the customer service centers of each of the brands into a single customer service entity providing support to each of the utility group brands. The MDUG chose Meridian, Idaho as the primary location of the service center. The Meridian location is home to the customer service center, customer development and programs group, and the scheduling group. A satellite customer service center is located in Bismarck, ND along with the credit and collections department.

Q. Now that the customer service function has been consolidated into one entity, who do those employees work for?

A. All of the customer service employees working in the areas of customer service, credit and collections, customer development and programs, and scheduling are Montana-Dakota Utilities employees.

Q. How is Intermountain charged for its portion of the customer service expense?

A. The cost allocations of the customer service function are detailed in the Intermountain Gas Company Cost Allocation Manual, which is Exhibit 10, sponsored by Mr. Dedden.

Q. What efficiencies have been gained through the structure and implementation of technology?

A. From an employee head count standpoint, the MDUG has been able to reduce the overall head count in the customer service area. Instead of each brand having its own management team, there is a single management team. Also, prior to combining the service center, each utility brand had its own customer information system. The MDUG has now successfully implemented a new customer information system (CIS) across all of the brands, finishing with IGC in August 2015. The CIS implemented is an Oracle project called Customer Care and Billing (CC&B). Having all of our brands on CC&B allows us to cross train our customer service agents so they can handle calls from multiple brands instead of a single brand.

Q. What benefits to Intermountain's customers have resulted from these structure changes and technology improvements you just described?

A. Due to the organizational restructuring, process improvements, and new technology implementations, Intermountain has been able to reduce the cost of the customer service function to its customers by nearly $1.0 million since 2010 to 2015. At the same time Intermountain has continued to provide the same, if not better, level of service to its customers.

There has also been an economic impact to the Treasure Valley due to the organizational restructuring. Intermountain employed 43 people in its customer service department prior to the consolidation of the customer service operations in Meridian. The Meridian location now employs 165 people, adding significant payroll to the local economy.

Q. How does Intermountain measure the quality of its customer service?

A. Intermountain uses several metrics in analyzing its service to customers, including customer calls, response time, length of call, and number of dropped calls. During 2015, the Customer Service office answered 600,298 calls with an overall average answer speed of 49 seconds. The average length of calls was 4 minutes 28 seconds, and the abandoned or dropped call rate was 5.4 % of all calls. The Company also tracks customer complaints. Of the 600,298 calls received in 2015, complaints reported to the ID PUC or escalated to a supervisory level relating to high bills and disconnection were only 69 and 175, respectively.

Q. Are there other things the Company is doing in the customer service area?

A. Yes, Intermountain has been a leader in moving customers from paper billing and payments to electronic billing and payment processing. Currently Intermountain issues approximately 19% of the monthly customer bills in electronic form. From June 2015 to June 2016 Intermountain has increased the number of electronic bills issued by approximately 20%. Intermountain currently collects approximately 66.5% of its monthly customer payments through the electronic process.

Intermountain has also worked hard to reduce the amount of bad debt expense by working with customers on payment plans. Intermountain is projecting a bad debt expense of 0.43% of gross revenue for 2016 which is in line with other gas only utilities in the Mountain region.

Intermountain also uses social media as a means to reach and inform our customers. Our Intermountain website, Facebook and Twitter are the primary sources of social media used by the Company.

Q. Do you have any other comments on the customer service provided by Intermountain?

A. Yes, only to reiterate what Nicole Kivisto pointed out in her testimony. Intermountain has ranked at the very top in customer satisfaction according to the JD Power’s customer service ranking for midsized gas utilities in the West.

According to mid-year results, Intermountain will finish near the top again in 2016.

Q. Does this conclude your testimony?

A. Yes.

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Attorneys for Intermountain Gas Company

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SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 03

Intermountain Gas Company
Calculation of Debt Interest Costs

Description	Due Date	Interest Rate	Original Balance	Average Balance	Annual Interest Expense	
TIAA Senior notes	9/18/2018	7.26%	58,000,000	14,315,818	1,039,328.38	7.26%
TIAA Series A	10/30/2025	4.08%	25,000,000	25,000,000	1,020,000.00	4.08%
TIAA Series B	10/30/2028	4.33%	25,000,000	25,000,000	1,082,500.00	4.33%
2016 LT Issuance	9/15/2046	4.50%	50,000,000	50,000,000	2,250,000.00	4.50%
U.S. Bank LOC	7/13/2018	Varies	-	-	88,019.89 *	
Debt amortization					170,325.00	
				114,315,818	5,650,173.27	4.94%

* represents the annual commitment fee for the operating line-of-credit.

TIAA Senior Notes

Balance	Days Outstanding	Rate	Interest
15,818,184	261	7.26%	821,184.77
10,545,457	104	7.26%	218,143.61
			1,039,328.38

Monthly Debt Amortization Expense

Amort Bank of America Oct 18, 2010	5,522.97
Amort 1st Mort bond series I-91	62.00
Amort 1st Mort bond series J-94	206.00
Amort 1st Mort bond series K-94	116.00
Amort 1st Mort bond series L-99	920.00
Amort 1st Mort bond series M-97	3,478.00
Amort Sr debent due 11-15-09	733.00
Amort Sr debent due 11-15-13	503.00
Amort 1st Mort bond series K-94	1,263.89
2016 LT Issuance (est cost of $500k)	1,388.89
	14,193.75
Annualized	12.00
Annual Debt Amortization Expense	170,325.00

Exhibit No. 03
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Intermountain Gas Company
Summary of Forecasted Debt and Equity Issuances and Retirements

Description	Maturity Date	2016	2017	2018	2019	2020
Equity Infusion		$ 13,000,000	$ 10,000,000	$ -	$ -	$ -
Debt Retirement						
TIAA Senior Notes - 7.26%	September 18, 2018	(5,272,727)	(5,272,727)	(5,272,730)	-	-
U.S. Bank Revolving Line of Credit	July 13, 2018	-	-	(65,000,000)	-	-
Debt Issuance						
2016 Long-Term Note		50,000,000	-	-	-	-
Replacement Revolving Line of Credit		-	-	65,000,000	-	-
		$ 57,727,273	$ 4,727,273	$ (5,272,730)	$ -	$ -

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IN THE STATE OF IDAHO)
)

DIRECT TESTIMONY OF STEPHEN GASKE

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1300 19th Street, NW, Suite 620, Washington, DC 20036.

Q. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were finance and economics. A copy of my résumé is included as Exhibit 04 to this testimony.

Q. Have you presented expert testimony in other proceedings?

A. Yes. I have filed testimony or testified in more than 100 regulatory proceedings in North America. These submissions have included testimony on the cost of capital and capital structure issues for electric and natural gas distribution and oil and natural gas pipeline operations before 11 state and provincial regulatory bodies. In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing, regulatory principles and generating plant economics before regulators in four Canadian provinces, and seven U.S. state public utility commissions. I also have testified or filed testimony or affidavits before various federal regulators, including the Federal Energy Regulatory Commission on more than thirty occasions, the National Energy Board of Canada, the U.S. Postal Rate Commission, and the Comisión Reguladora de Energía of México. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements, regulatory principles and market power. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive, and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses.

I. INTRODUCTION

A. Scope and Overview

Q. What is the scope of your testimony in this proceeding?

A. I have been asked by Intermountain Gas Company ("Intermountain" or the "Company") to estimate the cost of common equity capital for the Company's natural gas distribution operations in the state of Idaho. In this testimony, I calculate a range for the cost of common equity capital for Intermountain's Idaho natural gas distribution operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Intermountain's Idaho gas distribution operations. I then place Intermountain within the range established by the DCF analyses by comparing the risks of the Company to those of the proxy gas distribution companies and by considering several alternative benchmark analyses.

Q. What rate of return is Intermountain requesting in this proceeding?

A. Based on its test period capital structure, Intermountain is requesting the following rate of return:

Table G.1: Requested Rate of Return – Idaho Gas Distribution Operations[1]

Source	Percent	Cost	Overall Rate of Return
Long-Term Debt	50.000%	4.94%	2.47%
Common Equity	50.000%	9.90%	4.95%
TOTAL	100.000%		7.42%

As my testimony discusses, an overall allowed rate of return of 7.42 percent, with Intermountain at this time.

B. Company Background

Q. Please describe Intermountain's operations and those of its parent company, MDU Resources Group, Inc.

A. Intermountain is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in natural gas distribution in the state of Idaho. Intermountain provides gas distribution service to approximately 320,000 residential, commercial and industrial customers in approximately 75 communities in southern Idaho, the largest of which are Boise, Nampa, Meridian, Pocatello, and Caldwell.

Through its division, Montana-Dakota Utilities Co. ("Montana-Dakota"), MDU Resources is engaged in the generation, transmission, and distribution of electricity, and the distribution of natural gas in the states of Montana, North Dakota, South Dakota, and Wyoming. MDU Resources also owns Cascade Natural Gas Corporation, which distributes natural gas in the states of Washington and Oregon, and Great Plains Natural Gas Company, which distributes natural gas in the states of Minnesota and North Dakota. MDU Resources is also engaged in

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[1] Projected average capital structure and rate of return for 2016.

utility infrastructure construction, natural gas gathering and transmission, and produces and markets aggregates and other construction materials.

Natural gas distribution assets comprised 30.8 percent[2] of MDU Resources' total assets in 2015, and natural gas distribution revenues comprised 19.5 percent[3] of total operating revenues. Idaho accounted for 32.0 percent of the natural gas distribution operating sales revenues for MDU Resources, while Washington (26.0 percent), North Dakota (15.0 percent), Montana (8.0 percent), Oregon (8.0 percent), South Dakota (6.0 percent), Minnesota (3.0 percent) and Wyoming (2.0 percent) accounted for the other 68.0 percent of retail gas distribution operating sales revenues.[4]

Q. Would you please describe Intermountain's Idaho natural gas distribution service territory?

A. Intermountain provides natural gas distribution service to approximately 320,000 customers in 75 communities in Southern Idaho, operating 290 miles of transmission lines and 6,216 miles of distribution mains. As shown in the testimony of Company witness Scott Madison, the customer base in Idaho is approximately 90 percent residential customers and 10 percent commercial and industrial customers. Intermountain's service territory primarily consists of towns and small cities dotted throughout relatively sparsely populated areas. With the exception of Boise, the local economies served by Intermountain are heavily dependent on agriculture, light manufacturing, and providing retail and other services for surrounding agricultural areas.

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[2] MDU Resources, 2015 Form 10-K, at 83.

[3] *Ibid.*, at 82.

[4] *Ibid.*, at 11.

Q. What is your understanding of the factors that are driving the rate case filing by Intermountain?

A. As discussed in the testimony of Company witness Madison, Intermountain has not filed a rate case since 1985. The primary reasons for the filing are related to customer growth, which has resulted in increased investment in rate base, along with concurrent increases in operating costs necessary to serve this growing customer base. In addition, Intermountain has needed to replace customer-service related information and technology systems, has experienced increased operating expenses related to the regulatory demands associated with pipeline safety regulations and compliance, and has higher right of way costs. Company witness Nicole Kivisto testifies that Intermountain has spent approximately $551 million in capital additions since the last general rate case. The Company's rate base has increased to about $237 million, as filed in this proceeding, from approximately $66.4 million as filed in the last rate proceeding in 1985.

II. CAPITAL STRUCTURE

Q. What capital structure is Intermountain filing in this proceeding?

A. As discussed in the testimony of Intermountain witness Mark Chiles, Intermountain is using a capital structure consisting of 50 percent debt and 50 percent equity. Although Intermountain's common equity ratio has fluctuated around the 50 percent level in recent years, this is the target capital structure that Intermountain seeks to maintain in its operations.

Q. What effect does the capital structure have on the costs of doing business?

A. Most large companies are financed using a mix of debt and equity capital. Including a reasonably small amount of debt in the capital structure can provide a low-cost source of funds because the common equity holders shield lenders from a portion of the risks of the company. However, the requirement to pay a fixed level of interest and repay principal as scheduled, causes the possibility of bankruptcy or other financial distress to increase as the firm takes on more debt. Financial “leverage” provided by fixed debt payments also tends to translate relatively small fluctuations in a company’s operating income into much larger variations in the net income available to common stockholders. When the proportion of debt is increased beyond some level, both the lenders and the stockholders require greater rates of return on their investments to compensate for the greater risks involved. In financial theory, there is an optimal range of equity ratios that minimizes the overall cost of capital of a company.

Q. What factors are important for determining the appropriate capital structure for a company?

A. The amount of debt that is economical for a firm depends on its business risks and the perceived probability that it could experience unexpected difficulties that would render it unable to meet its debt obligations. Although firms in the same industry generally tend to have similar business risks, there is often a general, very broad range of equity ratios associated with companies in particular industries. Firms in the same industry have different capital structures for many reasons. For example, within a given industry, there may be wide differences in the vintages of capital and operating strategies of individual companies. Another important factor is the quality of a firm's earnings in terms of cash flow and continuing operations. When all factors are considered the managers of a company are usually in the best position to evaluate the prospective risks and operating needs of their company and determine the most appropriate capital structure.

Q. In your opinion, is the capital structure used by Intermountain in this rate filing reasonable?

A. Yes. Intermountain's equity ratio is comfortably within the range of equity ratios of the proxy companies. As shown in my Direct Testimony Exhibit 05, Schedule 8, the proxy company common equity ratios are in a range between 47 percent and 58 percent, with a median of 54.3 percent. Six of the seven proxy companies have higher common equity ratios than Intermountain, which indicates that its common equity ratio is neither unusual nor extreme.

III. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

Q. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company.

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia (262 U.S. 679, 693 (1923))*, the Court indicated that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the

> proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944))*. There the Court described the relevant criteria as follows:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;
2. sufficient to maintain the financial integrity of the regulated company; and
3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the “cost of capital” or “opportunity cost” in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk, there is a return that investors expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When an unregulated entity faces competition, the pressure of that competition and consumer choices will combine to determine the fair rate of return. However, when regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, both the consumer and the public interest depend on establishing a return that will readily attract capital without being excessive.

Q. How are the costs of preferred stock and long-term debt determined?

A. For purposes of setting regulated rates, the current embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

Q. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on two DCF analyses. In addition, I have conducted two risk premium analyses, a market DCF analysis of the S&P 500, and a Capital Asset Pricing Model ("CAPM") analysis as benchmarks to assess the reasonableness of the DCF results. Each of these approaches is described later in this testimony.

B. Interest Rates and the Economy

Q. What are the general economic factors that affect the cost of capital?

A. Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit 05 shows various general economic statistics. Real growth in Gross Domestic Product ("GDP") has averaged 2.6 percent annually during the past 30 years, 2.4 percent for the past 20 years, and 1.4 percent for the past 10 years. After increasing at an annual rate of 2.4 percent in 2015, the Bureau of Economic Analysis reported that GDP for the first quarter of 2016 grew at a real annual rate of 0.8 percent.[5] According to Blue Chip Economic Indicators, the consensus forecast for expected growth in real GDP is 1.9 percent in 2016[6] and 2.3 percent in 2017.[7] Likewise, the U.S. unemployment rate has improved in recent months to 4.7 percent,[8] but the labor force participation rate for civilians 16 years and over remained at 62.6 percent for May 2016, near the lowest rate since the late 1970s.[9] Improvements in the U.S. unemployment rate are partly attributed to the reduced U.S. labor force and are not fully explained by job growth. In light of these weak economic conditions, the Federal Reserve has maintained its federal

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[5] U.S. Department of Commerce, Bureau of Economic Analysis, News Release, May 27, 2016.

[6] Blue Chip Economic Indicators, Vol. 41, No. 6, June 10, 2016, at 2.

[7] *Ibid.*, at 3.

[8] U.S. Department of Labor, Bureau of Labor Statistics, News Release, June 3, 2016, at 1.

[9] Ibid, at 2.

funds rate of 0.25 percent to 0.50 percent for overnight loans to banks in order to provide continued liquidity to the U.S. financial markets.[10]

In October 2014, the Federal Open Market Committee ("FOMC") ended its Quantitative Easing program, which provided extraordinary monetary stimulus for the U.S. economy for several years through asset purchases of mortgage-backed securities and Treasury bonds. However, the Federal Reserve's accommodative policy continues today. Specifically, the FOMC recently noted, "[the FOMC's] policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions."[11]

In June 2016, the FOMC noted that, "with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen."[12] The FOMC further noted that "inflation is expected to remain low in the near term, in part due to earlier declines in energy prices," but is expected to rise over the medium term.

In addition to the stated expectations of the FOMC, market analysts are expecting increases in interest rates in the short and medium term. The May 2016 issue of Blue Chip Financial Forecasts surveyed leading economists and market participants concerning their views regarding the timing of possible future increases in short-term rates by the Federal Reserve. Blue Chip reports that approximately 87 percent of those surveyed expect that the FOMC will gradually

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[10] Statement of the Federal Open Market Committee, June 15, 2016.

[11] *Ibid*.

[12] *Ibid*.

increase its overnight policy rate by no later than September 2016.[13] The average yield on the 30-year U.S. Treasury bond in May 2016 was 2.63 percent. By contrast, the Blue Chip consensus estimate projects that the average yield on the 30-year U.S. Treasury bond will increase to 4.30 percent for the period from 2018 through 2022.[14] Thus, the consensus estimate from leading economists is for an increase of 167 basis points in U.S. Treasury bond yields over the next several years.

As pages 2-4 of Schedule 1 of Exhibit 05 show, interest rates on longer-term A-rated and Baa-rated public utility bonds have increased since the beginning of 2015. Between January 2015 and May 2016, the average yield on A-rated public utility bonds increased from 3.58 percent to 3.93 percent, and the average yield on Baa-rated public utility bonds increased from 4.39 percent to 4.60 percent. Credit spreads, which measure the incremental cost of corporate debt relative to U.S. Treasury bonds, are flat compared to one year ago, with the average spread of Baa-rated utility bonds over 30-year U.S. Treasury bonds at 2.01 percent in June 2015 and 1.97 percent in May 2016.

Investors also are influenced by both the historical and projected level of inflation. As shown on Page 1 of Schedule 1 of Exhibit 05, during the past decade, the Consumer Price Index has increased at an average annual rate of 2.0 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 1.8 percent. According to Blue Chip Economic Indicators, the Consumer Price Index

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[13] Blue Chip Financial Forecasts, Vol. 35, No. 5, May 1, 2016, at 14.

[14] Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.

is forecasted to increase by 1.3 percent[15] and 2.3 percent[16] for 2016 and 2017, respectively. Over the intermediate and longer-term, however, investors can expect higher inflation rates as the Federal Reserve's accommodative monetary policy, which began in 2008, places upward pressure on consumer and producer prices once economic growth returns to historical levels.

Q. How are current economic conditions reflected in the equity markets?

A. The equity markets have recovered from the large stock market decline in 2008 and 2009, but the Federal Reserve's massive purchases of federal debt and mortgage-backed securities have created artificially low interest rates on government bonds and a potential stock market valuation bubble that increases the risks in the equity market.

C. Discounted Cash Flow ("DCF") Method

Q. Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of common stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method, therefore, is a matter of calculating the current dividend yield and estimating the

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[15] Blue Chip Economic Indicators, Vol. 41, No. 6, June 10, 2016, at 2.

[16] *Ibid.*, at 3.

long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by ($1 + 0.75g$). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by ($1 + 0.5g$). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D_0(1 + 0.625g)}{P} + g$$

Where: K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D_0 = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

D. Flotation Cost Adjustment

Q. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. There are significant costs associated with issuing new common equity capital, and these costs must be considered in determining the cost of capital. Schedule 2 of Exhibit 05 shows a representative sample of flotation costs incurred with 32 new common stock issues by natural gas distribution companies since January 2004. Flotation costs associated with these new issues averaged 4.10 percent.

This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Intermountain must have an expected return that places a value on its equity that is approximately 4.0 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.04.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

E. DCF Study of Natural Gas Distribution Companies

Q. Would you please describe the overall approach used in your DCF analysis of Intermountain's cost of common equity for its Idaho natural gas distribution operations?

A. Because Intermountain's Idaho natural gas distribution operations must compete for capital with many other potential projects and investments, it is essential that the Company have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component. Since Intermountain is a subsidiary of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Intermountain's Idaho natural gas distribution operations as a stand-alone company is not possible. As an alternative, I have used a group of natural gas distribution companies that have publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for Intermountain's Idaho natural gas distribution operations.

Q. How did you select a group of natural gas distribution proxy companies?

A. I started with the twelve companies that The Value Line Investment Survey ("Value Line") classifies as Natural Gas Utilities to ensure that the company is considered to be primarily engaged in the natural gas distribution business and that retention growth rate projections are available. From that group, I eliminated any companies that did not have investment-grade credit ratings from either Standard & Poor's ("S&P") or Moody's Investors Service ("Moody's") because such companies are not sufficiently comparable in terms of business and financial risk to Intermountain. In addition, I excluded any companies that did not pay dividends, or that did not have future growth rate estimates provided by either Zacks or Thomson First Call, or that were currently engaged in significant mergers or acquisitions. In order to ensure that the companies are primarily engaged in the natural gas distribution business, I eliminated any companies that did not derive at least 70 percent of their operating income from regulated natural gas distribution operations in 2015, or that did not have at least 70 percent of their total assets devoted to the provision of natural gas distribution service in 2015. As shown on page 1 of Schedule 3 of Exhibit 05, seven companies met these criteria for inclusion in the proxy group.

Q. How did you calculate the dividend yields for the companies in your proxy group?

A. These calculations are shown on pages 1-2 of Schedule 4 of Exhibit 05. For the price component of the calculation, I used the average of the high and low stock prices for each month during the six-month period from December 2015 through May 2016. The average monthly dividend yields were calculated for each proxy group company by dividing the prevailing annualized dividend for the period by the average of the stock prices for each month. These dividend yields were then multiplied by the quarterly DCF model factor ($1 + 0.625g$) to arrive at the projected dividend yield component of the DCF model.

Q. Please describe the method you used to estimate the future growth rate that investors expect from this group of companies.

A. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect. I developed two different DCF analyses of the proxy companies. In the first approach, I conducted a Basic DCF analysis that relied on analysts' earnings forecasts for the growth rate component of the model. My second approach used a combination of the analysts' earnings growth projections and retention growth (also known as "sustainable growth") forecasts from Value Line (based on forecasts of dividends, earnings, and returns on equity) to produce a Blended Growth Rate Analysis.

F. Basic DCF Analysis

Q. How did you estimate the expected future growth rate in your Basic DCF analysis?

A. In my Basic DCF analysis, I have estimated expected future growth based on long-term earnings per share growth rate forecasts of investment analysts, which are an important source of information regarding investors' growth rate expectations. This Basic DCF analysis assumes that the analysts' earnings growth forecasts incorporate all information required to estimate a long-term expected growth rate for a company. I have used the consensus estimates of earnings growth forecasts published by Zacks Investment Research and Thomson First Call (as reported on Yahoo! Finance) as the primary sources for analysts' forecasts in my calculations. As shown on page 4 of Schedule 4 of Exhibit 05, the average of the analysts' long-term earnings growth rate estimates for the natural gas distribution proxy companies is 5.67 percent, and the median is 6.00 percent.

Q. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 6 of Schedule 4 of Exhibit 05. The annual dividend yield is multiplied by the quarterly dividend adjustment factor (*1 +*

0.625g), and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a cost of common equity for the proxy companies in a range from 7.59 percent to 11.06 percent. In this analysis, the median for the group is 9.40 percent and the third quartile is 10.24 percent.

G. Blended Growth Rate Analysis

Q. How did you use your Blended Growth Rate Analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A. The Blended Growth Rate approach combines: (i) Value Line retention growth forecasts; and (ii) consensus estimates of long-term earnings growth for each company from various investment analysts, as published by Zacks and Thomson First Call.

Q. What approach did you use in calculating the long-term growth retention Growth rate?

A. The long-term retention growth rate component is based on the calculation of retention growth rates using Value Line forecasts for each company.

Q. Please describe the retention growth rate component of your analysis.

A. I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long-run, growth in earnings and dividends per share depends in part on the amount of earnings that is being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q. How can a company's earnings retention rate affect its future growth?

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that is generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (*b*) by the rate of return on common equity (*r*) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 12 percent and retain 75 percent of its earnings might be expected to have a growth rate of 9 percent, computed as follows:

$$0.75 \times 12\% = 9\%$$

On the other hand, another company that is also expected to earn 12 percent but only retains 25 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$0.25 \times 12\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

Q. How did you calculate the expected future retention rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have three to five years in the future. Since these retention rates are projected to occur several years in the future, they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect three to five years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 3 of Schedule 4 of Exhibit 05. The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that is being retained and reinvested in the company. This earnings retention rate is multiplied by the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 4.44 percent, and the median is 4.71 percent.

Q. How did you utilize the analysts' projected earnings growth rates and the projected earnings retention growth rates in estimating expected growth for the proxy companies in the Blended Growth Rate Analysis?

A. As shown on page 5 of Schedule 4 of Exhibit 05, I calculated a weighted average of the analysts' projected earnings growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave one-half weighting to the analysts' earnings growth rate projections and one-half weighting to the projected retention growth rates. The average of the blended growth rates for the proxy companies is 5.06 percent, and the median is 5.17 percent.

Q. How did you utilize these Blended Growth Rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. These calculations are shown on page 7 of Schedule 4 of Exhibit 05. Again, the annual dividend yield for each company is multiplied by the quarterly dividend adjustment factor ($1 + 0.625g$), and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the cost of common equity capital for the proxy companies. This Blended Growth Rate Analysis indicates that the cost of common equity capital for the natural gas distribution proxy companies is in a range between 7.66 percent and 9.50 percent. In this analysis, the median for the group is 8.61 percent and the third quartile is 8.95 percent.

Q. Earlier you discussed the fact that the Federal Reserve Board has been setting interest rates and monetary policy in a way that artificially depresses yields on U.S. Treasury debt. What does this mean for the cost of common equity for gas distribution companies?

A. The DCF cost of equity results for regulated gas distribution companies are being affected by artificial factors in the current and projected capital markets, including the following two key factors: (1) the Federal Reserve's ongoing accommodative monetary policy; (2) and the market's expectation for substantially higher interest rates.

Rising interest rates historically have had a negative effect on stock prices, especially for dividend paying stocks such as utilities. When interest rates begin to rise, the return on gas utility equities may be less attractive to investors as compared with other investments of comparable risk. The market's expectation for rising interest rates suggests that the calculated cost of equity for the proxy companies using current market data is likely to be an artificially depressed estimate of investors' required return at this time.

H. Risk Premium Analysis

Q. Have you conducted additional analyses in determining the cost of equity capital for Intermountain?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinate to the claims of bondholders. This priority standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual return on large company common stocks has exceeded the return on long-term corporate bonds by a premium of 570 basis points (5.7 percent) per year from 1926-2015.[17] When this premium is added to the average yield on Moody's corporate bonds in recent months of approximately 4.3 percent[18], the result is an investor return requirement for large company stocks of approximately 10.0 percent. However, investors in smaller companies expect higher returns over the long term, due to the additional business and financial risks that smaller companies face. According to Ibbotson Associates, companies in the same size range as Intermountain's Idaho natural gas distribution operations have had a premium of 1,420 basis points (14.2 percent)

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[17] Morningstar SBBI Presentation, 1926-2015, Slide 6. Calculation: (12.0 percent – 6.3 percent = 5.7 percent).

[18] Exhibit 05, Schedule 1, at 3. The average yield on Moody's corporate bonds from December 2015 through May 2016 has been 4.34 percent.

over the average return on long-term corporate bonds.[19] When added to the recent average corporate bond yield, this size-related premium suggests an expected return of 18.6 percent. This analysis indicates that the rate of return that I am proposing in this proceeding would be low relative to the historic risk premiums earned by similarly-sized unregulated companies.

Q. Did you also perform another risk premium analysis?

A. Yes, I did. Research studies provide empirical support for the proposition that equity risk premia generally increase as interest rates decrease, and vice versa. In fact, the data provided in Schedule 5, Exhibit 05 produce statistical results that are consistent with existing research in this area. Using this data, I performed a linear regression to estimate the relationship between 30-year U.S. Treasury bonds and the risk premium required for regulated gas distribution companies. The resulting equation is presented in Schedule 5, Exhibit 05 and re-created below:

Intercept + Coefficient x Bond Yield = Risk Premium

0.08465 + (- 0.5653 x Bond Yield) = Risk Premium

The regression statistics indicate that this equation is statistically significant and the R-square reveals that approximately 79 percent of the variation in the risk premium is explained by the bond yield. The negative coefficient in the above equation demonstrates the inverse relationship between bond yields and the risk

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[19] Ibbotson SBBI 2015 Classic Yearbook, at 108-109. Ibbotson Associates defines size ranges based on market capitalization. I calculated the implied market capitalization for Intermountain Gas' Idaho natural gas distribution operations based on the Company's pro forma rate base ($236.926 million) and the projected average equity ratio for 2016 (50.00 percent). This places Intermountain's Idaho natural gas distribution operations in Ibbotson Associates' tenth decile. Calculation: 20.6 percent – 6.4 percent = 14.2 percent.

premium. For every change of 100 basis points in the bond yield, the risk premium changes by approximately 57 basis points in the opposite direction.

This Risk Premium analysis was conducted using three different risk-free rates: (1) the current average yield on 30-year Treasury bonds; (2) the near-term projected yields on 30-year Treasury bonds in 2016 and 2017; and (3) the longer-term projected yields on 30-year Treasury bonds from 2018-2022. Based on these three interest rates, the regression equation produces an average ROE estimate is 9.92 percent.

I. Market DCF Analysis

Q. What other analysis did you conduct in determining the cost of equity capital for Intermountain?

A. For an additional benchmark of the reasonableness of my DCF results, I calculated the current required return for the companies in the S&P 500 Index. Using data provided by the Bloomberg Professional service, I performed a market capitalization-weighted DCF calculation on the S&P 500 companies based on the current dividend yields and long-term growth rate estimates as of May 31, 2016. These calculations are shown in Schedule 6, pages 1-9 of Exhibit 05. The current secondary market required ROE for the S&P 500 is 12.13 percent. This analysis indicates that the rate of return that I am proposing in this proceeding is low relative to the return required by investors who invest in the S&P 500.

J. Forward-Looking CAPM

Q. Many analysts would argue that gas distribution companies are less risky than the S&P 500 companies. Does this make the S&P 500 a poor benchmark for evaluating the DCF results?

A. No. The DCF required return for the S&P 500 is significantly greater than the return required for the natural gas distribution company proxy group, and the large magnitude of this difference is an indicator that the proxy company DCF results may be on the low side. Some analysts use the CAPM to adjust for differences in risk between the market average and a particular group of proxy companies. While I do not consider the CAPM to be a reliable measure of the cost of capital, one could use it to adjust the S&P 500 results to achieve a risk-adjusted benchmark for the natural gas distribution company proxy group. For example, Beta is frequently used as the measure of relative risk in the CAPM. As shown on Schedule 6, page 11 of Exhibit 05, the average beta estimated by Value Line for the proxy companies is 0.74. Using this beta estimate would produce the following CAPM results:

Table G.2: CAPM Results

S&P Current Required Return	12.13%
Less: May '16 T-Bond	2.63%
Market Risk Premium	9.50%
x Proxy Company VL Beta	0.74
LDC Risk Premium	7.06%
Plus: May '16 T-Bond	2.63%
LDC CAPM Cost of Eq.	**9.69%**

Thus, if one were to use the CAPM as a benchmark of a reasonable return, this benchmark generally supports the recommended ROE of 9.9 percent in this proceeding.[20]

K. Relative Risk Analysis

Q. Have you compared the risks faced by Intermountain's Idaho natural gas distribution operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

1. Business Risk;
2. Regulatory Risk;
3. Financial Risk; and,
4. Market Risk.

Q. Please describe the business risks inherent in the natural gas distribution industry.

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived natural gas distribution assets, for

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[20] This CAPM calculation is identical to the one adopted by the U.S. Federal Energy Regulatory Commission earlier this year. *Martha Coakley, et al. v. Bangor Hydro-Electric Company, et al.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014); aff'd in Opinion No. 531-B, 150 FERC ¶ 61,165 (March 3, 2015). Note that FERC used the CAPM only as a benchmark, but set the allowed rate of return above the median indicated by a DCF analysis of proxy companies because of the current abnormal financial market conditions.

which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply, and competition may change in ways that adversely affect the value of the investment.

Q. What are some of the business risks faced by Intermountain's Idaho natural gas distribution operations?

A. The Company's natural gas distribution operations in Idaho face many of the same business risks that are associated with other natural gas distribution companies. However, Intermountain's Idaho natural gas distribution operations face some particular risks that distinguish the Company from the proxy group of distribution companies, including its smaller size and generally less diversified economies in the cities and towns that it serves.

As shown on page 1 of Schedule 3 of Exhibit 05, Intermoutain's Idaho natural gas distribution operations are significantly smaller than the operations of any of the proxy companies and a fraction of the size of the typical proxy company. For example, the proposed 2016 rate base of Intermountain's Idaho natural gas distribution operations is equal to only 4.5 percent of the year-end 2015 total assets of the median proxy company. Similarly, Intermountain's Idaho natural gas distribution test year requested operating revenues and operating income are only 10.8 percent and 9.3 percent of the year-end 2015 level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 9 and 22 times the size of Intermountain's Idaho natural gas distribution operations. The Company's smaller size has significant implications for business risks. Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies.

With its small revenue base relative to the proxy group companies, Intermountain's Idaho natural gas distribution operations are subject to greater risk that a major employer or industry, such as a manufacturing facility, agricultural processing facility or government facility, might downsize or close. For example, Intermountain has witnessed the downsizing, and even closure, of large potato processing plants as technology has replaced line workers. Events such as these could significantly affect overall employment and income in the towns served. Factors that negatively influence the local economy can reduce demand for Intermountain's Idaho natural gas distribution service and adversely impact investments in facilities used to provide those services.

Another risk faced by Intermountain is the fact that it currently recovers a substantial portion of its fixed costs in the volumetric component of its rates and has experienced declining average use per customer, due in part, to the relatively new housing stock of its customer base, more energy efficient appliances, and stricter building codes. As discussed in the testimony of Company witness Lori Blattner, Intermountain is proposing to raise the monthly customer charge for its Idaho natural gas distribution operations for residential and commercial customers. For example, Intermountain is proposing to raise the monthly customer charge for residential customers from $2.50 (summer)/$6.50 (winter) to $10.00 regardless of the time of year. Company witness Mike McGrath explains in his testimony that Intermountain is also proposing to implement a Fixed Cost

Collection Mechanism ("FCCM") that will break the link between Intermountain's (a) margin from its residential and commercial customers and, (b) the natural gas deliveries to these same core market customers.

Q. Would the implementation of Intermountain's proposed customer charge reduce the Company's risk profile relative to the proxy group?

A. No. Because the ROE recommendation is established for a company based on its risk profile relative to the proxy group, it is necessary to consider how the implementation of a higher customer charge would affect the Company's risk profile relative to the proxy companies. Schedule 7 of Exhibit 05 shows that the average monthly customer charge for the operating utilities held by the proxy group companies ranges from $5.00 to $23.00, with an average of $12.47. Schedule 7 shows that 66.67 percent of the operating utilities held by the proxy group have monthly customer charges for residential customers that are higher than the $10.00 customer charge being proposed by Intermountain in Idaho.

Similarly, Schedule 7 also shows the operating utilities with some form of volumetric protection (e.g., revenue decoupling mechanisms, straight fixed-variable rate design, formula rate plans) similar to the FCCM proposed by Intermountain. As shown on Schedule 7, 66.67 percent of the operating utilities held by the proxy group have protection against volumetric risk similar to the decoupling mechanism that is being proposed by Intermountain.

If Intermountain's requests to increase the customer charge and implement revenue decoupling in Idaho are approved, all else being equal, the Company will be comparable in risk to the proxy group companies on those factors, and no upward adjustment to the required rate of return on common equity would be necessary. However, if the PUC were to reject Intermountain's proposed customer charge increase or decoupling mechanism, the Company's Idaho natural gas distribution operations would have generally higher risk than the proxy companies in those characteristics.

Considering only its smaller size, Intermountain's Idaho natural gas distribution operations might require a return that is approximately 100 basis points higher than the return required for the typical proxy company. In addition, with the exception of Boise, the Company's gas distribution operations are primarily concentrated in smaller cities and towns with local economies that are generally less diversified than those of the proxy companies. In summary, Intermountain's Idaho natural gas distribution operations are riskier than the operations of the proxy companies.

Q. What are the regulatory risks faced by Intermountain's Idaho natural gas utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow for full cost recovery. In effect, the binding constraint on natural gas distribution companies is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive.

As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of natural gas distribution companies to finance their operations. Thus, in some instances, regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the natural gas distribution industry.

The regulatory environment can significantly affect both the access to, and cost of capital in several ways. As noted by Moody's, "[f]or rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[21] Moody's further noted that:

> Utility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a

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[21] Moody's Investors Service, *Regulated Electric and Gas Utilities*, December 23, 2013, at 9.

> disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.[22]

Regulatory Research Associates ("RRA") rates the Idaho PUC as Average / 2, which is the middle rating on the nine-point scale.[23] RRA describes the regulatory environment in Idaho as "relatively balanced from an investor viewpoint."[24] This RRA rating suggests that Intermountain's Idaho natural gas distribution operations have average regulatory risk.

Q. Would you please describe Intermountain's relative financial risks?

A. Financial risk exists to the extent that a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from credit ratings.

Page 2 of Schedule 3 of Exhibit 05 shows the credit ratings assigned by S&P and Moody's to each of the companies in the comparison group and MDU Resources. Intermountain does not have its own credit rating. The median S&P credit rating for companies in the proxy group is A. By comparison, MDU Resources' long-term rating from S&P is BBB+ with a negative outlook. This suggests that the perceived business and financial risk of MDU Resources is

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[22] *Ibid.*

[23] Regulatory Research Associates, Idaho Commission Profile, June 21, 2016.

[24] *Ibid.*

slightly higher than that of the typical company in the comparison group.

The capital structure data on Schedule 8 of Exhibit 05 show that Intermountain's proposed common equity ratio of 50.00 percent is almost four percent lower than the 53.88 percent median for the proxy companies as of March 31, 2016, suggesting that Intermountain's financial risk is above average relative to the proxy group. In addition, the Company's below-average credit rating suggests that a higher common equity ratio would be required to offset Intermountain's above-average business risks.

Q. Would you please describe Intermountain's market risks?

A. Market risk is associated with the changing value of all investments because of business cycles, inflation, and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Overall, the market risk of Intermountain's Idaho natural gas distribution business is comparable to that of the companies in the comparison group.

Q. How do the overall risks of the proxy companies compare with the risks faced by Intermountain's Idaho natural gas distribution operations?

A. Intermountain's Idaho natural gas distribution operations face overall risks that are above the median relative to those of the proxy companies. Although it has average regulatory risk, Intermountain has above-average business risks due primarily to its small size relative to the proxy companies, its rate design risk (i.e., very low customer charge) and volumetric risk due to the absence of a revenue decoupling mechanism despite declining average use per customer, and its exposure to relatively undiversified local economies in most of its service territory. Intermountain also has above-average financial risks due to its proposed common equity ratio being lower than the proxy group median, and the credit rating for MDU Resources being lower than the proxy group median.

Although my analysis assumes approval of Intermountain's proposed monthly customer charge and FCCM, absent approval of those proposals, the Company would continue to face greater rate design risk than the typical company in the proxy group, the majority of which have fixed customer charges well above that of Intermountain's current customer charge in Idaho. The greater business risk leads me to conclude that investors appraise the overall risks of Intermountain's Idaho natural gas distribution operations to be above average relative to the risks of the proxy companies. Consequently, Intermountain's Idaho natural gas distribution business requires an allowed rate of return that is significantly above the median of the range for the companies in the proxy group indicated by my DCF analyses.

IV. SUMMARY AND CONCLUSIONS

Q. Please summarize the results of your cost of capital study.

A. I conducted two DCF analyses on a group of natural gas distribution companies that have a range of risks that is roughly comparable to those of Intermountain's Idaho natural gas distribution operations. These results are summarized as follows:

Table G.3: Summary of DCF Results

	Basic DCF Analysis	Blended Growth Rate DCF Analysis
High	11.06%	9.50%
3rd Quartile	10.24%	8.95%
Median	9.40%	8.61%
1st Quartile	8.04%	8.17%
Low	7.59%	7.66%

In addition, I conducted two risk premium analyses, a market DCF analysis of the S&P 500, and a CAPM analysis to test the reasonableness of my DCF analyses. Those results are summarized as follows:

Table G.4: Benchmark Risk Premium and Market DCF Analyses

	Return
Risk Premium (Long-Term Corporate Bonds)	
vs. Large Company Stocks	10.0%
vs. Small Company Stocks	18.6%
Risk Premium (Regression of Authorized ROEs against 30-yr Treasury yields)	9.9%
Market DCF (S&P 500)	12.1%
Forward-Looking CAPM	9.7%

My risk premium, market DCF and CAPM analyses suggest that the DCF results generally are low relative to current market benchmarks. In particular, all of the DCF return estimates are considerably below the 18.6 percent risk premium return benchmark for companies in Intermountain's relative size range. Similarly, the DCF estimates for the natural gas distribution proxy companies are well below the 12.1 percent market DCF estimate for the S&P 500 companies, and supported by the 9.7 percent CAPM estimate for the natural gas distribution proxy companies.

Q. What rate of return on common equity do you recommend for Intermountain's Idaho natural gas distribution operations in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Intermountain's Idaho natural gas distribution operations at this time is 9.90 percent, which is approximately the midpoint between the median and the third quartile of the range for my Basic DCF analysis. This recommended return reflects my assessment that the overall risks of Intermountain's Idaho natural gas distribution operations are above average relative to those of the proxy companies, and the fact that the DCF results appear to be quite low relative to the other benchmarks at this time. Although the Company has average regulatory risk relative to the proxy companies, it has above average business and financial risks. In addition to its small size relative to the proxy companies, Intermountain's Idaho natural gas distribution operations are faced with significantly higher than average rate design risk as well as volumetric risk due to declining average use per customer. Furthermore, Intermountain has higher than average financial risks as demonstrated by its proposed equity ratio being lower than the proxy group median, and the credit rating for MDU Resources being below the proxy group median. Thus, my recommended return is appropriately positioned to reflect the risks faced by Intermountain's Idaho natural gas distribution operations relative to the risks faced by the proxy companies.

Q. Does this conclude your Prepared Direct Testimony?

A. Yes.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR THE AUTHORITY TO CHANGE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE TO NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	Case No. INT-G-16-02

EXHIBIT 04

J. Stephen Gaske, Ph.D.
Senior Vice President

Steve Gaske has more than 30 years of experience as an economic consultant, researcher, and professor in the fields of public utility economics, finance, and regulation. Dr. Gaske has provided consulting services in more than 300 regulatory, antitrust, tax, and civil proceedings. In addition, he has presented expert testimony in more than 100 state, provincial, and federal regulatory commission hearings in Canada, the U.S. and Mexico.

AREAS OF EXPERTISE

His specialty is the application to regulated industries of inter-related principles from economics, finance and regulatory theory. His areas of expertise include:

- Finance, cost of capital, and risk analysis;
- Rate design, cost allocation, cost of service, and pricing of services;
- Energy markets and the economics of public utilities and energy infrastructure;
- Competition and antitrust principles; and
- Regulatory economics, rules, and policies.

INDUSTRY EXPERTISE

His work has involved:

- Most of the major natural gas pipelines in North America;
- Many electric utilities;
- Many natural gas distribution companies;
- Several major oil pipelines;
- Railroads;
- Postal Service;
- Telephone and satellite telecommunications companies; and
- Sewer and water companies.

REPRESENTATIVE PROJECT EXPERIENCE

Some of the projects on which Dr. Gaske has worked include:

- Advisor to numerous U.S. and Canadian pipelines on economics, pricing strategies and regulatory matters;

- Development of computerized cost of service models for calculating both traditional and levelized rates for gas and oil pipelines, and rates for electric utilities;
- On behalf of a new, greenfield pipeline designed to carry Canadian gas to U.S. New England markets he served as the rate and financial advisor during the development, permitting and financing stages.
- A variety of White Papers on technical aspects of calculating the allowed rate of return for regulated companies, including white papers submitted in proceedings involving FERC generic rate of return for electric utilities, FERC rate of return for gas and oil pipelines, Canadian rate of return for pipelines and utilities;
- An analysis of the applicability of various finance theories to telephone ratemaking by the U. S. Federal Communications Commission;
- A study of the economic structure, risks and cost of capital of the satellite telecommunications industry;
- Author of several issues of the H. Zinder & Associates Summary of Natural Gas Pipeline Rates;
- Several studies of regional natural gas market competition, market power, pricing and capacity needs;
- An evaluation of Federal Energy Regulatory Commission policies designed to promote liquidity in the natural gas commodity markets;
- Numerous studies of electric rate, regulatory and market issues such as canceled plant treatment, time-differentiated rates, non-utility generation, competitive bidding, and open-access transmission;
- Author of two updates of the Edison Electric Institute Glossary of Electric Utility Terms;
- Several studies of pricing, contract provisions, competitive bidding programs, and transmission practices for independent electric generation; and,
- Several reports and projects on incentive regulation and the application of price cap regulation to both electric and natural gas companies.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Dr. Gaske has testified or filed testimony or affidavits in more than 100 regulatory proceedings on the following topics:

Commission	Topic
Alaska Regulatory Commission	Oil Pipeline Rate of Return/Rate Base
Alberta Energy and Utilities Board	Gas Pipeline Cost Allocation/Rate Design
Alberta Utilities Commission	Utility Cost of Capital; Gas Pipeline Contracts and

	Market Power
Colorado Board of Assessment Appeals	Property Tax Discount Rate
U.S. Economic Regulatory Administration	Gas Distribution Rate Design
U. S. Federal Energy Regulatory Commission	Electric Transmission Rate of Return; Gas Pipeline Cost Allocation and Rate Design; Rate of Return and Capital Structure; Competition; Revenue Requirements; Oil Pipeline Rate of Return and Pricing
Indiana Utilities Regulatory Commission	Electric Cost Allocation/Rate Design
Iowa Utilities Board	Electric Avoided Costs/Externalities
Maine Public Utilities Commission	Electric Rate Design/Demand Management
Comision Reguladora de Energia de México	Gas Pipeline Rate of Return
Montana Public Service Commission	Electric/Gas Distribution Rate of Return; Electric Cost Allocation and Rate Design
Minnesota Public Utilities Commission	Gas Distribution Rate of Return
National Energy Board of Canada	Gas Pipeline Cost Allocation and Rate Design; Oil Pipeline Service Structure and Rates
New Mexico Regulatory Commission	Electric Rate of Return
New York Public Service Commission	Gas Pipeline Capital Structure
New Brunswick Energy and Utilities Board	Gas Distribution Ratemaking
North Dakota Public Service Commission	Electric/Gas Distribution Rate of Return; Natural Gas Market Pricing; Electric Cost Allocation and Rate Design
Nova Scotia Utility and Review Board	Cost Allocation and Pricing of Bridge Access
Ontario Energy Board	Rate of Return; Access to and Pricing of Gas Pipeline Expansions; LNG Regulation
U.S. Postal Rate Commission	Postal Pricing/Rate Design

Régie de l'énergie du Québec	Rate of Return/Regulatory Principles
South Dakota Public Utilities Commission	Gas Distribution Rate of Return
Texas Public Utilities Commission	Electric Cost Allocation and Rate Design
Texas Railroad Commission	Gas Pipeline Cost Allocation/Rate Design
Wisconsin Public Service Commission	Electric Generation Economics
Wyoming Public Service Commission	Electric/Gas Distribution Rate of Return
Wyoming Board of Equalization	Property Tax Discount Rate

TEACHING/SPEAKING ENGAGEMENTS

Dr. Gaske has spoken on utility finance and economic issues before numerous professional groups. From 1983-1986, he served as Coordinator of the Edison Electric Institute Electric Rate Fundamentals Course. He has lectured on marginal cost estimation for electric utilities at the EEI rate course, and on both low-income rates and natural gas pipeline cost allocation and rate design before the American Gas Association Gas Rate Fundamentals Course. In addition, Dr. Gaske has taught college courses in Public Utility Economics, Transportation, Physical Distribution, Financial Management, Investments, Corporate Finance, and Corporate Financial Theory.

PROFESSIONAL HISTORY

CONSULTING

Concentric Energy Advisors, Inc. (2008 – present)
Senior Vice President

H. Zinder & Associates (1988 – 2008)
President/Senior Vice-President/Consultant

Independent Consulting on Public Utility Issues (1982 - 1988)

Olson & Company, Inc. (1980 – 1981)
Public Utility Consultant

H. Zinder & Associates (1977 – 1980)
Research Assistant and Supervisor of Regulatory Research

ACADEMIC/TEACHING

Trinity University (1986 – 1988)
Assistant Professor of Finance

Indiana University School of Business (1982 - 1986)

Associate Instructor of Public Utilities and Transportation

Northern Virginia Community College (1978)
Lecturer in Accounting

EDUCATION

Ph.D., Indiana University School of Business, 1987
M.B.A., George Washington University, 1977
B.A., University of Virginia, 1975

PROFESSIONAL ASSOCIATIONS

American Economic Association
American Finance Association
American Gas Association Rate Committee (1989-2001)
Energy Bar Association
Financial Management Association

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 05

Intermountain Gas Company

General Economic Statistics

1984-2015

	[1]	[2]	[3]	[4]	[5]
	Percentage Price Changes				
Year	Consumer Price Index	GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP ($ billions)	Nominal GDP Growth
1984	4.3%	3.5%	7.3%	4,040.7	
1985	3.6%	3.2%	4.2%	4,346.7	7.6%
1986	1.9%	2.0%	3.5%	4,590.2	5.6%
1987	3.6%	2.6%	3.5%	4,870.2	6.1%
1988	4.1%	3.5%	4.2%	5,252.6	7.9%
1989	4.8%	3.9%	3.7%	5,657.7	7.7%
1990	5.4%	3.7%	1.9%	5,979.6	5.7%
1991	4.2%	3.3%	-0.1%	6,174.0	3.3%
1992	3.0%	2.3%	3.6%	6,539.3	5.9%
1993	3.0%	2.4%	2.7%	6,878.7	5.2%
1994	2.6%	2.1%	4.0%	7,308.8	6.3%
1995	2.8%	2.1%	2.7%	7,664.1	4.9%
1996	3.0%	1.8%	3.8%	8,100.2	5.7%
1997	2.3%	1.7%	4.5%	8,608.5	6.3%
1998	1.6%	1.1%	4.5%	9,089.2	5.6%
1999	2.2%	1.5%	4.7%	9,660.6	6.3%
2000	3.4%	2.3%	4.1%	10,284.8	6.5%
2001	2.8%	2.3%	1.0%	10,621.8	3.3%
2002	1.6%	1.5%	1.8%	10,977.5	3.3%
2003	2.3%	2.0%	2.8%	11,510.7	4.9%
2004	2.7%	2.7%	3.8%	12,274.9	6.6%
2005	3.4%	3.2%	3.3%	13,093.7	6.7%
2006	3.2%	3.1%	2.7%	13,855.9	5.8%
2007	2.8%	2.7%	1.8%	14,477.6	4.5%
2008	3.8%	2.0%	-0.3%	14,718.6	1.7%
2009	-0.4%	0.8%	-2.8%	14,418.7	-2.0%
2010	1.6%	1.2%	2.5%	14,964.4	3.8%
2011	3.2%	2.1%	1.6%	15,517.9	3.7%
2012	2.1%	1.8%	2.2%	16,155.3	4.1%
2013	1.5%	1.6%	1.5%	16,663.2	3.1%
2014	1.6%	1.6%	2.4%	17,348.1	4.1%
2015	0.1%	1.0%	2.4%	17,937.8	3.4%
Average Rate of Change [6]:					
1986-2015	2.7%	2.2%	2.6%	4.8%	4.9%
1996-2015	2.2%	1.9%	2.4%	4.3%	4.4%
2006-2015	2.0%	1.8%	1.4%	3.2%	3.2%

Notes:

[1] U.S. Department of Labor, Bureau of Labor Statistics;
U.S. city average, all urban consumers, all items, not seasonally adjusted

[2] U.S. Department of Commerce, Bureau of Economic Analysis,
National Income and Product Accounts Tables, Table 1.1.9, Revised on March 25, 2016

[3] U.S. Department of Commerce, Bureau of Economic Analysis,
National Income and Product Accounts Tables, Table 1.1.1, Revised on March 25, 2016

[4] U.S. Department of Commerce, Bureau of Economic Analysis,
National Income and Product Accounts Tables, Table 1.1.5, Revised on March 25, 2016

[5] Equals annual percent change of Column [4]

[6] Nominal GDP growth rates based on geometric average rate of change

Exhibit No. 05
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Intermountain Gas Company

Bond Yield Averages

January 2010 - May 2016

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds		Credit Spreads	
				A-Rated	Baa-Rated	A-Rated	Baa-Rated
2010	JAN	4.60	5.76	5.77	6.16	1.17	1.55
	FEB	4.62	5.86	5.87	6.25	1.25	1.63
	MAR	4.64	5.81	5.84	6.22	1.20	1.58
	APR	4.69	5.80	5.81	6.19	1.12	1.49
	MAY	4.29	5.52	5.50	5.97	1.21	1.68
	JUN	4.13	5.52	5.46	6.18	1.34	2.05
	JUL	3.99	5.32	5.26	5.98	1.26	1.98
	AUG	3.80	5.05	5.01	5.55	1.20	1.74
	SEP	3.77	5.05	5.01	5.53	1.24	1.76
	OCT	3.87	5.15	5.10	5.62	1.23	1.75
	NOV	4.19	5.37	5.37	5.85	1.18	1.67
	DEC	4.42	5.55	5.56	6.04	1.14	1.62
2011	JAN	4.52	5.56	5.57	6.06	1.05	1.54
	FEB	4.65	5.66	5.68	6.10	1.03	1.45
	MAR	4.51	5.55	5.56	5.97	1.05	1.46
	APR	4.50	5.56	5.55	5.98	1.05	1.48
	MAY	4.29	5.33	5.32	5.74	1.03	1.45
	JUN	4.23	5.30	5.26	5.67	1.03	1.44
	JUL	4.27	5.30	5.27	5.70	0.99	1.43
	AUG	3.65	4.79	4.69	5.22	1.04	1.57
	SEP	3.18	4.60	4.48	5.11	1.30	1.93
	OCT	3.13	4.60	4.52	5.24	1.39	2.11
	NOV	3.02	4.39	4.25	4.93	1.23	1.92
	DEC	2.98	4.47	4.33	5.07	1.35	2.09
2012	JAN	3.03	4.45	4.34	5.06	1.31	2.04
	FEB	3.11	4.42	4.36	5.02	1.25	1.91
	MAR	3.28	4.54	4.48	5.13	1.20	1.85
	APR	3.18	4.49	4.40	5.11	1.21	1.93
	MAY	2.93	4.33	4.20	4.97	1.27	2.03
	JUN	2.70	4.22	4.08	4.91	1.38	2.21
	JUL	2.59	4.03	3.93	4.85	1.34	2.26
	AUG	2.77	4.09	4.00	4.88	1.23	2.11
	SEP	2.88	4.09	4.02	4.81	1.14	1.93
	OCT	2.90	3.97	3.91	4.54	1.01	1.64
	NOV	2.80	3.92	3.84	4.42	1.03	1.61
	DEC	2.88	4.05	4.00	4.56	1.12	1.67

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
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Intermountain Gas Company

Bond Yield Averages

January 2010 - May 2016

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds		Credit Spreads	
				A-Rated	Baa-Rated	A-Rated	Baa-Rated
2013	JAN	3.08	4.19	4.15	4.66	1.07	1.58
	FEB	3.17	4.27	4.18	4.74	1.02	1.58
	MAR	3.16	4.29	4.20	4.72	1.04	1.56
	APR	2.93	4.07	4.00	4.49	1.07	1.55
	MAY	3.11	4.23	4.17	4.65	1.05	1.54
	JUN	3.40	4.63	4.53	5.08	1.13	1.68
	JUL	3.61	4.76	4.68	5.21	1.08	1.60
	AUG	3.76	4.89	4.73	5.28	0.97	1.52
	SEP	3.79	4.95	4.80	5.31	1.02	1.52
	OCT	3.68	4.82	4.70	5.17	1.02	1.49
	NOV	3.80	4.91	4.77	5.24	0.97	1.44
	DEC	3.89	4.92	4.81	5.25	0.92	1.36
2014	JAN	3.77	4.76	4.63	5.09	0.86	1.32
	FEB	3.66	4.68	4.53	5.01	0.87	1.35
	MAR	3.62	4.65	4.51	5.00	0.89	1.37
	APR	3.52	4.52	4.41	4.85	0.89	1.33
	MAY	3.39	4.38	4.26	4.69	0.87	1.30
	JUN	3.42	4.44	4.29	4.73	0.87	1.31
	JUL	3.33	4.37	4.23	4.66	0.89	1.33
	AUG	3.20	4.29	4.13	4.65	0.93	1.45
	SEP	3.26	4.39	4.24	4.79	0.98	1.53
	OCT	3.04	4.22	4.06	4.67	1.02	1.63
	NOV	3.04	4.28	4.09	4.75	1.05	1.71
	DEC	2.83	4.17	3.95	4.70	1.11	1.86
2015	JAN	2.46	3.84	3.58	4.39	1.13	1.94
	FEB	2.57	3.93	3.67	4.44	1.11	1.87
	MAR	2.63	3.98	3.74	4.51	1.12	1.88
	APR	2.59	3.93	3.75	4.51	1.16	1.92
	MAY	2.96	4.35	4.17	4.91	1.22	1.95
	JUN	3.11	4.56	4.39	5.13	1.28	2.01
	JUL	3.07	4.57	4.40	5.22	1.33	2.16
	AUG	2.86	4.48	4.25	5.23	1.39	2.37
	SEP	2.95	4.59	4.39	5.42	1.43	2.47
	OCT	2.89	4.52	4.29	5.47	1.40	2.58
	NOV	3.03	4.62	4.40	5.57	1.37	2.54
	DEC	2.97	4.58	4.35	5.55	1.38	2.58
2016	JAN	2.86	4.56	4.27	5.49	1.41	2.63
	FEB	2.62	4.44	4.11	5.28	1.49	2.66
	MAR	2.68	4.33	4.16	5.12	1.47	2.44
	APR	2.62	4.09	4.00	4.75	1.37	2.12
	MAY	2.63	4.04	3.93	4.60	1.30	1.97

Intermountain Gas Company

Bond Yield Averages

January 2010 - May 2016

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds		Credit Spreads	
				A-Rated	Baa-Rated	A-Rated	Baa-Rated
2016	AVG	2.68	4.29	4.09	5.05	1.41	2.36

Notes:

[1] Bloomberg Finance L.P., 30-Year U.S. Treasury Bond
[2] Bloomberg Finance L.P., Moody's Average Corporate Bond Index
[3] Bloomberg Finance L.P., Moody's A-Rated Utility Bond Index
[4] Bloomberg Finance L.P., Moody's Baa-Rated Utility Bond Index
[5] Equals Column [3] − Column [1]
[6] Equals Column [4] − Column [1]

Intermountain Gas Company

Common Equity Flotation Costs of Natural Gas Distribution Companies

2004-2016

Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Piedmont Natural Gas Company, Inc.	1/20/2004	4,250,000	$42.500	$41.010	3.63%
MDU Resources Group, Inc.	2/4/2004	2,000,000	$23.320	$22.527	3.52%
UGI Corporation	3/18/2004	7,500,000	$32.100	$30.696	4.58%
Northwest Natural Gas Company	3/30/2004	1,200,000	$31.000	$29.990	3.37%
The Laclede Group, Inc.	5/25/2004	1,500,000	$26.800	$25.929	3.36%
Atmos Energy Corporation	7/13/2004	8,650,000	$24.750	$23.760	4.17%
Southern Union Company	7/26/2004	11,000,000	$18.750	$18.094	3.63%
Aquila, Inc.	8/18/2004	40,000,000	$2.550	$2.451	4.04%
Atmos Energy Corporation	10/21/2004	14,000,000	$24.750	$23.760	4.17%
AGL Resources Inc.	11/19/2004	9,600,000	$31.010	$30.080	3.09%
Cinergy Corporation	12/9/2004	6,100,000	$41.000	$40.510	1.21%
Southern Union Company	2/7/2005	14,910,000	$23.000	$22.300	3.14%
SEMCO Energy, Inc.	8/10/2005	4,300,000	$6.320	$6.067	4.17%
Chesapeake Utilities Corporation	11/16/2006	600,300	$30.100	$28.975	3.88%
Atmos Energy Corporation	12/7/2006	5,500,000	$31.500	$30.398	3.63%
Vectren Corporation	2/22/2007	4,600,000	$28.330	$27.338	3.63%
Unitil Corporation	12/10/2008	2,000,000	$20.000	$18.950	5.54%
Unitil Corporation	5/20/2009	2,400,000	$20.000	$18.950	5.54%
CenterPoint Energy, Inc.	9/10/2009	21,000,000	$12.000	$11.580	3.63%
CenterPoint Energy, Inc.	6/9/2010	22,000,000	$12.900	$12.449	3.63%
NiSource Inc.	9/8/2010	21,100,000	$16.500	$15.964	3.36%
Gas Natural Inc.	11/10/2010	2,100,000	$10.000	$9.400	6.38%
Unitil Corporation	5/10/2012	2,400,000	$25.250	$23.988	5.26%
Gas Natural Inc.	6/27/2012	700,000	$10.100	$9.494	6.38%
Piedmont Natural Gas Company, Inc.	1/29/2013	4,000,000	$32.000	$30.880	3.63%
The Laclede Group, Inc.	5/22/2013	8,700,000	$44.500	$42.780	4.02%
Gas Natural Inc.	7/11/2013	1,500,000	$10.000	$9.425	6.10%
Gas Natural Inc.	10/31/2013	1,134,155	$10.000	$9.425	6.10%
Atmos Energy Corporation	2/11/2014	8,000,000	$44.000	$42.460	3.63%
The Laclede Group, Inc.	6/5/2014	9,000,000	$46.250	$44.539	3.84%
South Jersey Industries, Inc.	5/12/2016	7,000,000	$26.250	$25.331	3.63%
Spire, Inc.	5/12/2016	1,900,000	$63.050	$61.000	3.36%
			Average 2004-2016:		4.10%
			Selected Flotation Costs for Cost of Equity:		4.00%

Sources: *SNL Financial LC*

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 2, p. 1 of 1

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Fiscal Year 2015 Operating Data

Company	Ticker	Total Assets ($ millions)	Operating Revenues ($ millions)	Operating Income ($ millions)	
Atmos Energy Corporation	ATO	9,092.9	4,142.1	631.4	2/
Spire Inc.	SR	5,290.2	1,976.4	272.5	2/
New Jersey Resources Corporation	NJR	3,284.4	2,734.0	248.5	2/
Northwest Natural Gas Company	NWN	3,069.4	741.8	124.2	1/
South Jersey Industries, Inc.	SJI	3,471.9	959.6	156.9	1/
Southwest Gas Corporation	SWX	5,358.7	2,463.6	288.3	1/
WGL Holdings, Inc.	WGL	5,261.4	2,659.8	260.8	2/
High		9,093	4,142	631	
Average		**4,976**	**2,240**	**283**	
Median		**5,261**	**2,464**	**261**	
Low		3,069	742	124	
Intermountain Gas Company		**$236.9**	**$265.0**	**$24.3**	3/
Intermountain Gas Company % of:					
- Proxy Company Median		4.50%	10.76%	9.32%	

Notes:

1/ Source: SNL Financial LC; data as of December 31, 2015

2/ Source: SNL Financial LC; data as of September 30, 2015

3/ Source: Intermountain Gas Company Rate Filing, based on proposed test year ending December 31, 2016.

For Intermountain, the figure is for Rate Base, not Total Assets.

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 3, p. 1 of 2

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Credit Ratings

Company	Ticker	Standard & Poor's	Moody's
Atmos Energy Corporation	ATO	A	A2
Spire Inc.	SR	A-	Baa2
New Jersey Resources Corporation (1)	NJR	AA	Aa2
Northwest Natural Gas Company	NWN	A+	A3
South Jersey Industries, Inc.	SJI	BBB+	--
Southwest Gas Corporation	SWX	BBB+	A3
WGL Holdings, Inc.	WGL	A+	A3
Average		**A**	**A3**
Median		**A**	**A3**
MDU Resources, Inc.	MDU	BBB+	--

Notes:

Source: SNL Financial LC as of May 31, 2016

(1) New Jersey Resources Corporation rating is for New Jersey Natural Gas Company

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 3, p. 2 of 2

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Dividend Yields

December 2015 - May 2016

Company	Ticker	Average Dividend Yield
Atmos Energy Corporation	ATO	2.44%
Spire, Inc.	SR	3.11%
New Jersey Resources Corporation	NJR	2.80%
Northwest Natural Gas Company	NWN	3.62%
South Jersey Industries, Inc.	SJI	4.12%
Southwest Gas Corporation	SWX	2.72%
WGL Holdings, Inc.	WGL	2.85%
Average		**3.09%**
Median		**2.85%**

			Price			Annualized	Dividend
			Low	High	Average	Dividend	Yield
Atmos Energy Corporation	ATO	Dec-15	60.42	64.79	$ 62.61	$ 1.68	2.68%
		Jan-16	60.00	69.22	64.61	$ 1.68	2.60%
		Feb-16	67.94	71.90	69.92	$ 1.68	2.40%
		Mar-16	68.60	74.60	71.60	$ 1.68	2.35%
		Apr-16	70.41	74.86	72.64	$ 1.68	2.31%
		May-16	70.84	75.10	72.97	$ 1.68	2.30%
							2.44%
Spire, Inc.	SR	Dec-15	55.24	61.04	$ 58.14	$ 1.96	3.37%
		Jan-16	57.10	63.94	60.52	$ 1.96	3.24%
		Feb-16	63.31	66.43	64.87	$ 1.96	3.02%
		Mar-16	64.39	68.79	66.59	$ 1.96	2.94%
		Apr-16	62.65	68.40	65.53	$ 1.96	2.99%
		May-16	61.00	66.20	63.60	$ 1.96	3.08%
							3.11%
New Jersey Resources Corporation	NJR	Dec-15	28.02	34.07	$ 31.05	$ 0.96	3.09%
		Jan-16	32.32	35.57	33.94	$ 0.96	2.83%
		Feb-16	33.37	36.57	34.97	$ 0.96	2.75%
		Mar-16	33.32	36.85	35.09	$ 0.96	2.74%
		Apr-16	34.55	36.88	35.71	$ 0.96	2.69%
		May-16	33.91	37.17	35.54	$ 0.96	2.70%
							2.80%
Northwest Natural Gas Company	NWN	Dec-15	47.78	51.85	$ 49.82	$ 1.87	3.75%
		Jan-16	49.30	52.01	50.66	$ 1.87	3.69%
		Feb-16	49.41	53.88	51.65	$ 1.87	3.62%
		Mar-16	48.90	54.51	51.71	$ 1.87	3.62%
		Apr-16	49.46	54.29	51.88	$ 1.87	3.60%
		May-16	51.12	57.95	54.54	$ 1.87	3.43%
							3.62%

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Dividend Yields

December 2015 - May 2016

Company	Ticker	Average Dividend Yield
Atmos Energy Corporation	ATO	2.44%
Spire, Inc.	SR	3.11%
New Jersey Resources Corporation	NJR	2.80%
Northwest Natural Gas Company	NWN	3.62%
South Jersey Industries, Inc.	SJI	4.12%
Southwest Gas Corporation	SWX	2.72%
WGL Holdings, Inc.	WGL	2.85%
Average		**3.09%**
Median		**2.85%**

			Price			Annualized	Dividend
			Low	High	Average	Dividend	Yield
South Jersey Industries, Inc.	SJI	Dec-15	21.24	24.40	$ 22.82	$ 1.06	4.62%
		Jan-16	22.06	24.86	23.46	$ 1.06	4.50%
		Feb-16	24.54	26.94	25.74	$ 1.06	4.10%
		Mar-16	25.27	29.14	27.21	$ 1.06	3.88%
		Apr-16	27.17	28.55	27.86	$ 1.06	3.79%
		May-16	26.29	28.97	27.63	$ 1.06	3.82%
							4.12%
Southwest Gas Corporation	SWX	Dec-15	50.53	56.71	$ 53.62	$ 1.62	3.02%
		Jan-16	53.51	58.92	56.22	$ 1.62	2.88%
		Feb-16	58.07	62.43	60.25	$ 1.62	2.69%
		Mar-16	59.49	67.29	63.39	$ 1.62	2.56%
		Apr-16	62.75	66.60	64.68	$ 1.62	2.50%
		May-16	64.39	70.51	67.45	$ 1.80	2.67%
							2.72%
WGL Holdings, Inc.	WGL	Dec-15	58.62	65.55	$ 62.09	$ 1.85	2.98%
		Jan-16	59.99	66.81	63.40	1.85	2.92%
		Feb-16	62.93	69.20	66.07	1.85	2.80%
		Mar-16	67.23	74.10	70.67	1.85	2.62%
		Apr-16	65.00	72.84	68.92	1.95	2.83%
		May-16	63.06	70.09	66.58	1.95	2.93%
							2.85%

Source: Bloomberg Finance L.P.

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Projected Earnings Retention Growth Rates

		Value Line Forecast 2019-21				
Company	Ticker	EPS	DPS	ROE	Retention Rate	Retention Growth
Atmos Energy Corporation	ATO	$4.00	$2.15	11.00%	46.25%	5.09%
Spire Inc.	SR	$4.20	$2.20	9.50%	47.62%	4.52%
New Jersey Resources Corporation	NJR	$1.95	$1.02	11.50%	47.69%	5.48%
Northwest Natural Gas Company	NWN	$3.15	$2.05	9.50%	34.92%	3.32%
South Jersey Industries, Inc.	SJI	$1.80	$1.40	9.50%	22.22%	2.11%
Southwest Gas Corporation	SWX	$4.50	$2.40	12.50%	46.67%	5.83%
WGL Holdings, Inc.	WGL	$3.55	$2.03	11.00%	42.82%	4.71%
Average						**4.44%**
Median						**4.71%**

Source: Value Line, as of June 3, 2016.

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Earnings Growth Rate Estimates

Company	Ticker	1/2 Zacks 5-Yr Earnings Growth	1/2 Yahoo Finance! Earnings Growth	Weighted Average
Atmos Energy Corporation	ATO	6.60%	6.40%	6.50%
Spire, Inc.	SR	4.60%	4.52%	4.56%
New Jersey Resources Corporation	NJR	6.50%	6.50%	6.50%
Northwest Natural Gas Company	NWN	4.00%	4.00%	4.00%
South Jersey Industries, Inc.	SJI	6.00%	6.00%	6.00%
Southwest Gas Corporation	SWX	5.00%	4.00%	4.50%
WGL Holdings, Inc.	WGL	7.30%	8.00%	7.65%
Average		**5.71%**	**5.63%**	**5.67%**
Median		**6.00%**	**6.00%**	**6.00%**

Source: Yahoo Finance! and Zacks Investment Research as of May 31, 2016.

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Blended Growth Rate Estimates

Company	Ticker	1/2 Retention Growth	1/2 Earnings Growth	Weighted Average
Atmos Energy Corporation	ATO	5.09%	6.50%	5.79%
Spire, Inc.	SR	4.52%	4.56%	4.54%
New Jersey Resources Corporation	NJR	5.48%	6.50%	5.99%
Northwest Natural Gas Company	NWN	3.32%	4.00%	3.66%
South Jersey Industries, Inc.	SJI	2.11%	6.00%	4.06%
Southwest Gas Corporation	SWX	5.83%	4.50%	5.17%
WGL Holdings, Inc.	WGL	4.71%	7.65%	6.18%
Average		**4.44%**	**5.67%**	**5.06%**
Median		**4.71%**	**6.00%**	**5.17%**

Source: Schedule 4, page 3 of 8, and Schedule 4, page 4 of 8

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 4, p. 5 of 7

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Basic DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
Atmos Energy Corporation	ATO	2.44%	2.54%	6.50%	9.04%	1.04	9.40%
Spire, Inc.	SR	3.11%	3.20%	4.56%	7.76%	1.04	8.07%
New Jersey Resources Corporation	NJR	2.80%	2.91%	6.50%	9.41%	1.04	9.79%
Northwest Natural Gas Company	NWN	3.62%	3.71%	4.00%	7.71%	1.04	8.02%
South Jersey Industries, Inc.	SJI	4.12%	4.27%	6.00%	10.27%	1.04	10.68%
Southwest Gas Corporation	SWX	2.72%	2.80%	4.50%	7.30%	1.04	7.59%
WGL Holdings, Inc.	WGL	2.85%	2.98%	7.65%	10.63%	1.04	11.06%
High					10.63%		11.06%
3rd Quartile					9.84%		10.24%
2nd Quartile (Median)					**9.04%**		**9.40%**
1st Quartile					7.73%		8.04%
Low					7.30%		7.59%

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 4, p. 6 of 7

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Blended Growth Rate DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
Atmos Energy Corporation	ATO	2.44%	2.53%	5.79%	8.32%	1.04	8.66%
Spire, Inc.	SR	3.11%	3.20%	4.54%	7.74%	1.04	8.05%
New Jersey Resources Corporation	NJR	2.80%	2.90%	5.99%	8.90%	1.04	9.25%
Northwest Natural Gas Company	NWN	3.62%	3.70%	3.66%	7.36%	1.04	7.66%
South Jersey Industries, Inc.	SJI	4.12%	4.22%	4.06%	8.28%	1.04	8.61%
Southwest Gas Corporation	SWX	2.72%	2.81%	5.17%	7.97%	1.04	8.29%
WGL Holdings, Inc.	WGL	2.85%	2.96%	6.18%	9.14%	1.04	9.50%
High					9.14%		9.50%
3rd Quartile					8.61%		8.95%
2nd Quartile (Median)					**8.28%**		**8.61%**
1st Quartile					7.86%		8.17%
Low					7.36%		7.66%

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Natural Gas ROE	[2] 30-year U.S. Treasury Bond	[3] Risk Premium
1992.1	12.42%	7.84%	4.58%
1992.2	11.98%	7.88%	4.10%
1992.3	11.91%	7.42%	4.49%
1992.4	11.92%	7.54%	4.38%
1993.1	11.75%	7.01%	4.74%
1993.2	11.71%	6.86%	4.85%
1993.3	11.40%	6.23%	5.17%
1993.4	11.12%	6.21%	4.92%
1994.1	11.12%	6.66%	4.46%
1994.2	10.84%	7.45%	3.39%
1994.3	10.87%	7.55%	3.31%
1994.4	11.53%	7.95%	3.58%
1995.2	11.00%	6.87%	4.13%
1995.3	11.07%	6.66%	4.40%
1995.4	11.61%	6.14%	5.47%
1996.1	11.45%	6.39%	5.06%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	7.00%	4.25%
1996.4	11.19%	6.54%	4.65%
1997.1	11.31%	6.90%	4.41%
1997.2	11.70%	6.88%	4.82%
1997.3	12.00%	6.44%	5.56%
1997.4	10.92%	6.04%	4.87%
1998.2	11.37%	5.79%	5.57%
1998.3	11.41%	5.32%	6.09%
1998.4	11.69%	5.11%	6.59%
1999.1	10.82%	5.43%	5.39%
1999.2	11.25%	5.82%	5.43%
1999.4	10.38%	6.31%	4.06%
2000.1	10.66%	6.15%	4.50%
2000.2	11.03%	5.95%	5.08%
2000.3	11.33%	5.78%	5.56%
2000.4	12.10%	5.62%	6.48%
2001.1	11.38%	5.42%	5.96%
2001.2	10.75%	5.77%	4.98%
2001.4	10.65%	5.21%	5.44%
2002.1	10.67%	5.55%	5.12%
2002.2	11.64%	5.57%	6.07%
2002.3	11.50%	4.96%	6.54%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.78%	6.61%
2003.2	11.36%	4.57%	6.80%
2003.3	10.61%	5.15%	5.46%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.86%	6.20%
2004.2	10.57%	5.31%	5.27%
2004.3	10.37%	5.01%	5.36%
2004.4	10.66%	4.87%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.34%	6.19%
2005.3	10.47%	4.43%	6.04%
2005.4	10.32%	4.66%	5.66%
2006.1	10.68%	4.69%	5.99%
2006.2	10.60%	5.19%	5.41%
2006.3	10.34%	4.90%	5.44%
2006.4	10.14%	4.70%	5.45%
2007.1	10.52%	4.81%	5.71%
2007.2	10.13%	4.98%	5.14%
2007.3	10.03%	4.85%	5.17%
2007.4	10.12%	4.53%	5.59%
2008.1	10.38%	4.34%	6.04%
2008.2	10.17%	4.57%	5.60%
2008.3	10.55%	4.44%	6.12%
2008.4	10.34%	3.49%	6.85%
2009.1	10.24%	3.62%	6.63%
2009.2	10.11%	4.23%	5.87%
2009.3	9.88%	4.18%	5.70%
2009.4	10.31%	4.35%	5.95%
2010.1	10.24%	4.59%	5.65%
2010.2	9.99%	4.20%	5.78%
2010.3	10.43%	3.73%	6.70%
2010.4	10.09%	4.14%	5.95%
2011.1	10.10%	4.53%	5.57%
2011.2	9.85%	4.33%	5.51%
2011.3	9.65%	3.54%	6.11%
2011.4	9.88%	3.03%	6.85%
2012.1	9.63%	3.12%	6.51%
2012.2	9.83%	2.84%	7.00%
2012.3	9.75%	2.68%	7.07%
2012.4	10.06%	2.87%	7.18%
2013.1	9.57%	3.12%	6.45%
2013.2	9.47%	3.22%	6.25%
2013.3	9.60%	3.67%	5.93%
2013.4	9.83%	3.81%	6.02%
2014.1	9.54%	3.58%	5.96%
2014.2	9.84%	3.38%	6.45%
2014.3	9.45%	3.20%	6.25%
2014.4	10.28%	2.90%	7.38%
2015.1	9.47%	2.45%	7.02%
2015.2	9.43%	2.92%	6.52%
2015.3	9.75%	2.91%	6.84%
2015.4	9.68%	2.97%	6.71%
2016.1	9.48%	2.66%	6.83%
2016.2	9.42%	2.54%	6.88%
Average	10.64%	5.01%	5.63%
Median	10.61%	4.89%	5.68%

Exhibit No. 05
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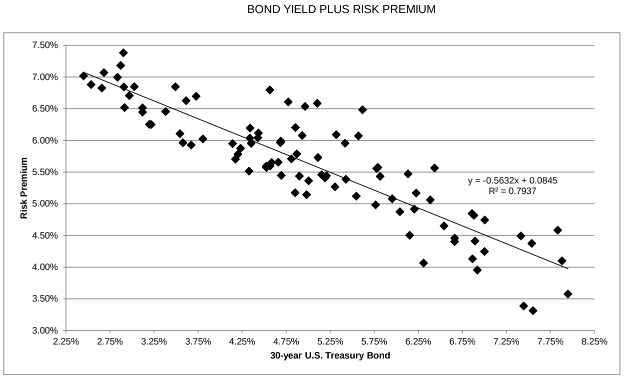

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.89092
R Square	0.79373
Adjusted R Square	0.79149
Standard Error	0.00413
Observations	94

ANOVA

	df	*SS*	*MS*	*F*	*ignificance F*
Regression	1	0.00605	0.00605	354.02755	0.00000
Residual	92	0.00157	0.00002		
Total	93	0.00762			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	0.0845	0.001558	54.26	0.00000	0.081438	0.087627	0.081438	0.087627
U.S. Govt. 30-year Treasury	-0.5632	0.029932	-18.82	0.00000	-0.622637	-0.503742	-0.622637	-0.503742

	[7]	[8]	[9]
	30-year U.S. Treasury Bond	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	2.65%	6.96%	9.61%
Near-term projected 30-year U.S. Treasury bond yield (Q2 2016 - Q3 2017) [5]	3.08%	6.72%	9.80%
Projected 30-year U.S. Treasury bond yield (2018 - 2022) [6]	4.30%	6.03%	10.33%
MEAN			9.91%

Notes:
[1] Source: Regulatory Research Associates
[2] Source: Bloomberg Professional, quarterly bond yields are the daily average of each trading day in the quarter
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14
[7] See Notes [4], [5] and [6]
[8] Equals 0.084532 + (-0.563190 x [7])
[9] Equals [7] + [8]

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.625g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Best Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Best Long-Term Growth Estimate
Alcoa Inc	AA	1,315.1	9.27	12,191	0.0771%	1.2945%	5.00%	0.001%	0.0039%
LyondellBasell Industries NV	LYB	426.7	81.36	34,719	0.2197%	4.179%	5.667%	0.0092%	0.0125%
American Express Co	AXP	951.0	65.76	62,540	0.3958%	1.764%	8.20%	0.007%	0.0325%
Verizon Communications Inc	VZ	4,076.3	50.90	207,483	1.3130%	4.4401%	3.952%	0.0583%	0.0519%
Broadcom Ltd	AVGO	390.4	154.36	60,270	0.3814%	1.2698%	15.142%	0.0048%	0.0578%
Boeing Co/The	BA	637.0	126.15	80,359	0.5085%	3.4562%	12.08%	0.0176%	0.0614%
Caterpillar Inc	CAT	583.9	72.51	42,338	0.2679%	4.2477%	7.225%	0.0114%	0.0194%
JPMorgan Chase & Co	JPM	3,656.7	65.27	238,670	1.5104%	2.9416%	4.206%	0.0444%	0.0635%
Chevron Corp	CVX	1,884.7	101.00	190,355	1.2046%	4.2376%	7.375%	0.051%	0.0888%
Coca-Cola Co/The	KO	4,326.2	44.60	192,948	1.2210%	3.139%	5.72%	0.0383%	0.0698%
AbbVie Inc	ABBV	1,617.4	62.93	101,780	0.6441%	3.6231%	12.009%	0.0233%	0.0774%
Walt Disney Co/The	DIS	1,622.4	99.22	160,979	1.0187%	1.4312%	10.075%	0.0146%	0.1026%
Extra Space Storage Inc	EXR	125.2	92.97	11,641	0.0737%	3.3559%	7.03%	0.0025%	0.0052%
EI du Pont de Nemours & Co	DD	873.5	65.41	57,136	0.3616%	2.3238%	8.25%	0.0084%	0.0298%
Exxon Mobil Corp	XOM	4,146.6	89.02	369,131	2.3360%	3.37%	11.523%	0.0787%	0.2692%
Phillips 66	PSX	525.6	80.36	42,236	0.2673%	3.1359%	6.803%	0.0084%	0.0182%
General Electric Co	GE	9,195.7	30.23	277,985	1.7592%	3.0433%	9.98%	0.0535%	0.1756%
HP Inc	HPQ	1,726.7	13.38	23,103	0.1462%	3.707%	3.763%	0.0054%	0.0055%
Home Depot Inc/The	HD	1,244.0	132.12	164,358	1.0401%	2.089%	13.469%	0.0217%	0.1401%
International Business Machines Corp	IBM	960.0	153.74	147,585	0.9340%	3.6425%	3.543%	0.034%	0.0331%
Concho Resources Inc	CXO	131.6	121.34	15,962	0.0000%	n/a	25.00%	n/a	0.00%
Johnson & Johnson	JNJ	2,750.6	112.69	309,970	1.9616%	2.8396%	6.036%	0.0557%	0.1184%
McDonald's Corp	MCD	877.9	122.06	107,151	0.6781%	2.9166%	10.311%	0.0198%	0.0699%
Merck & Co Inc	MRK	2,768.0	56.26	155,729	0.9855%	3.2705%	5.70%	0.0322%	0.0562%
3M Co	MMM	606.5	168.32	102,089	0.6461%	2.6378%	9.10%	0.017%	0.0588%
American Water Works Co Inc	AWK	177.7	74.10	13,169	0.0833%	2.0243%	7.34%	0.0017%	0.0061%
Bank of America Corp	BAC	10,271.9	14.79	151,922	0.9614%	1.3523%	7.90%	0.013%	0.076%
CSRA Inc	CSRA	163.3	24.77	4,045	0.0256%	1.6149%	10.00%	0.0004%	0.0026%
Pfizer Inc	PFE	6,064.8	34.70	210,450	1.3318%	3.4582%	6.20%	0.0461%	0.0826%
Procter & Gamble Co/The	PG	2,661.9	81.04	215,716	1.3651%	3.3045%	6.25%	0.0451%	0.0853%
AT&T Inc	T	6,156.0	39.15	241,007	1.5252%	4.9042%	4.25%	0.0748%	0.0648%
Travelers Cos Inc/The	TRV	292.4	114.14	33,374	0.2112%	2.348%	7.125%	0.005%	0.015%
United Technologies Corp	UTX	836.9	100.58	84,172	0.5327%	2.6248%	9.556%	0.014%	0.0509%
Analog Devices Inc	ADI	307.4	58.50	17,980	0.1138%	2.8718%	8.92%	0.0033%	0.0101%
Wal-Mart Stores Inc	WMT	3,138.8	70.78	222,162	1.4059%	2.8257%	2.91%	0.0397%	0.0409%
Cisco Systems Inc	CSCO	5,029.7	29.05	146,113	0.9247%	3.58%	8.767%	0.0331%	0.0811%
Intel Corp	INTC	4,722.0	31.59	149,168	0.9440%	3.2922%	8.517%	0.0311%	0.0804%
General Motors Co	GM	1,539.8	31.28	48,166	0.3048%	4.8593%	9.583%	0.0148%	0.0292%
Microsoft Corp	MSFT	7,860.5	53.00	416,605	2.6364%	2.717%	8.46%	0.0716%	0.223%
Dollar General Corp	DG	283.8	89.90	25,512	0.1614%	1.1123%	13.848%	0.0018%	0.0224%
Kinder Morgan Inc/DE	KMI	2,231.6	18.08	40,347	0.2553%	2.7655%	14.65%	0.0071%	0.0374%
Citigroup Inc	C	2,934.9	46.57	136,680	0.8650%	0.4295%	9.91%	0.0037%	0.0857%
American International Group Inc	AIG	1,119.0	57.88	64,770	0.4099%	2.2115%	9.50%	0.0091%	0.0389%
Honeywell International Inc	HON	762.1	113.83	86,752	0.5490%	2.0908%	9.32%	0.0115%	0.0512%
Altria Group Inc	MO	1,956.4	63.64	124,507	0.7879%	3.5512%	7.648%	0.028%	0.0603%
HCA Holdings Inc	HCA	391.1	78.02	30,510	0.0000%	n/a	10.75%	n/a	0.00%
Under Armour Inc	UA	183.1	37.73	6,910	0.0000%	n/a	22.567%	n/a	0.00%
International Paper Co	IP	411.2	42.16	17,335	0.1097%	4.1746%	7.50%	0.0046%	0.0082%
Hewlett Packard Enterprise Co	HPE	1,716.6	18.47	31,705	0.2006%	1.1911%	6.417%	0.0024%	0.0129%
Abbott Laboratories	ABT	1,469.2	39.63	58,222	0.3685%	2.6243%	11.733%	0.0097%	0.0432%
Aflac Inc	AFL	414.0	69.46	28,756	0.1820%	2.3611%	4.64%	0.0043%	0.0084%
Air Products & Chemicals Inc	APD	216.1	142.64	30,822	0.1951%	2.4117%	8.167%	0.0047%	0.0159%
Royal Caribbean Cruises Ltd	RCL	215.2	77.39	16,658	0.1054%	1.9382%	24.867%	0.002%	0.0262%
American Electric Power Co Inc	AEP	491.3	64.73	31,803	0.2013%	3.4605%	5.048%	0.007%	0.0102%
Hess Corp	HES	316.7	59.93	18,981	0.0000%	1.6686%	(20.09%)	0.00%	0.00%
Anadarko Petroleum Corp	APC	510.4	51.86	26,471	0.1675%	0.3857%	8.333%	0.0006%	0.014%
Aon PLC	AON	264.9	109.27	28,948	0.1832%	1.208%	11.23%	0.0022%	0.0206%
Apache Corp	APA	378.5	57.14	21,629	0.1369%	1.7501%	7.00%	0.0024%	0.0096%
Archer-Daniels-Midland Co	ADM	587.6	42.77	25,131	0.1590%	2.8057%	6.285%	0.0045%	0.01%
AGL Resources Inc	GAS	120.7	65.80	7,941	0.0503%	3.2219%	6.00%	0.0016%	0.003%
Automatic Data Processing Inc	ADP	455.5	87.84	40,014	0.2532%	2.4135%	10.286%	0.0061%	0.026%
Verisk Analytics Inc	VRSK	168.2	79.39	13,351	0.0000%	n/a	12.00%	n/a	0.00%
AutoZone Inc	AZO	29.9	762.20	22,759	0.0000%	n/a	11.93%	n/a	0.00%
Avery Dennison Corp	AVY	89.2	74.38	6,633	0.0420%	2.2049%	8.20%	0.0009%	0.0034%
Baker Hughes Inc	BHI	437.9	46.38	20,310	0.1285%	1.4661%	14.00%	0.0019%	0.018%
Ball Corp	BLL	141.8	72.30	10,252	0.0649%	0.7192%	4.40%	0.0005%	0.0029%
Bank of New York Mellon Corp/The	BK	1,077.1	42.06	45,302	0.2867%	1.6167%	9.567%	0.0046%	0.0274%

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Best Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Best Long-Term Growth Estimate
CR Bard Inc	BCR	73.3	219.04	16,060	0.1016%	0.4383%	10.75%	0.0004%	0.0109%
Baxter International Inc	BAX	552.3	43.16	23,836	0.1508%	1.2048%	10.50%	0.0018%	0.0158%
Becton Dickinson and Co	BDX	212.2	166.45	35,321	0.2235%	1.5861%	11.507%	0.0035%	0.0257%
Berkshire Hathaway Inc	BRK/B	1,255.6	140.54	176,462	0.0000%	n/a	7.10%	n/a	0.00%
Best Buy Co Inc	BBY	324.1	32.17	10,426	0.0660%	3.4815%	10.18%	0.0023%	0.0067%
H&R Block Inc	HRB	224.4	21.36	4,793	0.0303%	3.7453%	11.00%	0.0011%	0.0033%
Boston Scientific Corp	BSX	1,356.9	22.71	30,814	0.0000%	n/a	11.257%	n/a	0.00%
Bristol-Myers Squibb Co	BMY	1,669.3	71.70	119,689	0.7574%	2.1199%	20.556%	0.0161%	0.1557%
Brown-Forman Corp	BF/B	115.5	98.07	11,329	0.0717%	1.3868%	6.92%	0.001%	0.005%
Cabot Oil & Gas Corp	COG	465.0	23.97	11,146	0.0705%	0.3338%	40.785%	0.0002%	0.0288%
Campbell Soup Co	CPB	309.1	60.57	18,725	0.1185%	2.0604%	7.315%	0.0024%	0.0087%
Kansas City Southern	KSU	108.0	93.10	10,054	0.0636%	1.4178%	7.775%	0.0009%	0.0049%
Carnival Corp	CCL	562.1	47.74	26,836	0.1698%	2.9326%	17.007%	0.005%	0.0289%
Qorvo Inc	QRVO	127.5	50.97	6,500	0.0000%	n/a	15.498%	n/a	0.00%
CenturyLink Inc	CTL	546.1	27.12	14,809	0.0000%	7.9646%	(1.187%)	0.00%	0.00%
Cigna Corp	CI	256.5	128.11	32,862	0.2080%	0.0312%	8.623%	0.0001%	0.0179%
UDR Inc	UDR	267.1	36.03	9,625	0.0609%	3.275%	6.725%	0.002%	0.0041%
Frontier Communications Corp	FTR	1,173.1	5.17	6,065	0.0384%	8.1238%	11.55%	0.0031%	0.0044%
Clorox Co/The	CLX	129.3	128.54	16,625	0.1052%	2.4895%	6.56%	0.0026%	0.0069%
CMS Energy Corp	CMS	280.0	41.82	11,708	0.0741%	2.9651%	6.00%	0.0022%	0.0044%
Colgate-Palmolive Co	CL	893.0	70.41	62,877	0.3979%	2.2156%	8.355%	0.0088%	0.0332%
Comerica Inc	CMA	175.1	47.10	8,249	0.0522%	1.8684%	6.547%	0.001%	0.0034%
CA Inc	CA	417.5	32.32	13,492	0.0854%	3.1559%	5.50%	0.0027%	0.0047%
ConAgra Foods Inc	CAG	436.4	45.70	19,944	0.1262%	2.1882%	7.75%	0.0028%	0.0098%
Consolidated Edison Inc	ED	304.2	73.26	22,283	0.1410%	3.6582%	3.14%	0.0052%	0.0044%
SL Green Realty Corp	SLG	100.2	101.36	10,160	0.0643%	2.8414%	4.85%	0.0018%	0.0031%
Corning Inc	GLW	1,075.3	20.89	22,464	0.1422%	2.585%	12.337%	0.0037%	0.0175%
Cummins Inc	CMI	170.4	114.47	19,501	0.1234%	3.407%	4.26%	0.0042%	0.0053%
Danaher Corp	DHR	688.7	98.36	67,740	0.4287%	0.6507%	11.975%	0.0028%	0.0513%
Target Corp	TGT	589.3	68.78	40,530	0.2565%	3.2568%	10.352%	0.0084%	0.0266%
Deere & Co	DE	314.3	82.29	25,860	0.1637%	2.9165%	7.44%	0.0048%	0.0122%
Dominion Resources Inc/VA	D	616.2	72.25	44,522	0.2817%	3.8754%	6.45%	0.0109%	0.0182%
Dover Corp	DOV	155.1	66.75	10,356	0.0655%	2.5169%	10.475%	0.0016%	0.0069%
Dow Chemical Co/The	DOW	1,122.8	51.36	57,668	0.3649%	3.5826%	6.00%	0.0131%	0.0219%
Duke Energy Corp	DUK	688.8	78.23	53,884	0.3410%	4.2183%	4.71%	0.0144%	0.0161%
Eaton Corp PLC	ETN	458.0	61.63	28,227	0.1786%	3.6995%	8.417%	0.0066%	0.015%
Ecolab Inc	ECL	293.3	117.24	34,387	0.2176%	1.1941%	12.357%	0.0026%	0.0269%
PerkinElmer Inc	PKI	109.0	54.75	5,969	0.0378%	0.5114%	19.783%	0.0002%	0.0075%
EMC Corp/MA	EMC	1,953.2	27.95	54,592	0.3455%	1.6458%	10.78%	0.0057%	0.0372%
Emerson Electric Co	EMR	643.4	52.02	33,467	0.2118%	3.6524%	7.325%	0.0077%	0.0155%
EOG Resources Inc	EOG	550.3	81.36	44,771	0.0000%	0.8235%	(16.56%)	0.00%	0.00%
Entergy Corp	ETR	178.7	75.92	13,570	0.0859%	4.4784%	0.75%	0.0038%	0.0006%
Equifax Inc	EFX	119.0	125.73	14,964	0.0947%	1.0499%	12.233%	0.001%	0.0116%
EQT Corp	EQT	172.7	73.25	12,653	0.0801%	0.1638%	25.00%	0.0001%	0.02%
XL Group PLC	XL	283.4	34.35	9,734	0.0616%	2.329%	9.00%	0.0014%	0.0055%
FedEx Corp	FDX	268.4	164.97	44,282	0.2802%	0.6062%	13.056%	0.0017%	0.0366%
Macy's Inc	M	308.4	33.21	10,242	0.0648%	4.5468%	9.667%	0.0029%	0.0063%
FMC Corp	FMC	133.8	47.49	6,352	0.0402%	1.3898%	9.533%	0.0006%	0.0038%
Ford Motor Co	F	3,902.0	13.49	52,638	0.3331%	4.4477%	6.67%	0.0148%	0.0222%
NextEra Energy Inc	NEE	461.4	120.12	55,429	0.3508%	2.8971%	6.423%	0.0102%	0.0225%
Franklin Resources Inc	BEN	584.9	37.35	21,847	0.1383%	1.9277%	6.19%	0.0027%	0.0086%
Freeport-McMoRan Inc	FCX	1,252.1	11.08	13,874	0.0000%	n/a	(146.00%)	n/a	0.00%
TEGNA Inc	TGNA	217.6	22.96	4,996	0.0316%	2.439%	8.033%	0.0008%	0.0025%
Gap Inc/The	GPS	397.9	17.99	7,158	0.0453%	5.114%	8.05%	0.0023%	0.0036%
General Dynamics Corp	GD	305.6	141.87	43,362	0.2744%	2.1428%	7.65%	0.0059%	0.021%
General Mills Inc	GIS	594.4	62.78	37,317	0.2362%	2.9309%	10.16%	0.0069%	0.024%
Genuine Parts Co	GPC	149.6	96.92	14,501	0.0918%	2.7136%	6.325%	0.0025%	0.0058%
WW Grainger Inc	GWW	61.3	228.35	14,003	0.0886%	2.1371%	9.36%	0.0019%	0.0083%
Halliburton Co	HAL	859.3	42.18	36,244	0.2294%	1.707%	13.15%	0.0039%	0.0302%
Harley-Davidson Inc	HOG	181.1	46.39	8,401	0.0532%	3.0179%	11.08%	0.0016%	0.0059%
Harman International Industries Inc	HAR	70.6	78.24	5,520	0.0349%	1.7894%	17.50%	0.0006%	0.0061%
Harris Corp	HRS	124.7	78.77	9,825	0.0000%	2.539%	n/a	0.00%	n/a
HCP Inc	HCP	467.1	32.87	15,353	0.0972%	6.9973%	1.215%	0.0068%	0.0012%
Helmerich & Payne Inc	HP	108.0	61.15	6,607	0.0000%	4.4971%	(1.40%)	0.00%	0.00%
Hershey Co/The	HSY	152.8	92.85	14,183	0.0898%	2.5116%	9.175%	0.0023%	0.0082%
Synchrony Financial	SYF	833.9	31.20	26,018	0.0000%	n/a	7.163%	n/a	0.00%
Hormel Foods Corp	HRL	529.9	34.41	18,234	0.1154%	1.6856%	5.90%	0.0019%	0.0068%

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 6, p. 2 of 10

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

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S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Best Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Best Long-Term Growth Estimate
Arthur J Gallagher & Co	AJG	177.1	48.33	8,561	0.0542%	3.145%	9.163%	0.0017%	0.005%
Starwood Hotels & Resorts Worldwide Inc	HOT	169.5	73.43	12,449	0.0788%	2.0428%	7.256%	0.0016%	0.0057%
Mondelez International Inc	MDLZ	1,552.1	44.49	69,051	0.4370%	1.5284%	12.986%	0.0067%	0.0567%
CenterPoint Energy Inc	CNP	430.6	22.53	9,702	0.0614%	4.5717%	4.00%	0.0028%	0.0025%
Humana Inc	HUM	149.0	172.51	25,710	0.1627%	0.6724%	13.138%	0.0011%	0.0214%
Willis Towers Watson PLC	WLTW	138.4	128.02	17,723	0.1122%	1.4998%	21.467%	0.0017%	0.0241%
Illinois Tool Works Inc	ITW	359.4	106.03	38,104	0.2411%	2.0749%	7.85%	0.005%	0.0189%
Ingersoll-Rand PLC	IR	257.5	66.81	17,201	0.1089%	1.9159%	9.625%	0.0021%	0.0105%
Foot Locker Inc	FL	136.1	55.92	7,610	0.0482%	1.9671%	10.438%	0.0009%	0.005%
Interpublic Group of Cos Inc/The	IPG	402.4	23.90	9,617	0.0609%	2.5105%	8.00%	0.0015%	0.0049%
International Flavors & Fragrances Inc	IFF	79.7	129.00	10,283	0.0651%	1.7364%	10.50%	0.0011%	0.0068%
Jacobs Engineering Group Inc	JEC	121.9	50.69	6,180	0.0000%	n/a	6.553%	n/a	0.00%
Johnson Controls Inc	JCI	648.4	44.15	28,626	0.1812%	2.6274%	9.20%	0.0048%	0.0167%
Hanesbrands Inc	HBI	377.5	27.07	10,219	0.0647%	1.6254%	16.575%	0.0011%	0.0107%
Kellogg Co	K	350.0	74.37	26,033	0.1647%	2.6893%	5.823%	0.0044%	0.0096%
Perrigo Co PLC	PRGO	143.2	95.84	13,726	0.0869%	0.6052%	9.76%	0.0005%	0.0085%
Kimberly-Clark Corp	KMB	360.1	127.04	45,751	0.2895%	2.8967%	7.64%	0.0084%	0.0221%
Kimco Realty Corp	KIM	419.6	28.18	11,826	0.0748%	3.6196%	5.673%	0.0027%	0.0042%
Kohl's Corp	KSS	185.2	36.04	6,673	0.0422%	5.5494%	3.75%	0.0023%	0.0016%
Oracle Corp	ORCL	4,149.9	40.20	166,825	1.0557%	1.4925%	7.69%	0.0158%	0.0812%
Kroger Co/The	KR	953.8	35.76	34,107	0.2158%	1.1745%	9.904%	0.0025%	0.0214%
Legg Mason Inc	LM	105.4	34.50	3,636	0.0230%	2.5507%	18.36%	0.0006%	0.0042%
Leggett & Platt Inc	LEG	134.3	50.26	6,751	0.0427%	2.7059%	10.00%	0.0012%	0.0043%
Lennar Corp	LEN	183.4	45.57	8,358	0.0529%	0.3511%	8.75%	0.0002%	0.0046%
Leucadia National Corp	LUK	362.3	18.10	6,558	0.0415%	1.3812%	18.00%	0.0006%	0.0075%
Eli Lilly & Co	LLY	1,103.8	75.03	82,821	0.5241%	2.7189%	11.517%	0.0143%	0.0604%
L Brands Inc	LB	287.0	68.55	19,674	0.1245%	3.5011%	10.94%	0.0044%	0.0136%
Lincoln National Corp	LNC	239.0	45.85	10,958	0.0693%	2.181%	11.80%	0.0015%	0.0082%
Loews Corp	L	339.0	40.48	13,723	0.0000%	0.6176%	n/a	0.00%	n/a
Lowe's Cos Inc	LOW	886.1	80.13	71,004	0.4493%	1.7472%	16.558%	0.0079%	0.0744%
Host Hotels & Resorts Inc	HST	747.3	15.40	11,509	0.0728%	5.1948%	5.00%	0.0038%	0.0036%
Marsh & McLennan Cos Inc	MMC	521.2	66.07	34,438	0.2179%	2.0584%	11.618%	0.0045%	0.0253%
Masco Corp	MAS	332.7	32.64	10,861	0.0687%	1.1642%	14.476%	0.0008%	0.0099%
Mattel Inc	MAT	340.4	31.88	10,853	0.0687%	4.7679%	10.15%	0.0033%	0.007%
S&P Global Inc	SPGI	264.6	111.81	29,585	0.1872%	1.2879%	10.00%	0.0024%	0.0187%
Medtronic PLC	MDT	1,401.0	80.48	112,756	0.7136%	1.8887%	8.752%	0.0135%	0.0625%
CVS Health Corp	CVS	1,074.0	96.45	103,589	0.6556%	1.7626%	14.04%	0.0116%	0.092%
Micron Technology Inc	MU	1,037.0	12.72	13,191	0.0000%	n/a	6.10%	n/a	0.00%
Motorola Solutions Inc	MSI	174.6	69.27	12,095	0.0765%	2.3675%	5.275%	0.0018%	0.004%
Murphy Oil Corp	MUR	172.2	30.91	5,323	0.0000%	4.5293%	n/a	0.00%	n/a
Mylan NV	MYL	508.4	43.34	22,033	0.0000%	n/a	9.417%	n/a	0.00%
Laboratory Corp of America Holdings	LH	102.4	127.95	13,102	0.0000%	n/a	11.293%	n/a	0.00%
Newell Brands Inc	NWL	478.0	47.69	22,794	0.1442%	1.5936%	13.77%	0.0023%	0.0199%
Newmont Mining Corp	NEM	530.5	32.41	17,195	0.1088%	0.3085%	6.133%	0.0003%	0.0067%
Twenty-First Century Fox Inc	FOXA	1,095.7	28.88	31,645	0.2003%	1.0388%	13.838%	0.0021%	0.0277%
NIKE Inc	NKE	1,331.5	55.22	73,524	0.4653%	1.159%	13.912%	0.0054%	0.0647%
NiSource Inc	NI	321.5	23.86	7,672	0.0000%	2.7661%	n/a	0.00%	n/a
Noble Energy Inc	NBL	429.6	35.75	15,358	0.0972%	1.1189%	10.00%	0.0011%	0.0097%
Norfolk Southern Corp	NSC	295.7	84.06	24,860	0.1573%	2.8075%	11.767%	0.0044%	0.0185%
Eversource Energy	ES	317.2	55.24	17,523	0.1109%	3.2223%	7.125%	0.0036%	0.0079%
Northrop Grumman Corp	NOC	180.5	212.67	38,377	0.2429%	1.6928%	7.54%	0.0041%	0.0183%
Wells Fargo & Co	WFC	5,077.0	50.72	257,508	1.6296%	2.9968%	9.878%	0.0488%	0.161%
Nucor Corp	NUE	317.9	48.51	15,423	0.0976%	3.0921%	8.20%	0.003%	0.008%
PVH Corp	PVH	81.0	93.80	7,602	0.0481%	0.1599%	6.355%	0.0001%	0.0031%
Occidental Petroleum Corp	OXY	763.7	75.44	57,617	0.3646%	3.9767%	8.00%	0.0145%	0.0292%
Omnicom Group Inc	OMC	237.8	83.33	19,812	0.1254%	2.6401%	6.45%	0.0033%	0.0081%
ONEOK Inc	OKE	210.1	43.25	9,087	0.0575%	5.6879%	7.30%	0.0033%	0.0042%
Owens-Illinois Inc	OI	161.9	18.90	3,060	0.0000%	n/a	7.00%	n/a	0.00%
PG&E Corp	PCG	496.0	60.08	29,802	0.1886%	3.2623%	4.00%	0.0062%	0.0075%
Parker-Hannifin Corp	PH	134.7	114.84	15,467	0.0979%	2.1944%	8.212%	0.0021%	0.008%
PPL Corp	PPL	676.9	38.54	26,089	0.1651%	3.944%	4.775%	0.0065%	0.0079%
PepsiCo Inc	PEP	1,444.4	101.17	146,132	0.9248%	2.9752%	6.422%	0.0275%	0.0594%
Exelon Corp	EXC	921.7	34.27	31,586	0.1999%	3.7117%	4.574%	0.0074%	0.0091%
ConocoPhillips	COP	1,238.4	43.79	54,229	0.3432%	2.2836%	6.667%	0.0078%	0.0229%
PulteGroup Inc	PHM	346.0	18.76	6,492	0.0411%	1.919%	14.04%	0.0008%	0.0058%
Pinnacle West Capital Corp	PNW	111.1	73.59	8,179	0.0518%	3.3972%	4.648%	0.0018%	0.0024%
Pitney Bowes Inc	PBI	188.6	18.63	3,514	0.0222%	4.0258%	14.00%	0.0009%	0.0031%

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.625g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Best Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Best Long-Term Growth Estimate
PNC Financial Services Group Inc/The	PNC	499.3	89.74	44,809	0.2836%	2.2732%	6.048%	0.0064%	0.0172%
PPG Industries Inc	PPG	266.1	107.68	28,650	0.1813%	1.4859%	8.50%	0.0027%	0.0154%
Praxair Inc	PX	285.3	109.86	31,339	0.1983%	2.7307%	7.11%	0.0054%	0.0141%
Progressive Corp/The	PGR	583.0	33.30	19,414	0.1229%	2.6673%	8.84%	0.0033%	0.0109%
Public Service Enterprise Group Inc	PEG	505.9	44.75	22,640	0.1433%	3.6648%	3.428%	0.0053%	0.0049%
Raytheon Co	RTN	297.0	129.67	38,509	0.2437%	2.2596%	7.935%	0.0055%	0.0193%
Robert Half International Inc	RHI	131.3	41.59	5,462	0.0346%	2.1159%	11.63%	0.0007%	0.004%
Ryder System Inc	R	53.7	69.62	3,739	0.0237%	2.3556%	9.92%	0.0006%	0.0023%
SCANA Corp	SCG	142.9	69.91	9,991	0.0632%	3.2899%	5.80%	0.0021%	0.0037%
Edison International	EIX	325.8	71.63	23,338	0.1477%	2.6804%	4.759%	0.004%	0.007%
Schlumberger Ltd	SLB	1,391.2	76.30	106,151	0.6718%	2.6212%	7.225%	0.0176%	0.0485%
Charles Schwab Corp/The	SCHW	1,321.7	30.58	40,417	0.2558%	0.9156%	19.00%	0.0023%	0.0486%
Sherwin-Williams Co/The	SHW	92.5	291.09	26,924	0.1704%	1.1543%	17.70%	0.002%	0.0302%
JM Smucker Co/The	SJM	119.7	129.15	15,457	0.0978%	2.0751%	14.50%	0.002%	0.0142%
Snap-on Inc	SNA	58.1	161.82	9,409	0.0595%	1.5078%	4.80%	0.0009%	0.0029%
AMETEK Inc	AME	233.4	47.82	11,162	0.0706%	0.7528%	10.304%	0.0005%	0.0073%
Southern Co/The	SO	938.6	49.44	46,402	0.2936%	4.5307%	3.90%	0.0133%	0.0115%
BB&T Corp	BBT	812.0	36.37	29,534	0.1869%	3.0795%	5.598%	0.0058%	0.0105%
Southwest Airlines Co	LUV	638.7	42.48	27,131	0.1717%	0.9416%	9.083%	0.0016%	0.0156%
Southwestern Energy Co	SWN	392.7	13.67	5,368	0.0000%	n/a	(15.98%)	n/a	0.00%
Stanley Black & Decker Inc	SWK	150.1	113.18	16,990	0.1075%	1.9438%	10.50%	0.0021%	0.0113%
Public Storage	PSA	173.4	253.71	43,989	0.2784%	2.8379%	5.483%	0.0079%	0.0153%
SunTrust Banks Inc	STI	501.1	43.82	21,959	0.1390%	2.1908%	6.883%	0.003%	0.0096%
Sysco Corp	SYY	563.5	48.11	27,111	0.1716%	2.5774%	10.00%	0.0044%	0.0172%
TECO Energy Inc	TE	235.6	27.54	6,487	0.0411%	3.3406%	5.00%	0.0014%	0.0021%
Tesoro Corp	TSO	120.0	78.08	9,368	0.0000%	2.5615%	(0.503%)	0.00%	0.00%
Texas Instruments Inc	TXN	1,004.2	60.60	60,856	0.3851%	2.5083%	10.00%	0.0097%	0.0385%
Textron Inc	TXT	268.8	38.06	10,232	0.0648%	0.2102%	7.31%	0.0001%	0.0047%
Thermo Fisher Scientific Inc	TMO	393.5	151.77	59,723	0.3780%	0.3953%	11.825%	0.0015%	0.0447%
Tiffany & Co	TIF	126.0	61.96	7,808	0.0494%	2.9051%	8.317%	0.0014%	0.0041%
TJX Cos Inc/The	TJX	661.1	76.12	50,322	0.3185%	1.3663%	11.556%	0.0044%	0.0368%
Torchmark Corp	TMK	120.7	61.63	7,436	0.0471%	0.9086%	7.98%	0.0004%	0.0038%
Total System Services Inc	TSS	183.6	53.70	9,860	0.0624%	0.7449%	11.00%	0.0005%	0.0069%
Tyco International Plc	TYC	425.5	42.62	18,135	0.1148%	1.924%	13.00%	0.0022%	0.0149%
Ulta Salon Cosmetics & Fragrance Inc	ULTA	62.6	233.01	14,594	0.0000%	n/a	21.00%	n/a	0.00%
Union Pacific Corp	UNP	841.0	84.19	70,807	0.4481%	2.6131%	12.917%	0.0117%	0.0579%
UnitedHealth Group Inc	UNH	950.8	133.67	127,094	0.8043%	1.4962%	13.017%	0.012%	0.1047%
Unum Group	UNM	237.8	36.92	8,778	0.0556%	2.1668%	7.60%	0.0012%	0.0042%
Marathon Oil Corp	MRO	847.6	13.07	11,079	0.0000%	1.5302%	(2.437%)	0.00%	0.00%
Varian Medical Systems Inc	VAR	95.2	82.79	7,883	0.0000%	n/a	12.05%	n/a	0.00%
Ventas Inc	VTR	338.1	66.33	22,428	0.1419%	4.4022%	5.12%	0.0062%	0.0073%
VF Corp	VFC	417.0	62.32	25,989	0.1645%	2.3748%	10.768%	0.0039%	0.0177%
Vornado Realty Trust	VNO	188.8	95.52	18,031	0.1141%	2.6382%	5.45%	0.003%	0.0062%
Vulcan Materials Co	VMC	133.2	116.75	15,550	0.0984%	0.6852%	23.08%	0.0007%	0.0227%
Weyerhaeuser Co	WY	747.1	31.50	23,533	0.1489%	3.9365%	12.267%	0.0059%	0.0183%
Whirlpool Corp	WHR	76.0	174.62	13,265	0.0839%	2.2907%	17.04%	0.0019%	0.0143%
Williams Cos Inc/The	WMB	750.6	22.16	16,633	0.0000%	11.5523%	(2.067%)	0.00%	0.00%
WEC Energy Group Inc	WEC	315.6	60.14	18,983	0.1201%	3.2923%	6.00%	0.004%	0.0072%
Xerox Corp	XRX	1,013.0	9.97	10,100	0.0639%	3.1093%	11.60%	0.002%	0.0074%
Adobe Systems Inc	ADBE	500.2	99.47	49,756	0.0000%	n/a	20.286%	n/a	0.00%
AES Corp/VA	AES	659.0	11.09	7,308	0.0462%	3.9675%	4.918%	0.0018%	0.0023%
Amgen Inc	AMGN	751.2	157.95	118,655	0.7509%	2.5324%	7.971%	0.019%	0.0599%
Apple Inc	AAPL	5,477.4	99.86	546,976	3.4615%	2.2832%	11.563%	0.079%	0.4002%
Autodesk Inc	ADSK	224.6	58.27	13,087	0.0000%	n/a	20.96%	n/a	0.00%
Cintas Corp	CTAS	107.0	94.80	10,144	0.0642%	1.1076%	11.95%	0.0007%	0.0077%
Comcast Corp	CMCSA	2,417.8	63.30	153,044	0.9685%	1.7378%	11.349%	0.0168%	0.1099%
Molson Coors Brewing Co	TAP	193.8	99.18	19,222	0.1216%	1.6536%	19.767%	0.002%	0.024%
KLA-Tencor Corp	KLAC	155.7	72.93	11,356	0.0719%	2.852%	5.55%	0.002%	0.004%
Marriott International Inc/MD	MAR	254.2	66.04	16,789	0.1062%	1.8171%	11.96%	0.0019%	0.0127%
McCormick & Co Inc/MD	MKC	115.3	97.07	11,190	0.0708%	1.7719%	9.10%	0.0013%	0.0064%
Nordstrom Inc	JWN	172.9	37.98	6,568	0.0416%	3.8968%	7.68%	0.0016%	0.0032%
PACCAR Inc	PCAR	350.5	55.75	19,538	0.1236%	1.722%	7.833%	0.0021%	0.0097%
Costco Wholesale Corp	COST	439.0	148.77	65,315	0.4133%	1.2099%	10.787%	0.005%	0.0446%
St Jude Medical Inc	STJ	284.3	78.36	22,276	0.1410%	1.5824%	10.625%	0.0022%	0.015%
Stryker Corp	SYK	374.0	111.16	41,572	0.2631%	1.3674%	12.488%	0.0036%	0.0329%
Tyson Foods Inc	TSN	300.5	63.78	19,168	0.1213%	0.9407%	12.025%	0.0011%	0.0146%
Applied Materials Inc	AMAT	1,089.1	24.42	26,597	0.1683%	1.638%	15.433%	0.0028%	0.026%

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Best Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Best Long-Term Growth Estimate
Time Warner Inc	TWX	786.4	75.66	59,499	0.3765%	2.1279%	14.382%	0.008%	0.0542%
Bed Bath & Beyond Inc	BBBY	154.4	44.75	6,908	0.0437%	1.1173%	6.756%	0.0005%	0.003%
American Airlines Group Inc	AAL	578.2	31.91	18,449	0.0000%	1.2535%	(15.44%)	0.00%	0.00%
Cardinal Health Inc	CAH	325.8	78.95	25,723	0.1628%	2.2744%	12.00%	0.0037%	0.0195%
Celgene Corp	CELG	774.6	105.52	81,736	0.0000%	n/a	22.373%	n/a	0.00%
Cerner Corp	CERN	338.1	55.61	18,801	0.0000%	n/a	16.30%	n/a	0.00%
Cincinnati Financial Corp	CINF	164.5	69.10	11,366	0.0000%	2.7786%	n/a	0.00%	n/a
Cablevision Systems Corp	CVC	222.2	34.68	7,706	0.0000%	n/a	9.25%	n/a	0.00%
DR Horton Inc	DHI	370.9	30.56	11,335	0.0717%	1.0471%	15.283%	0.0008%	0.011%
Flowserve Corp	FLS	130.4	48.13	6,275	0.0397%	1.5791%	11.667%	0.0006%	0.0046%
Electronic Arts Inc	EA	301.6	76.75	23,149	0.0000%	n/a	11.267%	n/a	0.00%
Express Scripts Holding Co	ESRX	632.5	75.55	47,788	0.0000%	n/a	13.80%	n/a	0.00%
Expeditors International of Washington Inc	EXPD	182.1	48.55	8,839	0.0559%	1.6478%	8.533%	0.0009%	0.0048%
Fastenal Co	FAST	288.9	46.03	13,297	0.0842%	2.607%	12.675%	0.0022%	0.0107%
M&T Bank Corp	MTB	159.0	119.50	19,000	0.1202%	2.3431%	5.445%	0.0028%	0.0065%
Fiserv Inc	FISV	222.3	105.33	23,418	0.0000%	n/a	12.74%	n/a	0.00%
Fifth Third Bancorp	FITB	767.7	18.87	14,487	0.0917%	2.7557%	3.833%	0.0025%	0.0035%
Gilead Sciences Inc	GILD	1,331.8	87.06	115,948	0.7338%	2.1594%	1.457%	0.0158%	0.0107%
Hasbro Inc	HAS	124.7	87.29	10,885	0.0689%	2.337%	10.40%	0.0016%	0.0072%
Huntington Bancshares Inc/OH	HBAN	798.9	10.45	8,348	0.0528%	2.6794%	5.875%	0.0014%	0.0031%
Welltower Inc	HCN	357.0	68.91	24,601	0.1557%	4.992%	4.67%	0.0078%	0.0073%
Biogen Inc	BIIB	219.1	289.73	63,466	0.0000%	n/a	8.274%	n/a	0.00%
Linear Technology Corp	LLTC	239.1	47.32	11,314	0.0716%	2.705%	6.913%	0.0019%	0.0049%
Range Resources Corp	RRC	169.7	42.59	7,229	0.0000%	0.1878%	(25.535%)	0.00%	0.00%
Northern Trust Corp	NTRS	228.2	74.10	16,907	0.1070%	1.9433%	11.447%	0.0021%	0.0122%
Paychex Inc	PAYX	360.1	54.22	19,526	0.1236%	3.0985%	9.775%	0.0038%	0.0121%
People's United Financial Inc	PBCT	310.9	15.88	4,936	0.0000%	4.2821%	n/a	0.00%	n/a
Patterson Cos Inc	PDCO	99.1	48.81	4,837	0.0306%	1.9668%	7.667%	0.0006%	0.0023%
QUALCOMM Inc	QCOM	1,468.9	54.92	80,673	0.5105%	3.8602%	10.40%	0.0197%	0.0531%
Roper Technologies Inc	ROP	101.2	171.08	17,313	0.1096%	0.7014%	11.433%	0.0008%	0.0125%
Ross Stores Inc	ROST	401.8	53.40	21,456	0.1358%	1.0112%	12.457%	0.0014%	0.0169%
AutoNation Inc	AN	103.1	50.44	5,201	0.0000%	n/a	8.64%	n/a	0.00%
Starbucks Corp	SBUX	1,464.9	54.89	80,408	0.5089%	1.4575%	18.622%	0.0074%	0.0948%
KeyCorp	KEY	842.4	12.82	10,799	0.0683%	2.6521%	6.333%	0.0018%	0.0043%
Staples Inc	SPLS	646.3	8.80	5,687	0.0360%	5.4545%	1.603%	0.002%	0.0006%
State Street Corp	STT	395.9	63.06	24,968	0.1580%	2.1567%	8.63%	0.0034%	0.0136%
US Bancorp	USB	1,726.4	42.82	73,925	0.4678%	2.3821%	5.86%	0.0111%	0.0274%
Symantec Corp	SYMC	612.3	17.36	10,629	0.0673%	1.7281%	8.686%	0.0012%	0.0058%
T Rowe Price Group Inc	TROW	248.2	77.06	19,127	0.1210%	2.803%	10.908%	0.0034%	0.0132%
Waste Management Inc	WM	444.3	60.95	27,078	0.1714%	2.6907%	8.326%	0.0046%	0.0143%
CBS Corp	CBS	415.3	55.20	22,925	0.1451%	1.087%	17.772%	0.0016%	0.0258%
Allergan plc	AGN	395.6	235.75	93,253	0.0000%	n/a	13.50%	n/a	0.00%
Whole Foods Market Inc	WFM	321.0	32.35	10,385	0.0657%	1.6692%	7.973%	0.0011%	0.0052%
Constellation Brands Inc	STZ	176.4	153.15	27,018	0.1710%	1.0447%	12.955%	0.0018%	0.0222%
Xilinx Inc	XLNX	255.5	47.39	12,110	0.0766%	2.7854%	8.233%	0.0021%	0.0063%
DENTSPLY SIRONA Inc	XRAY	234.2	62.16	14,560	0.0921%	0.4987%	9.42%	0.0005%	0.0087%
Zions Bancorporation	ZION	204.6	28.02	5,734	0.0363%	0.8565%	9.00%	0.0003%	0.0033%
Alaska Air Group Inc	ALK	123.3	66.40	8,184	0.0518%	1.6566%	5.49%	0.0009%	0.0028%
Invesco Ltd	IVZ	417.3	31.40	13,102	0.0829%	3.5669%	11.282%	0.003%	0.0094%
Intuit Inc	INTU	255.9	106.66	27,291	0.1727%	1.1251%	17.11%	0.0019%	0.0296%
Morgan Stanley	MS	1,937.0	27.37	53,016	0.3355%	2.1922%	6.433%	0.0074%	0.0216%
Microchip Technology Inc	MCHP	214.8	51.68	11,102	0.0703%	2.7825%	9.64%	0.002%	0.0068%
Chubb Ltd	CB	464.5	126.61	58,808	0.3722%	2.1799%	9.50%	0.0081%	0.0354%
Hologic Inc	HOLX	278.8	34.41	9,595	0.0000%	n/a	8.943%	n/a	0.00%
Chesapeake Energy Corp	CHK	684.6	4.29	2,937	0.0000%	n/a	(3.63%)	n/a	0.00%
Citizens Financial Group Inc	CFG	529.0	23.55	12,457	0.0788%	2.0382%	9.00%	0.0016%	0.0071%
O'Reilly Automotive Inc	ORLY	96.5	264.43	25,506	0.0000%	n/a	15.536%	n/a	0.00%
Allstate Corp/The	ALL	374.4	67.51	25,274	0.1599%	1.9553%	8.25%	0.0031%	0.0132%
FLIR Systems Inc	FLIR	137.6	31.15	4,287	0.0271%	1.5409%	15.00%	0.0004%	0.0041%
Equity Residential	EQR	365.5	69.21	25,296	0.1601%	2.9114%	6.427%	0.0047%	0.0103%
BorgWarner Inc	BWA	217.6	34.03	7,406	0.0469%	1.5281%	12.787%	0.0007%	0.006%
Newfield Exploration Co	NFX	198.5	40.77	8,092	0.0000%	n/a	16.485%	n/a	0.00%
Urban Outfitters Inc	URBN	117.4	28.53	3,349	0.0000%	n/a	14.838%	n/a	0.00%
Simon Property Group Inc	SPG	309.4	197.64	61,152	0.3870%	3.2382%	7.92%	0.0125%	0.0306%
Eastman Chemical Co	EMN	147.8	73.36	10,845	0.0686%	2.5082%	5.50%	0.0017%	0.0038%
AvalonBay Communities Inc	AVB	137.2	179.88	24,673	0.1561%	3.002%	7.423%	0.0047%	0.0116%
Prudential Financial Inc	PRU	442.0	79.25	35,029	0.2217%	3.5331%	9.55%	0.0078%	0.0212%

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Best Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Best Long-Term Growth Estimate
United Parcel Service Inc	UPS	690.5	103.09	71,179	0.4504%	3.0265%	9.611%	0.0136%	0.0433%
Apartment Investment & Management Co	AIV	156.6	42.65	6,679	0.0423%	3.095%	11.765%	0.0013%	0.005%
Walgreens Boots Alliance Inc	WBA	1,080.2	77.40	83,611	0.5291%	1.8605%	13.20%	0.0098%	0.0698%
McKesson Corp	MCK	225.0	183.14	41,210	0.2608%	0.6116%	12.70%	0.0016%	0.0331%
Lockheed Martin Corp	LMT	304.5	236.23	71,921	0.4551%	2.7939%	7.61%	0.0127%	0.0346%
AmerisourceBergen Corp	ABC	215.9	74.98	16,185	0.1024%	1.8138%	12.50%	0.0019%	0.0128%
Capital One Financial Corp	COF	512.1	73.24	37,506	0.2374%	2.1846%	6.741%	0.0052%	0.016%
Waters Corp	WAT	80.9	137.55	11,133	0.0000%	n/a	8.594%	n/a	0.00%
Dollar Tree Inc	DLTR	235.6	90.54	21,328	0.0000%	n/a	17.667%	n/a	0.00%
Darden Restaurants Inc	DRI	126.7	67.83	8,596	0.0544%	2.9485%	14.06%	0.0016%	0.0076%
Diamond Offshore Drilling Inc	DO	137.2	25.82	3,542	0.0000%	n/a	n/a	n/a	n/a
NetApp Inc	NTAP	289.1	25.53	7,380	0.0467%	2.9769%	8.967%	0.0014%	0.0042%
Citrix Systems Inc	CTXS	155.1	84.92	13,171	0.0000%	n/a	16.70%	n/a	0.00%
Goodyear Tire & Rubber Co/The	GT	265.9	27.97	7,438	0.0471%	1.0011%	7.00%	0.0005%	0.0033%
DaVita HealthCare Partners Inc	DVA	206.5	77.32	15,967	0.0000%	n/a	11.358%	n/a	0.00%
Hartford Financial Services Group Inc/The	HIG	393.4	45.17	17,769	0.1124%	1.8596%	9.333%	0.0021%	0.0105%
Iron Mountain Inc	IRM	212.0	36.74	7,787	0.0493%	5.2803%	9.40%	0.0026%	0.0046%
Estee Lauder Cos Inc/The	EL	222.6	91.78	20,428	0.1293%	1.3075%	11.855%	0.0017%	0.0153%
Yahoo! Inc	YHOO	949.9	37.94	36,040	0.0000%	n/a	6.535%	n/a	0.00%
Principal Financial Group Inc	PFG	289.9	44.56	12,916	0.0817%	3.5009%	8.14%	0.0029%	0.0067%
Stericycle Inc	SRCL	84.9	97.99	8,321	0.0000%	n/a	14.45%	n/a	0.00%
Universal Health Services Inc	UHS	89.8	134.86	12,106	0.0766%	0.2966%	8.883%	0.0002%	0.0068%
E*TRADE Financial Corp	ETFC	278.7	27.89	7,774	0.0000%	n/a	18.07%	n/a	0.00%
Skyworks Solutions Inc	SWKS	190.2	66.76	12,700	0.0804%	1.5578%	16.674%	0.0013%	0.0134%
National Oilwell Varco Inc	NOV	377.1	32.95	12,424	0.0000%	0.607%	(9.35%)	0.00%	0.00%
Quest Diagnostics Inc	DGX	141.5	77.17	10,916	0.0691%	2.0733%	8.905%	0.0014%	0.0062%
Activision Blizzard Inc	ATVI	738.2	39.26	28,983	0.1834%	0.6623%	12.00%	0.0012%	0.022%
Rockwell Automation Inc	ROK	130.3	116.05	15,117	0.0957%	2.4989%	6.927%	0.0024%	0.0066%
Kraft Heinz Co/The	KHC	1,216.0	83.19	101,155	0.6401%	2.7648%	21.688%	0.0177%	0.1388%
American Tower Corp	AMT	424.6	105.78	44,917	0.2842%	1.9285%	20.412%	0.0055%	0.058%
Regeneron Pharmaceuticals Inc	REGN	103.2	398.93	41,156	0.0000%	n/a	23.293%	n/a	0.00%
Amazon.com Inc	AMZN	471.8	722.79	341,033	0.0000%	n/a	50.747%	n/a	0.00%
Ralph Lauren Corp	RL	57.0	94.33	5,379	0.0340%	2.1202%	7.62%	0.0007%	0.0026%
Boston Properties Inc	BXP	153.6	125.63	19,298	0.1221%	2.0696%	6.55%	0.0025%	0.008%
Amphenol Corp	APH	307.9	58.72	18,081	0.1144%	0.9537%	9.26%	0.0011%	0.0106%
Pioneer Natural Resources Co	PXD	163.6	160.32	26,221	0.1659%	0.0499%	20.00%	0.0001%	0.0332%
Valero Energy Corp	VLO	469.8	54.70	25,698	0.1626%	4.3876%	4.208%	0.0071%	0.0068%
L-3 Communications Holdings Inc	LLL	77.0	137.21	10,559	0.0668%	2.0407%	9.94%	0.0014%	0.0066%
Western Union Co/The	WU	491.1	19.45	9,553	0.0605%	3.2905%	6.826%	0.002%	0.0041%
CH Robinson Worldwide Inc	CHRW	142.8	74.98	10,705	0.0677%	2.2939%	10.275%	0.0016%	0.007%
Accenture PLC	ACN	623.8	118.97	74,212	0.4696%	1.8492%	9.72%	0.0087%	0.0456%
Yum! Brands Inc	YUM	407.4	82.09	33,447	0.2117%	2.2414%	11.60%	0.0047%	0.0246%
Prologis Inc	PLD	525.1	47.53	24,957	0.1579%	3.5346%	5.175%	0.0056%	0.0082%
FirstEnergy Corp	FE	424.7	32.81	13,935	0.0882%	4.3889%	0.085%	0.0039%	0.0001%
VeriSign Inc	VRSN	108.5	85.46	9,270	0.0000%	n/a	9.85%	n/a	0.00%
Quanta Services Inc	PWR	144.2	24.03	3,464	0.0000%	n/a	8.00%	n/a	0.00%
Henry Schein Inc	HSIC	82.1	173.73	14,257	0.0000%	n/a	11.22%	n/a	0.00%
Ameren Corp	AEE	242.6	49.55	12,023	0.0761%	3.4309%	5.283%	0.0026%	0.004%
NVIDIA Corp	NVDA	534.0	46.72	24,948	0.1579%	0.9846%	9.667%	0.0016%	0.0153%
Scripps Networks Interactive Inc	SNI	95.1	64.34	6,119	0.0387%	1.5542%	11.733%	0.0006%	0.0045%
Sealed Air Corp	SEE	197.1	46.44	9,155	0.0579%	1.3781%	4.267%	0.0008%	0.0025%
Cognizant Technology Solutions Corp	CTSH	605.9	61.44	37,225	0.0000%	n/a	13.783%	n/a	0.00%
Intuitive Surgical Inc	ISRG	38.1	634.71	24,157	0.0000%	n/a	13.065%	n/a	0.00%
Aetna Inc	AET	350.6	113.23	39,698	0.2512%	0.8832%	11.111%	0.0022%	0.0279%
Affiliated Managers Group Inc	AMG	53.8	173.52	9,337	0.0000%	n/a	13.91%	n/a	0.00%
Republic Services Inc	RSG	343.9	48.28	16,603	0.1051%	2.4855%	7.868%	0.0026%	0.0083%
eBay Inc	EBAY	1,148.9	24.46	28,102	0.0000%	n/a	8.887%	n/a	0.00%
Goldman Sachs Group Inc/The	GS	415.4	159.48	66,247	0.4192%	1.6303%	15.145%	0.0068%	0.0635%
Sempra Energy	SRE	249.5	107.12	26,726	0.1691%	2.8193%	8.33%	0.0048%	0.0141%
Moody's Corp	MCO	194.3	98.64	19,166	0.1213%	1.5004%	11.00%	0.0018%	0.0133%
Priceline Group Inc/The	PCLN	49.6	1,264.33	62,760	0.0000%	n/a	18.10%	n/a	0.00%
F5 Networks Inc	FFIV	67.0	110.20	7,381	0.0000%	n/a	13.18%	n/a	0.00%
Akamai Technologies Inc	AKAM	175.6	54.58	9,584	0.0000%	n/a	17.333%	n/a	0.00%
Reynolds American Inc	RAI	1,427.3	49.70	70,939	0.4489%	3.3803%	9.485%	0.0152%	0.0426%
Devon Energy Corp	DVN	524.0	36.09	18,911	0.1197%	0.665%	8.233%	0.0008%	0.0099%
Alphabet Inc	GOOGL	293.7	748.85	219,919	0.0000%	n/a	15.66%	n/a	0.00%
Red Hat Inc	RHT	181.4	77.46	14,054	0.0000%	n/a	17.70%	n/a	0.00%

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.625g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Best Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Best Long-Term Growth Estimate
Netflix Inc	NFLX	428.3	102.57	43,931	0.0000%	n/a	35.50%	n/a	0.00%
Allegion PLC	ALLE	95.7	67.64	6,475	0.0410%	0.7096%	13.567%	0.0003%	0.0056%
Agilent Technologies Inc	A	327.8	45.89	15,041	0.0952%	1.0024%	10.133%	0.001%	0.0096%
Anthem Inc	ANTM	263.0	132.16	34,752	0.2199%	1.9673%	8.91%	0.0043%	0.0196%
CME Group Inc/IL	CME	338.6	97.89	33,149	0.2098%	2.4517%	13.123%	0.0051%	0.0275%
Juniper Networks Inc	JNPR	383.9	23.41	8,988	0.0569%	1.7087%	9.633%	0.001%	0.0055%
BlackRock Inc	BLK	163.4	363.85	59,441	0.3762%	2.5175%	13.537%	0.0095%	0.0509%
DTE Energy Co	DTE	179.4	90.68	16,271	0.1030%	3.2201%	5.54%	0.0033%	0.0057%
Nasdaq Inc	NDAQ	164.5	66.01	10,860	0.0687%	1.9391%	7.923%	0.0013%	0.0054%
Philip Morris International Inc	PM	1,551.3	98.68	153,079	0.9687%	4.1346%	9.187%	0.0401%	0.089%
salesforce.com Inc	CRM	677.5	83.71	56,714	0.0000%	n/a	25.389%	n/a	0.00%
MetLife Inc	MET	1,098.7	45.55	50,044	0.3167%	3.5126%	7.10%	0.0111%	0.0225%
Monsanto Co	MON	436.8	112.47	49,132	0.3109%	1.9205%	7.85%	0.006%	0.0244%
Under Armour Inc	UA/C	217.6	34.97	7,608	0.0000%	n/a	25.19%	n/a	0.00%
Coach Inc	COH	278.0	39.42	10,960	0.0694%	3.4247%	10.963%	0.0024%	0.0076%
Fluor Corp	FLR	139.2	52.78	7,349	0.0465%	1.5915%	1.357%	0.0007%	0.0006%
Dun & Bradstreet Corp/The	DNB	36.3	126.90	4,601	0.0291%	1.5209%	11.75%	0.0004%	0.0034%
CSX Corp	CSX	955.9	26.43	25,264	0.1599%	2.7242%	5.867%	0.0044%	0.0094%
Edwards Lifesciences Corp	EW	211.8	98.50	20,859	0.0000%	n/a	17.60%	n/a	0.00%
Ameriprise Financial Inc	AMP	165.8	101.67	16,858	0.1067%	2.9507%	11.00%	0.0031%	0.0117%
Xcel Energy Inc	XEL	508.0	41.37	21,014	0.1330%	3.2874%	4.95%	0.0044%	0.0066%
Rockwell Collins Inc	COL	130.2	88.40	11,509	0.0728%	1.4932%	8.323%	0.0011%	0.0061%
FMC Technologies Inc	FTI	226.4	27.23	6,164	0.0000%	n/a	(8.10%)	n/a	0.00%
Zimmer Biomet Holdings Inc	ZBH	199.2	122.11	24,329	0.1540%	0.7862%	10.493%	0.0012%	0.0162%
CBRE Group Inc	CBG	335.4	29.85	10,013	0.0000%	n/a	12.50%	n/a	0.00%
Signet Jewelers Ltd	SIG	78.4	98.97	7,763	0.0491%	1.0508%	14.40%	0.0005%	0.0071%
MasterCard Inc	MA	1,078.3	95.90	103,410	0.6544%	0.7925%	15.00%	0.0052%	0.0982%
CarMax Inc	KMX	193.5	53.66	10,382	0.0000%	n/a	13.552%	n/a	0.00%
Intercontinental Exchange Inc	ICE	119.0	271.12	32,276	0.2043%	1.2541%	13.667%	0.0026%	0.0279%
Fidelity National Information Services Inc	FIS	326.5	74.27	24,246	0.1534%	1.4003%	12.00%	0.0021%	0.0184%
Chipotle Mexican Grill Inc	CMG	29.2	441.96	12,906	0.0000%	n/a	16.879%	n/a	0.00%
Wynn Resorts Ltd	WYNN	101.8	96.18	9,790	0.0620%	2.0794%	10.00%	0.0013%	0.0062%
Assurant Inc	AIZ	61.9	87.39	5,413	0.0343%	2.2886%	12.36%	0.0008%	0.0042%
NRG Energy Inc	NRG	314.9	16.38	5,158	0.0000%	0.7326%	(27.35%)	0.00%	0.00%
Monster Beverage Corp	MNST	203.0	150.00	30,456	0.0000%	n/a	18.958%	n/a	0.00%
Regions Financial Corp	RF	1,266.7	9.83	12,452	0.0788%	2.645%	4.905%	0.0021%	0.0039%
Teradata Corp	TDC	130.0	28.34	3,684	0.0000%	n/a	9.604%	n/a	0.00%
Mosaic Co/The	MOS	349.8	25.23	8,826	0.0559%	4.3599%	0.85%	0.0024%	0.0005%
Expedia Inc	EXPE	136.3	111.24	15,162	0.0960%	0.863%	22.286%	0.0008%	0.0214%
Discovery Communications Inc	DISCA	150.5	27.85	4,191	0.0000%	n/a	13.45%	n/a	0.00%
CF Industries Holdings Inc	CF	233.1	27.66	6,447	0.0408%	4.3384%	17.15%	0.0018%	0.007%
Viacom Inc	VIAB	346.6	44.37	15,379	0.0973%	3.606%	6.487%	0.0035%	0.0063%
Alphabet Inc	GOOG	343.4	735.72	252,676	0.0000%	n/a	15.66%	n/a	0.00%
Wyndham Worldwide Corp	WYN	112.0	67.39	7,544	0.0477%	2.9678%	7.65%	0.0014%	0.0037%
Spectra Energy Corp	SE	700.9	31.86	22,331	0.1413%	5.0847%	10.20%	0.0072%	0.0144%
First Solar Inc	FSLR	102.2	49.65	5,076	0.0000%	n/a	5.50%	n/a	0.00%
Mead Johnson Nutrition Co	MJN	186.7	82.28	15,359	0.0972%	2.0053%	9.84%	0.0019%	0.0096%
TE Connectivity Ltd	TEL	357.6	60.00	21,457	0.1358%	2.4667%	12.20%	0.0033%	0.0166%
Discover Financial Services	DFS	412.2	56.81	23,419	0.1482%	1.9715%	9.895%	0.0029%	0.0147%
TripAdvisor Inc	TRIP	132.9	67.74	9,003	0.0000%	n/a	16.308%	n/a	0.00%
Dr Pepper Snapple Group Inc	DPS	185.8	91.40	16,983	0.1075%	2.3195%	13.243%	0.0025%	0.0142%
Visa Inc	V	1,904.8	78.94	150,364	0.9516%	0.7094%	16.641%	0.0068%	0.1583%
Xylem Inc/NY	XYL	178.9	44.66	7,990	0.0506%	1.3874%	15.00%	0.0007%	0.0076%
Marathon Petroleum Corp	MPC	529.8	34.83	18,454	0.1168%	3.675%	8.35%	0.0043%	0.0098%

Intermountain Gas Company

Market DCF Calculation as of May 31, 2016

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.625g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return
S&P 500	**2.54%**	**2.69%**	**9.44%**	**12.13%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Best Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Best Long-Term Growth Estimate
Tractor Supply Co	TSCO	133.4	96.10	12,822	0.0811%	0.999%	15.763%	0.0008%	0.0128%
Level 3 Communications Inc	LVLT	357.9	53.95	19,310	0.0000%	n/a	(0.69%)	n/a	0.00%
Transocean Ltd	RIG	365.2	9.79	3,575	0.0000%	n/a	(6.20%)	n/a	0.00%
Essex Property Trust Inc	ESS	65.4	227.23	14,868	0.0941%	2.8165%	6.827%	0.0026%	0.0064%
General Growth Properties Inc	GGP	883.2	26.87	23,732	0.1502%	2.8284%	6.915%	0.0042%	0.0104%
Realty Income Corp	O	257.6	60.09	15,481	0.0980%	3.974%	3.67%	0.0039%	0.0036%
Seagate Technology PLC	STX	298.5	22.56	6,734	0.0426%	11.1702%	5.05%	0.0048%	0.0022%
WestRock Co	WRK	252.6	39.61	10,006	0.0633%	3.7869%	2.85%	0.0024%	0.0018%
Western Digital Corp	WDC	281.4	46.54	13,098	0.0829%	4.2974%	1.94%	0.0036%	0.0016%
Church & Dwight Co Inc	CHD	128.3	98.48	12,638	0.0800%	1.4419%	9.288%	0.0012%	0.0074%
Federal Realty Investment Trust	FRT	70.9	153.19	10,862	0.0687%	2.4545%	6.255%	0.0017%	0.0043%
Twenty-First Century Fox Inc	FOX	798.5	29.24	23,349	0.1478%	1.026%	13.838%	0.0015%	0.0204%
JB Hunt Transport Services Inc	JBHT	112.7	82.72	9,319	0.0590%	1.0638%	13.738%	0.0006%	0.0081%
Lam Research Corp	LRCX	159.6	82.81	13,216	0.0836%	1.4491%	9.717%	0.0012%	0.0081%
Mohawk Industries Inc	MHK	74.1	196.69	14,573	0.0000%	n/a	11.10%	n/a	0.00%
Pentair PLC	PNR	180.7	60.24	10,886	0.0689%	2.2576%	9.25%	0.0016%	0.0064%
Vertex Pharmaceuticals Inc	VRTX	247.4	93.15	23,041	0.0000%	n/a	50.533%	n/a	0.00%
Facebook Inc	FB	2,311.9	118.81	274,673	0.0000%	n/a	31.337%	n/a	0.00%
United Rentals Inc	URI	88.5	69.67	6,166	0.0000%	n/a	14.13%	n/a	0.00%
United Continental Holdings Inc	UAL	335.7	45.09	15,137	0.0000%	n/a	(11.42%)	n/a	0.00%
Navient Corp	NAVI	330.5	13.71	4,531	0.0000%	4.6681%	n/a	0.00%	n/a
Delta Air Lines Inc	DAL	771.6	43.46	33,533	0.2122%	1.2425%	18.495%	0.0026%	0.0392%
Baxalta Inc	BXLT	683.5	45.23	30,917	0.0000%	0.6191%	n/a	0.00%	n/a
Mallinckrodt PLC	MNK	109.3	63.36	6,927	0.0000%	n/a	9.154%	n/a	0.00%
News Corp	NWS	199.6	12.34	2,463	0.0156%	1.6207%	8.893%	0.0003%	0.0014%
Centene Corp	CNC	170.5	62.35	10,629	0.0000%	n/a	17.172%	n/a	0.00%
Macerich Co/The	MAC	148.5	76.32	11,333	0.0717%	3.5639%	7.12%	0.0026%	0.0051%
Martin Marietta Materials Inc	MLM	63.5	189.04	12,009	0.0760%	0.8464%	22.156%	0.0006%	0.0168%
PayPal Holdings Inc	PYPL	1,212.0	37.79	45,803	0.0000%	n/a	16.075%	n/a	0.00%
Alexion Pharmaceuticals Inc	ALXN	224.0	150.90	33,805	0.0000%	n/a	26.098%	n/a	0.00%
Columbia Pipeline Group Inc	CPGX	400.4	25.54	10,226	0.0000%	2.1731%	n/a	0.00%	n/a
Endo International PLC	ENDP	222.7	15.81	3,520	0.0000%	n/a	4.70%	n/a	0.00%
News Corp	NWSA	380.4	11.96	4,549	0.0288%	1.6722%	8.893%	0.0005%	0.0026%
Global Payments Inc	GPN	154.0	77.69	11,964	0.0757%	0.0515%	13.443%	0.00%	0.0102%
Crown Castle International Corp	CCI	337.6	90.81	30,654	0.1940%	3.8982%	15.50%	0.0076%	0.0301%
Delphi Automotive PLC	DLPH	273.0	67.96	18,552	0.1174%	1.7069%	10.083%	0.002%	0.0118%
Advance Auto Parts Inc	AAP	73.6	153.84	11,316	0.0716%	0.156%	11.006%	0.0001%	0.0079%
Michael Kors Holdings Ltd	KORS	179.4	42.72	7,665	0.0000%	n/a	n/a	n/a	n/a
Illumina Inc	ILMN	147.2	144.83	21,319	0.0000%	n/a	14.481%	n/a	0.00%
Acuity Brands Inc	AYI	43.8	259.04	11,353	0.0718%	0.2007%	19.60%	0.0001%	0.0141%
Alliance Data Systems Corp	ADS	58.9	222.19	13,096	0.0000%	n/a	14.00%	n/a	0.00%
LKQ Corp	LKQ	306.7	33.07	10,142	0.0000%	n/a	15.467%	n/a	0.00%
Nielsen Holdings PLC	NLSN	360.8	53.39	19,263	0.1219%	2.3225%	12.333%	0.0028%	0.015%
Garmin Ltd	GRMN	189.1	42.52	8,039	0.0509%	4.7977%	7.425%	0.0024%	0.0038%
Cimarex Energy Co	XEC	94.8	116.28	11,025	0.0000%	0.2752%	(4.37%)	0.00%	0.00%
Zoetis Inc	ZTS	496.2	47.42	23,530	0.1489%	0.8013%	15.40%	0.0012%	0.0229%
Equinix Inc	EQIX	69.4	362.00	25,133	0.1591%	1.9337%	22.05%	0.0031%	0.0351%
Digital Realty Trust Inc	DLR	159.3	95.45	15,208	0.0962%	3.6878%	5.94%	0.0035%	0.0057%
Discovery Communications Inc	DISCK	248.7	26.77	6,658	0.0000%	n/a	13.45%	n/a	0.00%
Average for Companies Paying Dividends with Positive Best Long-Term Growth Estimates						**2.39%**	**9.69%**		

Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.625 x Column [3]/100)
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P.
[6] Source: Bloomberg Finance L.P.
[7] Equals Column [5] x Column [6]
[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and BEst Long-Term Growth Estimate does not equal "n/a" and is greater than 0%
[9] Source: Bloomberg Finance L.P.
[10] Source: Bloomberg Finance L.P.
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
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Intermountain Gas Company

CAPM Analysis

1	S&P Current Required Return [1]	12.13%
2	Less: May '16 T-Bond [2]	2.63%
3	Market Risk Premium [3]	9.50%
4	x Value Line Beta [4]	0.74
5	LDC Risk Premium [5]	7.06%
6	Plus: May '16 T-Bond [2]	2.63%
7	**LDC CAPM Cost of Eq. [6]**	**9.69%**

[1] Source: Schedule 6 Market DCF, Page 1
[2] Source: Schedule 1 Bond Yields, Page 3
[3] Equals [1] − [2]
[4] Source: Schedule 6 Beta, Page 1
[5] Source: [3] * [4]
[6] Source: [5] + [6]

Intermountain Gas Company
Beta
As of June 3, 2016

		Value Line
Atmos Energy Corporation	ATO	0.75
Spire Inc.	SR	0.70
New Jersey Resources Corporation	NJR	0.80
Northwest Natural Gas Company	NWN	0.65
South Jersey Industries, Inc.	SJI	0.80
Southwest Gas Corporation	SWX	0.75
WGL Holdings, Inc.	WGL	0.75
Mean		0.74

Source: Value Line; dated June 3, 2016

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 7, p. 1 of 1

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Residential Customer Charge and Non-Volumetric Rate Design

						Non-Volumetric Rate Design			
Company	Ticker	Utility	State	Residential Customer Charge	Residential Customer Charge Heating/Cooling	Formula Rate Plan	Revenue Decoupling Mechanism	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design
				[1]	[1]	[2]	[2]	[2]	[3]
Atmos Energy Corporation	ATO [4]	Atmos Energy Corporation	CO	$11.00		N	N	N	N
		Atmos Energy Corporation	KS	$18.19		N	N	N	N
		Atmos Energy Corporation	KY	$16.00		N	N	N	N
		Atmos Energy Corporation	LA	$13.96		Y	N	N	Y
		Atmos Energy Corporation	MS	$6.95		Y	N	N	Y
		Atmos Energy Corporation	TN	$15.40		Y	N	N	Y
		Atmos Energy Corporation (Mid-Tex)	TX	$18.20		Y	N	N	Y
		Atmos Energy Corporation	VA	$10.98		N	N	N	N
New Jersey Resources Corporation	NJR	New Jersey Natural Gas Company	NJ	$8.25		N	Y	N	Y
Northwest Natural Gas Company	NWN	Northwest Natural Gas Company	OR	$8.00		N	Y	N	Y
		Northwest Natural Gas Company	WA	$7.00		N	N	N	N
South Jersey Industries, Inc.	SJI	South Jersey Gas Company	NJ	$9.63		N	Y	N	Y
Southwest Gas Corporation	SWX	Southwest Gas Corporation	AZ	$10.70		N	Y	N	Y
		Southwest Gas Corporation	CA	$5.00		N	Y	N	Y
		Southwest Gas Corporation	NV	$10.80		N	Y	N	Y
Spire, Inc.	SR	Alabama Gas Corporation	AL	$22.52		Y	N	N	Y
		Laclede Gas Company	MO	$19.50		N	N	N	N
		Missouri Gas Energy	MO	$23.00		N	N	Y	Y
WGL Holdings, Inc.	WGL	WGL Holdings, Inc.	DC	$5.30	$9.90	N	N	N	N
		WGL Holdings, Inc.	MD	$10.20	$12.20	N	Y	N	Y
		WGL Holdings, Inc.	VA	$11.25		N	Y	N	Y
Average Customer Charge				$12.47					
Minimum Customer Charge				$5.00					
Maximum Customer Charge				$23.00					
Total Number of Jurisdictions (Y)									14
Total Number of Jurisdictions									21
Percent of Jurisdictions									66.7%

Notes:

[1] Source: Company Tariffs
[2] Source: American Gas Association, Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List, May 2016.
[3] Identifies companies with either a formula rate plan, revenue decoupling mechanism or straight fixed-variable rate design.
[4] Source: Natural Gas Utility Rate Structure: The Customer Charge Component, American Gas Association, May 28, 2015

Intermountain Gas Company

Selected Natural Gas Distribution Companies
Capital Structures as of March 31, 2016

$ millions

Company	Ticker	Long-Term Debt	%	Preferred Stock	%	Common Equity	%	Total Capital	
Atmos Energy Corporation	ATO	$ 2,455,559.0	42.34%	$ -	0.00%	3,344,565.0	57.66%	$ 5,800,124.0	1/
Spire Inc.	SR	1,851,600.0	52.41%	-	0.00%	1,681,400.0	47.59%	$ 3,533,000.0	1/
New Jersey Resources Corporation	NJR	844,391.0	41.15%	-	0.00%	1,207,482.0	58.85%	$ 2,051,873.0	1/
Northwest Natural Gas Company	NWN	569,745.0	41.38%	-	0.00%	806,955.0	58.62%	$ 1,376,700.0	1/
South Jersey Industries, Inc.	SJI	1,046,968.0	48.91%	-	0.00%	1,093,442.0	51.09%	$ 2,140,410.0	1/
Southwest Gas Corporation	SWX	1,388,968.0	45.67%	-	0.00%	1,652,282.0	54.33%	$ 3,041,250.0	1/
WGL Holdings, Inc.	WGL	1,194,251.0	46.12%	-	0.00%	1,395,114.0	53.88%	$ 2,589,365.0	1/
Median			**45.67%**		**0.00%**		**54.33%**		
Intermountain Gas Company			50.00%	-	0.00%		50.00%		2/

1/ Source: SNL Financial LC; data as of March 31, 2016
2/ Source: Intermountain Gas Company

Exhibit No. 05
Case No. INT-G-16-02
S. Gaske, IGC
Schedule 8, p. 1 of 1

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

DIRECT TESTIMONY OF TED DEDDEN

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. **Please state your name, title and business address.**

A. My name is Ted Dedden. I am the Accounting & Finance Director of Intermountain Gas Company. My business address is 555 S. Cole Road, Boise Idaho 83707.

Q. **Mr. Dedden, would you please summarize your educational and professional experience.**

A. I have been with Intermountain Gas Co. for over 3 years, with prior experience with one of Intermountain's affiliate companies – Cascade Natural Gas Corp. as their Manager, Accounting Systems for three years. Prior to this role, I served in various accounting and finance groups with Puget Sound Energy from 1978 until 2000 in staff and management roles with progressive responsibilities in Plant Accounting, General Accounting, and Division Operations. I am a graduate of the University of Puget Sound with a bachelor's degree in Business Administration, with an accounting emphasis.

Q. **What is the purpose of your testimony in this proceeding?**

A. My testimony describes Intermountain Gas Company's, ("Intermountain" or the "Company") unadjusted 2016 test year Rate Base and Income Statement In addition, I will discuss the nature of transactions with affiliated companies during the test year, the costs of which are reflected in test year expenses sponsored by Mr. Jacob Darrington.

Q. **Are you sponsoring any exhibits?**

A. Yes. In addition to my testimony, I am sponsoring the following exhibits, which are described in herein:

Exhibit No. 06	Unadjusted Rate Base
Exhibit No. 07	Monthly Rate Base Balances
Exhibit No. 08	Unadjusted Income Statement
Exhibit No. 09	Other Revenues
Exhibit No. 10	IGC Cost Allocation Manual
Exhibit No. 11	Affiliate Charges Included in Test Year

I. UNADJUSTED TEST YEAR RATE BASE AND INCOME STATEMENT

Q. What is the Company's proposed test year for this case?

A. Intermountain is proposing a test period ending December 31, 2016, reflecting six months actual, January to June, and six months projected data, July to December.

Q. Please describe the basis for the 2016 projected data.

A. The 2016 projected data was prepared as part of the Company's ongoing budgeting process. It incorporates the Company's best outlook for capital and expense items for calendar year 2016 and the forecasted revenues for that period.

Q. Have any adjustments been made to the forecast to determine the test period rate base and revenue requirement?

A. Yes. Several adjustments to the forecast were necessary to determine the appropriate rate base and expense levels for rate making purposes. These adjustments are discussed by Company witness Jacob Darrington in his testimony.

Q. What is the unadjusted rate base for the test year?

A. As shown on Exhibit 06, page 1, column (b), line 9, the unadjusted rate base for the test period is $235,968,612. It consists of five items; net gas plant in service, materials and supplies inventory, gas storage inventory, accumulated deferred income taxes and customer advances.

Net plant is the thirteen-month average of gross plant less the thirteen-month average of accumulated provisions for depreciation. Added to the net plant amount is materials and supplies inventory and gas storage inventory, both of which are thirteen-month averages. Accumulated deferred income taxes and customer advances are deductions from rate base as they are recognized as an interest-free funding mechanism from ratepayers. Exhibit 07, pages 1-6 show the development of the thirteen-month averages for the items described above.

Q. Please discuss how the forecasted, July to December, amounts were determined.

A. The July to December forecasted amounts are shown on Exhibit 07, pages 1-6, lines 15-25. These amounts were determined as follows:

<u>Gas Plant in Service</u>: is based on forecasted capital expenditures and retirements. On a quarterly basis, department managers review current spending and update future months to determine forecasted capital expenditures and retirements. Then the plant accounting group runs the close out and depreciation process.

<u>Accumulated Provision for Depreciation and Amortization</u>: is based on forecasted capital expenditures and retirements. On a quarterly basis, department managers review current spending and update future months to determine

forecasted capital expenditures and retirements. Then the plant accounting group runs the close out and depreciation process.

Plant Materials and Operating Supplies and Undistributed Stores: are based on a three-year historical average.

Gas Storage Inventory: is based on projected boil-off, injections, and withdrawals for the period ending December 31, 2016.

Accumulated Deferred Income Taxes: is based on the Company's approved capital budget and the resultant book-tax timing differences as well as book-tax timing differences on assets previously placed in service.

Advances in Aid of Construction: is based on a historical three-year average.

Q. What are the unadjusted revenues and expenses for the test year?

A. As shown on Exhibit 08, page 1, column (d), line 3, the unadjusted test year total operating revenues are $236,530,903. The unadjusted test year expenses are $235,335,918 as shown on Exhibit 08, page 1, column (d), line 24. This produces a net operating income of $1,194,985 as shown on Exhibit 08, page 1, column (b), line 25.

Q. What are the components of the test year operating revenues?

A. Test year operating revenue consists of gas operating revenue and other revenues. Gas operating revenues are the revenues generated by the sale and transportation of gas under the Company’s sale and transportation rate schedules. As shown on Exhibit 08, page 1, column (d), line 1, the unadjusted test year gas operating revenues are $233,637,331. Forecasted, July to December, gas operating revenues from residential and commercial customers are based on forecasted customers, weather-normalized usage per customer amounts, and currently approved rates. Forecasted gas operating revenues from industrial customers are based on currently approved rates and forecasted usage obtained from the Industrial Services Manager, which is primarily based on historical usage. Forecasted Gas Operating Revenues also includes non-regulated sales of liquefied natural gas (LNG) from the Company's Nampa storage facility, which are forecasted based on historical figures.

Q. Will you please explain how you included revenues and cost of gas expenses related to the Cost of Gas Delivered but Unbilled (CGDU) in the presentation of your test year data?

A. Yes. Test year operating revenue and cost of gas expense through June 2016 includes a reduction to revenue of $27.6 million and a reduction to cost of gas expense of $21.2 million due to the effect of CGDU resulting in a gross margin reduction of $6.4 million. This same deficit is removed from the determination of revenue requirement as seen in the testimony of Company witness Darrington. For simplicity, the forecast period July – December 2016 does not include revenue or cost of gas expense related to CGDU.

Q. What Other Revenues did the Company record during the test year?

A. The Company recorded other revenues associated with miscellaneous services, field collection charges, return check charges, account initiation charges, reconnection charges, interest on past due accounts, other miscellaneous non-operating revenues, cash discounts, rents, interest income, Allowance for Funds

Used During Construction ("AFUDC") equity, and non-utility revenues. Forecasted other revenues for the period July to December are based on calendar year 2015. In total, the Company recorded Other Revenues of $2,893,572 during the test year, as shown on Exhibit 08, page 1, line 2, column (d). An itemized listing of other revenues is shown on Exhibit 09, page 1, column (d).

Q. What expenses are included in the Company's unadjusted income statement?

A. The following classification of expenses are included in the Company's income statement:

- Cost of gas;
- Operating and maintenance expenses;
- Depreciation and amortization expenses;
- Taxes Other Than Income Taxes;
- Federal and State Income Taxes; and
- Interest Expenses.

The unadjusted test year levels for these expense items are shown on Exhibit 08, page 1, column (d), lines 5 through 23.

Q. Please discuss the how the forecasted, July to December, amounts were determined.

A. The July to December forecasted amounts are shown on Exhibit 08, page 1, column (c). These amounts were determined as follows:

- <u>Cost of Gas</u>: is based on forecasted customers, weather-normalized usage per customer amounts, and currently approved rates. Cost of gas related to non-regulated sales of LNG is forecasted based on historical data.
- <u>Operation and Maintenance Expense</u>: is forecasted by each department of the Company. Forecasting is done at the object level (i.e. Labor, Contract Service, Materials) and not at a FERC account level (i.e. Transmission

Facilities Operations/Maintenance Expense, Distribution Operations/ Maintenance Expense). In order to obtain the Functional categories (determined by FERC account), the Company used 2015 historical data to allocate the forecasted amounts to the various FERC accounts.

- <u>Depreciation</u>: is based on Idaho PUC approved depreciation rates, assets currently in service, and forecasted capital additions and retirements. Forecasted capital additions and retirements are determined by each department's expectation of future projects to be completed or retired by December 31, 2016.
- <u>Payroll Taxes</u>: are primarily based on total taxable compensation multiplied by a payroll tax rate, 7.5 percent, based on last year’s tax to salary percentage. Payroll taxes related to incentive compensation were calculated on an individual basis. Payroll taxes related to supplemental executive retirement plan payments were forecasted based on history;
- <u>Property Taxes</u>: are based on an annual tax assessment received from Idaho counties in May for the July to June tax period;
- <u>Franchise Taxes</u>: are based on the portion of Company customers that live within city limits of a city that has a 3% franchise tax. Not all Company customers live within city limits, therefore, the forecast is based on a historical realized rate of 2.58% of all revenue;
- <u>Interest Expense</u>: is based on the Company's line of credit, outstanding bonds, and forecasted new long-term debt. The line of credit interest expense is based on a combination of Prime and LIBOR rate estimates provided to the

Company by the MDUR Treasury Department. Interest expense on the Company's outstanding bonds is based on the stated interest rates identified in the terms of each bond issuance; and

- Income Taxes: are based on the statutory federal rate of 35.0% and Idaho rate of 7.4% for an effective tax of 39.81%. The estimate also includes permanent and timing differences.

II. AFFILIATE TRANSACTIONS

Q. Does Intermountain's revenue requirement include costs which are directly or indirectly charged to the Company by affiliated companies?

A. Yes, it does.

Q. Does Intermountain receive charges from MDU Resources Group, Inc. ("MDUR")?

A. Yes. MDUR has several departments that provide services to the operating companies. These departments include:

- Payroll Shared Services;
- Procurement Shared Services;
- Enterprise Technology Service;
- General and Administrative Services.

Q. What services does Payroll Shared Services provide to Intermountain?

A. Payroll Shared Services processes payroll and is also responsible for the preparation, filing and payment of all payroll-related federal, state and local tax returns. Since Intermountain does not have any departments that provide payroll related services, Payroll Shared Services is also responsible for the accumulation of time entry records, and maintenance of employee records for the Company.

Q. Please describe the services provided by Procurement Shared Services.

A. Procurement Shared Services creates and maintains the Corporation's national accounts for the purchase of products, goods and services. The group is also responsible for monitoring the level of services, quantities, discounts and rebates associated with established national accounts. Intermountain places specific purchase requests for required materials and services with approved vendors.

Q. What function does the Enterprise Technology Services provide?

A. Enterprise Technology Services provides policy guidance, infrastructure-related information technology ("IT") functions and security-focused governance.

Q. Is there also a Utility Group IT department?

A. Yes. The Utility Group IT Department is responsible for supporting applications specific to the utility group such as customer care and billing system; financial software; Supervisory Control and Data Acquisition ("SCADA") and mobile applications; Enterprise Geographic Information System ("GIS"), and the project and fixed asset accounting software ("PowerPlan").

Q. What services does the General and Administrative Services function provide?

A. The General and Administrative Services function provides the following services to all MDUR companies:

- Corporate governance, accounting and planning;
- Communications and public affairs;

- Human resources;
- Internal Audit;
- Investor Relations;
- Legal;
- Risk Management;
- Tax and compliance;
- Travel; and
- Treasury Services.

Q. How are the costs of the General and Administrative Services function billed to the MDUR companies?

A. Costs that directly relate to a business unit are directly assigned to that business. The remaining unassigned expenses are allocated to the operating companies using the corporate allocation methodology.

Q. Please describe the corporate allocation methodology.

A. The allocation factor is developed to apportion unassigned administrative costs via a capitalization factor based on the 12-month average capitalization at March 31. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations).

Q. Are there other affiliated costs that are allocated to or from Intermountain?

A. Yes. There are certain affiliate-owned assets, such as the General Office/Annex facility, that are used for the benefit of all MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (i.e., asset return plus annual operating expenses) is computed for the shared assets. The resulting revenue requirement is billed to the other MDUR operating companies as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Q. Does Intermountain own facilities that are billed to other MDUR companies?

A. Yes. Intermountain owns the Customer Care Center located in Meridian, ID. The revenue requirement associated with that facility is billed to Montana-Dakota/Great Plains and Cascade as a monthly fee.

Q. How are the amounts billed to affiliated companies associated with the customer care center reflected in Intermountain's determination of its revenue requirement in this proceeding?

A. Revenues from affiliate billings for the Customer Care Center are included in Other Operating Revenues (Account 488).

Q. Are there departments at Montana-Dakota/Great Plains that provide services to each of operating companies?

A. Yes. These departments include:

- Leadership Group – composed of the Executive Group and Directors that oversee shared utility specific functions;
- Customer Services – include such functions as the call center, scheduling and online services;
- Information Technology and Communications – provides services associated with Management Information Systems, Technology and Compliance;
- Administrative Services – provides such functions as procurement, office services, and fleet operations;

- Gas Supply and Control.

Q. How are the costs associated with these services billed to the individual operating utilities?

A. The groups have calculated methodologies to allocate the costs to the utility companies based on services performed for each utility company.

Q. Have you prepared an exhibit, which summarizes the nature and level of such charges?

A. Yes. Exhibit No. 10 is the Company's cost allocation manual which provides details of the services and the allocation methodology. Exhibit No. 11 provides a summary of affiliated charges included in the Company's revenue requirement.

Q. Does that complete your direct testimony?

A. Yes, it does.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 06

Intermountain Gas Company

Rate Base - 13-Month Average

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Company Unadjusted Rate Base
	(a)	(b)
1	Gas Plant in Service:	
2	Original Cost	$ 612,621,131
3	Less Accumulated Depreciation	(312,607,666)
4	Net Gas Plant in Service	300,013,465
5	Materials & Supplies Inventory	3,149,131
6	Gas Storage Inventory	4,055,522
7	Accumulated Deferred Income Taxes	(63,356,335)
8	Advances in Aid of Construction	(7,893,171)
9	Rate Base	$ 235,968,612

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Exhibit No. 06
Case No. INT-G-16-02
T. Dedden, IGC

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IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 07

Intermountain Gas Company

Gas Plant in Service - Original Cost

For the Test Year Ending December 31, 2016[1]

Line No.	Month	Gas Plant in Service a/c 1010 and 1060	Average Balance
	(a)	(b)	(c)
1	December 2015	$ 599,920,846	
2			$ 600,758,812
3	January 2016	601,596,777	
4			602,705,226
5	February	603,813,675	
6			603,648,203
7	March	603,482,731	
8			604,160,811
9	April	604,838,891	
10			605,821,207
11	May	606,803,522	
12			608,210,049
13	June	609,616,576	
14			611,553,277
15	July	613,489,977	
16			615,278,112
17	August	617,066,247	
18			618,971,228
19	September	620,876,208	
20			623,178,195
21	October	625,480,182	
22			626,557,555
23	November	627,634,927	
24			630,610,898
25	December	633,586,869	
			-
26			7,351,453,573
27			12
28			$ 612,621,131

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Accumulated Depreciation - Gas Plant in Service
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Accumulated Provision for Depreciation a/c 1080 and 1110	Average Balance
	(a)	(b)	(c)
1	December 2015	$ (304,247,389)	
2			$ (304,725,374)
3	January 2016	(305,203,358)	
4			(306,348,712)
5	February	(307,494,066)	
6			(307,805,967)
7	March	(308,117,867)	
8			(308,733,854)
9	April	(309,349,841)	
10			(309,884,447)
11	May	(310,419,053)	
12			(310,899,572)
13	June	(311,380,090)	
14			(312,338,546)
15	July	(313,297,002)	
16			(314,268,020)
17	August	(315,239,037)	
18			(316,217,660)
19	September	(317,196,283)	
20			(318,178,370)
21	October	(319,160,456)	
22			(320,156,747)
23	November	(321,153,038)	
24			(321,734,715)
25	December	(322,316,392)	
			-
26			(3,751,291,984)
27			12
28			$ (312,607,666)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Exhibit No. 07
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Intermountain Gas Company

Materials & Supplies Inventory

For the Test Year Ending December 31, 2016[1]

Line No.	Month	Plant Materials & Operating Supplies a/c 1540	Undistributed Stores a/c 1630	Month End Total	Average Balance
	(a)	(b)	(c)	(d)	(e)
1	December 2015	$ 2,920,938	$ -	$ 2,920,938	
2					$ 2,988,021
3	January 2016	3,048,127	6,977	3,055,104	
4					3,087,336
5	February	3,103,015	16,553	3,119,568	
6					3,102,734
7	March	3,078,240	7,660	3,085,900	
8					3,176,885
9	April	3,221,312	46,558	3,267,870	
10					3,303,353
11	May	3,297,913	40,922	3,338,835	
12					3,277,147
13	June	3,235,382	(19,924)	3,215,458	
14					3,191,666
15	July	3,066,424	101,450	3,167,874	
16					3,216,868
17	August	3,167,364	98,497	3,265,861	
18					3,207,242
19	September	3,111,774	36,849	3,148,623	
20					3,143,675
21	October	3,128,634	10,093	3,138,727	
22					3,152,874
23	November	3,163,030	3,990	3,167,020	
24					2,941,776
25	December	2,716,531	-	2,716,531	
					-
26				Total	37,789,577
27				Divided by	12
28				Average Balance	$ 3,149,131

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Gas Storage Inventory
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Gas Storage a/c 1642	Average Balance
	(a)	(b)	(c)
1	December 2015	$ 3,187,218	
2			$ 3,137,882
3	January 2016	3,088,545	
4			3,042,657
5	February	2,996,769	
6			2,911,449
7	March	2,826,129	
8			3,055,486
9	April	3,284,842	
10			3,352,956
11	May	3,421,070	
12			3,450,450
13	June	3,479,830	
14			3,806,338
15	July	4,132,846	
16			4,455,187
17	August	4,777,528	
18			5,113,417
19	September	5,449,306	
20			5,404,896
21	October	5,360,486	
22			5,415,819
23	November	5,471,151	
24			5,519,732
25	December	5,568,313	
			-
26			48,666,269
27			12
28			$ 4,055,522

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Exhibit No. 07
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Intermountain Gas Company
Deferred Income Taxes
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Accumulated Deferred Income Taxes a/c 2820	Average Balance
	(a)	(b)	(c)
1	December 2015	$ (63,327,538)	
2			$ (63,323,363)
3	January 2016	(63,319,187)	
4			(63,307,134)
5	February	(63,295,080)	
6			(63,270,191)
7	March	(63,245,301)	
8			(63,218,584)
9	April	(63,191,866)	
10			(63,187,509)
11	May	(63,183,151)	
12			(63,287,946)
13	June	(63,392,741)	
14			(63,401,765)
15	July	(63,410,788)	
16			(63,419,812)
17	August	(63,428,835)	
18			(63,437,859)
19	September	(63,446,882)	
20			(63,455,906)
21	October	(63,464,929)	
22			(63,473,953)
23	November	(63,482,976)	
24			(63,491,999)
25	December	(63,501,022)	
			-
26			(760,276,021)
27			12
28			$ (63,356,335)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Exhibit No. 07
Case No. INT-G-16-02
T. Dedden, IGC

Intermountain Gas Company
Advances in Aid of Construction
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Advances in Aid of Construction a/c 2520	Average Balance
	(a)	(b)	(c)
1	December 2015	$ (8,035,657)	
2			$ (8,025,639)
3	January 2016	(8,015,621)	
4			(8,053,447)
5	February	(8,091,272)	
6			(8,074,315)
7	March	(8,057,357)	
8			(8,066,617)
9	April	(8,075,877)	
10			(8,107,717)
11	May	(8,139,557)	
12			(8,214,225)
13	June	(8,288,892)	
14			(8,093,879)
15	July	(7,898,865)	
16			(7,718,432)
17	August	(7,537,999)	
18			(7,568,110)
19	September	(7,598,221)	
20			(7,605,557)
21	October	(7,612,892)	
22			(7,596,511)
23	November	(7,580,129)	
24			(7,593,605)
25	December	(7,607,080)	
			-
26		Total	(94,718,054)
27		Divided by	12
28		Average Balance	$ (7,893,171)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Exhibit No. 07
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AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 08

Intermountain Gas Company
Statement of Operating Income
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual Data Ending 6/30/2016	Forecasted Data For the Period 7/31/2016-12/31/2016		Total (Cols. b+c)
	(a)	(b)	(c)		(d)
1	Gas Operating Revenues	$ 140,984,189	$ 92,653,142		$ 233,637,331
2	Other Revenues	1,544,887	1,348,685	[2]	2,893,572
3	Total Operating Revenue	142,529,076	94,001,827		236,530,903
4	Operating Expenses				
5	Cost of Gas	91,867,781	58,310,385		150,178,166
6	Operation & Maintenance				
7	Production	33,854	12,711		46,565
8	Natural Gas Storage, Terminaling, and Processing	628,120	754,974		1,383,094
9	Transmission	284,410	211,628		496,038
10	Distribution	9,340,668	9,514,169		18,854,837
11	Customer Accounts	4,965,569	4,413,061		9,378,630
12	Customer Service and Informational	109,390	93,220		202,610
13	Sales	652,915	610,738		1,263,653
14	Administrative and General	7,532,347	7,615,725		15,148,072
15	Other	(53,885)	147,395		93,510
16	Depreciation	10,565,532	11,141,580		21,707,112
17	Payroll Taxes	926,166	816,836		1,743,002
18	Property Taxes	1,578,871	1,620,000		3,198,871
19	Franchise Taxes	4,141,133	2,946,727		7,087,860
20	Interest Expense	2,032,150	2,316,273		4,348,423
21	Total Operating Expense				
22	Before Incomes Taxes	134,605,021	100,525,422		235,130,443
23	Income Taxes	2,870,940	(2,665,465)		205,475
		-	-		-
24	Total Operating Expenses	137,475,961	97,859,957		235,335,918
25	Net Operating Income	$ 5,053,115	$ (3,858,130)		$ 1,194,985

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 09, Page 1

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IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 09

Intermountain Gas Company
Other Revenues and Interest Income
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual Data Ending 6/30/2016	Forecasted Data For the Period 7/31/2016-12/31/2016	Total
	(a)	(b)	(c)	(d)
1	Other Revenues			
2	Miscellaneous Service Revenue	$ 606,844	$ 573,625	$ 1,180,469
3	Field Collection Charge	15	870	885
4	Return Check Charge	58,720	40,060	98,780
5	Account Initiation Charge	481,284	565,302	1,046,586
6	Reconnection Charge	25,894	8,162	34,056
7	Interest on Past Due Accounts	367,312	139,696	507,008
8	Other Miscellaneous Non-Operating Revenues	7,917	7,800	15,717
9	Cash Discounts	3,834	10,703	14,537
10	Rent	-	2,325	2,325
11	Non-Utility Revenue	-	142	142
12	Total	1,551,820	1,348,685	2,900,505
13	Interest Income			
14	Interest Income	(6,933)	-	(6,933)
15	AFUDC Equity	-	-	-
16	Total	(6,933)	-	(6,933)
17	Total Other Revenues and Interest Income	$ 1,544,887	$ 1,348,685	$ 2,893,572

NOTES

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

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)

EXHIBIT 10

Intermountain Gas Company

Cost Allocation Manual

2016

INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

Exhibit No. 10
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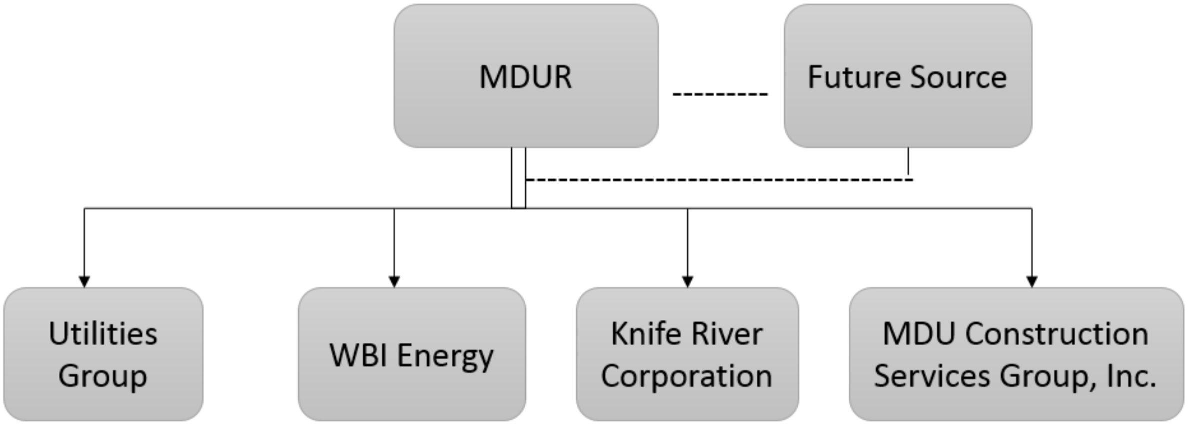
Table of Contents

Overview

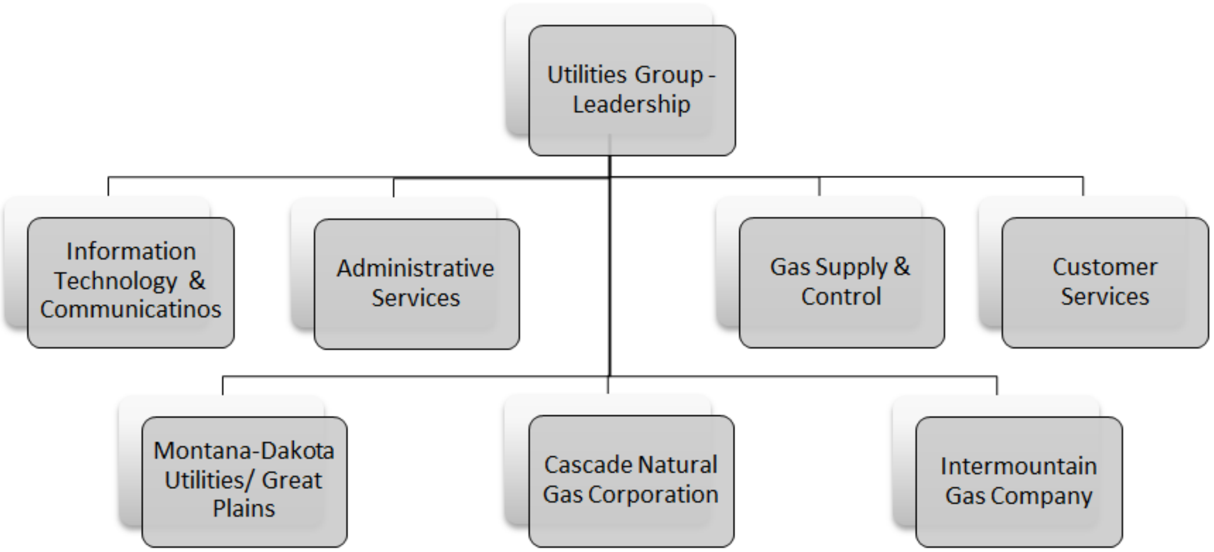
Intermountain Gas Company (IGC), a subsidiary of MDU Resources Group, Inc. (MDUR), conducts business in Idaho with regulated gas distribution operations.

Below is an overview of the operational structure for the purpose of assigning costs. The diagrams presented are intended to provide an overview for cost allocation only and are not intended to represent the legal structure of the Corporation. Note that costs from MDUR and FutureSource are directly assigned or allocated and charged to the operating companies (i.e. Utilities Group, WBI Energy, etc.)

Corporate Level



Utility Group Level



This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to the proper utility for Intermountain Gas Company.

This document will discuss the allocations from:

- MDUR and FutureSource to Intermountain Gas Company
- Montana-Dakota/Great Plains (MDU) and Cascade Natural Gas (CNG) to Intermountain Gas Company
- Intermountain Gas to MDU and CNG

Overall, the approach to allocating costs at each level is to directly assign costs when applicable and to allocate costs based on the function or driver of the cost.

MDU Resources Group, Inc. (MDUR) Allocations

The MDUR corporate staff consists of shared services departments (payroll, procurement and enterprise technology) and administrative and general departments.

Shared Services

MDU Resources Group, Inc. has several departments that provide specific services to the operating companies. These departments have developed a pricing methodology which is updated annually for the allocation of costs to the MDUR operating companies that utilize their services. (See Exhibit II) These departments include:

Payroll Shared Services

Payroll Shared Services department provides comprehensive payroll services for MDUR companies and employees. It processes payroll in compliance with appropriate federal, state and local tax laws and regulations. Payroll Shared Services is also responsible for preparation, filing and payment of all payroll related federal, state and local tax returns. It also maintains and facilitates payments and accurate reporting to payroll vendors for employee benefits and other payroll deductions. For Intermountain Gas Company, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Intermountain Gas Company does not have any departments that provide these payroll related services.

Procurement Shared Services

Procurement Shared Services creates and maintains the Corporation’s national accounts for the purchase of products, goods and services. National accounts take advantage of the combined purchasing power of all of the Corporation’s operating companies. National accounts, or preferred vendor agreements, typically are negotiated at the corporate level rather than at the local company level. Procurement Shared Services also is responsible for monitoring the level of services, quantities, discounts and rebates associated with established national accounts. Intermountain Gas Company has a single procurement department that places specific purchase requests for materials and services required to conduct business with approved vendors.

Enterprise Technology Service

Enterprise Technology Services (ETS) provides policy guidance, infrastructure related IT functions and security-focused governance. ETS seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. ETS works to increase the quality and consistency of technology, increase functionality and service to the enterprise, provide governance for managing and controlling risk and reduce costs through economies of scale.

Intermountain Gas Company’s IT department consists of Montana-Dakota/Great Plains employees physically located in Kennewick, Washington, Boise, Idaho, and Bismarck, North Dakota. This Department is responsible for supporting applications specific to the utility group such as the Customer Care & Billing System, the JD Edwards financial software, Scada and mobile applications, Enterprise GIS, and PowerPlan which is the project and fixed asset accounting software. In addition the utility group IT department develops business continuity plans in the case of disaster recovery.

General and Administrative Services

Administrative and general functions performed by MDUR for the benefit of the operating companies include the following departments:

- Corporate governance, accounting & planning
- Communications & public affairs
- Human resources
- Internal audit
- Investor relations
- Legal
- Risk management
- Tax and compliance
- Travel
- Treasury services

Intermountain Gas Company receives an allocation of these corporate costs. Corporate Policy No. 50.9 states “*It is the policy of the Company to allocate MDU Resources Group, Inc.’s (MDU) administrative costs and general expenses to the MDU’s business units*”. Business units described in the policy have been referred to as operating companies in this document. The policy states that costs that directly relate to a business unit will be directly assigned to the applicable business unit and only the remaining unassigned expenses will be allocated to the operating companies using the corporate allocation methodology. The allocation factor developed to apportion MDUR’s unassigned administrative costs is a capitalization factor which is based on 12 month average capitalization at March 31, effective July 1 and at September 30, effective January 1 each year. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations). The computation of the Corporate Overhead Allocation Factors is shown in Exhibit I.

Intermountain Gas Company is reflected as IGC in the Corporate Overhead Allocation Factors in Exhibit I. Operating companies that receive allocated costs on a monthly basis from MDUR include:

- Montana Dakota – Electric utility segment
- Montana Dakota/Great Plains – Gas utility segment
- Cascade Natural Gas (CNG)
- Intermountain Gas Company (IGC)
- WBI Energy Transmission
- WBI Midstream
- Knife River Construction (KRC)
- MDU Construction Services Group, Inc. (CSG)

Corporate costs are recorded in the administrative and general (A&G) function for IGC.

Montana-Dakota/Great Plains Allocation of Cost to/from Others

Allocations to/from other MDUR Companies

Certain Montana-Dakota/Great Plains owned assets, such as the General Office/Annex facility, located at the utility headquarters in Bismarck, and the assets associated with the contribution made for FutureSource assets, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including CNGC and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Intermountain Gas Company owns the customer care center located in Meridian, ID. To cover the cost of ownership and operating costs associated with that owned asset, a revenue requirement (asset return plus annual operating expenses) is computed similarly to Montana-Dakota owned assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Certain Cascade owned assets, such as the portion of the General Office facility used for Shared Services (i.e. Gas Control, IT), located at the utility headquarters in Kennewick, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including MDU and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Allocations to other Utility Companies

Montana-Dakota/Great Plains has several departments that provide services to all four utility operating companies (Montana-Dakota, Great Plains, Cascade Natural Gas Co. and Intermountain Gas Company). These departments include:

- Leadership Group - composed of the Executive Group and Directors that oversee shared utility specific functions
- Customer Services - (Call Center, Scheduling and Online Services)
- Information Technology and Communications- (Management Information Systems, Technology and Compliance)
- Administrative Services - (Procurement, Office Services, Fleet Operations)
- Gas Supply & Control

These operational groups have calculated the proper allocation to use to allocate the costs to the utility companies based on services performed for each utility company. The allocation methodology is included in Exhibit III.

Standard Labor Distributions

Labor/Reimbursable expense allocations

The development of standard labor distributions for Intermountain Gas Company employees is described below based on the type of employee. Standard labor distributions are used for all employees to account for certain expenses as detailed below.

Labor, benefit costs and reimbursable expenses are directly assigned to a jurisdiction where possible. If the expense is not direct, the appropriate jurisdiction is charged as follows:

Union Employees

Time tickets are required for productive time when working on capital projects. The employee specifies the proper capital project work order created to track project costs. To account for Operations, Maintenance, and non-productive time, standard payroll labor distributions are established for all employees. These standard labor distributions are calculated for union employees based on the historical actual charges.

Non-Union Employees

Non-union employees are not required to submit detailed time tickets with applicable general ledger accounts specified. Rather each employee has a "standard" set of general ledger accounts that split the labor costs based on an expected ratio of work. This split can be unique and is based on the employee's position. Costs are distributed based on this standard labor distribution for each employee, and the allocations are reviewed periodically.

Common Facilities

Customer Service Center

The Utility Group operates a Customer Service Center in Meridian, Idaho for the purpose of providing telephone customer service to customers served by Montana Dakota Utilities (MDU), Intermountain Gas Co. (IGC), and Cascade

Natural Gas Corp. (CNG). Operating expense allocations of the Customer Service Center are described on Page 6 – Allocations to other Utility Companies; Customer Services.

Capital costs of the Customer Service Center are recorded on IGC's books. Allocable costs of the facility and equipment include depreciation expense, a return on the invested capital of the facility using Cost of Capital, and income taxes associated with the return on invested capital (net of cost of debt associated with the facility). The allocable costs are billed monthly to CNG and MDU.

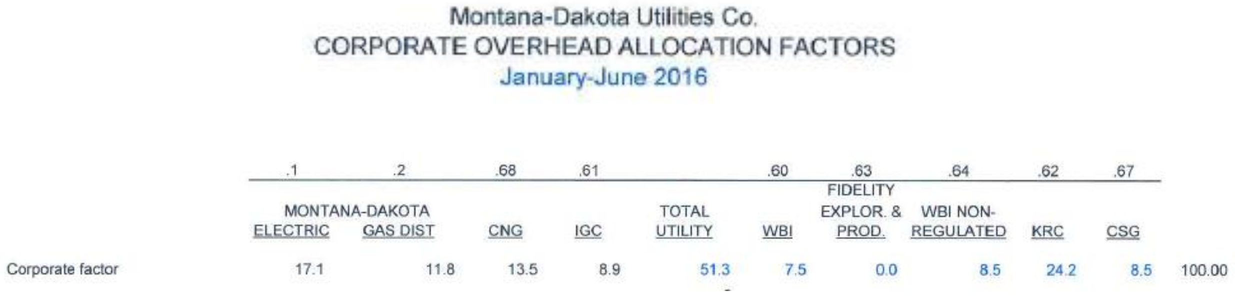
The cost driver for the allocations is customers served by each utility.

Boise General Office

The Boise General Office provides office facilities for administrative and general functions of Intermountain Gas Co.. In addition to IGC corporate staff in the General Office, the facility is also utilized by Information Technology (IT) and Geographic Informations Systems (GIS) staff that serve the Utility Group. A cost recovery process exists for the Boise General Office that is identical to the Customer Service Center process, however also includes occupancy expenses of the facility in addition to depreciation expense, a return on the invested capital of the facility, and income taxes associated with the return on invested capital (net of cost of debt associated with the facility). The allocable costs are billed monthly to CNG and MDU.

The cost driver for the allocations is customers served by each utility.

Exhibit I- MDUR Corporate Overhead factor



Montana-Dakota Utilities Co.
CORPORATE OVERHEAD ALLOCATION FACTORS
January-June 2016

	.1	.2	.68	.61		.60	.63	.64	.62	.67	
	MONTANA-DAKOTA ELECTRIC	MONTANA-DAKOTA GAS DIST	CNG	IGC	TOTAL UTILITY	WBI	FIDELITY EXPLOR. & PROD.	WBI NON-REGULATED	KRC	CSG	
Corporate factor	17.1	11.8	13.5	8.9	51.3	7.5	0.0	8.5	24.2	8.5	100.00

Exhibit II- MDUR Shared Services Pricing Methodology

MDU Resources Shared Services
Pricing Methodology - Effective for 2016

Note: MDU Resources' use of Shared Services – MDU Resources costs for each shared services function is charged based on the corporate allocation factor.

761 – Payroll Shared Services:

Payroll Shared Services costs are invoiced based on the number of employees paid and stated as a cost per check. The word check, for this purpose, generically refers to paper paychecks, direct deposits and paycard transactions.

Checks are charged on a tiered structure, intended to recognize the fixed or baseline effort associated with maintaining a payroll cycle and associated reporting, regardless of number of people paid. It is also intended to reward consolidation of multiple pay groups and companies where possible and to align charges with the additional effort required to maintain multiple pay groups and pay cycles.

The monthly volume for this step pricing is accumulated individually for each pay cycle processed.

Checks for weekly pay cycles, cost per check based on the number of checks written per month:
$ 4.25 per check for the first 500 checks
$ 0.75 per check for the next 500 checks
$ 0.15 per check for each additional check

Checks for non-weekly pay cycles, cost per check based on the number of checks written per month:
$ 4.25 per check for the first 1500 checks
$ 0.75 per check for the next 500 checks
$ 0.15 per check for each additional check

Additionally, there will be a $4.00 charge for each tax payment and $250.00 charge for each quarterly tax filing and $2 charge for each W2

There is a $500 per month minimum charge for each operating company.

There is a premium charge of $50 per transaction for specific off cycle checks and back-pay calculations. Examples of transactions included in the premium charge schedule are missing hours, refunded deductions, length of service awards submitted too late for inclusion in a scheduled payroll process, and back pay calculation because an increase was submitted after the pay period that includes the effective date. Examples of transactions excluded from the premium charge calculation are bonus payments, final paychecks, certified wage settlements, or any payment required as a result of a Shared Service or system error.

762 –Procurement Shared Services:

Procurement Shared Services costs are invoiced based on five separate factors, all carrying an equal weight of 20%. The factors are:

- Number of Visa Cards as of 8/1/15
- Total Visa Spend for 2014
- National Account Spend for 2014
- Number of Construction Equipment Acquisitions in 2014
- Number of Fleet Acquisitions in 2014

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
# VISA cards	152	853	493	955	721	303	116	3,593
% of VISA cards	4.23%	23.74%	13.72%	26.58%	20.07%	8.43%	3.23%	100%
VISA spend	1,800,832	7,180,723	5,027,712	11,336,841	9,504,352	2,765,773	1,415,939	39,032,172
% of Total VISA spend	4.61%	18.40%	12.88%	29.04%	24.35%	7.09%	3.63%	100%
National Account Spend	10,807,047	21,243,800	7,343,785	83,067,624	43,281,702	5,163,992	3,135,070	174,043,020
% of National Account Spend	6.21%	12.20%	4.22%	47.73%	24.87%	2.97%	1.80%	100%

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
# Construction Equip Acquisitions	0	55	13	86	111	22	7	294
% of Construction Equip Acquisitions	0.00%	18.71%	4.42%	29.25%	37.76%	7.48%	2.38%	100%
# Fleet Acquisitions	0	65	33	119	266	36	23	542
% of Fleet Acquisitions	0.00%	11.99%	6.09%	21.96%	49.08%	6.64%	4.24%	100%
Total weighted allocation factor	3.01%	17.01%	8.27%	30.91%	31.22%	6.52%	3.06%	100.00%

766 –Time Entry Shared Services:

Service provided 100% to the MDU Utility Group.

Enterprise Technology Services (ETS):

There are several ETS departments, and each is billed out based on its own criteria. They are as follows:

Application Services (765) 100% of these costs are based on the corporate factor.

Customer Relations (965) – Two factors are used in the invoicing of the enterprise costs associated with customer relations. Those costs are invoiced based upon the number of devices supported by customer relations. The metric used to determine device counts is devices that have checked into active directory during a 60 day period in the summer of 2015. The remaining costs are for costs specific to the IPT are invoiced upon the IPT allocation.

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
Device Counts	266	1,057	496	1,810	1,277	457	658	6,021
% of Device Counts	4.42%	17.55%	8.24%	30.06%	21.21%	7.59%	10.93%	100%
Totals	4.42%	17.55%	8.24%	30.06%	21.21%	7.59%	10.93%	100%
IPT Allocation	217	527	341	1,382	66	297	275	3,078
% of IPT Allocation	7.0%	17.0%	11.0%	44.5%	2.0%	9.6%	8.9%	100%
Totals	7.0%	17.0%	11.0%	44.5%	2.0%	9.6%	8.9%	100%

Communications & Security (971)

Enterprise charges for the communications group are invoiced using three weighted allocation factors. The factors are as follows:

1. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (20%)
2. Internet/Firewall Access – Number of user accounts (30%)
3. Security (50%)

The costs are invoiced based on the following percentages:

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
WAN/LAN/MAN	2	52	128	203	57	17	13	472
% of Business Unit Locations	0.42%	11.02%	27.12%	43.01%	12.08%	3.60%	2.75%	100%

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
Internet Access/Firewall	266	1,057	496	1,810	1,277	457	658	6,021
% of User Accounts	4.42%	17.55%	8.24%	30.06%	21.21%	7.59%	10.93%	100%
Security								
% of Handsets	20.00%	10.34%	20.00%	20.00%	20.00%	5.82%	3.84 %	100%
Totals	11.41%	12.63%	17.90%	27.62%	18.78%	5.91%	5.75%	100.00%

Operations (972) – Enterprise charges for the operations group are invoiced using two separate factors. 95.1% of the costs are based upon the number of servers that are supported for a particular business unit. These servers are then broken out between full service servers and shared service servers. 4.9% of the costs are for costs specific to the AS/400 are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

The costs that are based upon the number of servers are based on the following percentages:

1. Full Service Servers - (75%)
2. Shared Service Servers – (25%)

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
Full Service Servers	252	147	43	90	20	0	0	552
% of Full Service Servers	45.65%	26.64%	7.79%	16.30%	3.62%	0.00%	0.00%	100%
Shared Service Servers	0	95	38	59	66	32	88	378
% of Full Service Servers	0.00%	25.13%	10.05%	15.61%	17.46%	8.47%	23.28%	100%
Totals	34.24%	26.25%	8.36%	16.13%	7.08%	2.12%	5.82%	100%

Finance and Administration (982) –. Costs for the finance and administration group are invoiced based upon the combined methodologies of the four previously identified ETS groups.

	MDUR	MDU	WBIE	KRC	CSG	CNG	IGC	Total
% of Total Finance & Administration	26.41%	16.64%	12.42%	21.52%	13.01%	4.29%	5.71%	100%

Exhibit III- Utility Operations Support Allocation Methodology

Utility Operations Support
Labor Distribution Allocation Methodology

Leadership Group:

- Includes Executive Vice Presidents & Directors
- Oversees all shared, utility specific functions in the following areas:
    - Customer Services
    - Administrative Services
    - Information Technology & Communications
    - Engineering and Operations Procedures
    - Gas Supply and Gas Control
- Allocation methodology:
    - Equal portion allocated to each utility company, or brand
    - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for Great Plains) to non-utility based on historical estimates, with remainder allocated to gas and electric based on meter count.
    - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocate between gas and electric based on meter count.

Customer Services:

- Director
    - 35% to CNG, 30% to IGC, 35% Montana-Dakota/Great Plains [1] (1% to non-utility) and remainder split between gas and electric meter count.
- Management team
    - Supervisors: Front line supervision for Customer Service Center
        - 30% to CNG, 30% to IGC, 40% Montana-Dakota/Great Plains [1] (2% to non-utility) and remainder allocated to gas and electric based on the estimate of time required to supervise
    - Manager: Customer service
        - 30% CNG, 20% IGC, 50% Montana-Dakota/Great Plains [1] (2% to non –utility) and remainder allocated to gas and electric meter count.
- Credit
    - Responsible for credit and collections for the Utility Group
    - Allocation Methodology
        - Most agents only handle credit activity for one brand, they charge all time to that brand
        - For agents that handle multiple brands, time is charged based on how much time is spent on each brand

---

[1] Based on estimated time using history

    - For agents that only handle credit activity for Montana-Dakota/Great Plains:
      - Allocated to gas and electric based on meter count

      For agents that handle credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on average time spent in each utility with the Montana-Dakota/Great Plains portion allocated to gas and electric based on meter count.

- Scheduling
  - Responsible for scheduling field work for employees performing work in the field for the Utility Group
  - Responsible for emergency response 24/7
  - Allocation Methodology:
  - Management team:
    - Manager 20% IGC, 30% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - Team Leads 25% IGC, 25% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - For employees that only schedule one brand, charge time to that brand
    - For employees that schedule both IGC and CNG, split time 50/50 based on estimated time required
    - For employees who schedule all brands, split evenly
    - For employees that only schedule Montana-Dakota/Great Plains:
      - Allocated between gas and electric based on meter count
    - For employees that schedule credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on the shared utility. The Montana-Dakota/Great Plains allocation is based on the gas and electric meter count.

- Customer Service
  - Responsible for handling all inbound calls during regular operating hours
  - Allocation Methodology:
    - Teams leads and Customer Care Representatives (CCR's) when only responsible for one brand, charge all that time to one brand
    - For employees covering multiple brands, estimates are routinely made for allocations for the pay period
    - For employees responsible for Montana-Dakota/Great Plains:
      - 3% (including 0.5% for Great Plains) is charged to non-utility for credit activity associated with non-utility charges, based on best estimate of time required
      - Remainder is allocated between gas and electric based on meter count

    - For employees responsible for Montana-Dakota/Great Plains and another brand, the portion allocated to non-utility is reduced accordingly to 3% (including 0.5% for Great Plains) of the total associated with Montana-Dakota/Great Plains.

- Customer Programs & Support
  - Responsible for inbound self-service, web help, customer program transactions, and analytical support for the Utility Group
  - Allocation Methodology:
  - Manager
    - 30% IGC, 30% CNG, 40% Montana-Dakota/Great Plains[1] (allocate to gas and electric based on meter count)
      - Based on additional time for Montana-Dakota/Great Plains on social media updates & Credit Dept. responsibilities
  - Supervisor, Team Lead, and Support Staff
    - Equal portion allocated to each brand
    - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for GPNG) to non-utility, based on historical estimates, with remainder allocated to gas and electric based on meter count.
    - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocated to gas and electric based on meter count.

- Note: Exceptions may be made on an individual basis from these guidelines
  - Employees may be assigned special projects, and allocation methodology may be changed accordingly.
  - Labor allocation may always be made on an actual time spent basis rather than these guidelines.
  - Supervisors may alter these guidelines based on their individual scenario.

Exhibit No. 10
Case No. INT-G-16-02
T. Dedden, IGC
p. 16 of 16

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 11

Intermountain Gas Company
Cross Charge Summary
For the Test Year Ending December 31, 2016 [1]

Line No.	Cross Charge Department (a)	June YTD Actuals (b)	Six Month Forecast (c)	Total (d)
1	Geographic Information Service	$ 294,243.89	$ 331,590.57	$ 625,834.46
2	MDU Cross Charges	902,557.68	809,306	1,711,863.28
3	MDUR Cross Charges	1,208,736.02	1,586,824	2,795,560.50
4	Credit & Collections	254,331.43	305,524	559,855.81
5	Customer Services, Dir	(184,399.95)	207,053	22,653.20
6	Meridian-Customer Service	957,452.98	1,127,751	2,085,204.05
7	Customer Development/Programs	229,087.55	264,555	493,642.68
8	Scheduling	159,663.74	168,847	328,510.47
9	IT Risk Mgt	889,458.47	935,101	1,824,559.16
10	Information Tech, Dir	(61,100.35)	-102,174	(163,274.41)
11	Communications	93,385.65	184,921	278,306.59
12	Information Systems	1,171,052.90	389,266	1,560,318.87
13	Mobile Services Manager	169,924.10	175,515	345,439.60
14	Office Services	1,635,692.08	1,292,379	2,928,070.88
15	Cascade Natural Gas Corp.	216,213.12	215,111	431,324.01
16		$ 7,936,299.31	$ 7,891,569.83	$ 15,827,869.14

Notes

[1] Test Year ending December 31, 2016 is composed of actual results from January 1 - June 30, 2016 and forecasted results from July 1, 2016 - December 31, 2016.

Exhibit No. 11
Case No. INT-G-16-02
T. Dedden, IGC

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

DIRECT TESTIMONY OF JACOB DARRINGTON

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

I. INTRODUCTION

Q. Please state your name, business address, and present position with Intermountain Gas Company.

A. My name is Jacob Darrington. I am employed by Intermountain Gas Company (" Intermountain" or "the Company") as a Regulatory Analyst. My business address is 555 South Cole Road, Boise, Idaho 83707.

Q. Would you please describe your education and professional experience.

A. I graduated from Boise State University in May 2011 with a Bachelor of Arts Degree in Accounting-Finance. In January 2012, I began work at Deloitte Tax as a Tax Consultant where I prepared federal and multi-state tax returns for businesses and high-net worth individuals. Additionally, I worked as a tax specialist as a part of the audit team to help with auditing the provision for income taxes for a regulated utility. I earned my CPA license in the summer of 2013. I continue to keep my CPA license active in the state of Idaho. In the fall of 2013 I was promoted to Tax Senior at Deloitte and took on the additional responsibility of reviewing tax returns of other Tax Consultants. In April of 2015, I took a position with Intermountain Gas Company as a Regulatory Analyst. In July of 2015 I attended the Regulatory Rate School in Chicago sponsored by the American Gas Association.

Q. Would you briefly describe your responsibilities in your current position?

A. Yes. As a Regulatory Analyst, my primary responsibility as it relates to this proceeding includes the gathering, analyzing, and coordinating of data from various departments throughout the Company required for the preparation and calculation of the revenue requirement and rate base.

Q. What is the purpose of your testimony in this docket?

A. My testimony will cover two main areas. First, I will address Intermountain’s regulatory adjustments to the Company’s rate base. Second, I will discuss the Company’s adjustments to operating revenues and expenses. Third, I will discuss Intermountain’s revenue requirement.

Q. What is the Company’s proposed test year for this case?

A. As described by Company witness Dedden, Intermountain is proposing a test period reflecting six months actual and six months projected data for the twelve-months ending December 31, 2016.

Q. Does the Company anticipate adjusting the test period projections later in this docket?

A. Yes. The Company will provide to the Idaho Public Utilities Commission (“Commission”) monthly updates to the six months of projections for the period July 1, 2016, through December 31, 2016, to reflect actual data.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits, which are described in my testimony:

Exhibit No. 12	Rate base
Exhibit No. 13	Rate Base Components and Adjustments
Exhibit No. 14	Operating Income
Exhibit No. 15	Adjustments to Operating Income

Exhibit No. 16 Summary Revenue Requirement Calculation

II. RATE BASE

Q. What exhibits do you have that summarize the Company's thirteen-month average rate base and explains the adjustments to rate base?

A. Exhibit 12 is composed of two tables that shows summaries of the unadjusted components of rate base as presented by Company witness Dedden as well as adjustments to those components. Exhibit 13 is a series of worksheets that describe each of the adjustments made to rate base.

Q. Is the thirteen-month average method used for all rate base items?

A. Yes, with the exception of the Cash Working Capital allowance, all items included in the determination of rate base have been calculated using the average of thirteen monthly balances. The average of the thirteen monthly balances reflects the level of investment maintained by the Company during the course of the year and is intended to normalize changes in the balances that occur during the year. The derivation of the Cash Working Capital allowance is discussed later in this testimony.

Q. What is Intermountain's projected gas plant in service as of December 31, 2016?

A. The thirteen-month average level of gross investment in gas utility plant in service included in the Company's rate base as of December 31, 2016 is $596,065,559, as shown on Exhibit 12, page 1, column (d), line 2. The thirteen-month average calculation of this figure can be found on Exhibit 13, page 1, column (e), line 28.

Q. Does this amount of gross plant investment as of December 31, 2016 reflect any adjustments?

A. Yes. The balance of gross plant investment reflects an adjustment to remove the Asset Retirement Obligations ("AROs") in the amount of $16,555,572 as shown on Exhibit 12, page 2, column (b), line 2 and Exhibit 13, page 1, column (c).

Q. What is the total amount of Intermountain' s projected accumulated provisions for depreciation and amortization?

A. Intermountain's projected accumulated depreciation and amortization as of December 31, 2016 is $308,450,846, as shown on Exhibit 12, page 1, column (d), line 3. The thirteen-month average calculation of this figure can be found on Exhibit 13, page 2, column (f), line 28.

Q. Are you proposing any adjustments be made to the accumulated reserve for depreciation and amortization?

A. Yes. The accumulated provision balances have been adjusted to remove the AROs and Retirement Work in Progress in the amount of $4,303,085 and $146,265, respectively, as shown on Exhibit 12, page 2, column (b) and (c), line 3 and detailed on Exhibit 13, page 2, column (c) and (d).

Q. How was the level of net plant included in rate base calculated?

A. Net plant included in rate base is $287,614,713, and was calculated by subtracting the total amount of adjusted accumulated depreciation from the total amount of adjusted gross plant as shown on Exhibit 12, page 1, column (d), line 4.

Q. What level of Materials and Supplies was included in rate base?

A. Intermountain included in rate base a thirteen-month average of the materials and supplies balance of $3,149,131, as shown on Exhibit 12, page 1, column (d), line 5 and as calculated on Exhibit 13, page 3, column (e), line 28.

Q. Did the Company include any gas storage inventory in rate base?

A. Yes. Intermountain included a thirteen-month average of the gas storage inventory balance of $3,195,613 in rate base, as shown on Exhibit 12, page 1, column (d), line 6 and as calculated on Exhibit 13, page 4, column (f), line 28.

Q. Does this amount of gas storage inventory reflect any adjustments?

A. Yes. The amount reflects two adjustments to the gas storage inventory held at the Company's Nampa storage facility. The first adjustment of $856,019, as seen on Exhibit 12, page 2, column (d), line 6 and Exhibit 13, page 4, column (c), removes the gas storage inventory associated with non-utility sales of liquefied natural gas ("LNG"). The second adjustment of $3,890, as seen on Exhibit 12, page 2, column (e), line 6 and Exhibit 13, page 4, column (d), removes those costs associated with the utility portion of gas storage inventory at the Nampa storage facility in excess of 2 million gallons.

Q. Why is the established level of utility storage gas at the Nampa storage facility set to 2 million gallons?

A. This is the amount of LNG required to 1) maintain operational and training requirements at the Nampa and Rexburg LNG Facilities, 2) maintain an adequate supply of LNG to provide for the annual "boiloff" gas that naturally occurs with the warming of LNG and 3) maintain minimum LNG levels to ensure the integrity of the storage tank.

Q. Is Cash Working Capital included in rate base?

A. Yes. Cash working capital ("CWC") is the amount of funds required to finance the day-to-day operations of the Company. A CWC requirement represents the amount of cash the Company needs to keep on hand to meet its cash operating expenses. The test year rate base includes $1,032,688 for CWC as shown on Exhibit 12, page 1, column (d), line 7 and calculated on Exhibit 13, page 5, column (e), line 18. The CWC calculation is based upon a lead-lag study.

Q. What is a lead-lag study?

A. A lead-lag study analyzes the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services, but pays for them at a later date. The "leads" and "lags" are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. This CWC factor is then multiplied by the annual test year cash revenues and expenses to determine the amount of CWC required for operations.

Q. What is the amount of accumulated deferred income taxes (“ADIT”) deducted from rate base?

A. The level of ADIT deducted from rate base is $50,172,477, as shown on Exhibit 12, page 1, column (d), line 8. The calculation of this number is shown on Exhibit 13, page 6, column (k), line 28.

Q. What is ADIT and why is it a rate base adjustment?

A. Deferred income taxes arise when income tax amounts provided for book purposes differ from the amount of taxes due and payable in the test period. The primary cause of this tax difference is the straight line depreciation rates used for ratemaking purposes, versus the accelerated depreciation rates used when calculating state and federal income tax obligations. For a utility with a growing rate base, there is generally a higher depreciation expense for tax purposes than for regulatory book purposes, causing the taxes computed for regulatory books (and thus, included in revenue requirement) to be more than the taxes actually payable, in the early years of the asset's life. In later years, the situation reverses itself. The accumulated balance of these deferred taxes is, in essence, either a source or use of funds available to the company. The net balance of accumulated deferred taxes has been deducted from rate base.

Q. Please explain how the level of ADIT was determined.

A. ADIT was analyzed on an item-by-item basis to determine whether the ADIT was attributable to items included in rate base. Amounts attributable to an asset or liability in rate base have been reflected in the ADIT adjustment. Additional adjustments were made to remove state deferred income taxes and to comply with various IRS rules related to deferred taxes. These adjustments total $13,183,858 and are shown on Exhibit 12, page 2, columns (f) – (l), line 8 and on Exhibit 13, page 6, columns (c) – (i).

Q. How has Intermountain accounted for advances in aid of construction in the Company's rate base?

A. Advances in aid of construction in the amount of $7,893,171 have been deducted from rate base, as shown on Exhibit 12, page 1, column (d), line 9 and calculated on Exhibit 13, page 7, column (c), line 28. This represents the thirteen-month average balance of cash advances received from customers as of December 31, 2016 for construction attributable to Intermountain's operations. Similar to ADIT, the advances in aid of construction represent a source of funds available to the Company and appropriately offset the plant in service balances reflected in rate base.

Q. What is Intermountain's proposed test year rate base?

A. The Company's test year rate base, as of December 31, 2016, adjusted for the known and measurable adjustments discussed above, is projected to be $236,926,497, as shown on Exhibit 12, page 1, column (d), line 10.

Q. Does this conclude your testimony as it pertains to the Company's rate base?

A. Yes.

III. OPERATING REVENUES AND EXPENSES

Q. What exhibits do you have that summarize the Company's operating revenues and expenses and the adjustments made thereto?

A. Exhibit 14 presents the unadjusted operating revenues and expenses as presented by Company witness Dedden, regulatory adjustments to those operating revenues and expenses, and the resulting Company proposed operating revenues and expenses. Exhibit 15 presents the detail supporting the proposed regulatory adjustments to Company's operating revenues and expenses.

Q. What is the unadjusted projected level of operating revenues and expenses for the twelve months ended December 31, 2016?

A. As presented by Company witness Dedden, for the twelve months ended December 31, 2016, the Company projects total operating revenues to be $236,530,903, as shown on Exhibit 14, page 1, column (b), line 3. The Company projects total operating expenses to be $235,335,918 as shown on Exhibit 14, page 1, column (b), line 24. This produces unadjusted net operating income of $1,194,985 as shown on Exhibit 14, page 1, column (b), line 25.

Q. Are you proposing any adjustments to the test year gas operating revenues and expenses?

A. Yes. Exhibit 14, page 2 lists each proposed adjustment to test year gas operating revenues and expenses.

Q. Please describe the Unbilled Adjustment shown on Exhibit 14, page 2, column (b), lines 1 and 5.

A. This adjustment removes unbilled revenues and cost of gas expenses from the determination of the revenue requirement. This unbilled adjustment is the result of the difference in the timing of when gas is provided to our customers and when those customers are billed for the gas used. To create a proper matching of gas costs and revenues for the test year, unbilled revenues and cost of gas have been excluded from the calculation of the revenue requirement. The adjustment increases revenues by $27,605,926 and cost of gas expenses by $21,246,004, as shown on Exhibit 15, page 1, column (d), lines 16 and 17. This adjustment pertains only to the year-to-date actual data through June 2016. As discussed by

Company witness Dedden, the forecast period July through December 2016 does not include unbilled revenues and cost of gas expenses.

Q. Is the Company proposing an adjustment to revenues and expenses associated with non-utility LNG sales from the Nampa facility?

A. Yes. Non-utility sales of liquefied natural gas have been removed from the Company's test year revenues and cost of gas expenses, as shown on Exhibit 14, page 2, column (c), lines 1 and 5 and Exhibit 15, page 2, column (d), lines 1 and 2. The result of the adjustment reduces operating revenues by $1,813,230 and related cost of gas expenses by $1,461,140. This adjustment eliminates revenues and cost of gas expenses not associated with the provisioning of regulated gas services to Intermountain's customers.

Q. Please explain the franchise tax adjustment shown on Exhibit 14, page 2, column (d), lines 1 and 19.

A. Franchise taxes are not recovered through base rates, and thus have been removed from the Company's revenues and expenses for the test year. As seen on Exhibit 15, page 3, column (d), lines 1 and 2, the adjustment reduces the Company's test year revenues by $7,087,154 and expense by $7,087,860.

Q. Please describe the proposed lost gas expense adjustment shown on Exhibit 14, page 2, column (e), line 5.

A. The purpose of this adjustment is to reflect the current level of lost gas expense. This adjustment reduces operating expenses by $803,928. Exhibit 15, pages 4 and 5 support the calculation of this adjustment.

Q. Please explain the proposed normalizing adjustment shown on Exhibit 14, column (f), lines 1 and 5.

A. This adjustment represents the difference between test year revenues and cost of gas and normalized revenues and costs of gas. Normalized revenues and cost of gas reflect the effects from both weather normalization and customer rate class migrations. The process for determining weather normalization is addressed by Company witness Blattner. Customer rate class migrations refers to the Company's general service, large volume, or transport customers who have changed rate classes at some point during the test year. The Company removed these customers' actual and forecasted volumes, revenues, and cost of gas from their previous rate class and included them for a full twelve month period in their new rate class.

As shown on Exhibit 15, page 6, column (b), lines 10 and 11, this adjustment reduces operating revenues by $442,726 and operating expenses by $336,443. Supporting calculations are presented on Exhibit 15, pages 7-16.

Q. Can you describe briefly Intermountain's Non-Executive Incentive Compensation Plan?

A. Yes. Intermountain's plan consists of three components. The first component is based on achieving a target level of net income. The second and third components are based on cost control and customer satisfaction goals. Each component is worth an equal portion of the incentive payment. There is also a fourth goal -- for directors only -- based on a review of the Company's Employee Survey with employees during the year.

Q. Is the Company proposing an adjustment to incentive compensation expense?

A. Yes. Exhibit 14, page 2, column (g), line 9, 10, 11, 13, 14, and 17 and Exhibit 15, page 17, column (b), lines 8 and 9 remove the portion of incentive compensation expense that is based on the Company achieving a target level of net income. The remaining portion of incentive compensation expense relates to the metrics described above. These metrics are designed to benefit the Company's customers by incentivizing Company employees to control costs while maintaining a safe, reliable system and a high level of customer satisfaction. The adjustment reduces incentive compensation expense by $373,269 and payroll taxes by $32,728 for a total adjustment to operating expenses of $405,997.

Exhibit 15, page 18 provides supporting calculations that are reflected on page 17 of the Exhibit.

Q. Is the Company proposing an adjustment to the test year level of expenses associated with Executive Compensation?

A. Yes. Exhibit 14, page 2, column (h), line 14, 15, and 17 and Exhibit 15, page 19, column (d), lines 1 and 2 remove all Supplemental Executive Retirement Plan compensation, Supplemental Income Security Plan compensation and executive incentive compensation expenses. The Company has chosen to not charge its customers for these expenses and has therefore removed them from the determination of the revenue requirement. The Executive Compensation adjustment reduces operating expenses by $1,052,398 and payroll taxes by $68,332.

Exhibit 15, pages 20 and 21 provide supporting calculations that are reflected on page 19 of the Exhibit.

Q. Has the Company removed revenues and expenses associated with non-utility activities?

A. Yes. Exhibit 14, page 2, column (i), lines 2 and 15 and Exhibit 15, page 22, column (d), lines 4 and 10 remove from revenues and expenses those costs associated with non-utility activities. Non-utility revenues include miscellaneous revenue and interest income related to the non-qualifying executive compensation. The non-utility expenses include donations, lobbying and Arid Club dues. The "Other Revenue and Expense" adjustment increases other revenues by $6,791 and reduces operating expenses by $256,321.

Q. Is the Company proposing to remove interest expense from the test year expenses?

A. Yes. Exhibit 14, page 2, column (j), line 20 and Exhibit 15, page 23, column (d), line 1 reduce operating expenses by $4,348,423. The interest expense for the test period used to determine income tax expense will be the weighted average cost of debt included in the Company's cost of capital multiplied by average rate base.

Q. Has the Company adjusted the test year level of income tax expense?

A. Yes. Exhibit 14, page 2, column (k), line 23 and Exhibit 15, page 25, column (c), line 78 increase test year income tax expense by $2,544,743. Exhibit 15, pages 24 and 25 present the entire test year income tax expense calculation and include the adjusted level of revenues and expenses discussed above as well as various permanent and temporary timing differences.

Q. What are the adjusted level of revenues and operating expenses that result from the adjustments you are proposing?

A. As shown on Exhibit 14, page 1, column (d), lines 3 and 24, the adjusted level of operating revenues and expenses for the twelve months ended December 31, 2016 are $254,800,510 and $243,305,823, respectively.

Q. Does that conclude your testimony as it pertains to the Company's operating revenues and expenses?

A. Yes it does.

IV. REVENUE REQUIREMENT

Q. Please explain how the adjusted net income was converted to the required level of operating revenues.

A. Exhibit 16, page 2, shows the calculation of the conversion factor, which is applied to the required net income to produce the required revenue increase. The conversion factor takes into account revenue-sensitive items that change as revenue changes, including uncollectibles, the Commission's regulatory fee, Idaho state income taxes, and federal income taxes. As shown on Exhibit 16, page 2, column (c), line 9, the conversion factor was determined to be 1.67055.

Q. Please summarize the requested revenue requirement.

A. Page 1 of Exhibit 16 presents the calculation of the Company's revenue deficiency. Based upon an average rate base of $236,926,497, adjusted operating income of $11,494,687, and a weighted average cost of capital of 7.42%, as presented by Company witness Chiles, the Company's projected after-tax operating income at proposed rates is $17,579,946. Consequently, the Company's revenue deficiency for the test period ending December 31, 2016 is $10,165,700. This revenue deficiency requires an overall increase in rates to the Company's customers of 4.04%.

Q. Does this conclude your direct testimony?

A. Yes it does.

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
______________________________________	)	

EXHIBIT 12

Intermountain Gas Company

Rate Base - 13-Month Average

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Company Unadjusted Rate Base	Company Adjustments	Company Adjusted Rate Base
	(a)	(b)	(c)	(d)
1	Gas Plant in Service:			
2	Original Cost[2]	$ 612,621,131	$ (16,555,572)	$ 596,065,559
3	Less Accumulated Depreciation[3]	(312,607,666)	4,156,820	(308,450,846)
4	Net Gas Plant in Service	300,013,465	(12,398,752)	287,614,713
5	Materials & Supplies Inventory[4]	3,149,131	-	3,149,131
6	Gas Storage Inventory[5]	4,055,522	(859,909)	3,195,613
7	Cash Working Capital[6]	1,032,688	-	1,032,688
8	Accumulated Deferred Income Taxes[7]	(63,356,335)	13,183,858	(50,172,477)
9	Advances in Aid of Construction[8]	(7,893,171)	-	(7,893,171)
10	Rate Base	$ 237,001,300	$ (74,803)	$ 236,926,497

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 13, Page 1.

[3] See Exhibit No. 13, Page 2.

[4] See Exhibit No. 13, Page 3.

[5] See Exhibit No. 13, Page 4.

[6] See Exhibit No. 13, Page 5.

[7] See Exhibit No. 13, Page 6.

[8] See Exhibit No. 13, Page 7.

Intermountain Gas Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2016[1]

Line No.	Description	ARO Adjustment[2]	RWIP Adjustment[3]	Non-Utility Storage Adjustment[4]	Utility Storage Adjustment[4]	Idaho Deferred Taxes Adjustment[5]	CWIP Adjustment[5]	FAS109 Adjustment[5]	Gross-Up Adjustment[5]	Section 1031 Like-Kind Exchange Adjustment[5]	Contributions in Aid of Construction Adjustment[5]	Uniform Capitalization Adjustment[5]	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Gas Plant in Service:												
2	Original Cost	$ (16,555,572)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,555,572)
3	Less Accumulated Depreciation	4,303,085	(146,265)	-	-	-	-	-	-	-	-	-	4,156,820
4	Net Gas Plant in Service	(12,252,487)	(146,265)	-	-	-	-	-	-	-	-	-	(12,398,752)
5	Materials & Supplies Inventory	-	-	-	-	-	-	-	-	-	-	-	-
6	Gas Storage Inventory	-	-	(856,019)	(3,890)	-	-	-	-	-	-	-	(859,909)
7	Cash Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
8	Accumulated Deferred Income Taxes	-	-	-	-	8,933,012	(7,311)	(2,118,305)	3,268,513	115,672	2,762,610	229,667	13,183,858
9	Advances in Aid of Construction	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base	$ (12,252,487)	$ (146,265)	$ (856,019)	$ (3,890)	$ 8,933,012	$ (7,311)	$ (2,118,305)	$ 3,268,513	$ 115,672	$ 2,762,610	$ 229,667	$ (74,803)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 13, Page 1, Column (c) and Exhibit 13, Page 2, Column (c).

[3] See Exhibit No. 13, Page 2, Column (d).

[4] See Exhibit No. 13, Page 4, Columns (c) and (d).

[5] See Exhibit No. 13, Page 6, Columns (c), (d), (e), (f), (g), (h), and (i).

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J. Darrington, IGC
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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 13

Intermountain Gas Company
Gas Plant in Service - Original Cost
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Gas Plant in Service a/c 1010 and 1060[2]	ARO Adjustment[3]	Month End Total	Average Balance
	(a)	(b)	(c)	(d)	(e)
1	December 2015	$ 599,920,846	$ (18,208,107)	$ 581,712,739	
2					$ 582,550,705
3	January 2016	601,596,777	(18,208,107)	583,388,670	
4					584,497,119
5	February	603,813,675	(18,208,107)	585,605,568	
6					586,521,311
7	March	603,482,731	(16,045,678)	587,437,053	
8					588,115,133
9	April	604,838,891	(16,045,678)	588,793,213	
10					589,775,529
11	May	606,803,522	(16,045,678)	590,757,844	
12					592,109,551
13	June	609,616,576	(16,155,318)	593,461,258	
14					595,397,959
15	July	613,489,977	(16,155,318)	597,334,659	
16					599,122,794
17	August	617,066,247	(16,155,318)	600,910,929	
18					602,815,910
19	September	620,876,208	(16,155,318)	604,720,890	
20					607,022,877
21	October	625,480,182	(16,155,318)	609,324,864	
22					610,402,237
23	November	627,634,927	(16,155,318)	611,479,609	
24					614,455,580
25	December	633,586,869	(16,155,318)	617,431,551	
					-
26				Total	$ 7,152,786,705
27				Divided by	12
28				Average Balance	$ 596,065,559

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 07, Page 1, Column (b).

[3] As per prior Commission orders, the Asset Retirement Obligation is removed from the calculation of rate base to avoid double charging customers for the cost of removing tangible long-lived assets. The cost of removal is already included in the Company's approved depreciation rates.

Intermountain Gas Company
Accumulated Depreciation - Gas Plant in Service
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Accumulated Provision for Depreciation a/c 1080 and 1110[2]	ARO Adjustment[3]	RWIP Adjustment[4]	Month End Total	Average Balance
	(a)	(b)	(c)	(d)	(e)	(f)
1	December 2015	$ (304,247,389)	$ 4,726,372	$ (238,276)	$ (299,759,293)	
2						$ (300,227,129)
3	January 2016	(305,203,358)	4,726,372	(217,978)	(300,694,964)	
4						(301,761,243)
5	February	(307,494,066)	4,726,372	(59,828)	(302,827,522)	
6						(303,458,268)
7	March	(308,117,867)	4,185,070	(156,217)	(304,089,014)	
8						(304,704,704)
9	April	(309,349,841)	4,185,070	(155,623)	(305,320,394)	
10						(305,887,482)
11	May	(310,419,053)	4,185,070	(220,586)	(306,454,569)	
12						(306,883,479)
13	June	(311,380,090)	4,194,750	(127,048)	(307,312,388)	
14						(308,270,844)
15	July	(313,297,002)	4,194,750	(127,048)	(309,229,300)	
16						(310,200,318)
17	August	(315,239,037)	4,194,750	(127,048)	(311,171,335)	
18						(312,149,958)
19	September	(317,196,283)	4,194,750	(127,048)	(313,128,581)	
20						(314,110,668)
21	October	(319,160,456)	4,194,750	(127,048)	(315,092,754)	
22						(316,089,045)
23	November	(321,153,038)	4,194,750	(127,048)	(317,085,336)	
24						(317,667,013)
25	December	(322,316,392)	4,194,750	(127,048)	(318,248,690)	
						-
26					Total	$ (3,701,410,151)
27					Divided by	12
28					Average Balance	$ (308,450,846)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 07, Page 2, Column (b).

[3] As per prior Commission orders, the Asset Retirement Obligation is removed from the calculation of rate base to avoid double charging customers for the cost of removing tangible long-lived assets. The cost of removal is already included in the Company's approved depreciation rates.

[4] Accumulated Provision for Depreciation related to the Retirement Work in Process represents the work performed but not yet completed to retire plant-in-service. Retirement work in process is removed from the calculation of rate base because it represents assets that are in the process of being retired but are still used and useful at the end of the month.

Intermountain Gas Company
Materials & Supplies Inventory
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Plant Materials & Operating Supplies a/c 1540[2]	Undistributed Stores a/c 1630[3]	Month End Total	Average Balance
	(a)	(b)	(c)	(d)	(e)
1	December 2015	$ 2,920,938	$ -	$ 2,920,938	
2					$ 2,988,021
3	January 2016	3,048,127	6,977	3,055,104	
4					3,087,336
5	February	3,103,015	16,553	3,119,568	
6					3,102,734
7	March	3,078,240	7,660	3,085,900	
8					3,176,885
9	April	3,221,312	46,558	3,267,870	
10					3,303,353
11	May	3,297,913	40,922	3,338,835	
12					3,277,147
13	June	3,235,382	(19,924)	3,215,458	
14					3,191,666
15	July	3,066,424	101,450	3,167,874	
16					3,216,868
17	August	3,167,364	98,497	3,265,861	
18					3,207,242
19	September	3,111,774	36,849	3,148,623	
20					3,143,675
21	October	3,128,634	10,093	3,138,727	
22					3,152,874
23	November	3,163,030	3,990	3,167,020	
24					2,941,776
25	December	2,716,531	-	2,716,531	
					-
26				Total	$ 37,789,577
27				Divided by	12
28				Average Balance	$ 3,149,131

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 07, Page 3, Column (b).

[3] See T. Dedden's Exhibit 07, Page 3, Column (c).

Intermountain Gas Company
Gas Storage Inventory
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Gas Storage a/c 1642[2]	Non-Utility Gas Storage Adjustment[3]	Utility Gas Storage Adjustment[4]	Month End Total	Average Balance
	(a)	(b)	(c)	(d)	(e)	(f)
1	December 2015	$ 3,187,218	$ (1,146,733)	$ -	$ 2,040,485	
2						$ 2,005,941
3	January 2016	3,088,545	(1,117,148)	-	1,971,397	
4						1,941,314
5	February	2,996,769	(1,085,538)	-	1,911,231	
6						1,857,316
7	March	2,826,129	(1,022,728)	-	1,803,401	
8						2,059,409
9	April	3,284,842	(969,425)	-	2,315,417	
10						2,410,005
11	May	3,421,070	(916,477)	-	2,504,593	
12						2,535,540
13	June	3,479,830	(866,659)	(46,684)	2,566,487	
14						2,973,581
15	July	4,132,846	(752,171)	-	3,380,675	
16						3,731,637
17	August	4,777,528	(694,929)	-	4,082,599	
18						4,447,109
19	September	5,449,306	(637,687)	-	4,811,619	
20						4,795,830
21	October	5,360,486	(580,445)	-	4,780,041	
22						4,764,259
23	November	5,471,151	(722,674)	-	4,748,477	
24						4,825,420
25	December	5,568,313	(665,950)	-	4,902,363	
						-
26					Total	$ 38,347,361
27					Divided by	12
28					Average Balance	$ 3,195,613

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 07, Page 4, Column (b).

[3] Non-Utility Gas Storage Inventory represents the balance of LNG that is dedicated to non-utility LNG sales and as a result is removed from the calculation of rate base.

[4] This includes the removal of inventory not needed for Utility purposes, but not reserved for non-utility LNG sales.

Intermountain Gas Company
Cash Working Capital
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Test Year Revenues and Expenses at Proposed Rates	Revenue Lag/ Expense (Leads)	CWC Factor[2]	Cash Working Capital Requirement
	(a)	(b)	(c)	(d)	(e)
	REVENUES				
1	Revenues at Proposed Rates	$ 264,966,210	44.96	12.32%	$ 32,636,207
2	Plus Franchise Tax	7,087,860	44.96	12.32%	873,020
3	Plus Interest Expense	5,852,084	44.96	12.32%	720,808
4	(Less) Uncollectibles	(890,022)	44.96	12.32%	(109,625)
5	(Less) Depreciation and Amortization	(21,707,112)	44.96	12.32%	(2,673,691)
6	(Less) Return on Equity	(17,579,946)	44.96	12.32%	(2,165,343)
7	**TOTAL - REVENUES**	$ 237,729,075			$ 29,281,376
	EXPENSES				
8	Employee Benefits	$ 507,190	(9.24)	-2.53%	$ (12,837)
9	Payroll and Withholdings	27,292,360	(13.82)	-3.79%	(1,033,344)
10	PGA Expense	168,822,659	(41.29)	-11.31%	(19,096,257)
11	Other Operations and Maintenance (less uncollectibles)	16,551,065	(31.74)	-8.69%	(1,439,083)
12	Payroll Taxes	1,641,942	(24.70)	-6.77%	(111,129)
13	Property Taxes	3,198,871	(131.88)	-36.13%	(1,155,756)
14	Franchise Tax	7,087,860	(169.50)	-46.44%	(3,291,474)
15	Interest Expense	5,852,084	(87.68)	-24.02%	(1,405,782)
16	Income Tax	6,775,042	(37.88)	-10.38%	(703,027)
17	**TOTAL EXPENSES**	$ 237,729,075			$ (28,248,688)
18	**CASH WORKING CAPITAL REQUIREMENT**				$ 1,032,688

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] Column (c) / 365 days.

Intermountain Gas Company
Deferred Income Taxes
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Accumulated Deferrec Income Taxes a/c 2820[2]	Idaho Deferred Taxes Adjustment[3]	CWIP Adjustment[4]	FAS109 Adjustment[5]	Gross-Up Adjustment[6]	Section 1031 Like-Kind Exchange Adjustment[7]	Contributions in Aid of Construction Adjustment[8]	Uniform Capitalization Adjustment[9]	Total	Average Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	December 2015	$ (63,327,538)	$ 8,755,341	$ 13,827	$ (2,032,486)	$ 3,222,154	$ 220,329	$ 2,812,480	$ 146,648	$ (50,189,245)	
2											$ (50,175,262)
3	January 2016	(63,319,187)	8,781,542	27,194	(2,044,709)	3,227,393	219,339	2,805,467	141,683	(50,161,278)	
4											(50,130,230)
5	February	(63,295,080)	8,804,814	27,733	(2,056,932)	3,232,632	218,348	2,831,945	137,359	(50,099,181)	
6											(50,089,019)
7	March	(63,245,301)	8,823,314	7,372	(2,069,155)	3,237,872	217,357	2,820,075	129,609	(50,078,857)	
8											(50,037,246)
9	April	(63,191,866)	8,841,134	(15,965)	(2,081,378)	3,243,111	216,366	2,826,557	166,407	(49,995,634)	
10											(49,957,721)
11	May	(63,183,151)	8,867,267	(2,896)	(2,093,601)	3,248,350	215,375	2,848,845	180,003	(49,919,808)	
12											(50,062,146)
13	June	(63,392,741)	8,941,308	(21,241)	(2,121,586)	3,272,443	31,766	2,901,114	184,454	(50,204,483)	
14											(50,240,010)
15	July	(63,410,788)	8,973,634	(21,244)	(2,136,440)	3,280,821	30,910	2,764,603	242,967	(50,275,537)	
16											(50,309,986)
17	August	(63,428,835)	9,005,963	(21,244)	(2,151,290)	3,289,202	30,057	2,638,300	293,413	(50,344,434)	
18											(50,304,220)
19	September	(63,446,882)	9,038,291	(21,244)	(2,166,141)	3,297,583	29,204	2,659,377	345,807	(50,264,005)	
20											(50,259,092)
21	October	(63,464,929)	9,070,620	(21,244)	(2,180,991)	3,305,964	28,352	2,664,512	343,538	(50,254,178)	
22											(50,257,567)
23	November	(63,482,976)	9,102,949	(21,244)	(2,195,842)	3,314,344	27,499	2,653,045	341,269	(50,260,956)	
24											(50,247,230)
25	December	(63,501,022)	9,135,277	(21,244)	(2,210,692)	3,322,725	26,646	2,662,478	352,329	(50,233,503)	
											-
26										Total	$ (602,069,729)
27										Divided by	12
28										Average Balance	$ (50,172,477)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 07, Page 5, Column (b).

[3] In prior orders and communications, the Commission has ordered the Company to flow through most deferred state income taxes (DSIT). Generally Accepted Accounting Principles (GAAP) requires the Company to state the amount of DSIT in its 282 account, offset by a regulatory asset and gross-up. DSIT required to be flowed-through is not recorded on the Company's income statement. This adjustment removes the DSIT required by GAAP.

[4] Accumulated Deferred Income Taxes related to Construction Work In Process book-tax timing differences are removed from the calculation of rate base because Construction Work in Process is not included in the calculation of rate base due to the fact that the assets have not been completed and therefore are not considered used and useful.

[5] The FAS109 balance represents the measurement of accumulated deferred income taxes at the future tax rate at which the book-tax timing differences are expected to reverse, as required by ASC 740. In order to comply with IRS normalization rules regarding excess accumulated deferred income taxes, the Average Rate Adjustment Method must be used to measure deferred taxes and therefore the FAS109 balance must be removed from the calculation of rate base. Additionally, the FAS109 balance also includes the measurement of deferred state income taxes as required by ASC 740. However, IGC is required to flow-through deferred state income taxes and therefore the FAS109 balance must be removed from the calculation of rate base.

[6] The Gross-Up balance is removed from the calculation of rate base because it relates to the gross-up on the regulatory asset/liability that is created to reflect the difference between the FAS109 deferred income taxes and the APB11 deferred income taxes. To comply with IRS normalization rules the Company is only including the APB11 deferred taxes in the calculation of rate base, therefore, the Gross-Up amount should be removed from the calculation of rate base.

[7] In order to comply with the IRS normalization rules, the Company is removing the deferred income taxes associated with Sec. 1031 exchanges.

[8] This adjustment captures the accumulated deferred income taxes related to Contributions in Aid of Construction.

[9] This adjustment captures the accumulated deferred income taxes related to Gas Storage Inventory.

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J. Darrington, IGC
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Intermountain Gas Company
Advances in Aid of Construction
For the Test Year Ending December 31, 2016[1]

Line No.	Month	Month-End Balance a/c 2520[2]	Average Balance
	(a)	(b)	(c)
1	December 2015	$ (8,035,657)	
2			$ (8,025,639)
3	January 2016	(8,015,621)	
4			(8,053,447)
5	February	(8,091,272)	
6			(8,074,315)
7	March	(8,057,357)	
8			(8,066,617)
9	April	(8,075,877)	
10			(8,107,717)
11	May	(8,139,557)	
12			(8,214,225)
13	June	(8,288,892)	
14			(8,093,879)
15	July	(7,898,865)	
16			(7,718,432)
17	August	(7,537,999)	
18			(7,568,110)
19	September	(7,598,221)	
20			(7,605,557)
21	October	(7,612,892)	
22			(7,596,511)
23	November	(7,580,129)	
24			(7,593,605)
25	December	(7,607,080)	
			-
26		Total	$ (94,718,054)
27		Divided by	12
28		Average Balance	$ (7,893,171)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 07, Page 6, Column (b).

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 14

Intermountain Gas Company

Statement of Operating Income with Adjustments

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Company Unadjusted Direct[2]		Company Adjustments[3]	Company Direct Present[4]	Proposed Revenue Deficiency (Over Collection)		Company Direct Proposed[5]
	(a)	(b)		(c)	(d)	(e)		(f)
1	Gas Operating Revenues	$ 233,637,331		$ 18,262,816	$ 251,900,147	$ 10,165,700		$ 262,065,847
2	Other Revenues	2,893,572	[6]	6,791	2,900,363	-		2,900,363
3	Total Operating Revenue	236,530,903		18,269,607	254,800,510	10,165,700		264,966,210
4	Operating Expenses							
5	Cost of Gas	150,178,166		18,644,493	168,822,659	-		168,822,659
6	Operation & Maintenance							
7	Production	46,565		-	46,565	-		46,565
8	Natural Gas Storage, Terminaling, and Processing	1,383,094		-	1,383,094	-		1,383,094
9	Transmission	496,038		(3,297)	492,741	-		492,741
10	Distribution	18,854,837		(118,581)	18,736,256	-		18,736,256
11	Customer Accounts	9,378,630		(111,430)	9,267,200	36,536		9,303,736
12	Customer Service and Informational	202,610		-	202,610	-		202,610
13	Sales	1,263,653		(26,782)	1,236,871	-		1,236,871
14	Administrative and General	15,148,072		(1,328,388)	13,819,684	19,081		13,838,765
15	Other	93,510		(93,510)	-	-		-
16	Depreciation	21,707,112		-	21,707,112	-		21,707,112
17	Payroll Taxes	1,743,002		(101,060)	1,641,942	-		1,641,942
18	Property Taxes	3,198,871		-	3,198,871	-		3,198,871
19	Franchise Taxes	7,087,860		(7,087,860)	-	-		-
20	Interest Expense	4,348,423		(4,348,423)	-	-		-
21	Total Operating Expense							
22	Before Income Taxes	235,130,443		5,425,162	240,555,605	55,617		240,611,222
23	Income Taxes	205,475		2,544,743	2,750,218	4,024,824	[7]	6,775,042
24	Total Operating Expenses	235,335,918		7,969,905	243,305,823	4,080,441		247,386,264
25	Net Operating Income	$ 1,194,985		$ 10,299,702	$ 11,494,687	$ 6,085,259		$ 17,579,946

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See T. Dedden's Exhibit 08, Page 1, Column (d).

[3] See Exhibit No. 14, Page 2.

[4] Column (b) + Column (c).

[5] Column (d) + Column (e).

[6] See T. Dedden's Exhibit 09, Page 1, Column (d), line 17.

[7] Reflects statutory income tax rates at 39.81%: Federal at 35% and Idaho at 7.4%.

Exhibit No. 14
Case No. INT-G-16-02
J. Darrington, IGC
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Intermountain Gas Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Unbilled Adjustment[2]	Non-Utility LNG Sales Adjustment[3]	Franchise Tax Adjustment[4]	Lost Gas Expense Adjustment[5]	Normalization Adjustment[6]	Non-Executive Incentive Compensation Expense Adjustment[7]	Executive Compensation Expense Adjustment[8]	Other Revenue And Expense Adjustment[9]	Interest Expense Adjustment[10]	Income Tax Adjustment[11]	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Gas Operating Revenues	$ 27,605,926	$ (1,813,230)	$ (7,087,154)	$ -	$ (442,726)	$ -	$ -	$ -	$ -	$ -	$ 18,262,816
2	Other Revenues	-	-	-	-	-	-	-	6,791	-	-	6,791
3	Total Operating Revenue	27,605,926	(1,813,230)	(7,087,154)	-	(442,726)	-	-	6,791	-	-	18,269,607
4	Operating Expenses											
5	Cost of Gas	21,246,004	(1,461,140)	-	(803,928)	(336,443)	-	-	-	-	-	18,644,493
6	Operation & Maintenance	-	-	-	-	-	-	-	-	-	-	-
7	Production	-	-	-	-	-	-	-	-	-	-	-
8	Natural Gas Storage, Terminaling, and Processin	-	-	-	-	-	-	-	-	-	-	-
9	Transmission	-	-	-	-	-	(3,297)	-	-	-	-	(3,297)
10	Distribution	-	-	-	-	-	(118,581)	-	-	-	-	(118,581)
11	Customer Accounts	-	-	-	-	-	(111,430)	-	-	-	-	(111,430)
12	Customer Service and Informational	-	-	-	-	-	-	-	-	-	-	-
13	Sales	-	-	-	-	-	(26,782)	-	-	-	-	(26,782)
14	Administrative and General	-	-	-	-	-	(113,179)	(1,215,209)	-	-	-	(1,328,388)
15	Other	-	-	-	-	-	-	162,811	(256,321)	-	-	(93,510)
16	Depreciation	-	-	-	-	-	-	-	-	-	-	-
17	Payroll Taxes	-	-	-	-	-	(32,728)	(68,332)	-	-	-	(101,060)
18	Property Taxes	-	-	-	-	-	-	-	-	-	-	-
19	Franchise Taxes	-	-	(7,087,860)	-	-	-	-	-	-	-	(7,087,860)
20	Interest Expense	-	-	-	-	-	-	-	-	(4,348,423)	-	(4,348,423)
21	Total Operating Expense											
22	Before Incomes Taxes	21,246,004	(1,461,140)	(7,087,860)	(803,928)	(336,443)	(405,997)	(1,120,730)	(256,321)	(4,348,423)	-	5,425,162
23	Income Taxes	-	-	-	-	-	-	-	-	-	2,544,743	2,544,743
24	Total Operating Expenses	21,246,004	(1,461,140)	(7,087,860)	(803,928)	(336,443)	(405,997)	(1,120,730)	(256,321)	(4,348,423)	2,544,743	7,969,905
25	Net Operating Income	$ 6,359,922	$ (352,090)	$ 706	$ 803,928	$ (106,283)	$ 405,997	$ 1,120,730	$ 263,112	$ 4,348,423	$ (2,544,743)	$ 10,299,702

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Page 1, Column (d), Lines 16 and 17.

[3] See Exhibit No. 15, Page 2, Column (d), Lines 1 and 2.

[4] See Exhibit No. 15, Page 3, Column (d), Lines 1 and 2.

[5] See Exhibit No. 15, Page 4, Column (d), Line 20.

[6] See Exhibit No. 15, Page 6, Column (b), Lines 10 and 11.

[7] See Exhibit No. 15, Page 17, Column (b), Lines 11-16.

[8] See Exhibit No. 15, Page 19, Column (d), Lines 4-6.

[9] See Exhibit No. 15, Page 22, Column (d), Lines 12 and 13.

[10] See Exhibit No. 15, Page 23, Column (d), Line 1.

[11] See Exhibit No. 15, Page 25, Column (c), Line 78.

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SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 15

Intermountain Gas Company
Unbilled Adjustment
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Tariff	Unbilled Therms	Unbilled Revenues[2]	Unbilled Cost of Gas[2]
	(a)	(b)	(c)	(d)
1	December 2015			
2	RS-1	5,448,489	$ 4,141,451	$ 3,028,761
3	RS-2	26,410,518	17,912,142	13,623,866
4	GS	15,195,106	9,985,160	7,774,880
5	Total	47,054,113	32,038,753	24,427,507
6	June 2016			
7	RS-1	(372,936)	(325,450)	(207,312)
8	RS-2	(3,500,912)	(2,492,124)	(1,805,945)
9	GS	(2,283,203)	(1,615,252)	(1,168,246)
10		(6,157,052)	(4,432,827)	(3,181,503)
11	Net Change			
12	RS-1	5,075,553	3,816,001	2,821,449
13	RS-2	22,909,606	15,420,018	11,817,921
14	GS	12,911,903	8,369,908	6,606,634
15	Total	40,897,061	$ 27,605,926	$ 21,246,004
16	Adjustment to Gas Operating Revenues			$ 27,605,926
17	Adjustment to Cost of Gas			21,246,004
18	Total			$ 6,359,922

PURPOSE OF ADJUSTMENT

To remove unbilled revenues and cost of gas expenses from the revenue requirement.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] Revenue and cost of gas are calculated using currently effective rates.

Intermountain Gas Company
Non-Utility LNG Sales Adjustment
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual Amount	Forecasted Amount	Total Amount
	(a)	(b)	(c)	(d)
1	Adjustment to Gas Operating Revenues	$ (563,230)	$ (1,250,000)	$ (1,813,230)
2	Adjustment to Cost of Gas	(461,140)	(1,000,000)	(1,461,140)
3	Total Non-Utility LNG Sales Adjustment	$ (102,090)	$ (250,000)	$ (352,090)

PURPOSE OF ADJUSTMENT

To remove revenues and cost of gas expenses related to non-utility sales of liquefied natural gas.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Franchise Tax Adjustment
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual Amount	Forecasted Amount	Total Amount
	(a)	(b)	(c)	(d)
1	Adjustment to Gas Operating Revenues	$ (4,140,427)	$ (2,946,727)	$ (7,087,154)
2	Adjustment to Franchise Taxes	(4,141,133)	(2,946,727)	(7,087,860)
3	Total Franchise Tax Adjustment	$ 706	$ -	$ 706

PURPOSE OF ADJUSTMENT

To remove revenues and expenses related to the collection and remittance of franchise taxes.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Lost Gas Expense Adjustment
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual	Forecast	Total
	(a)	(b)	(c)	(d)
1	Test Year			
2	Lost Gas Expense	$ 711,422	$ 492,055	$ 1,203,477
3	Normalized			
4	RS-1 Therms	22,660,127	9,812,563	32,472,690
5	RS-2 Therms	119,838,399	60,338,574	180,176,973
6	GS-10 & 11 Therms	70,602,560	37,288,907	107,891,467
7	GS-60 Therms	12,235	45,519	57,754
8	GS-12 (CNG) Therms	4,007	3,426	7,433
9	IS-R Therms	84,621	52,776	137,397
10	IS-C Therms	11,863	4,147	16,010
11	LV Therms	3,093,310	3,224,250	6,317,560
12	T-3 Therms	20,574,067	19,335,220	39,909,287
13	T-4 Therms	138,352,837	126,283,835	264,636,672
14	T-5 Therms	10,367,730	9,408,430	19,776,160
15	Total Therms[2]	385,601,756	265,797,647	651,399,403
16	Lost Gas Rate[3]			0.2143%
17	Total Lost Gas Therms[4]			1,395,949
18	Weighted Average Cost of Gas			$ 0.28622
19	Lost Gas Expense[5]			$ 399,549
20	Adjustment to Cost of Gas[6]			$ (803,928)

PURPOSE OF ADJUSTMENT

To calculate the current level of lost gas expense.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Pages 8 and 12-15.

[3] See Exhibit No. 15, Page 5, Column (b), Line 16.

[4] Line 15 x Line 16.

[5] Line 17 x Line 18.

[6] Line 19 - Line 2.

Intermountain Gas Company
Average Lost Gas
For the Test Year Ending December 31, 2016

Line No.	Description	Oct 2012- Sept 2013	Oct 2013-Sep 2014	Oct 2014- Sep 2015
	(a)	(b)	(c)	(d)
1	Core Purchased Gas	327,556,540	331,807,940	293,930,590
2	Transport Gas	282,638,160	277,902,920	293,573,841
3	LNG Storage Withdrawals (Boil-off)	993,899	7,154,248	1,702,854
4	Imbalance Draft	466,890	-	2,723,140
5	Deliveries to System	611,655,489	616,865,108	591,930,425
6	Core Customer Billed	324,521,587	335,827,672	294,800,808
7	Core Customer Unbilled (Oct True-up)	6,585,356	5,168,187	6,611,279
8	Less: Core Customer Unbilled (prior year)	(4,900,710)	(6,585,356)	(5,168,187)
9	Transport Billed	282,638,160	277,902,920	293,573,841
10	Company Use	400,038	218,129	442,552
11	LNG Injections	542,895	1,710,685	1,491,905
12	Imbalance Pack	-	726,790	-
13	Deliveries to Customers	609,787,326	614,969,027	591,752,198
14	Lost Gas[1]	1,868,163	1,896,081	178,227
15	Lost Gas Percentage of System Deliveries[2]	0.3054%	0.3074%	0.0301%
16	Lost Gas Three-Year Average[3]	0.2143%		

NOTES

[1] Line 5 - Line 13.

[2] Line 14 / Line 15.

[3] The average of Columns (b), (c), and (d), Line 15.

Intermountain Gas Company

Normalization Adjustment

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Amount
	(a)	(b)
1	Test Year	
2	Gas Operating Revenues[2]	$ 252,342,873
3	Cost of Gas[3]	168,759,553
4	Margin	83,583,320
5	Normalized	
6	Gas Operating Revenues[4]	251,900,147
7	Cost of Gas[5]	168,423,110
8	Margin	83,477,037
9	Adjustment	
10	Gas Operating Revenues[6]	(442,726)
11	Cost of Gas[7]	(336,443)
12	Margin	$ (106,283)

PURPOSE OF ADJUSTMENT

To normalize therm sales for the test year ending December 31, 2016.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 14, Page 1, Column (b), Line 1 plus Exhibit No. 14, Page 2, Columns (b), (c), and (d), Line 1.

[3] See Exhibit No. 14, Page 1, Column (b), Line 5 plus Exhibit No. 14, Page 2, Columns (b) and (c), Line 5 less Exhibit No. 15, Page 4, Column (d), Line 2.

[4] See Exhibit No. 15, Page 7, Column (e), Line 8 plus Exhibit No. 15, Page 11, Column (c), Line 5.

[5] See Exhibit No. 15, Page 7, Column (f), Line 8 plus Exhibit No. 15, Page 11, Column (d), Line 5 less Exhibit No. 15, Page 4, Column (d), Line 19.

[6] Line 6 - Line 2.

[7] Line 7 - Line 3.

Intermountain Gas Company
Core Market Sales Normalization Summary
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Tariff	Normalized Therms[2]	Normalized Revenue[3]	Customer Charge Revenue[4]	Total Revenue[5]	Normalized Cost of Gas[6]
	(a)	(b)	(c)	(d)	(e)	(f)
1	RS-1	32,472,690	$ 25,741,559	$ 3,102,436	$ 28,843,995	$ 18,071,162
2	RS-2	180,176,973	124,410,197	11,077,964	135,488,161	93,054,807
3	GS-10 & 11	107,891,467	73,048,310	1,737,424	74,785,734	55,271,003
4	GS-60	57,754	41,024	218	41,242	29,587
5	GS-12 (CNG)	7,433	4,732	333	5,065	3,809
6	IS-R	137,397	93,185	3,840	97,025	70,961
7	IS-C	16,010	10,580	444	11,024	8,201
8	Total	320,759,724	$ 223,349,587	$ 15,922,659	$ 239,272,246	$ 166,509,530

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Page 8, Column (n).

[3] See Exhibit No. 15, Page 9, Column (d).

[4] See Exhibit No. 15, Page 10, Column (n).

[5] Column (c) + Column (d).

[6] See Exhibit No. 15, Page 9, the sum of Columns (g), (h), and (j).

Intermountain Gas Company
Core Market Normalized Therms
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Therms Tariff	Actual Therms Jan-16	Actual Therms Feb-16	Actual Therms Mar-16	Actual Therms Apr-16	Actual Therms May-16	Actual Therms Jun-16	Forecasted Therms Jul-16	Forecasted Therms Aug-16	Forecasted Therms Sep-16	Forecasted Therms Oct-16	Forecasted Therms Nov-16	Forecasted Therms Dec-16	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	RS-1	7,684,619	5,905,147	4,371,370	2,794,492	1,242,137	724,237	298,845	218,726	296,422	728,914	2,594,464	5,675,192	32,534,565
2	Weather Normalization Adjustment	(629,545)	(15,529)	75,400	432,503	110,925	(35,629)	-	-	-	-	-	-	(61,875)
3	Total	7,055,074	5,889,618	4,446,770	3,226,995	1,353,062	688,608	298,845	218,726	296,422	728,914	2,594,464	5,675,192	32,472,690
4	RS-2	37,144,814	28,927,401	22,310,224	15,239,352	8,565,361	6,797,638	4,609,253	3,991,474	4,398,743	6,318,311	13,298,773	27,722,020	179,323,364
5	Weather Normalization Adjustment	(2,524,690)	392,633	472,476	1,893,612	890,438	(270,860)	-	-	-	-	-	-	853,609
6	Total	34,620,124	29,320,034	22,782,700	17,132,964	9,455,799	6,526,778	4,609,253	3,991,474	4,398,743	6,318,311	13,298,773	27,722,020	180,176,973
7	GS-10 & 11													
8	Block 1	4,993,559	4,582,855	3,942,852	3,140,333	1,898,024	1,401,197	855,754	700,054	930,777	1,170,333	3,390,683	4,204,578	30,809,022
9	Block 2	11,078,206	8,560,109	6,392,244	4,295,661	2,436,132	2,133,158	1,319,575	1,128,716	1,509,540	1,367,342	3,580,287	8,237,564	52,310,134
10	Block 3	6,213,866	4,303,869	3,151,455	1,627,884	948,385	888,312	742,308	690,208	696,204	1,059,661	1,540,578	4,186,705	26,179,814
11	Total	22,285,631	17,446,833	13,486,551	9,063,878	5,282,541	4,422,667	2,917,637	2,518,978	3,136,521	3,597,336	8,511,548	16,628,847	109,298,970
12	Migration and Weather Normalization Adjustment													
13	Block 1	(664,701)	(31,853)	53,882	358,510	108,835	(400)	(400)	-	-	-	-	-	(176,127)
14	Block 2	(859,760)	(33,413)	30,478	142,777	24,299	(3,600)	(3,600)	-	-	-	-	-	(702,819)
15	Block 3	(275,667)	(77,435)	(60,904)	(41,637)	(25,423)	(29,529)	(17,960)	-	-	-	-	-	(528,555)
16	Total	(1,800,128)	(142,701)	23,456	459,650	107,711	(33,529)	(21,960)	-	-	-	-	-	(1,407,501)
17	GS-10 & 11 Adjusted													
18	Block 1	4,328,858	4,551,002	3,996,734	3,498,843	2,006,859	1,400,797	855,354	700,054	930,777	1,170,333	3,390,683	4,204,578	31,034,872
19	Block 2	10,218,446	8,526,696	6,422,722	4,438,438	2,460,431	2,129,558	1,315,975	1,128,716	1,509,540	1,367,342	3,580,287	8,237,564	51,335,715
20	Block 3	5,938,199	4,226,434	3,090,551	1,586,247	922,962	858,783	724,348	690,208	696,204	1,059,661	1,540,578	4,186,705	25,520,880
21	Total	20,485,503	17,304,132	13,510,007	9,523,528	5,390,252	4,389,138	2,895,677	2,518,978	3,136,521	3,597,336	8,511,548	16,628,847	107,891,467
22	GS-60													
23	Block 1	-	-	-	-	400	2,627	3,309	3,155	1,858	392	6	-	11,747
24	Block 2	-	-	-	-	757	8,451	18,588	9,209	4,737	-	-	-	41,742
25	Block 3	-	-	-	-	-	-	4,265	-	-	-	-	-	4,265
26	Total	-	-	-	-	1,157	11,078	26,162	12,364	6,595	392	6	-	57,754
27	GS-12 (CNG)	169	104	351	1,487	1,714	182	522	649	349	1,454	231	221	7,433
28	IS-R	44,420	23,236	12,318	1,933	1,631	1,083	383	376	731	1,190	13,007	37,089	137,397
29	IS-C													
30	Block 1	958	713	478	307	26	20	-	-	10	179	1,247	1,973	5,911
31	Block 2	2,746	1,862	1,283	194	-	-	-	-	-	-	-	738	6,823
32	Block 3	2,444	832	-	-	-	-	-	-	-	-	-	-	3,276
33	Total	6,148	3,407	1,761	501	26	20	-	-	10	179	1,247	2,711	16,010

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Core Market Normalized Revenue and Cost of Gas
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Therms[2]	Revenue Rate/Therm[3]	Total Revenue	Fixed Cost of Gas Rate/Therm[3]	Variable Cost of Gas Rate/Therm[3]	Fixed Cost of Gas	Variable Cost of Gas	Lost Gas Rate/Therm[4]	Lost Gas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	RS-1									
2	April - November	9,406,036	$ 0.87267	$ 8,208,365	$ 0.23005	$ 0.32584	$ 2,163,859	$ 3,064,863	$ 0.00061	$ 5,769
3	December - March	23,066,654	0.76011	17,533,194	0.23005	0.32584	5,306,484	7,516,039	0.00061	14,148
4	Total	32,472,690		$ 25,741,559			$ 7,470,343	$ 10,580,902		$ 19,917
5	RS-2									
6	April - November	65,732,095	$ 0.71185	46,791,392	$ 0.18982	$ 0.32603	12,477,266	21,430,635	$ 0.00061	40,318
7	December - March	114,444,878	0.67822	77,618,805	0.18982	0.32603	21,723,927	37,312,464	0.00061	70,197
8	Total	180,176,973		$ 124,410,197			$ 34,201,193	$ 58,743,099		$ 110,515
9	GS-1									
10	April - November									
11	Block 1	13,953,700	$ 0.72918	10,174,759	$ 0.18561	$ 0.32606	2,589,946	4,549,743	$ 0.00061	8,559
12	Block 2	17,930,287	0.70745	12,684,782	0.18561	0.32606	3,328,041	5,846,349	0.00061	10,998
13	Block 3	8,078,991	0.68643	5,545,662	0.18561	0.32606	1,499,542	2,634,236	0.00061	4,955
14	December - March									
15	Block 1	17,081,172	0.67833	11,586,671	0.18561	0.32606	3,170,436	5,569,487	0.00061	10,477
16	Block 2	33,405,428	0.65713	21,951,709	0.18561	0.32606	6,200,381	10,892,174	0.00061	20,490
17	Block 3	17,441,889	0.63667	11,104,727	0.18561	0.32606	3,237,389	5,687,102	0.00061	10,698
18	Total	107,891,467		$ 73,048,310			$ 20,025,735	$ 35,179,091		$ 66,177
19	GS-60									
20	April - November									
21	Block 1	11,747	0.72918	8,566	$ 0.18561	$ 0.32606	2,180	3,830	$ 0.00061	7
22	Block 2	41,742	0.70745	29,530	0.18561	0.32606	7,748	13,610	0.00061	26
23	Block 3	4,265	0.68643	2,928	0.18561	0.32606	792	1,391	0.00061	3
24	December - March									
25	Block 1	-	0.67833	-	0.18561	0.32606	-	-	0.00061	-
26	Block 2	-	0.65713	-	0.18561	0.32606	-	-	0.00061	-
27	Block 3	-	0.63667	-	0.18561	0.32606	-	-	0.00061	-
28	Total	57,754		$ 41,024			$ 10,720	$ 18,831		$ 36
29	GS-12 (CNG)									
30	Total Year	7,433	$ 0.63667	$ 4,732	$ 0.18561	$ 0.32606	$ 1,380	$ 2,424	$ 0.00061	$ 5
31	IS-R									
32	Total Year	137,397	$ 0.67822	$ 93,185	$ 0.18982	$ 0.32603	$ 26,081	$ 44,796	$ 0.00061	$ 84
33	IS-C									
34	Total Year									
35	Block 1	5,911	$ 0.67833	$ 4,010	$ 0.18561	$ 0.32606	$ 1,097	$ 1,927	$ 0.00061	4
36	Block 2	6,823	0.65713	4,484	0.18561	0.32606	1,266	2,225	0.00061	4
37	Block 3	3,276	0.63667	2,086	0.18561	0.32606	608	1,068	0.00061	2
38	Total	16,010		$ 10,580			$ 2,971	$ 5,220		$ 10

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Page 8.

[3] Based on currently effective rates.

[4] See Exhibit No. 15, Page 4, Column (d), Line 16 multiplied by Exhibit No. 15, Page 4, Column (d), Line 18.

Intermountain Gas Company
Core Market Customer Charge Revenue
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Tariff	Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Forecasted Jul-16	Forecasted Aug-16	Forecasted Sep-16	Forecasted Oct-16	Forecasted Nov-16	Forecasted Dec-16	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customers													
2	RS-1	67,871	67,909	67,792	67,488	67,149	66,759	66,821	66,905	66,996	67,167	67,274	67,357	
3	RS-2	238,657	239,101	239,620	239,913	240,209	240,504	241,150	241,746	242,300	242,944	243,367	243,796	
4	GS-10 & 11	32,179	32,174	32,149	32,089	32,034	31,963	32,028	32,081	32,130	32,221	32,275	32,329	
5	GS-60	-	-	-	2	10	19	21	18	18	17	4	-	
6	GS-12 (CNG)	3	3	3	3	3	3	2	3	3	3	3	3	
7	IS-R	81	82	82	84	84	85	85	85	85	85	85	85	
8	IS-C	7	8	8	8	8	9	9	9	9	9	9	9	
	Total	338,798	339,277	339,654	339,587	339,497	339,342	340,116	340,847	341,541	342,446	343,017	343,579	
9	Customer Charge[2]													
10	RS-1	$ 6.50	$ 6.50	$ 6.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 6.50	
11	RS-2	6.50	6.50	6.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	6.50	
12	GS-10 & 11	9.50	9.50	9.50	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	9.50	
13	GS-60	9.50	9.50	9.50	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	9.50	
14	GS-12 (CNG)	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	
15	IS-R	6.50	6.50	6.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	6.50	
16	IS-C	9.50	9.50	9.50	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	9.50	
17	Customer Charge Revenue													
18	RS-1	$ 441,162	$ 441,409	$ 440,648	$ 168,720	$ 167,873	$ 166,898	$ 167,053	$ 167,263	$ 167,490	$ 167,918	$ 168,185	$ 437,821	$ 3,102,436
19	RS-2	1,551,271	1,554,157	1,557,530	599,783	600,523	601,260	602,875	604,365	605,750	607,360	608,418	1,584,674	11,077,964
20	GS-10 & 11	305,701	305,653	305,416	64,178	64,068	63,926	64,056	64,162	64,260	64,442	64,550	307,126	1,737,537
21	GS-60	-	-	-	4	20	38	42	36	36	34	8	-	218
22	GS-12 (CNG)	29	29	29	29	29	29	19	29	29	29	29	29	333
23	IS-R	527	533	533	210	210	213	213	213	213	213	213	553	3,840
24	IS-C	67	76	76	16	16	18	18	18	18	18	18	86	444
25	GS Rate Migration Adjustment	(38)	(29)	(29)	(6)	(4)	(4)	(4)	-	-	-	-	-	(113)
26	Total	$ 2,298,716	$ 2,301,827	$ 2,304,203	$ 832,933	$ 832,734	$ 832,377	$ 834,271	$ 836,085	$ 837,795	$ 840,013	$ 841,420	$ 2,330,287	$ 15,922,659

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] Based on currently effective rates.

Exhibit No. 15
Case No. INT-G-16-02
J. Darrington, IGC

Intermountain Gas Company
Industrial Sales Normalization Summary
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Tariff	Normalized Therms[2]		Normalized Revenue[3]		Normalized Cost of Gas[4]
	(a)	(b)		(c)		(d)
1	LV-1	6,317,560	$	3,127,950	$	2,723,963
2	T-3	39,909,287		714,239		(13,435)
3	T-4	264,636,672		8,136,475		(382,832)
4	T-5	19,776,160		649,237		(14,567)
5	Total	330,639,679	$	12,627,901	$	2,313,129

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Pages 12-15, Column (n).

[3] See Exhibit No. 15, Page 16, Column (d).

[4] See Exhibit No. 15, Page 16, the sum of Columns (g), (h), and (j).

Intermountain Gas Company
Industrial - LV-1 Normalized Therms
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Therms Tariff	Actual Therms Jan-16	Actual Therms Feb-16	Actual Therms Mar-16	Actual Therms Apr-16	Actual Therms May-16	Actual Therms Jun-16	Forecasted Therms Jul-16	Forecasted Therms Aug-16	Forecasted Therms Sep-16	Forecasted Therms Oct-16	Forecasted Therms Nov-16	Forecasted Therms Dec-16	Total Therms Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	LV-1													
2	Block 1	631,407	575,963	572,022	476,854	468,888	448,284	437,000	464,425	468,975	543,275	654,775	655,800	6,397,668
3	Block 2	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Block 3	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Total	631,407	575,963	572,022	476,854	468,888	448,284	437,000	464,425	468,975	543,275	654,775	655,800	6,397,668
6	LV-1 Migration Adjustment													
7	Block 1	(19,933)	(40,896)	(19,567)	288	-	-	-	-	-	-	-	-	(80,108)
8	Block 2	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Block 3	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Adjusted LV-1													
11	Block 1	611,474	535,067	552,455	477,142	468,888	448,284	437,000	464,425	468,975	543,275	654,775	655,800	6,317,560
12	Block 2	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Block 3	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total	611,474	535,067	552,455	477,142	468,888	448,284	437,000	464,425	468,975	543,275	654,775	655,800	6,317,560

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Industrial - T-3 Normalized Therms
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Therms Tariff	Actual Therms Jan-16	Actual Therms Feb-16	Actual Therms Mar-16	Actual Therms Apr-16	Actual Therms May-16	Actual Therms Jun-16	Forecasted Therms Jul-16	Forecasted Therms Aug-16	Forecasted Therms Sep-16	Forecasted Therms Oct-16	Forecasted Therms Nov-16	Forecasted Therms Dec-16	Total Therms Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	T-3													
2	Block 1	563,596	564,977	580,557	567,904	569,134	560,253	660,170	650,100	639,520	670,680	649,240	597,980	7,274,111
3	Block 2	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	3,000,000
4	Block 3	2,788,083	2,484,455	2,811,710	2,537,543	2,420,415	2,286,300	2,171,060	1,945,300	1,754,260	2,390,960	2,440,530	3,265,420	29,296,036
5	Total	3,601,679	3,299,432	3,642,267	3,355,447	3,239,549	3,096,553	3,081,230	2,845,400	2,643,780	3,311,640	3,339,770	4,113,400	39,570,147
6	T-3 Migration Adjustment													
7	Block 1	20,778	25,476	49,025	60,062	87,617	96,182	-	-	-	-	-	-	339,140
8	Block 2	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Block 3	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Adjusted T-3													
11	Block 1	584,374	590,453	629,582	627,966	656,751	656,435	660,170	650,100	639,520	670,680	649,240	597,980	7,613,251
12	Block 2	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	3,000,000
13	Block 3	2,788,083	2,484,455	2,811,710	2,537,543	2,420,415	2,286,300	2,171,060	1,945,300	1,754,260	2,390,960	2,440,530	3,265,420	29,296,036
14	Total	3,622,457	3,324,908	3,691,292	3,415,509	3,327,166	3,192,735	3,081,230	2,845,400	2,643,780	3,311,640	3,339,770	4,113,400	39,909,287

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Industrial - T-4 Normalized Therms
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Therms Tariff	Actual Therms Jan-16	Actual Therms Feb-16	Actual Therms Mar-16	Actual Therms Apr-16	Actual Therms May-16	Actual Therms Jun-16	Forecasted Therms Jul-16	Forecasted Therms Aug-16	Forecasted Therms Sep-16	Forecasted Therms Oct-16	Forecasted Therms Nov-16	Forecasted Therms Dec-16	Total Therms Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	T-4													
2	Block 1	10,831,993	10,332,852	10,329,441	9,250,060	9,018,455	8,459,377	8,310,590	8,305,619	8,662,312	9,310,356	10,528,033	11,249,950	114,589,038
3	Block 2	8,623,497	8,469,141	8,804,916	7,499,231	7,149,462	5,830,445	5,701,601	6,374,843	6,707,486	7,251,257	7,655,180	8,849,709	88,916,768
4	Block 3	11,359,829	9,088,602	7,786,681	3,518,006	3,835,575	2,565,366	2,988,349	2,081,977	3,385,774	7,328,953	7,978,695	8,153,191	70,070,998
5	Total	30,815,319	27,890,595	26,921,038	20,267,297	20,003,492	16,855,188	17,000,540	16,762,439	18,755,572	23,890,566	26,161,908	28,252,850	273,576,804
6	T-4 Migration and Special Contracts Adjustment													
7	Block 1	(718,299)	(677,800)	(757,344)	(654,383)	(818,157)	(774,109)	(737,040)	(748,000)	(746,000)	(786,000)	(723,000)	(800,000)	(8,940,132)
8	Block 2	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Block 3	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Adjusted T-4													
11	Block 1	10,113,694	9,655,052	9,572,097	8,595,677	8,200,298	7,685,268	7,573,550	7,557,619	7,916,312	8,524,356	9,805,033	10,449,950	105,648,906
12	Block 2	8,623,497	8,469,141	8,804,916	7,499,231	7,149,462	5,830,445	5,701,601	6,374,843	6,707,486	7,251,257	7,655,180	8,849,709	88,916,768
13	Block 3	11,359,829	9,088,602	7,786,681	3,518,006	3,835,575	2,565,366	2,988,349	2,081,977	3,385,774	7,328,953	7,978,695	8,153,191	70,070,998
14	Total	30,097,020	27,212,795	26,163,694	19,612,914	19,185,335	16,081,079	16,263,500	16,014,439	18,009,572	23,104,566	25,438,908	27,452,850	264,636,672

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

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J. Darrington, IGC

Intermountain Gas Company
Industrial - T-5 Normalized Therms
For the Test Year Ending December 31, 2016[1]

Line No.	Rate Therms Tariff	Actual Therms Jan-16	Actual Therms Feb-16	Actual Therms Mar-16	Actual Therms Apr-16	Actual Therms May-16	Actual Therms Jun-16	Forecasted Therms Jul-16	Forecasted Therms Aug-16	Forecasted Therms Sep-16	Forecasted Therms Oct-16	Forecasted Therms Nov-16	Forecasted Therms Dec-16	Total Therms Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	T-5													
2	Demand	45,435	45,435	45,435	45,435	45,435	45,435	44,685	44,685	44,685	44,685	44,685	44,685	540,720
3	Commodity	1,345,688	1,261,503	1,357,265	1,309,806	1,344,669	1,301,037	1,326,885	1,275,235	1,282,450	1,325,435	1,286,550	1,325,485	15,742,008
4	Over-Run	437,768	245,505	383,994	435,728	400,438	544,329	211,770	179,130	378,160	198,840	481,640	136,850	4,034,152
5	T-5 Migration Adjustment													
6	Demand	(750)	(750)	(750)	(750)	(750)	(750)	-	-	-	-	-	-	(4,500)
7	Commodity	-	-	(18,406)	(22,500)	(23,250)	(22,500)	-	-	-	-	-	-	(86,656)
8	Over-Run	-	-	18,406	22,500	23,250	22,500	-	-	-	-	-	-	86,656
9	Adjusted T-5													
10	Demand	44,685	44,685	44,685	44,685	44,685	44,685	44,685	44,685	44,685	44,685	44,685	44,685	536,220
11	Commodity	1,345,688	1,261,503	1,338,859	1,287,306	1,321,419	1,278,537	1,326,885	1,275,235	1,282,450	1,325,435	1,286,550	1,325,485	15,655,352
12	Over-Run	437,768	245,505	402,400	458,228	423,688	566,829	211,770	179,130	378,160	198,840	481,640	136,850	4,120,808

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Exhibit No. 15
Case No. INT-G-16-02
J. Darrington, IGC

Intermountain Gas Company
Industrial Normalized Revenue and Cost of Gas
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Therms[2]	Revenue Rate/Therm[3]	Total Revenue	Fixed Cost of Gas Rate/Therm[3]	Variable Cost of Gas Rate/Therm[3]	Fixed Cost of Gas	Variable Cost of Gas	Lost Gas Rate/Therm[4]	Lost Gas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	LV-1									
2	Block 1	6,317,560	$ 0.49512	$ 3,127,950	$ 0.10275	$ 0.32781	$ 649,129	$ 2,070,959	$ 0.00061	$ 3,875
3	Block 2	-	0.45663	-	0.10275	0.32781	-	-	0.00061	-
4	Block 3	-	0.33442	-	-	0.32781	-	-	0.00061	-
5	Total	6,317,560		$ 3,127,950			$ 649,129	$ 2,070,959		$ 3,875
6	T-3									
7	Block 1	7,613,251	$ 0.05465	$ 416,064	$ -	$ (0.00095)	$ -	$ (7,233)	$ 0.00061	$ 4,670
8	Block 2	3,000,000	0.02205	66,150	-	(0.00095)	-	(2,850)	0.00061	1,840
9	Block 3	29,296,036	0.00792	232,025	-	(0.00095)	-	(27,831)	0.00061	17,969
10	Total	39,909,287		$ 714,239			$ -	$ (37,914)		$ 24,479
11	T-4									
12	Block 1	105,648,906	$ 0.05777	$ 6,103,337	$ -	$ (0.00206)	$ -	$ (217,637)	$ 0.00061	$ 64,802
13	Block 2	88,916,768	0.01928	1,714,315	-	(0.00206)	-	(183,169)	0.00061	54,539
14	Block 3	70,070,998	0.00455	318,823	-	(0.00206)	-	(144,346)	0.00061	42,979
15	Total	264,636,672		$ 8,136,475			$ -	$ (545,152)		$ 162,320
16	T-5									
17	Demand	536,220	$ 0.84253	$ 451,781	$ -	$ -	$ -	$ -	$ -	$ -
18	Commodity	15,655,352	0.00111	17,377	-	(0.00135)	-	(21,135)	0.00061	9,603
19	Over-Run	4,120,808	0.04370	180,079	-	(0.00135)	-	(5,563)	0.00061	2,528
20	Total			$ 649,237			$ -	$ (26,698)		$ 12,131

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Pages 12-15, Column (n).

[3] Based on currently effective rates.

[4] See Exhibit No. 15, Page 4, Column (d), Line 16 multiplied by Exhibit No. 15, Page 4, Column (d), Line 18.

Intermountain Gas Company

Non-Executive Incentive Compensation Expense Adjustment

For the Test Year Ending December 31, 2016[1]

Line No.	Description		Amount
	(a)		(b)
1	Test Year		
2	Incentive Compensation Expense	$	1,038,672
3	Payroll Tax Expense		70,942
4	Pro Forma		
5	Incentive Compensation Expense[2]		665,403
6	Payroll Tax Expense[3]		38,214
7	Adjustment		
8	Incentive Compensation Expense		(373,269)
9	Payroll Tax Expense		(32,728)
10	Total Incentive Compensation Adjustment	$	(405,997)
11	Adjustment to Transmission	$	(3,297)
12	Adjustment to Distribution		(118,581)
13	Adjustment to Customer Accounts		(111,430)
14	Adjustment to Sales		(26,782)
15	Adjustment to Administrative and General		(113,179)
16	Adjustment to Payroll Taxes		(32,728)
17	Total Incentive Compensation Adjustment	$	(405,997)

PURPOSE OF ADJUSTMENT

To remove the earnings metric from the Company's non-executive incentive compensation expense.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, Page 18, Column (f), Line 6.

[3] See Exhibit No. 15, Page 18, Column (g), Line 6.

Intermountain Gas Company

Non-Executive Incentive Compensation Expense Calculation

For the Test Year Ending December 31, 2016[1]

Line No.	Paygrade Tier	Allocated Salary By Tier	Percentage Payout	Incentive Compensation	Remove Net Income Metric	Adjusted Incentive Compensation	Payroll Tax
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Tier 1	$ 2,779,899	5.00%	$ 138,995	-33.33%	$ 92,668	$ 7,089
2	Tier 2	5,121,248	7.00%	358,487	-33.33%	239,003	18,283
3	Tier 3	2,616,994	10.00%	261,699	-33.33%	174,475	10,533
4	Tier 4	102,063	15.00%	15,309	-25.00%	11,482	166
5	Tier 5	985,167	20.00%	197,033	-25.00%	147,775	2,143
6	Total	$ 11,605,371		$ 971,523		$ 665,403	$ 38,214

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Executive Compensation Expense Adjustment
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual	Forecasted	Total
	(a)	(b)	(c)	(d)
1	Adjustment to Operation and Maintenance Expense[2]	$ (348,974)	$ (703,424)	$ (1,052,398)
2	Adjustment to Payroll Tax Expense[3]	(24,930)	(43,402)	(68,332)
3	Total Executive Compensation Adjustment	$ (373,904)	$ (746,826)	$ (1,120,730)
4	Adjustment to Administrative and General			$ (1,215,209)
5	Adjustment to Other			162,811
6	Adjustment to Payroll Taxes			(68,332)
7	Total			$ (1,120,730)

PURPOSE OF ADJUSTMENT

To remove executive and certain non-executive incentive compensation and supplemental income expenses and the related payroll tax expenses.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 15, the sum of Pages 20 and 21, Column (d), Line 1.

[3] See Exhibit No. 15, the sum of Pages 20 and 21, Column (d), Line 2.

Intermountain Gas Company
Other Incentive Compensation Expense
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual	Forecasted	Total
	(a)	(b)	(c)	(d)
1	Adjustment to Operation and Maintenance Expense[2]	$ (338,217)	$ (434,695)	$ (772,912)
2	Adjustment to Payroll Tax Expense	(13,706)	(32,602)	(46,308)
3	Total Other Incentive Compensation Adjustment	$ (351,923)	$ (467,297)	$ (819,220)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] Includes executive and certain non-executive incentive compensation expenses based on earnings per share

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Intermountain Gas Company
Executive Supplemental Income Expense
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual	Forecasted	Total
	(a)	(b)	(c)	(d)
1	Adjustment to Operation and Maintenance Expense[2]	$ (10,757)	$ (268,729)	$ (279,486)
2	Adjustment to Payroll Tax Expense	(11,224)	(10,800)	(22,024)
3	Total Executive Supplemental Income Expense Adjustment	$ (21,981)	$ (279,529)	$ (301,510)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] Includes Supplemental Executive Retirement Plan and Supplemental Income Security Plan compensation expenses.

Intermountain Gas Company

Other Revenue and Expenses Adjustment

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual	Forecasted	Total
	(a)	(b)	(c)	(d)
1	Income:			
2	Non-Utility Revenue Adjustment	$ -	$ (142)	$ (142)
3	Interest Income Adjustment	6,933	-	6,933
4	Subtotal	6,933	(142)	6,791
5	Expense:			
6	Arid Club Dues Adjustment	(2,723)	(1,410)	(4,133)
7	Donations Adjustment	(68,926)	(112,591)	(181,517)
8	Civic, Political, and Related Activities Adjustment	(36,859)	(33,394)	(70,253)
9	Other Deductions Adjustment	(418)	-	(418)
10	Subtotal	(108,926)	(147,395)	(256,321)
11	Total Other Expenses Adjustment	$ 115,859	$ 147,253	$ 263,112
12	Adjustment to Other Revenues			$ 6,791
13	Adjustment to Other			(256,321)
14	Total			$ 263,112

PURPOSE OF ADJUSTMENT

To remove non-utility revenues and expenses.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company

Interest Expense Adjustment

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Actual	Forecasted	Total
	(a)	(b)	(c)	(d)
1	Adjustment to Interest Expense	$ (2,032,150)	$ (2,316,273)	$ (4,348,423)

PURPOSE OF ADJUSTMENT

To remove interest expense.

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

Intermountain Gas Company
Income Tax Calculation
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Forecasted	Adjustments	Proforma Amount
	(a)	(b)	(c)	(d)
1	Total Operating Revenue[2]	$ 236,530,903	$ 18,269,607	$ 254,800,510
2	Total Operating Expenses Before Interest Expense and Income Taxes[3	230,782,020	9,773,585	240,555,605
3	Interest Charges[4]	4,348,423	1,503,661	5,852,084
4	Pre-Tax Income[5]	1,400,460	6,992,361	8,392,821
5	Permanent Tax Adjustments:			
6	401K Dividend Deduction	(123,189)	-	(123,189)
7	50% Meals and Entertainment	81,713	-	81,713
8	Club Dues	4,133	(4,133)	-
9	Lobbying Expenses	70,253	(70,253)	-
10	Total Permanent	32,910	(74,386)	(41,476)
11	Temporary Tax Adjustments:			
12	Accrued 401K Pension	(5,508)	-	(5,508)
13	Bad Debt Expenses	(39,018)	-	(39,018)
14	Charitable Contributions	181,517	(181,517)	-
15	Customer Advances	267,239	(695,816)	(428,577)
16	Deferred Compensation - Officers	(246,020)	246,020	-
17	Incentive Compensation	1,038,672	(373,269)	665,403
18	LNG Sales Deferred Revenue	101,582	(101,582)	-
19	Payroll Taxes - Incentive Compensation	70,942	(32,728)	38,214
20	Postretirement Benefit Costs	(235,697)	-	(235,697)
21	SISP/SERP Expense - Current	(627)	627	-
22	SISP/SERP Expense Officers	(536,050)	536,050	-
23	SISP/SERP Expense Officers - PBO	334,864	(334,864)	-
24	Unamortized Loss on Reacquired Debt	72,216	-	72,216
25	Uniform Capitalization	(36,695)	624,355	587,660
26	Vacation Pay	38,692	-	38,692
27	AFUDC Debt - CWIP	(303,594)	303,594	-
28	AFUDC Equity - CWIP	26,353	(26,353)	-
29	Capitalized Interest - CWIP	(955)	955	-
30	Contribution in aid of construction - CWIP	939,024	(939,024)	-
31	Plant Temporary Differences Federal	412,038	(193,684)	218,354
32	Total Temporary	2,078,975	(1,167,236)	911,739
33	Total Tax Adjustments[6]	2,111,885	(1,241,622)	870,263
34	Taxable income before state income taxes[7]	3,512,345	5,750,739	9,263,084
35	State Current Income Tax Calculation:			
36	Taxable income before state income taxes	3,512,345	5,750,739	9,263,084
37	Bonus Modification	(5,336,799)	-	(5,336,799)
38	State taxable income	(1,824,454)	5,750,739	3,926,285
39	State tax rate	7.40%	7.40%	7.40%
40	State income tax (expense)/benefit before adjustments	135,010	(425,555)	(290,545)
41	State Net Operating Loss	-	-	-
42	State Tax Credits	-	-	-
42	Permanent Building Fund	(10)		(10)
42	Investment tax credit recapture	(18,856)		(18,856)
43	Investment tax credit	-	145,273	145,273
44	Return and other adjustments	-	-	-
45	Total State Current Income Taxes (expense)/benefit	116,144	(280,282)	(164,138)

Intermountain Gas Company

Income Tax Calculation

For the Test Year Ending December 31, 2016[1]

Line No.	Description	Forecasted	Adjustments	Proforma Amount
	(a)	(b)	(c)	(d)
46	State Deferred Income Tax Calculation			
47	Deferred Gas Cost and SERP timing differences[8]	(536,050)	536,050	-
48	State deferred tax rate	7.40%	7.40%	7.40%
49	State NOL	-	-	-
50	State Deferred Income Taxes (expense)/benefit[9]	(39,668)	39,668	-
51	Total State Income Taxes (expense)/benefit[10]	76,476	(240,614)	(164,138)
52	Federal Current Income Tax Calculation:			
53	Taxable income before state income taxes	3,512,345	5,750,739	9,263,084
54	State income tax - Current year	116,144	(280,282)	(164,138)
55	Federal taxable income	3,628,489	5,470,457	9,098,946
56	Federal tax rate	35.00%	35.00%	35.00%
57	Federal income tax (expense)benefit before adjustments	(1,269,971)	(1,914,660)	(3,184,631)
58	Federal Net Operating Loss	-	-	-
59	State Net Operating Loss	-	-	-
60	Federal Tax Credits	-	-	-
61	State Tax Credits	-	-	-
62	FIN 48 Adjustments	-	-	-
63	Return and other adjustments	-	-	-
64	Total Federal Current Income Taxes (expense)/benefit	(1,269,971)	(1,914,660)	(3,184,631)
65	Federal Deferred Income Tax Calculation			
66	Non fixed asset & CWIP timing differences[11]	2,176,634	(1,483,249)	693,385
67	Federal deferred tax rate	35.00%	35.00%	35.00%
68	Deferred taxes	761,822	(519,137)	242,685
69	Deferred Gas Cost & SERP timing differences[8]	(536,050)	536,050	-
70	Federal deferred tax rate[12]	32.41%	32.41%	32.41%
71	Deferred taxes	(173,734)	173,734	-
72	Utility fixed asset timing differences[13]	412,038	(193,684)	218,354
73	Federal deferred tax rate[14]	22.75%	22.75%	22.75%
74	Deferred taxes	93,745	(44,066)	49,679
75	Federal Deferred Income Taxes (expense)/benefit[15]	681,833	(389,469)	292,364
76	Total Federal Income Taxes (expense)/benefit[16]	(588,138)	(2,304,129)	(2,892,267)
77	ITC Amortization	306,187		306,187
78	Total tax (expense)/benefit[17]	$ (205,475)	$ (2,544,743)	$ (2,750,218)

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 14, Page 1, Columns (b), (c), and (d), Line 3.

[3] See Exhibit No. 14, Page 1, Column (b), (c), and (d), the sum of Lines 5-19.

[4] Interest expense for purposes of calculating income tax expense is calculated as the weighted average cost of debt multiplied by average rate base.

[5] Line 1 - Line 2 - Line 3.

[6] Line 10 + Line 32.

[7] Line 4 + Line 33.

[8] See Line 22. The IPUC requires the flow-through of state income taxes. However, deferred taxes related to deferred gas costs, the Supplemental Income Security Plan and the Supplemental Executive Retirement Plan are not required to be flowed through. There are no deferred gas costs in this filing and SISP and SERP expenses have been removed.

[9] Line 47 x Line 48 - Line 49.

[10] Line 45 + Line 50.

[11] Line 32 - Line 22 - Line 28- Line 31.

[12] Federal statutory tax rate of 35% less the Federal tax effect of the Idaho statutory rate of 7.4%.

[13] See Line 31.

[14] This is the Average Rate Assumption Method rate.

[15] Line 68 + Line 71 + Line 74.

[16] Line 64 + Line 75.

[17] Line 51 + Line 76 + Line 77.

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 16

Intermountain Gas Company
Deficiency in Operating Revenue
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Amount
	(a)	(b)
1	Rate Base[2]	$ 236,926,497
2	Operating Income at Present Rates[3]	11,494,687
3	Earned Rate of Return[4]	4.852%
4	Cost of Capital[5]	7.420%
5	Operating Income at Proposed Rates[6]	17,579,946
6	Operating Income Deficiency[7]	6,085,259
7	Gross Revenue Conversion Factor[8]	1.67055
8	**Deficiency in Operating Revenue[9]**	**$ 10,165,700**

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] See Exhibit No. 12, Page 1, Column (d), Line 10.

[3] See Exhibit No. 14, Page 1, Column (d), Line 25.

[4] Line 2 / Line 1.

[5] See Table 7 - Proposed Return on Rate Base sponsored by Company Witness Chiles.

[6] Line 1 x Line 4.

[7] See Line 5 - Line 2.

[8] See Exhibit No. 16, Page 2, Column (c), Line 9.

[9] Line 6 x Line 7.

Exhibit No. 16
Case No. INT-G-16-02
J. Darrington, IGC

Intermountain Gas Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2016[1]

Line No.	Description	Rate	Gross Revenue Conversion Factor
	(a)	(b)	(c)
1	Operating Revenues (without add-on taxes)		1.00000
2	Commission Fees[2]	0.1877%	0.00188
3	Uncollectibles Expense	0.3594%	0.00359
4	State Taxable Income[3]		0.99453
5	State Income Tax[4]	7.40%	0.07360
6	Income Before Federal Income Tax[5]		0.92093
7	Federal Income Tax[6]	35.00%	0.32233
8	Operating Income After Taxes[7]		0.59861
9	Gross Revenue Conversion Factor[8]		1.67055

NOTES

[1] Test Year ending December 31, 2016 is composed of actual financial data from January 1 - June 30, 2016 and forecasted financial data from July 1, 2016 - December 31, 2016.

[2] Per Commission Order 33498.

[3] Line 1 - Line 2 - Line 3.

[4] Line 4 x Column (b), Line 5.

[5] Line 4 - Line 5.

[6] Line 6 x Column (b), Line 7.

[7] Line 6 - Line 7.

[8] 1 / Line 8.

Exhibit No. 16
Case No. INT-G-16-02
J. Darrington, IGC

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

DIRECT TESTIMONY OF BRANKO TERZIC

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name, title and business address.

A. My name is Branko Terzic and my business address is 1800 M Street NW, Second Floor, Washington, D.C. 20036.

Q. By whom are you employed and in what capacity?

A. I am employed as a Managing Director at the Berkeley Research Group.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Intermountain Gas Company ("Intermountain" or the "Company")

Q. Mr. Terzic, please describe your educational and professional background.

A. I have a B.S. in Engineering from the University of Wisconsin – Milwaukee. I have over four decades of regulatory, consulting and management experience in the natural gas and electric public utility sectors. My regulatory experience includes service as a commissioner on the Public Service Commission of Wisconsin (1981-1986) and on the Federal Energy Regulatory Commission (1990-1993). My management experience in natural gas includes serving as Chairman, President and Chief Executive Officer of Yankee Energy System Inc. and its main subsidiary Yankee Gas Services Company, a distribution gas utility in Connecticut. I have also served as a consultant to both private corporations and to government agencies (domestic and international) on a range of regulatory issues affecting the electric and natural gas utility sectors. I am a member of the Society of Utility Regulatory Financial Analysts, the U.S. Association for Energy Economics, the Natural Gas Roundtable, and the Association of Energy Engineers, among others. I have guest lectured on energy topics at Johns Hopkins

University, Yale University, Syracuse University, and George Washington University, and am currently a faculty member at the Washington Campus (sixteen university MBA members), where I continue to lecture on issues related to the energy industry. A copy of my curriculum vitae is attached as Exhibit 17.

Q. What is the purpose of your testimony?

A. My testimony is broken into two parts.

First, I intend to explain why the Idaho Public Utilities Commission (the Commission) should approve Intermountain's proposal, presented in the testimony of Lori B. Blattner, 1) to increase the customer charge for residential and commercial customers. and 2) presented in the testimony of David Swenson, to introduce a demand related rate for industrial customers.

In the second part of my testimony, I intend to explain why the Commission should approve the Company's decoupling proposal called a Fixed Cost Collection Mechanism, as presented in the testimony of Michael P. McGrath.

I. CUSTOMER CHARGE

Q. What is the ratemaking basis for customer charges and a demand related charge?

A. Both of these charges have their basis in the fact that public utilities, such as electric, natural gas and water utilities, are both capital intensive and have other fixed costs as a proportion of their annual revenue requirements. This means that the utility incurs these costs regardless of the level of natural gas volumes flowing through the distribution system.

Given that fact, it seems reasonable to charge a fixed monthly fee to recover some or all of these costs. It seems reasonable to me that residential and commercial customers would understand the basis for a “customer” charge as representing a charge to recover some or all of the costs to deliver, or distribute, natural gas to their home or business and to meter and bill the same. Ms. Blattner’s testimony presents the disparity between the current customer charges and the actual level customer costs associated with providing monthly service.

The introduction of demand based charges for the larger industrial gas customers is, in my opinion well overdue. There is a sound theoretical and practical basis for demand charges and this has been recognized for over a century. For example, a demand rate was developed by the British engineer Dr. James Hopkinson in 1892. In the U.S. the rate engineer Harry Barker, writing in the book Public Utility Rates (1917) describes Hopkinson’s work and notes that at that time a three part rate was proposed with “… a charge based on the customer’s maximum demand at any time (for this is related to the investment for that customer).. a second part, proportional to the amount of service shown by meter… a third part – a fixed sum to cover the cost per customer of expenses proportional only to the number of customers.”(P.7) Notice that this was written at the turn of the last century where it was already recognized that customer demand directly caused the necessary level of investment and that a “customer charge”, the ‘third part” in his summary, was warranted.

A fixed charge per month for large industrial customers has already been adopted by the natural gas utility serving Northern Idaho and by other gas distribution companies in the Northwest as well.

Q. What is the origin of fixed costs in a public utility revenue requirement?

A. The four major components of a public utility's annual revenue requirement, the basis for rates, include 1) operating and maintenance expense, 2) depreciation expense, 3) taxes and 4) return of rate base. Even upon casual inspection one can see that few costs vary in the test year with volume of service.

For example, depreciation and return do not vary with customer volumes during the test year. The annual depreciation expense ($21,707,112) is based on a rate base and annual depreciation rate both approved by the regulator. So these are "fixed" costs. Likewise the annual return is based on the approved rate base and approved rate of return. The return too is a fixed cost. Property taxes are fixed and based on rate base. Income taxes are based on the approved return times the tax rate. Leaving us with the cost category of annual "operating and maintenance" expenses which consist of labor costs – mostly fixed payroll and benefits with some overtime. In sum, for a gas distribution system, a significant high level of costs are fixed during the test year.

Q. Why is there such a high level of fixed costs in a natural gas distribution utility?

A. First consider that a natural gas distribution system is designed and built to 1) connect all customers to the distribution grid, and 2) to meet the maximum peak demand required by customers. The size needed and commensurate reasonable construction costs are approved by the regulator and the approved capital costs become the main part of the utility's rate base. Utilities are capital intensive meaning that there is a large capital investment needed for every dollar of revenue. Gas distribution companies typically need a dollar or more of investment for each dollar of revenue.

The term demand (also called capacity) of a utility system is the cumulative peak demand of all customers in terms of usage during the peak day. A natural gas system is designed and built to meet the "design peak day" which is the peak load that would occur if the system experienced the occurrence of the lowest temperatures during the heating system."[1] In the case of a natural gas distribution system this demand is expressed in term of therms or cubic feet of gas which can be delivered on the peak day.

Q. What is the basis for the establishment of customer and demand charges in a utility system?

A. The questions of both the establishment and level of customer charges and demand charges are key issues in the subsequent cost of service studies (COS), also called allocated cost of service studies (ACOSS). These COS studies provide the basis for 1) allocation of the revenue requirement to different classes of service and 2) provide information for the design of ultimate utility rates.

Cost of service studies can be performed on the basis of embedded (accounting) costs or on estimates of Long-run marginal or Short-run marginal costs. For regulated utilities in the US, mostly it is the embedded costs which are

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[1] Gas Rate Fundamentals, 4th Edition, American Gas Association Pate Committee 1987 P.229

the basis for a cost of service study and ensuing apportionment. As more fully described in the testimony of Ms. Blattner, the COS proceeds by taking the annual revenue requirement and apportioning it in three steps: functionalization, classification and allocation. The functions are storage and gas supply, transmission, distribution, other customer costs and revenue related costs. The classification apportions the previously functionalized costs to demand related (capacity), commodity related (gas volumes) and customer related costs. The third step is to allocate the classified costs to the various customer classes. Demand costs relate to the peak usage of a utility's customers. The end result is that the COS develops the revenue required from each class of customer based on the addition of the customer, demand and commodity costs attributable to that class.

The next step is the design of utility rates for each class guided by the regulator's direction as to what portion of the customer, demand and commodity related costs should go into a volumetric charge and how much into fixed monthly charges.

Q. What underlying principle is the basis for allocating demand costs in a cost of service study?

A. According to Professor Alfred Kahn in The Economics of Regulation (1988) the basis for demand allocation is "the respective causal responsibilities of various buyers" (P.95/I), or in other words what is known among regulators as the "cost causer is the cost payer" principle. Kahn elaborates that the "proper measure of that responsibility is the proportionate share of each customer to total demand placed on the system at its peak."

This view is confirmed by Drs. Paul J. Garfield and Wallace P. Lovejoy in Public Utility Economics (1964) as “The annual peak demand on the system determines the size of the plant; the latter essentially determines the total demand or capacity costs.” They also point out that “the major difficulty arises in the allocation of a cost category designated demand or capacity costs” and has “been the subject of study since the turn of the last century [20th]”

Probably the most quoted authority on public utility rate making is Professor James Bonbright writing in Principles of Public Utility Rates. In discussing the various cost apportionment formulas for capacity cost available, Bonbright writes “of the formulas described the one that would probably come closest to receiving support from the economists, at least from the standpoint of cost analysis, is the system peak method.” (P. 354)

Most state commissions, some with over a hundred years of experience, have settled by now on their preferred demand allocation method or methods for their jurisdictional gas and electric utilities. FERC has done the same and for natural gas pipelines, switching in 1992 from a “Seaboard” formula of 50% demand in the fixed rate and 50% in the volumetric, to a 100% of fixed cost in the fixed rate (called straight fixed-variable).

Q. What costs are related to the “customer charge” on a gas distribution system?

A. According to the Gas Rate Fundamentals handbook “Customer-related costs, then, are primarily distribution and customer accounting costs. They are allocated directly to the customer of a particular class of service. Metering costs are an example of customer-related costs." (P. 137)

These costs vary with the number of customer and typically include, beside meter reading costs, the costs of billing a customer and some distribution costs. The exact make up of costs associated with "customer charges" varies with the practices of the individual state commissions. That is, some states may include more distribution system costs than others related to demand.

The reason for this is that for residential gas meters and the utility's billing systems do not allow for residential and GS customers to be charged for their maximum demand on the system. Therefore the next best solution is to convert the expected demand charge into a customer charge, which is equitable as customers in this class are similar to each other so that the customer charge collects as a demand charge would.

The testimony of Lori B. Blattner indicates that Intermountain's unit customer-related costs are estimated at $13.50 per month, while the Company's monthly customer charge is only $2.50 in the summer and $6.50 in the winter months. Thus, a customer going on vacation for a summer month and shutting off gas appliances would pay only $2.50, which would be grossly inadequate to recover the fixed cost investment in the distribution system standing by to provide service for that customer during the entire month, let alone the associated meter reading and billing costs. The implication of that fact is that other customers would have to cover this shortfall in revenues.

Q. Would higher residential customer charges negatively impact disproportionate numbers of low income customers, compared to the company's general population of residential customers?

A. Not in this case. The company has prepared an analysis that shows that the usage of low income customers is similar to the usage of the general population. Thus it is not correct to assume that all low natural gas usage customers are also "low income" customers. Low usage can come from the decision by a high income customer to only use natural gas only for cooking rather than space heating. Low usage can also occur annually from retirees who move to warmer climates in the winter leaving their homes vacant for the high heating consumption months. Conversely, high natural gas usage may be experienced by large but poor families cooking and space heating with older less-efficient appliances in poorly insulated homes.

Low income customers will always be affected greater by increases in the cost of any essential compared to higher income customers. That is purely a mathematical statement. Increasing the customer charge is economic efficient pricing. Kahn directly addresses this issue by stating that variations from this pricing may be made for "expediency and practicality" but that "objections to the principle itself" are for the most part not susceptible to scientific refutation, since basically they involve nonscientific value judgments." (P. 100-102/I) Having attempted to deal with special rates for "low income" customers as a state PSC commissioner during the high periods of inflation in the 1980's I would discourage using utility rates to ameliorate problems of poverty.

Q. **Would the shift in customer charge, as proposed by Intermountain, discourage conservation or encourage unnecessary use of natural gas?**

A. I do not believe so. Correctly done the average customer should see a monthly bill at the same level before the change as after. While the fixed customer charge will increase, the volumetric charge will decrease, leading, on average, to a total bill the same as before. Thus, there would not be any price signal indicating that delivered gas service was any cheaper than before.

Even if the commodity price of natural is slightly lower in the future, due to this shift, it is not people who use natural gas but their appliances and devices. These devices do not see any price. When the weather gets colder the family furnace or cooking range will not use more gas just because it is less expensive than it was before. Yes, customers do control the thermostat, but is it likely that small changes in gas commodity price will cause major changes in life style choices (increasing thermostat settings in winter or cooking more often) for the average consumer? Conversely, if the price of gas is lower, it is also highly unlikely that consumers will go out and install a second furnace and a second kitchen range.

With respect to which price signals to consumers would cause them to replace lower efficiency furnaces and appliances for new ones, I believe that consumers are more likely to change their furnaces and appliances due to mechanical problems, age and rebates and other promotional programs than changes in commodity gas costs. I doubt whether gas appliance sales have skyrocketed during this recent period of commodity gas prices at the recent low

$2.00 per MCF level coming down from a high a few years ago of $8.00 per MCF.

Q. Do you support Intermountain's proposal to change their rate structure and implement a demand charge for large industrial natural gas customers?

A. Yes, I do. As I indicated earlier in this testimony the capital investment in the natural gas system is a factor of the size of the system in terms of how much gas can be delivered in a specific period of time. The more gas required in that time period, called the "demand" (from the view of the customer and "capacity" from the view of the utility when making its capital investment), the larger, physically, the system needs to be and the greater capital cost in incurred. Under the most basic rate making principles that entities which cause the demand should pay their proportionate share of costs in meeting that demand. Volumetric use is not the controlling factor here but the size of the system is since size dictates how much gas can flow, at safe pressure, in the relevant time period.

For example, most of us are aware that filling a swimming pool with a garden hose would take longer than filling it with a fire hose. The final volume of water would be the same to fill the pool from either hose. However, the capacity or demand from the fire hose would be much greater than that through the garden hose. Most people would understand that a large fire hose would be more expensive than a garden hose and the same is true for the large natural gas pipes required by large industrial customers. The large industrial customers would have larger service pipes and they would use a larger portion of the capacity of the common distribution system in the streets.

Another cost associated with “demand” incurred by the distribution gas system is the cost of Federal Energy Regulatory Commission (FERC) regulated interstate natural gas pipeline system delivering gas to the distribution system’s city gate. In 1992 the FERC adopted a rate making design called “straight fixed-variable” (SFV) which allocated all of the fixed costs to a monthly fixed charge for capacity (demand) leaving only variable costs in the volumetric rate.

Distribution gas utilities as customers of natural gas pipelines pay a fixed monthly demand rate based on their reservation of maximum capacity needed. This capacity/demand is a function of the simultaneous maximum demand placed by the distribution customers on the system. If that demand increases the distribution gas utility must sign up for more capacity. If demand diminishes the utility can reduce its demand reservation. Thus the demand of large industrial customers, along with demand of other customer classes dictates how much pipeline capacity must be reserved. Thus an industrial demand charge will more fairly allow this cost to be allocated to the customers causing the demand. Since changes in rate design are generally designed to collect the same revenue requirement, as before the change, increases in fixed costs would be accompanied with a decrease in the volumetric rate.

II. FIXED COST COLLECTION MECHANICISM

Q. Turning now to the second part of your testimony, do you have an opinion on whether the Commission should adopt he Company’s proposal to implement a Fixed Cost Collection Mechanism (“FCCM”)?

A. Yes. It is my opinion that the FCCM presented in Mr. McGrath's testimony is a necessary component of the Demand Side Management (DSM) program presented in the testimony of Allison A. Spector in this proceeding.

Ms. Spector's testimony includes a description of the company's proposed DSM program, the program direct cost and reference to a revenue decoupling proposal in the form of the FCCM Tariff in Mr. McGrath's testimony. The purpose of the FCCM is to mitigate revenue losses resulting from this conservation program and other factors. It is my opinion that the FCCM is a critical component of the DSM proposal and its acceptance by the commission would be in keeping with the public interest and good regulatory practice.

Q. What is the nature of the term "fixed costs" in the context of the FCCM proposal?

A. As I explained earlier, a natural gas utility incurs certain fixed costs during the test year period for which the revenue requirement is estimated, and upon which rates are based. These costs do not vary with the volume of natural gas delivered through the Company's distribution system or taken by any individual customer. An allocated cost of service study, as prepared by all natural gas utilities in support of rate design, has within it a breakdown of fixed and variable costs by customer class. The problem arises when natural gas distribution rates are designed to predominately recover costs in the volumetric component and experienced volumes fall below those expected. The result will be programmatic deficiency in revenue and failure to collect needed revenues.

Q. Why would the acceptance of the FCCM be in the public interest and good regulatory practice?

A. Because a FCCM is a natural and important component or counter-weight to a well designed and implemented demand-side management (DSM) program. It is a regulatory mechanism for mitigating economic penalties on the utility associated with the desire to obtain environmental and consumer benefits commensurate with a well-designed DSM program.

DSM is one technique for reducing natural gas distribution company demand and usage. It usually responds to a utility regulatory commission's desire to look at both supply-side and demand-side options, with an accompanying analysis costs and rate impacts. Typical regulatory DSM objectives are the promotion of efficiency in the consumption of energy and obtaining environmental benefits. The Idaho Commission has extensive experience with such programs, having accepted and reviewed filings by both its electric and natural gas utilities.

The treatment of DSM programs in the natural gas distribution industry is detailed in the National Regulatory Research Institute's (NRRI) August 1994 paper "Integrated Resources Planning for Local Gas Distribution Companies: A Critical Review of Regulatory Policy Issues". That paper refers to the two basic elements of a DSM program as "a set of administrative procedures and ratemaking mechanism." In accordance with this report in these Intermountain Gas Company proceedings Ms. Spector has presented the procedures for DSM and Mr. McGrath has presented a rate making mechanism.

Q. Is a request for a decoupling mechanism, such as the FCCM proposal appropriate when a utility adopts a demand side management program?

A. Yes, it is. The Commission recognized this with its earlier cases in the electric industry. For natural gas distribution utilities, the cited NRRI paper clearly states that ratemaking mechanism elements when adopting DSM "generally attempt to allow recovery of investments and expenses of various options, recovery of revenues caused by lost sales due to successful implementation of demand-side management (DSM) options, or otherwise make supply side and DSM options equally profitable, offer additional financial incentives for successful DSM options, and promote overall costs minimization." (Page 3) In this case, Mr. McGraths testimony on FCCM lays out a specific proposal in keeping with the DSM program.

Q. Is ratemaking treatment to recover lost revenues an indispensable part of a DSM proposal?

A. It is. The NRRI report is direct on this point: "Recognizing the fact that adoption of cost-effective DSM options may lead to a reduction in sales, and therefore, a reduction of revenues and profits, mechanisms to compensate the utility for lost revenues have been proposed and used." Thus, I believe it is indispensable.

Q. Is there a case where a DSM program may not lead to a reduction in "revenues and profits"?

A. In most cases DSM would lead to reduction in revenues. However, if the distribution gas company rate design had all fixed costs in a monthly fixed charge, or if rates were based on steep declining block rates, then the lost revenues would merely reflect lower purchased gas costs. In that case the utility's return (profit) would be collected in the fixed charge or early rate blocks.

This is not the case in regard to Intermountain Gas Company's tariffs where both the residential services tariffs RS-1 and RS-2 have fixed monthly customer charges of $2.50 per bill April to November and $6.50 December through March with an energy charge based on dollars per therm. In this type of rate design the bulk of the revenue comes to the utility in the energy charges and this would include revenues to cover the return component of the revenue requirement. There is also the exception where the DSM objective of reduction of negative environmental impacts is to be accomplished by increasing the direct use of natural gas.

Q. Is a decoupling mechanism, such as the FCCM proposed here, only required when a distribution gas company applies for a DSM program?

A. No. A decoupling mechanism is appropriate, in my opinion, whenever a utility rate design is such that a decrease in sales volumes adversely affects the ability of the utility to earn a reasonable return on investment. Mr. McGrath's testimony listed a number of reasons why natural gas sales per customer were declining on Intermountain's system, and those factors are found all around the United States, not just here in Idaho. A legal principle in regulation is that the commission approved rates must give the utility a reasonable opportunity to earn a fair return on investment. When a commission has direct evidence that a regulatory policy or rate design results directly in the inability of a utility to have that opportunity, then the policy or rate design must be corrected or effects mitigated.

Q. Is the FCCM the only decoupling mechanism available?

A. No. Regulators have approved a variety of decoupling mechanisms based on local preferences, practices and circumstances. The FCCM proposal for Intermountain was made with knowledge of this Commission's first case to investigate financial disincentives to energy efficiency in the case of an electric utility back in 2004. The result was a pilot Fixed Cost Adjustment mechanism (FCA) for Idaho Power Company in 2007. In 2012 that pilot was made permanent. Additionally, in 2015, the Commission approved a three-year pilot program for an FCA mechanism for Avista Utilities' electric and natural gas operations.

Q. Have regulators explicitly cited lost revenue as a reason for implementing a recovery mechanism?

A. Yes, for example the Ontario Energy Board, the public utility regulatory agency in the Province of Ontario, has explicitly listed, among its "Guiding principles for the DSM Framework" as a principle number "4. Gas utilities will be able to recover costs and lost revenues from DSM programs."[2] In this case, we have a regulator – the Ontario Energy Board – and there are likely others, which has publicly tied decoupling as a required condition for DSM implementation.

Q. What is the significance of an FCCM, or similar mechanism, to utility investors?

A. A regulated utility, such as a natural gas distribution company, is required to have facilities sufficient to provide safe, reliable and adequate service to its customers. This means that sufficient physical facilities must be built and available to provide

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[2] As cited in its recent "Report of the Board Demand Side Management Framework for Natural Gas Distributers (2015-2020) EB-1024-0134"

needed service. The funds to pay for the construction of the assets come from debt and equity provided by investors. Regulators do not include the cost of utility assets in the revenue requirement until the facilities are actually providing service. An announcement that the utility has implemented DSM indicates to the investor that the utility, with regulatory approval, is instituting programs to decrease sales of natural gas on the system. Without some mechanism to compensate for the revenue from these programmatic lost sales the investor would assume that the opportunity earn a reasonable return on their investment has been or is being diminished especially when the rate design, as in this case, is predominately based on volumes. This factor, unmitigated, would signal increased risk to the investor. Thus the establishment of FCCM provides a better opportunity, but again no guarantee, of reasonable returns in the future.

Q. **Does the issue of giving utility investors a reasonable opportunity to earn a fair return also extend to Intermountain's proposed increase in its customer charge for residential and commercial customers and the establishment of demand charges for large industrial customers?**

A. Yes, it does and for similar reasons. The FCCM is proposed in response to the request to establish a DSM program. The customer charge and demand charges are also designed to, in addition to addressing issues of equity and cost causation, reduce the uncertainty of revenue collection but from all of the other factors which affect volumetric sales negatively as I explained earlier in my testimony.

Q. **Does that conclude your testimony?**

A. Yes it does.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 17

Curriculum Vitae

Branko Terzic
BERKELEY RESEARCH GROUP, LLC
1800 M Street NW, 2nd Floor | Washington, DC 20036

Direct: 202.480.2647
bterzic@thinkbrg.com

EDUCATION

B.S. Engineering	University of Wisconsin – Milwaukee, 1972

PRESENT EMPLOYMENT

Managing Director, Berkeley Research Group LLC

PREVIOUS POSITIONS

President
Branko Terzic & Associates, Inc.
June 1, 2014 – May 25, 2015

Executive Director
Deloitte Center for Energy Solutions
June 1, 2012-May 30, 2014

Regulatory Policy Leader in the Energy & Resources Group
Deloitte Services LP
May 24, 1999 - May 30, 2014

Regional Managing Partner of Resources, Energy & Infrastructure Practice
Deloitte & Touche Central Europe LLP
1999-2004

Chairman, President and Chief Executive Officer
Yankee Energy System, Inc. (NYSE Listed company later acquired by NU in 1999)
1994 - 1998

Managing Director
Arthur Andersen Economic Consulting, Washington, D.C.
1993-1994

Commissioner
U.S. Federal Energy Regulatory Commission
October 20, 1990, to May 24, 1993

Group Vice President
AUS Consultants; Moorestown, New Jersey (Regional Office: Milwaukee, Wisconsin)
December 1, 1986, to October 19, 1990

Commissioner
State of Wisconsin Public Service Commission - Madison, Wisconsin
March 1, 1981, to December 1, 1986

Partner
Terzic & Mayer Public Utility Consultants - Milwaukee, Wisconsin
1979 to 1981

Vice President
Associated Utility Services, Inc. (now AUS Consultants) - Milwaukee, Wisconsin
1976 to 1979

Staff Appraiser
American Appraisal Associates, Inc.- Milwaukee, Wisconsin
1974 to 1976 and 1969 to 1971

Special Investigations Engineer and Environmental Engineer
Wisconsin Electric Power Company - Milwaukee, Wisconsin
1972 to 1974

HONORARY DOCTORATES

2009	Doctor of Sciences in Engineering University of Wisconsin-Milwaukee

PROFESSIONAL AWARDS, RECOGNITION

2009 Energy Efficiency Forum inductee HALL OF FAME June 15, 2009
Energy Efficiency Forum, National Press Club, Washington, DC

2008 “Champion” Award February 6, 2008
Women’s Council on Energy and Environment, Washington, DC

2002 Natural Gas Roundtable Appreciation Award December 17, 2002
Natural Gas Roundtable, Washington DC

1999 Distinguished University Graduate 1999 Commencement May 1999
University of Wisconsin - Milwaukee

1993 Distinguished Service Award October 5, 1993 James C. Bonbright Utility Center,
University of Georgia

1991 Achievement Award for Founding of the Society November 21, 1991
Society of Depreciation Professionals

1990 State of Wisconsin Certificate of Congratulations November 16, 1990
Governor Tommy Thompson

1990 State of Wisconsin Racing Board Resolution of Commendation
November 16, 1990 Wisconsin Racing Board

1989 Citizen of the Year 1989 May 1, 1989 Greater Milwaukee Legal Auxiliary

1987 National Association of Regulatory Utility Commissioners Engineers' Resolution of Commendation June 18, 1987 National Conference of Regulatory Utility Commission Engineers

1983 Honorary Kentucky Colonel appointment Governor John Y. Brown

PROFESSIONAL AFFILIATIONS

Prior

Director, American Gas Association 1994-1998
Director, New England Council 1994-1998
Delegate of the Energy Industry, U.S.A. Department of Commerce's Transatlantic Business Dialogue,1996
Member, National Association of Regulatory Utility Commissioners
- NARUC Committee on Finance and Technology, 1985 to 1986.
- NARUC Ad Hoc Committee on Insurance in Regulated Industry, 1986.
- Chairman, NARUC Committee on Engineering, 1983-1985. Subcommittees included Depreciation, Management, Audit, and Valuation
- Co-Chairman Ad Hoc Committee on Utility Diversification 1986.

Present

Member, Energy Efficiency Forum Executive Committee
Member, Society of Depreciation Professionals
Member, Society of Utility Regulatory Financial Analysts
Member, Association of Energy Engineers
Member, The Natural Gas Roundtable
Member, Energy Bar Association
Member, United States Association for Energy Economics
Senior Member, American Society of Mechanical Engineers
Faculty Member, The Washington Campus MBA Programs

BUSINESS AND NOT-FOR-PROFIT AFFILIATIONS

Chairman, State of Wisconsin Racing Board (State official in part-time capacity)
May 27, 1988, to October 19, 1990 Madison, Wisconsin

Board Member National Regulatory Research Institute
1988 to 1990 at The Ohio State University

PUBLICATIONS

ARTICLES (Representative listing)

"10 [Electric power] Myths "
July-August 2013 ELECTRIC PERSPECTIVES

"History repeats itself: a guide from 30 years ago"
September 2009 OIL AND GAS FINANCE JOURNAL

"The Future of Conventional Fuels"
October 2009 OIL AND GAS FINANCIAL JOURNAL

"Regulators and Risk: Deloitte's 2009 Survey of State Regulators"
May 2009 EEI ELECTRIC PERSPECTIVES

"The electricity challenge of the 21st century"
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"The Economics of Climate Change: The Stern Review"
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"100 Years of Regulation"
July 24, 2007 Milwaukee Journal Sentinel newspaper (with George Edgar)

"Global Regulation: Exporting America to the World"
February 2007 Public Utilities Fortnightly (with Gregory Aliff)

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“Reinventing The Classic Business Strategy”
December 2005 Public Utilities Fortnightly (w David Fornari)

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

DIRECT TESTIMONY OF LORI A. BLATTNER

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is Lori A. Blattner. I am a Regulatory Analyst with Intermountain Gas Company ("Intermountain" or "Company"). My business address is 555 South Cole Road, Boise, ID 83707.

Q. Ms. Blattner, would you please summarize your educational and professional experience.

A. I graduated from University of Idaho in 1993 with a Bachelors degree in Agricultural Economics. I joined Intermountain Gas in 1997. During my time in the Regulatory Department, I have attended several ratemaking classes, including a Threshold Associates cost allocation training, Navigant Consulting cost of service workshop, and an SGA Ratemaking seminar. Throughout my career at Intermountain, I have been responsible for cost of service and rate making. I have also been involved at a high level in integrated resource planning, developing the annual purchased gas cost adjustment, weather normalization and forecasting.

Q. Have you previously testified before this Commission?

A. No.

Q. What is the purpose of your testimony?

A. My testimony covers three areas. First, I will discuss and support the weather normalization process used to develop the test period billing determinants. Second, I will discuss the allocated class cost of service study prepared for this case. Third I will discuss and explain the rate design changes that are being proposed in this proceeding.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring the following exhibits:

Ex. 18	Weather Normalization Opinion
Ex. 19	Minimum System Study Results
Ex. 20	Class Cost of Service Summary Results
Ex. 21	Class Cost of Service Results – Account Detail
Ex. 22	Class Cost of Service Account Inputs
Ex. 23	Class Cost of Service Allocation Factors
Ex. 24	Rate Design Calculations

II. WEATHER NORMALIZATION

Q. Is Intermountain proposing an adjustment to reflect normal weather?

A. Yes.

Q. Why is an adjustment to gas utility revenues and volumes to normalize weather appropriate?

A. Temperature is the primary driver of variances in natural gas usage, and the Company’s rates include charges that are based on consumption. Since these charges are dependent on consumption, variations in weather will affect the amount of revenue received by the Company. For example, a year with lower consumption due to warmer than normal temperatures will result in lower revenues for the Company. Conversely higher consumption due to colder than normal temperatures will result in higher revenues for the Company. The Company’s proposed DSM programs will also result in incrementally lower usage per customer.

Weather Normalization is the term used to describe the process by which usage levels are adjusted to the level they would have been under normal weather conditions and from which normalized (pro forma) revenues can be determined.

Q. Would you please describe the weather normalization process?

A. Yes. To determine the degree to which actual gas sales were higher or lower than normal as a result of actual weather, it is necessary to first quantify the relationship between weather and sales. This quantification is achieved through the use of multiple regression analysis. The company developed regression equations based on eleven years of data: one that describes RS-1 sales; another that describes RS-2 sales; and one that describes small commercial sales (GS-1).

Q. What are HDD's?

A. HDD's, or heating degree days, are units used to relate a day's temperature to the energy demands of temperature sensitive load, primarily for space heating. HDD's are calculated by subtracting a day's average temperature from a reference temperature, in this case 65° Fahrenheit.

Q. Please continue with your explanation of the weather normalization process.

A. Once the regression equations have been specified and estimated, it is the coefficients of the weather variables that are of primary importance to the weather adjustment process. These coefficients measure the response of sales to changes in the weather. For example, the coefficient of HDD65 in the residential equation represents the change in the number of therms per customer that a change in one HDD65 would cause. By multiplying this coefficient by the difference between the normal number of heating degree days for a particular month and the number that actually occurred, the difference between actual and normal therms per customer is determined.

Q. What data did you use to determine the normal heating degree days?

A. Normal heating degree days are based on a rolling 30-year average of heating degree days reported each month by the National Weather Service. The IGC service area contains regions with different weather patterns. To incorporate these different weather patterns normal weather was constructed using customer class weighted weather data from the Boise, Caldwell, Twin Falls, Sun Valley, Pocatello, Rexburg, and Idaho Falls weather stations. Each year, normal is recalculated to include the most recent year and drop off the oldest year, thereby reflecting the most recent information available. The normal weather used in this weather normalization process includes the 30 year period 1986 through 2015.

Q. Is your proposed weather adjustment process consistent with sound statistical practices and the methodology approved in the Company's Weather Normalization Case?

A. Yes, the methodology has been reviewed by two experts in statistics and forecasting, Professors Fry and Shannon from Boise State University. In their opinion, attached as Exhibit 18, "the methods used by Intermountain Gas Company are an appropriate and adequate basis for weather normalization". They go on to state that Intermountain's approach follows the methodology approved by the Idaho Public Utilities Commission in Case U-1034-134.

Q. What are the results of the weather normalization process?

A. The test year in this proceeding is the twelve months ending December 31, 2016, and consists of six months of actual data, January through June of 2016, and six months of forecasted data. The six months of actual data has been weather normalized as discussed above. The results of the weather normalization are summarized in Table B.1 below.

Table B.1: Weather Normalization Results

Rate Class	Actual HDD	Normal HDD	Actual Therms	Normal Therms	Difference Therms
R-1	4,003.2	3,985.6	22,722,002	22,660,127	(61,875)
R-2	3,891.0	3,931.4	118,984,790	119,838,399	853,609
GS-1	4,076.1	4,034.9	71,988,101	71,008,852	(979,249)
Total					(187,515)

The actual and normal degree days vary for each of the rate classes due to the weather station weighting process described above. Overall, the weather normalization adjustment results in a reduction in usage of 187,515 therms. There is a corresponding revenue adjustment as explained by Company witness Darrington.

III. ALLOCATED CLASS COST OF SERVICE STUDY

Q. What is an Allocated Class Cost of Service Study ("ACOSS")?

A. An ACOSS is an analysis of costs that assigns to each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Q. What is the purpose of an ACOSS?

A. The purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return that is provided by each class of service of the utility can be determined. The ACOSS is a tool used to assist in determining revenue responsibility by rate class and rate design. The results of the ACOSS will provide the analyst with the data necessary to design cost-based rates.

Q. What is the guiding principal that should be followed when preparing an ACOSS?

A. Cost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question; which customer or group of customers causes the utility to incur particular types of costs? In order to answer this question, it is necessary to establish a relationship between a utility's customers and the particular costs incurred by the utility in serving those customers.

Q. What are the steps to performing ACOSS?

A. In order to establish the cost responsibility of each customer class, initially a three step analysis of the utility's total operating costs must be undertaken. The three steps which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Intermountain's functional cost categories associated with gas service include:

Storage, Transmission, and Distribution. In addition, the ACOSS includes a function for the cost of gas in order to separately track gas costs from base rate costs. Gas costs are addressed in the Company's annual Purchased Gas Cost Adjustment filing (PGA) and are not part of this proceeding.

Q. Please describe cost classification.

A. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost defining characteristics of: (1) customer related; (2) demand or capacity related; and (3) commodity related.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are largely a function of the number and density of customers served, and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer billing and accounting expenses.

Demand costs are capacity related costs associated with a plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Commodity costs are those costs that vary with the throughput sold to, or transported for, customers.

Q. Please describe cost allocation.

A. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs are directly assigned or are allocated on customer, demand, commodity and internal allocation factors.

Direct assigned relates to the specific identification and isolation of plant and/or expenses that are incurred to serve a specific customer or group of customers. Direct assignments are based on analyses of detailed data that directly links costs to a rate class, or to a subset of customers in a rate class. Direct assignment of costs is the preferred allocation approach because no allocation is required to determine the costs of serving customers in each class. However, it is not realistic to assume that a large portion of the Company's plant and expenses can be directly assigned as the majority of the costs are joint use facilities.

Customer, demand and commodity external allocation factors such as the number of customers, peak day usage, and annual usage are developed from the Company's records. Internal allocation factors are developed within the ACOSS from previously allocated costs, such as plant or labor costs.

Q. How have the demand-related costs been allocated in the ACOSS?

A. Demand costs have been primarily allocated using a coincident peak demand methodology. As described by Company Witness Gilchrist, Intermountain's system has been designed and built to meet the peak demands of the customers, therefore allocating the demand costs on the basis of peak day utilization is in keeping with the cost causation principle. The coincident peak day used to develop the allocation factor is the Company's most recent peak day which occurred January 1, 2016.

Q. How was distribution mains plant account, Account 376, classified and allocated in the ACOSS?

A. A portion of the distribution mains account was classified as customer and the remaining costs were classified as demand. Identifying a portion of mains investment as customer related is an accepted principle throughout the gas industry. The assumption is that distribution mains (FERC Account No. 376) are installed to meet both system peak load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the investment in this plant are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and numbers of customers.

Q. What are the factors that affect the level of distribution mains facilities installed by a utility?

A. There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the utility's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

Q. How is the customer component of distribution mains determined?

A. The two most commonly used methods for determining the customer cost component of distribution mains facilities are: (1) the zero-intercept approach; and (2) the most commonly installed, minimum-sized unit of plant investment approach.

Under the zero-intercept approach, which is the method utilized in Intermountain's ACOSS, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the utility's gas system against the actual size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the utility's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. This method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. While the zero-intercept method, with reliable data, estimates the customer costs associated with a zero-size pipe diameter, the minimum-size method may include some capacity costs since any minimum size pipe considered will, in fact, be capable of actually delivering some gas.

Q. Please discuss how the zero-intercept study was performed and its results.

A. The results of the zero-intercept study are shown in Exhibit 19. The Company's plant accounting records provided the installed cost, footage, type (plastic, steel), size (diameter) and vintage (date of installation) for the distribution mains. The vintage installed costs were translated to a common current cost using the Handy-Whitman Index ("HWI"). The HWI calculates cost trends for different types of utility construction with separate indices for gas, electric and water industries. Using the HWI adjusted costs, an installed cost per foot was calculated for each pipe size and type and a regression analysis of the unit costs and pipe size was performed for both steel and plastic pipe types. The results of the regression analysis can be expressed formulaically as:

$$y = mx + b$$

Where: y = average cost per installed foot of Intermountain's distribution mains

m = cost per installed foot per inch of pipe diameter

x = diameter of distribution mains

b = cost per installed foot

The regression analysis shows that regardless of the diameter of the main, the average cost of a distribution main in Intermountain's system will be at least equal to $8.55 per installed foot. This per foot cost component is related to the process of extending the distribution mains to connect customers, which is a function of the length of the main and not the size of the main, and represents the customer cost component of distribution mains.

Q. How were the results of the zero-intercept study used in the ACOSS?

A. As shown in Exhibit 19, the customer cost unit rate for both steel and plastic type pipe was applied to the total distribution mains footage for each pipe type to determine the total customer costs. This total customer cost was divided by the total HWI adjusted cost of distribution mains to provide the customer cost percentage of 47.16%. This percentage was used in the ACOSS to apportion the historical installed costs of distribution mains to the customer component and allocated to the rate classes on a customer factor. The remaining distribution mains costs were classified as demand and allocated on the peak day factor.

Q. How were the other distribution plant accounts classified in the ACOSS?

A. Plant accounts 380 through 385 are classified as customer related. These accounts include costs related to services, meters, meter installations, and regulators. Plant accounts 375, Structures and Improvements, and 378, Measuring and Regulation, are classified as demand. Account 374, Land and Land Rights, was allocated on an internal factor based on structures, mains, and services and therefore has costs classified as both demand and customer.

Q. How were the distribution plant accounts allocated to the rate classes?

A. As noted above the demand component of distribution mains is allocated on the peak day factor. The other two demand related distribution plant accounts were allocated using a peak and average methodology. Accounts 375, Distribution Structures and Improvements, and 378, Distribution Measuring and Regulation

Equipment, contain costs related to both peak and annual usage both of which are included in the calculation of the peak and average allocation factor.

The services, meters, meter installation and house regulator accounts were allocated on weighted customer basis. The weighting factor was based on a study of the costs of meters for each rate class. Account 385, Industrial Regulation, was allocated on a weighted customer basis excluding the residential classes.

Q. How were the storage plant accounts treated in the ACOSS?

A. The storage plant accounts contain the costs related to the Company's LNG facilities. As discussed by Company Witness Gilchrist these facilities are needed to provide deliverability and reliability during peak periods. Therefore, the storage plant accounts are classified as demand and allocated on a peak day basis.

Q. How were the transmission plant accounts treated in the ACOSS?

A. The transmission plant accounts contain the costs related to the Company's high pressure transmission facilities. As discussed by Company Witness Gilchrist these facilities were designed and sized to provide deliverability during peak periods. Therefore, the transmission plant accounts are classified as demand and allocated on a peak day basis.

Q. How were the general and intangible plant accounts treated in the ACOSS?

A. The general and intangible plant accounts were allocated on an internal factor based on the allocations of storage, transmission and distribution plant.

Q. Please describe the method used to allocate the accumulated depreciation reserve and depreciation expenses.

A. The accumulated reserve and depreciation expense were allocated on internal factors based on the allocation of the associated plant.

Q. Please describe the method used to allocate the storage, transmission and distribution Operations and Maintenance ("O&M") expense?

A. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account.

Q. How were the customer accounting expenses, accounts 902 – 904, treated in the ACOSS?

A. Meter reading expense, account 902, is allocated on the basis of the number of customers. Customer records and collection expense, account 903, is allocated on a weighted customer basis based on meter costs. Account 904, uncollectible expense, is allocated to the residential and general service classes based on an analysis of account write-offs.

Q. How were customer service and sales expenses treated in the ACOSS?

A. Customer service expenses, accounts 907 and-908, are allocated on a customer basis. Sales expenses, accounts 910 – 913, are allocated to the residential and general service classes on a peak day throughput basis.

Q. Please describe the treatment of Administrative and General ("A&G") costs in the ACOSS.

A. Accounts 923 and 924, outside services and property insurance, are plant related and allocated on an internal factor consisting of allocated storage, transmission and distribution plant. Accounts 925 and 926, injuries and damage and employee pensions and benefits, are labor related costs and are allocated on an internal labor factor. Rents and general plant maintenance expenses, accounts 931 and 932, are allocated on total plant basis and the remaining A&G expenses are allocated on an internal factor comprised of O&M expenses excluding A&G.

Q. How were taxes other than income taxes treated in the ACOSS?

A. Taxes other than income were allocated on a plant or labor basis depending on the nature of the tax. For example, payroll taxes were allocated on a labor basis while property taxes were allocated on the basis of plant.

Q. How were income taxes allocated to each customer class?

A. Income taxes are calculated for each rate class based on the pre-tax net income for the class.

Q. What rate classes were included in the ACOSS?

A. In this proceeding Intermountain is proposing to restructure some of its existing rate classes and the revised rate classes are those used in the ACOSS. Currently Intermountain has two residential rate classes with the primary difference between the classes being the presence of gas water heating. Intermountain is proposing to combine these two rate classes into a single residential rate class. Intermountain is also proposing to combine its two industrial customer transportation rate classes, T4 and T5, into a single rate class.

Q. Why are these classes being restructured?

A. As more fully explained below, Rate Schedules RS-1 and RS-2 are being combined because there is no justification for having different rate classifications for customers based on whether they use gas for space heating or water heating in addition to space heating.

With the addition of a demand charge to the T-4 customer class, the T-4 and T-5 classes are essentially the same type of service. Therefore, they are being combined into a single class of service.

Q. Please describe the results of the ACOSS?

A. The results of the ACOSS are shown on Exhibit 20. Page 1 of this exhibit provides a summary of the rate base, revenues, expenses and returns at current rates by class. As shown on line 17, the residential class is slightly below the system average return while the Large Volume Sales (LV-1) and Firm Transport Service class (T-4) show returns well above the system average. The General Service class (GS) shows a return significantly below the system average. The Interruptible Transport Service (T-3) exhibits a return well above the system average which is to be expected as this class is not allocated any peak demand related costs.

Q. Does the ACOSS show the class revenue requirements at equal rates of return?

A. Yes. Exhibit 20, Page 2, provides the results by class at equal rates of return. Line 10 of this exhibit shows the level of the revenue deficiency or surplus necessary to move the class to the system average return. Line 12 of this exhibit shows the revenue increase or decrease proposed for each rate class and line 20 shows the propose return for each class at the proposed rates. This information is summarized in Table 2 below:

TABLE B.2 – Summary of ACOSS Results

Rate Class	Return @ Current Rates	Revenue (Deficiency)/Surplus @ Equal Return	Proposed Increase	Return @ Proposed Rates
Residential	4.41%	($7,775,305)	$7,755,305	7.42%
General Service	2.21%	($4,466,759)	$4,466,759	7.42%
Large Volume	23.38%	$141,850	($141,805)	7.42%
T3	143.99%	$528,042	($528,042)	7.42%
T4	11.45%	$1,386,472	($1,386,472)	7.42%
Total	4.85%	($10,165,700)	$10,165,700	7.42%

Q. Please explain the remaining pages of Exhibit 20 and Exhibits 21, 22 and 23.

A. Exhibit 20, page 3 shows the rate base by function by class. Page 4 provides a functional cost of service, by class at equal rates of return and page 5 provides a functional and total unit cost analysis by class. The unit cost analysis provides support for the proposed customer and demand charges.

Exhibit 21 shows how each account is classified and allocated to the classes. Exhibit 22 shows how the amount of each account and how the account is functionalized, classified and allocated. Exhibit 23 provides all the external and internal allocation factors used in the study.

IV. RATE DESIGN

A. Introduction

Q. Please explain the organization of your testimony concerning the Company's proposed changes to rate classes, rate structures, and rate design.

A. In subsections B, C, D, and E of this Section IV of my testimony, I will describe and explain the Company's proposals related to rate schedules and rate structures as follows. Specifically, I will explain the Company's proposals to:

1. Eliminate the current rate schedules for residential heating service (Rate Schedule RS-1) and residential heating and hot water service (Rate Schedule RS-2) and create a single rate schedule for service to all residential customers (Rate Schedule RS);
2. Modify the Rate Schedule GS-1 rate structure so that the rates charged to the customers in this class more closely reflect the Company's costs to serve these customers, helping to reduce subsidization within the class;
3. Eliminate the seasonal rate structures by which residential and general service customers are charged higher rates in the summer than in the winter periods;
4. Combine the T-4 and T-5 rate schedules to create a single rate structure for the Company's Industrial firm transportation service customers (Rate Schedule T-4);
5. Modify the Rate Schedule LV-1 rate structure, by adding a demand charge, so that the customers in this class are charged for the distribution system capacity that is made available for their service;
6. Apply the current Rate Schedule T-5 rate structure, which includes a demand charge, to the proposed Rate Schedule T-4 rate structure,

In subsection F of this Section IV of my testimony, I will present and support the calculations and analysis that I performed to develop the Company's proposed rates.

Q. **In developing the rate design proposals that you describe and support in the following sections, were you guided by any principles and directives?**

A. Yes, I took into account (1) the findings and recommendations of Company Witness Terzic, in his testimony in this proceeding concerning customer charges and demand charges and (2) the principles of rate design that were developed by James C. Bonbright.

Q. **Please summarize Company Witness Terzic's findings and recommendations concerning customer charges and demand charges.**

A. Mr. Terzic explains that customer charges and demand charges are two types of fixed fees that are appropriate elements of sound rate design, because these charges do not vary based on the level of natural gas volumes flowing through the distribution system. Said another way, the Company's fixed costs to construct, operate and maintain the Company's distribution system should be largely recovered through fixed charges.

Q. **What are the Bonbright rate design directives?**

A. The industry has long accepted the principles of rate design first put forth by James C. Bonbright, [1] which are:

- Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation;
- Effectiveness of yielding total revenue requirements;
- Revenue (and cash flow) stability from year to year;

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[1] James C. Bonbright. Principles of Public Utility Rates (1st ed. 1961).

- Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers;
- Fairness in apportioning cost of service among different consumers (rates based on cost causation);
- Avoidance of "undue discrimination"; and
- Efficiency, promoting efficient use of energy by the customer (e.g., such that utility's infrastructure and resources are not strained).

B. Proposed Revisions to Current Residential Rate Classifications

Q. Please explain the Company's proposal to revise the residential rate classifications.

A. Currently, the Company's Rate Schedule RS-1 is applicable to residential customers that use natural gas for space heating, and other purposes, but not for water heating, and Rate Schedule RS-2 is applicable to residential customers that use natural gas for both natural gas water heating and natural gas space heating, as well as other purposes. As I described in the introduction, the Company is proposing to eliminate the separate Rate Schedules RS-1 and RS-2 and to create a new Rate Schedule RS.

Q. Please describe the current Rate Schedules RS-1 and RS-2.

A. In 2015 the Company provided service to 66,783[2] RS-1 customers and 236,007[2] RS-2 Customers. Actual RS-1 2015 consumption was 30,711,979 therms and RS-2 consumption was 169,532,903. RS-1 customers paid an average cost of $0.90657 per therm for gas service, which was 16 percent greater than the average

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[2] Customer numbers that support the revenue reported in Intermountain's 2015 FERC Form 2. .

cost of $0.78177 per therm that RS-2 customers paid for gas service. Table B.3 below shows the average monthly usage by RS-1 and RS-2 customers, and Table 4, below, shows the currently effective RS-1 and RS-2 rates.

Table B.3 Residential Average Monthly Usage[3]

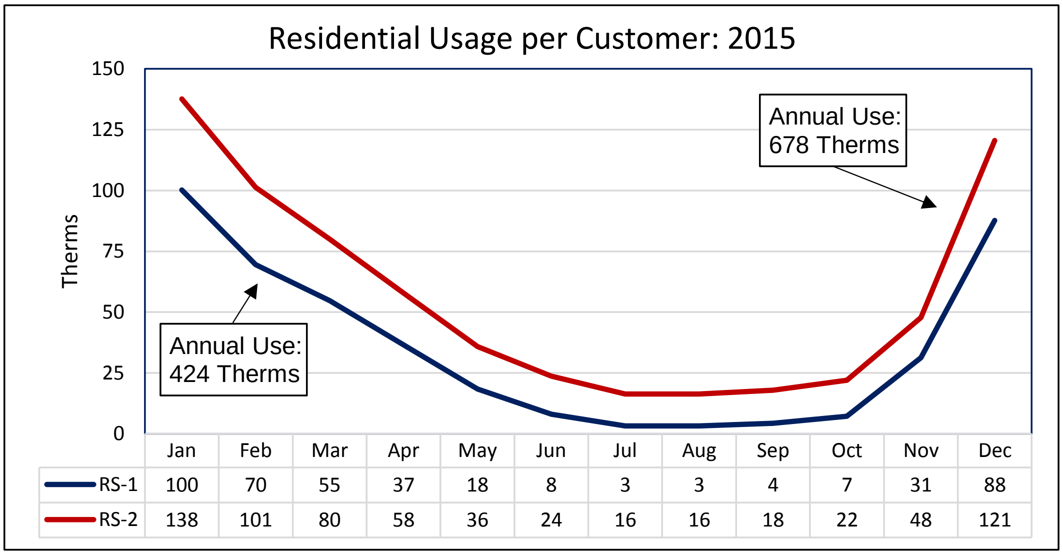

Table B.4 Residential Distribution Rates[4]

	RS-1	RS-2	Difference	% Difference
Customer Charge per month				
Summer	$2.50	$2.50	$0.00	0.0%
Winter	$6.50	$6.50	$0.00	0.0%
Margin Charge per Therm[5]				
Summer	$0.31617	$0.19539	$0.15199	38.20%
Winter	$0.20361	$0.16176	$0.07306	20.55%

Q. Please explain why the Company is proposing to eliminate the separate Rate Schedules RS-1 and RS-2 and to create a new Rate Schedule RS.

A. The Company is proposing to eliminate the separate Rate Schedules RS-1 and RS-2 because Intermountain's cost drivers[6] for gas service to residential

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[3] The analysis summarized in Table 2X is derived from 2015 billing system data.

[4] Fiftieth Revised Sheet No. 01, Fiftieth Revised Sheet No. 02. Effective July 1, 2016.

[5] RS-1 Commodity Charges shown are net of Cost of Gas, $0.55589 per therm. RS-2 Commodity Charges are net of Cost of Gas, $0.51585 per Therm.

customers that use gas for space heating are not meaningfully different from the cost drivers for gas service to customers that use gas for water heating as well as space heating.

Further, there is certainly no cost justification for charging commodity rates to RS-2 customers that are lower than the RS-1 rates by 21 percent in the winter and 38 percent in the summer. It is not appropriate that, on an annual basis, average annual charges per therm to RS-2 customers are 16 percent less ($.0.12481 per therm) than average annual charges to RS-1 customers.

Q. Are you aware of any gas distribution companies that have separate rate schedules for residential customers that use gas for (1) space heating and (2) hot water in addition to space heating?

A. No, I am not. I reviewed the tariffs of Avista Idaho and gas distribution companies in surrounding states[7] and I determined that, other than Intermountain Gas, no gas distribution company has separate rate schedules for residential customers that use gas for space heating and for hot water in addition to space heating.

C. Modifications to Rate Schedule GS-1

Q. Please describe the current Rate Schedules GS-1.

A. According to the provisions of Rate Schedule GS-1, service is available at any point on the Company's distribution system to customers whose requirements for natural gas do not exceed 2,000 therms per day. In 2015 the Company provided

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[6] These cost drivers are, generally, the allocators that are used in the ACOSS to allocate the balances in the Company's plant and expense accounts to each rate class.

[7] I reviewed the tariffs of the following gas distribution companies: Avista Utilities (Idaho), MDU (Montana), Avista Utilities (Oregon), Cascade Natural Gas Corporation (Oregon), Cascade Natural Gas Corporation (Washington), Avista Utilities (Washington).

service to 31,738[8] GS-1 customers. Actual GS-1 consumption in 2015 was 103,111,511 therms and GS-1 customers paid an average cost of $0.71955 per therm for gas service. Table B.5, below, shows the currently effective GS-1 rates.

Table B.5 General Service Distribution Rates[9]

			RS-1		
			Summer	Winter	
Customer Charge			$2.50	$6.50	per month
Commodity Charge per Therm[10]					
	Block 1	1st 200 Therms per bill	$0.21690	$0.16605	per Therm
	Block 2	Next 1,800 Therms per Bill	$0.19517	$0.14485	per Therm
	Block 3	Over 2,000 Therms per bill	$0.17415	$0.12439	per Therm

The customers in Rate Schedule GS-1 are very diverse. Approximately 60 percent of GS-1 customers use less than 1,200 therms annually[11], which is comparable to the annual consumption of Residential RS-2 customers who use gas for space and hot water heating. At the other extreme, the largest 50 customers, which used at least 93,000 therms annually in 2015, represent 0.15 percent of total 2015 GS-1 customers, and 7.1 percent (6,834,601 therms) of total 2015 GS-1 annual consumption. This diversity of GS-1 annual consumption is demonstrated in Table 6 below, which shows the cumulative distribution of GS-1 customers, by annual consumption. Table B.6 demonstrates that Rate Schedule GS-1 includes a wide range of customers that are very different. At one extreme, 97.5 percent of the GS-1 customers consumed less than 20,000 therms in 2015; at

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[8] Customer numbers that support the revenue reported in Intermountain's 2015 FERC Form 2.

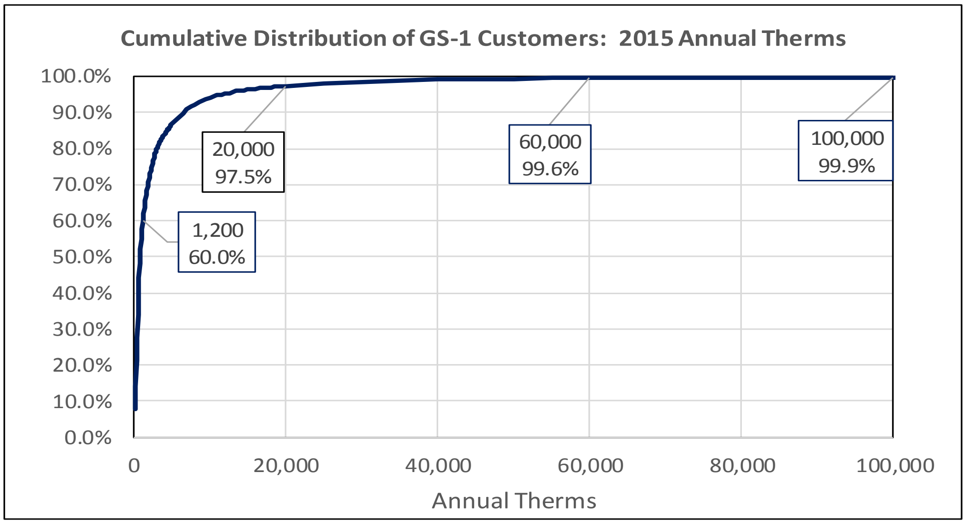
[9] Fifty-Second Revised Sheet No. 03. Effective July 1, 2016.

[10] GS-1 Commodity Charges shown are net of cost of gas of $0.51167 per therm.

[11] Intermountain provided service to 31,738 GS-1 customers in 2015; 19,484 GS-1 customers (61.4 percent) used 1,200 therms or less. Total therm consumption by these customers was 9,323,339 therms, or 9.0 percent of total actual billing system GS-1 consumption.

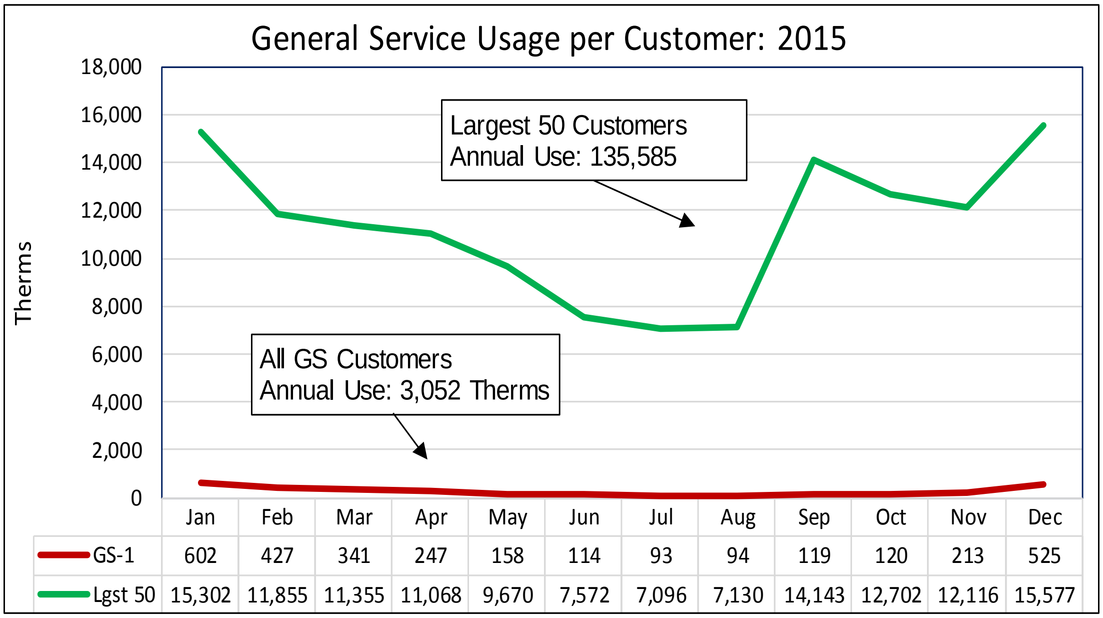
the other extreme, 0.2 percent of the GS-1 customers consumed at least 100,000 therms.

Table B.6 GS-1 Annual Consumption Cumulative Distribution



As another approach to demonstrate the diversity of GS-1 customers, Table B.7 below shows the average monthly usage by all GS-1 customers, and the 50 largest GS-1 customers.

Table B.7 General Service Average Monthly Usage



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
🟥 GS-1	602	427	341	247	158	114	93	94	119	120	213	525
🟩 Lgst 50	15,302	11,855	11,355	11,068	9,670	7,572	7,096	7,130	14,143	12,702	12,116	15,577

Based on this analysis of the GS-1 customers, the Company has determined that although the current GS-1 rate structure is a reasonable basis for charging most of the GS-1 customers, it is appropriate and necessary to make modifications to GS-1 rates and rate structures that would impact mostly the largest GS-1 customers, because the largest GS-1 customers are similar to many Industrial LV-1 customers, and very different from most GS-1 customers.

Q. Please explain the Company's proposed modifications to the Rate Schedule GS-1 rate structure.

A. The Company is proposing to add a fourth rate block to the GS-1 rate structure that would apply to a GS-1 customer's monthly consumption that exceeds 10,000 therms in a month. The company selected 10,000 for the fourth block to more reasonably reflect the cost to serve these largest GS-1 customers, which will therefore reduce the subsidization by the largest GS-1 customers of the smaller

GS-1 customers. This fourth block will also allow for better alignment between the rates charged to the largest GS-1 customers and the rates charged to the Company's LV-1 Large Volume Firm Sales Service customers.[12]

Customers that utilize the fourth block are typically small industrial type customers. Often, they are growing businesses that will eventually qualify for an industrial class. The fourth block rate will allow them to grow their business at a rate that is fair in comparison to similar type businesses that are larger in scale.

Q. Please explain how adding the fourth block, for monthly consumption in excess of 10,000 therms, will better align the rates charged to the largest GS-1 customers with the rates charged to the Company's LV-1 Large Volume Firm Sales Service customers.

A. The Company is proposing to modify the GS-1 rate structure – with specific attention to the largest customers in this rate class: (1) to better align the Company's rates with the costs to serve these customers, and (2) to align the rates charged to large GS-1 customers with the rates charged to LV-1 customers. The 50 largest GS-1 customers, with annual consumption between 98,000 and 541,000 therms, are similar to Rate LV-1 customers, which typically use between 200,000 therms and 500,000 annually. However, the 2015 average cost per therm to these large GS-1 customers, $0.7004 per therm,[13] was significantly greater than the 2015 average cost per therm to the Company's LV-1 customers, $0.4945 per therm. By adding a fourth block and setting the rate for monthly consumption in

---

[12] Service under the Company's Rate Schedule LV-1 is available to customers that use at least 200,000 therms annually.

[13] (1) Actual 2015 billing system revenues from all customers with annual usage of at 100,000 therms was $4,540,601; (2) Annual 2015 billing system usage from all customers with annual usage of at least 100,000 therms was 6,482,602; (3) $4,540,601 / 6,482,602 = $0.7004.

the fourth block at an appropriate level, the Company's proposed modification to the GS-1 rate structure will address the significant difference between rates charged to large GS-1 customers and rates charged to the Company's LV-1 customers.

D. Elimination of Seasonal Rates

Q. Please describe and explain the Company's current Rate Schedules that charge different rates for gas service in the summer and winter.

A. A list of the current rate schedules with rates that differ by season are listed in Table B.8, below.

Table B.8 Intermountain Rate Schedules with Seasonal Rate Structures

Rate Schedule	
RS-1	Residential Service
RS-2	Residential Service- Space and Water Heating
GS-1	General Service
IS-R	Residential Interruptible Snowmelt Service
IS-C	Small Commercial Interruptible Snowmelt Service

For the Rate Schedules listed in Table 8, the customer charges and the per therm charges for winter months (billing periods ending December through March) are less than the customer charges and the per therm charges for summer months (billing periods ending April through November).

The rates charged to customers in Industrial Rate Schedules LV-1 (Large Volume Firm Sales Service), T-3 (Interruptible Distribution Transportation Service), T-4 (Firm Distribution Only Transportation Service), and T-5 (Firm Distribution Service with Maximum Daily Demands) are the same throughout the year; the rates do not vary by season.

Q. Please explain why the Company is proposing to eliminate rate structures with seasonal rates that are lower for gas service during winter months and higher for gas usage in summer months.

A. The Company is proposing to eliminate seasonal rates because there is no cost justification to continue the current seasonal rate structures. The results of the Company's ACOSS are not developed or reported by season.

Q. Are you aware of any gas distribution companies that have rate structures with seasonal rates that are lower for gas service during winter months and higher for gas usage in summer months?

A. No, I am not. I reviewed the tariffs of Avista Idaho and gas distribution companies in surrounding states[14] and I determined that, other than Intermountain Gas, no gas distribution company has rates that are different by season.

E. Cost Based Customer Charges

Q. Please summarize the testimony of Company Witness Terzic that addresses cost-based customer charges.

A. To summarize the points that Mr. Terzic makes in his testimony concerning customer charges, Mr. Terzic recommends that Residential RS and General Service GS-1 customer charges should be increased (1) to match the Company's costs, which are largely fixed, from year to year with the Company's distribution service revenues; (2) to make the Company's rates to these classes better reflect the unit customer-related costs to serve customers in these classes.

Q. Please provide the current RS-1, RS-2 and GS-1 customer charges.

---

[14] I reviewed the tariffs of the following gas distribution companies: Avista Utilities (Idaho), MDU (Montana), Avista Utilities (Oregon), Cascade Natural Gas Corporation (Oregon), Cascade Natural Gas Corporation (Washington), Avista Utilities (Washington).

A. I have prepared Table B.9, below, to show the current customer charges. To demonstrate the large differences between the current Residential and General Service customer charges and costs to serve, I have also included in Table B.9 the unit customer-related costs as determined in Exhibit INT-20: Class Cost of Service Summary Results.

Table B.9 Customer Charges and Unit customer-related ACOSS Results

Customer Charge per bill	RS-1	RS-2	IS-R	GS-1	IS-C
Summer	$2.50	$2.50	$2.50	$2.00	$2.00
Winter	$6.50	$6.50	$6.50	$9.50	$9.50
ACOSS	$13.61	$13.61	$13.61	$46.85	$46.85

The Company's proposed rates, which are described in the following Section IV.F of my testimony, reduces the significant gap between the current customer charges and the unit customer-related costs.

F. Proposed Large Industrial Firm Transportation Rate Schedule

Q. Please summarize the Company's proposal relating to current Rate Schedules T-4 and T-5.

A. As described and supported in the testimony of Company Witness Swenson, the Company is proposing to combine Rate Schedules T-4 and T-5, and to charge one set of rates to all customers in this new rate classification.

As I explain in Section IV.H, Rate Design, to design the single set of rates for the new Rate Schedule T-4, I used the ACOSS results for the new Rate T-4 and the combined billing determinants of current T-4 and T-5 customers, accounting for customer migration.

G. Cost-based Demand Charges

Q. Please summarize the testimony of Company Witness Terzic that addresses cost-based demand charges.

A. To summarize the points that Mr. Terzic makes in his testimony concerning demand charges for large industrial customers, Mr. Terzic recommends that demand charges should be implemented for Intermountain's large industrial firm service rate classes because customers' demand (as measured by daily consumption) is closely related to the required capacity of the distribution system, and the capital investment in that distribution system.

Q. Please describe how you designed the proposed demand charges for Industrial customers.

A. The Company plans to implement demand charges for Rate Schedules LV-1 and Rate Schedule T-4. As explained in the testimony of Mr. Swenson, the Company has worked with customers in these classes to determine levels of contract demand that appropriately reflect the capacity that the Company must have available, to provide firm reliable service to each of these customers. I designed the Rate Schedule LV-1 and T-4 demand charges to recover a large proportion of the respective class distribution margin revenue requirement at equal rates of return. I designed commodity (per therm) charges for these classes to recover the smaller portion of the class distribution margin revenue requirement at equal rates of return that was not recovered by the demand charges that I designed.

H. Rate Design

1. Introduction

Q. Please describe the principles that you followed in designing the Company's proposed base rates.

A. I developed the proposed rates to be consistent with what I am told are the Commission's long standing rate structure goals of setting rates based primarily on cost of service, and minimizing inter and intra class subsidies. I was also generally guided by Bonbright's rate design principles, and especially Mr. Bonbright's objectives that utility rate structures must be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability.

Q. Please explain your understanding of these principles.

A. An efficient rate structure promotes economically justified use of the Company's sales and distribution services, and discourages wasteful use. Rate design simplicity is achieved if the customers understand what they are being charged, *i.e.,* the level of rates and the rate structure. Rate continuity requires that changes to the rate structure should be gradual allowing customers to modify their usage patterns over time. A rate design is fair if no customer class pays more than the costs to serve that class. A rate design provides for earnings stability if the Company has a reasonable opportunity to earn its allowed rate of return during the time that the rates are in effect.

Q. Have you prepared a schedule that shows how you calculated the proposed rates?

A. Yes, I have prepared Exhibit 24 to show the analysis and calculations that I used to determine the final proposed base rates. Exhibit 24 is organized into the following sections that are related to steps in the rate design process.

- Section A shows proforma test year normalized calendar month revenue detail.
- Section B shows billing determinant detail.
- Section C shows the development of class revenue targets.
- Section D shows the development of the proposed rates.

In each section, columns A through F show data and calculations by rate class and totals. I have also provided a detailed line-by-line explanation of the calculations in Column G.

1. Class Revenue Targets

Q. What is the revenue requirement that you used for the purpose of designing rates?

A. I designed the Company's base rates to recover distribution margin of $93,243,187 which is shown on Exhibit 20: Class Cost of Service Summary Results, Page 2, Line 13 Column (b), less Line 3 Column (b) and Exhibit 24 Column F, Line 55.

Q. How did you assign the total distribution margin of $93,243,187 to each of the Company's rate classes?

A. I determined class revenue targets based on the class revenue requirements at equal rates of return for each rate class[15] as determined in the ACOSS that I

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[15] The ACOSS develops separate revenue requirements for each rate class, as shown in Exhibit 20.

prepared. As described above in this testimony, the ACOSS total base-revenue requirement for the Company is net of the costs recovered through Intermountain's purchased gas adjustment mechanism.

2. Base Rate Calculations

Q. Please explain how you designed the Company's proposed base rates.

A. To design base rates that would recover the class base revenue targets from the previous step, I followed the process that is described below:

a. I (i) determined the appropriate level of customer charges for Rate Schedules RS and GS-1 and (ii) calculated Customer Charge revenues for these classes

b. I (i) determined the appropriate level of demand charges for the Company's Industrial firm service Rate Schedules LV-1 and T-4 and (ii) calculated Demand Charge revenues for these classes

c. I determined the remaining Rate Schedule class revenue requirement to be recovered from volumetric rates in one of the following approaches:

    1. For Rate Schedules RS and GS-1, I subtracted Customer Charge revenues from total Rate Schedule distribution margin revenue requirements
    2. For Rate Schedules LV-1 and T-4, I subtracted Demand Charge Revenues from Rate Schedule distribution margin revenue requirements
    3. For Rate Schedule T-3, the volumetric rates were designed to recover the total Rate Schedule class revenue requirement

d. I determined the appropriate commodity charges by block, for those Rate Structures with multiple rate blocks

e. I calculated revenues at final rates.

Q. Please explain Step (a) in the rate design process, which you described as determining the appropriate level of customer charges and calculating Customer Charge revenues.

A. To determine the appropriate level of customer charges for Rate Schedules RS and GS-1, I considered: (1) the customer-related rates and unit costs, which are summarized in Table B.9; in Section IV.E of this testimony, above and (2) Bonbright's rate design principles of rate continuity and customer impacts.

As shown in Table B.9, the customer related costs for the Residential class are $13.61 per customer. However, to adhere to Bonbright's principles mentioned above, the Company is proposing a more gradual increase in the Residential customer charge to $10.00. The customer related costs for the GS-1 class are $45.85. Again, the Company is proposing a more gradual change of $35.00.

Q. Please explain the calculation of Rate Schedule RS and GS-1 class customer charge revenues and the class volumetric revenue target.

A. I calculated class customer charge revenues by multiplying the proposed customer charges times the customer count billing determinants, which are shown in Exhibit 24, Line 12. To determine the commodity revenue targets for Rate Schedule RS and GS-1, (the remaining class revenue target to be recovered from volumetric rates to these classes), I subtracted the class customer charge revenues from the total class revenue target, shown on Exhibit 24, Line 65.

To the extent the Company’s required revenue is not collected through the customer charge and the volumetric charge, the surplus or deficit will be trued up using the Company’s proposed FCCM as described by Company Witness McGrath.

Q. Please explain Step (b) in the rate design process, which you described as determining the appropriate level of demand charges for the Company’s Industrial firm service rate classes and calculating Demand Charge revenues.

A. I set the demand charges for Rate Schedules LV-1 and T-4 at levels that would recover a large portion of the class revenue requirement at equal rate of return. The demand charges of $0.30 per therm for LV-1 and T-4 are shown on Exhibit 24, Line 79, and the demand charge revenues are shown on Exhibit 24, Line 80.

Q. Please explain Step (d) in the rate design process, which you described as determining the appropriate rates by block, for those Rate Structures with multiple rate blocks.

A. As a preliminary matter, I determined that I would design the new fourth GS-1 rate block to apply to monthly usage of 10,000 therms or more, based on my review of GS-1 billing data. I then determined that I should set the commodity rate for that fourth block at $0.07500 per therm, to reduce the difference between bills at GS-1 rates to these customers and bills at LV-1 rates.

After I determined the appropriate Rate for the fourth block, Rate Schedule GS-1, I calculated volumetric rates for all other Rate Schedules, as shown on Exhibit 24, Lines 110 through and 118.

Q. Please explain Step (e) in the rate design process, which you described as calculating revenues at final rates.

A. Step (e) is simply the calculation of the revenues that the proposed rates would produce, based on rate case Billing Determinants. My calculations, which are presented in Exhibit 24 Lines 120 to 133, show that the proposed base rates produce total distribution margins of $93,244,715, which is greater than the base revenue requirement of $93,243,187 by $1,528. The difference is caused by rounding the proposed per therm rates to five significant digits and the proposed customer charges and demand charges to two significant digits.

3. Bill Impact Analysis

Q. Have you prepared bill-impact analyses?

A. Yes. An average RS-1 customer will see an annual increase of approximately $14.00 or 3% per year. Current RS-2 customers with average usage will experience an increase of $27.70 per year, or 5%. A GS customer with average usage will see an increase of 6% per year, or $145.90.

Q. Does this conclude your testimony on rate design?

A. Yes, it does.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 18

BOISE STATE UNIVERSITY
COLLEGE OF BUSINESS AND ECONOMICS
Department of Information Technology and Supply Chain Management

June 22, 2016

Ms. Lori Blattner
Intermountain Gas Company
555 South Cole Road
Boise, Idaho 83709

Dear Ms. Blattner,

At the request of Intermountain Gas Company, we have reviewed the methodology used to develop statistical models for forecasting monthly and annual natural gas demand measured in therms for three different customer classes (RS-1, RS-2, and GS). In our opinion, the methods used are appropriate and are based on sound statistical methodology. The indicator variables used in the forecasting models for therm usage are consistent with business practice and the economic theory.

While there are alternative statistical approaches that could be employed that would be acceptable, there is no basis for believing that alternative methods would provide superior results to those that your method has delivered. Therefore, we are of the opinion that the methods used by Intermountain Gas Company are an appropriate and adequate basis for weather normalization. Furthermore, the methodology the company has used is consistent with that previously approved by the Idaho Public Utilities Commission. Your approach follows the methodology approved by the Idaho Public Utilities Commission in Case U-1034-134.

You tested the forecasting accuracy potential for each model. You conducted a backward forecast to see how well the models forecast monthly and annual therm use for the years 2010-2015. You also ran a "true forecast" test on the first four months of 2016 which were not used in developing the model. The forecast test results demonstrate the viability of the selected models.

In summary, based on our analysis, the forecasting approach that you have used is appropriate and the process you used to arrive at the preferred models is consistent with standard forecasting methodology. This opinion is supported by our academic backgrounds and experiences. Patrick Shannon holds a Ph.D. in Statistics and Quantitative Methods from the University of Oregon, has co-authored several university textbooks including editions 1-9 of *Business Statistics: A Decision-Making Approach*, and has consulted for numerous public and private sector organizations. Phillip Fry has a Ph.D. in quantitative business analysis from Louisiana State University. He has been a co-author on the textbook *Business Statistics: A Decision-Making Approach (editions 5-9)* published by Pearson.

Sincerely,

Phillip Fry

Phillip Fry, Ph.D

Patrick Shannon, Ph.D.

Exhibit No. 18
Case No. INT-G-16-02
L. Blattner, IGC
p. 1 of 1

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 19

INTERMOUNTAIN GAS COMPANY
Distribution Plant - Mains
Zero-Intercept Method
December 31, 2015

1	**ZERO SIZE COST**								
2	**PLASTIC**								
3		$5.50	per foot	x	19,067,846	feet	=	$	104,900,256.18
4	**STEEL**								
5		$13.17	per foot	x	12,594,696	feet	=	$	165,930,162.68
6	**TOTAL ZERO-SIZE COST (A)**							$	270,830,418.86
7	**SYSTEM COST NEW**								
8	Plastic							$	148,571,466.77
9	Steel								425,726,574.01
10	**TOTAL SYSTEM COST NEW (B)**							$	574,298,040.79
11	**Customer Cost (A/B)**								**47.16%**
12	**Capacity Cost (1.0-Customer Cost)**								**52.84%**

13 **NOTES:**
14 1. Used weighted average cost per foot grouped by size classification
15 2. Removed low footage, large pipe size (10, 12, 16) and outlier 3.5 inch pipe size data points

2015 Mains Study.xls, Study Notes

Exhibit No. 19
Case No. INT-G-16-02
L. Blattner, IGC
p. 1 of 1

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 20

CLASS COST OF SERVICE STUDY
December 31, 2016
Current Return

Line No.	Description	System Total	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)	Transportation Sub-Total
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(J)
	Rate Base							
1	Net Plant in Service	$ 596,065,557	$ 396,955,080	$ 136,097,336	$ 1,494,898	$ 649,483	$ 60,868,760	$ 63,013,141
2	Accumulated Reserve	(308,450,847)	(205,495,580)	(70,418,739)	(772,482)	(336,609)	(31,427,438)	(32,536,529)
3	Other Rate Base Items	(50,688,216)	(34,741,228)	(11,324,031)	(113,019)	(52,325)	(4,457,612)	(4,622,957)
4	Total Rate Base	$ 236,926,494	$ 156,718,272	$ 54,354,566	$ 609,397	$ 260,549	$ 24,983,710	$ 25,853,656
	Revenues at Current Rates							
5	Rate Schedule Revenues	$ 251,900,147	$ 164,429,181	$ 74,843,065	$ 3,127,950	$ 714,239	$ 8,785,712	$ 12,627,901
6	Other Gas Revenues	2,900,363	2,048,327	650,808	5,720	-	195,508	201,229
7	Total Revenues	$ 254,800,510	$ 166,477,508	$ 75,493,873	$ 3,133,670	$ 714,239	$ 8,981,220	$ 12,829,130
	Expenses at Current Rates							
8	Cost of Gas	$ 168,822,659	$ 111,196,930	$ 55,312,600	$ 2,723,963	$ (13,435)	$ (397,399)	$ 2,313,129
9	Operations & Maintenance Expenses	45,185,020	29,218,719	12,865,252	137,688	139,246	2,824,115	3,101,049
10	Depreciation Expense	21,707,112	14,500,968	4,951,460	53,825	23,941	2,176,918	2,254,684
11	Taxes Other Than Income Taxes	4,840,813	3,162,375	1,233,481	13,639	9,600	421,718	444,957
12	Total Operating Expenses - Current	$ 240,555,605	$ 158,078,992	$ 74,362,793	$ 2,929,115	$ 159,353	$ 5,025,352	$ 8,113,820
	Interest Charges	$ 5,852,084	$ 3,870,941	$ 1,342,558	$ 15,052	$ 6,436	$ 617,098	$ 638,585
	Taxable Income	8,392,821	4,527,575	(211,478)	189,503	548,451	3,338,770	4,076,724
13	Income Taxes	$ 2,750,218	$ 1,483,627	$ (69,299)	$ 62,098	$ 179,720	$ 1,094,072	$ 1,335,889
14	Total Expenses - Current	$ 243,305,823	$ 159,562,619	$ 74,293,494	$ 2,991,213	$ 339,073	$ 6,119,424	$ 9,449,709
15	Current Operating Income	$ 11,494,687	$ 6,914,889	$ 1,200,378	$ 142,457	$ 375,166	$ 2,861,796	$ 3,379,420
16	Total Cost of Service	$ 254,800,510	$ 166,477,508	$ 75,493,873	$ 3,133,670	$ 714,239	$ 8,981,220	$ 12,829,130
17	Return at Current Rates	4.85%	4.41%	2.21%	23.38%	143.99%	11.45%	13.07%
18	Revenue Cost Ratio	1.05	1.04	1.02	1.05	2.11	1.47	

Exhibit No. 20
Case No. INT-G-16-02
L. Blattner, IGC

Exhibit No. 20
Case No. INT-G-16-02
L. Blattner, IGC
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CLASS COST OF SERVICE STUDY
December 31, 2016
Equal and Proposed Return

Line No.	Description (A)	System Total (B)	Residential Service (C)	General Service (D)	Large Volume (E)	Transport Service (Interruptible) (F)	Transport Service (Firm) (G)	Transportation Sub-Total (J)
	Revenue Requirement at Equal Rates of Return							
1	Required Return	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%
2	Required Operating Income	$ 17,579,946	$ 11,628,496	$ 4,033,109	$ 45,217	$ 19,333	$ 1,853,791	$ 1,918,341
3	Operating Income (Deficiency)/Surplus	$ (6,085,259)	$ (4,713,607)	$ (2,832,731)	$ 97,240	$ 355,834	$ 1,008,005	$ 1,461,079
	Expenses at Equal Return							
3	Cost of Gas	$ 168,822,659	$ 111,196,930	$ 55,312,600	$ 2,723,963	$ (13,435)	$ (397,399)	$ 2,313,129
4	Operations & Maintenance Expenses	45,240,637	29,262,600	12,875,683	137,750	139,307	2,825,297	3,102,354
5	Depreciation Expense	21,707,112	14,500,968	4,951,460	53,825	23,941	2,176,918	2,254,684
6	Taxes Other than Income	4,840,813	3,162,375	1,233,481	13,639	9,600	421,718	444,957
7	Total Expense - Required	$ 240,611,222	$ 158,122,873	$ 74,373,225	$ 2,929,177	$ 159,414	$ 5,026,534	$ 8,115,125
8	Income Taxes	$ 6,775,042	$ 4,481,444	$ 1,554,298	$ 17,426	$ 7,451	$ 714,423	$ 739,299
9	Total Revenue Requirement at Equal Return	$ 264,966,210	$ 174,232,813	$ 79,960,632	$ 2,991,820	$ 186,197	$ 7,594,748	$ 10,772,765
10	Revenue (Deficiency)/Surplus	$ (10,165,700)	$ (7,755,305)	$ (4,466,759)	$ 141,850	$ 528,042	$ 1,386,472	$ 2,056,364
11	Unit Cost (Revenue Req. per therm)	$ 0.4068	$ 0.8188	$ 0.7406	$ 0.4736	$ 0.0047	$ 0.0267	$ 0.0332
	Revenue Requirement at Proposed Rates							
12	Proposed Revenue Increase	$ 10,165,700	$ 7,755,305	$ 4,466,759	$ (141,850)	$ (528,042)	$ (1,386,472)	$ (2,056,364)
13	Rate Schedule Revenue as Proposed	262,065,847	172,184,486	79,309,824	2,986,100	186,197	7,399,240	10,571,537
14	Other Revenue	2,900,363	2,048,327	650,808	5,720	-	195,508	201,229
15	Total Revenue as Proposed	$ 264,966,210	$ 174,232,813	$ 79,960,632	$ 2,991,820	$ 186,197	$ 7,594,748	$ 10,772,765
16	Percent Revenue Change	3.99%	4.66%	5.92%	-4.53%	-73.93%	-15.44%	-16.03%
17	Expenses (excl. Income Taxes)	240,611,222	158,122,873	74,373,225	2,929,177	159,414	5,026,534	8,115,125
	Taxable Income	18,502,903	12,238,999	4,244,849	47,591	20,348	1,951,116	
18	Income Taxes	6,775,042	4,481,444	1,554,298	17,426	7,451	714,423	739,299
19	Operating Income as Proposed	$ 17,579,946	$ 11,628,496	$ 4,033,109	$ 45,217	$ 19,333	$ 1,853,791	$ 1,918,341
20	Return at Proposed Rates	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%
21	Percent of Parity	100%	100%	100%	100%	100%	100%	100%

CLASS COST OF SERVICE STUDY
December 31, 2016
Functional Rate Base

Description	System Total	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)	Transportation Sub-Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(J)
Storage							
Capacity	$ 15,343,209	$ 7,616,548	$ 3,783,667	$ 74,090	$ -	$ 3,868,904	$ 3,942,994
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 15,343,209*	*$ 7,616,548*	*$ 3,783,667*	*$ 74,090*	*$ -*	*$ 3,868,904*	*$ 3,942,994*
Transmission							
Capacity	$ 33,746,335	$ 16,752,075	$ 8,321,916	$ 162,956	$ -	$ 8,509,389	$ 8,672,345
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 33,746,335*	*$ 16,752,075*	*$ 8,321,916*	*$ 162,956*	*$ -*	*$ 8,509,389*	*$ 8,672,345*
Distribution							
Capacity	$ 44,268,967	$ 21,628,642	$ 10,751,558	$ 223,722	$ 125,237	$ 11,539,808	$ 11,888,767
Customer	$ 143,567,982	$ 110,721,007	$ 31,497,425	$ 148,630	$ 135,312	$ 1,065,608	$ 1,349,550
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 187,836,950*	*$ 132,349,649*	*$ 42,248,983*	*$ 372,351*	*$ 260,549*	*$ 12,605,417*	*$ 13,238,317*
Gas							
Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Revenues							
Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
TOTAL							
Capacity	$ 93,358,512	$ 45,997,265	$ 22,857,141	$ 460,767	$ 125,237	$ 23,918,101	$ 24,504,106
Customer	$ 143,567,982	$ 110,721,007	$ 31,497,425	$ 148,630	$ 135,312	$ 1,065,608	$ 1,349,550
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
							$ 25,853,656
TOTAL RATE BASE	***$ 236,926,494***	***$ 156,718,272***	***$ 54,354,566***	***$ 609,397***	***$ 260,549***	***$ 24,983,710***	***$ 25,853,656***

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CLASS COST OF SERVICE STUDY
December 31, 2016
Functional Revenue Requirement - Equal Rates of Return

Description	System Total	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)	Transportation Sub-Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(J)
Storage							
Capacity	$ 4,709,878	$ 2,338,038	$ 1,161,466	$ 22,743	$ -	$ 1,187,631	$ 1,210,374
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 4,709,878*	*$ 2,338,038*	*$ 1,161,466*	*$ 22,743*	*$ -*	*$ 1,187,631*	*$ 1,210,374*
Transmission							
Capacity	$ 7,789,850	$ 3,866,972	$ 1,920,993	$ 37,616	$ -	$ 1,964,268	$ 2,001,884
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 7,789,850*	*$ 3,866,972*	*$ 1,920,993*	*$ 37,616*	*$ -*	*$ 1,964,268*	*$ 2,001,884*
Distribution							
Capacity	$ 14,004,682	$ 6,465,312	$ 3,485,001	$ 76,386	$ 77,326	$ 3,900,658	$ 4,054,370
Customer	$ 69,639,140	$ 50,365,560	$ 18,080,572	$ 131,112	$ 122,306	$ 939,590	$ 1,193,009
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 83,643,823*	*$ 56,830,872*	*$ 21,565,573*	*$ 207,498*	*$ 199,632*	*$ 4,840,248*	*$ 5,247,378*
Gas							
Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ 168,822,659	$ 111,196,930	$ 55,312,600	$ 2,723,963	$ (13,435)	$ (397,399)	$ 2,313,129
Sub-total	*$ 168,822,659*	*$ 111,196,930*	*$ 55,312,600*	*$ 2,723,963*	*$ (13,435)*	*$ (397,399)*	*$ 2,313,129*
Revenues							
Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
TOTAL							
Capacity	$ 26,504,410	$ 12,670,322	$ 6,567,460	$ 136,745	$ 77,326	$ 7,052,557	$ 7,266,628
Customer	$ 69,639,140	$ 50,365,560	$ 18,080,572	$ 131,112	$ 122,306	$ 939,590	$ 1,193,009
Commodity	$ 168,822,659	$ 111,196,930	$ 55,312,600	$ 2,723,963	$ (13,435)	$ (397,399)	$ 2,313,129
							$ 10,772,765
Total Revenue Requirement	***$ 264,966,210***	***$ 174,232,813***	***$ 79,960,632***	***$ 2,991,820***	***$ 186,197***	***$ 7,594,748***	***$ 10,772,765***

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CLASS COST OF SERVICE STUDY
December 31, 2016
Unit Cost

	System Total	Residential Service	General Service	Large Volume	Transport Service (Interruptible)	Transport Service (Firm)	Transportation Sub-Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(J)
Storage							
Capacity ($/therm)	$ 0.0072	$ 0.0110	$ 0.0108	$ 0.0036	$ -	$ 0.0042	$ 0.0037
Customer ($/month)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity ($/therm)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission							
Capacity ($/therm)	$ 0.0120	$ 0.0182	$ 0.0178	$ 0.0060	$ -	$ 0.0069	$ 0.0062
Customer ($/month)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity ($/therm)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution							
Capacity ($/therm)	$ 0.0215	$ 0.0304	$ 0.0323	$ 0.0121	$ 0.0019	$ 0.0137	$ 0.0125
Customer ($/month)	$ 17.0302	$ 13.6057	$ 46.8532	$ 604.2039	$ 1,698.6974	$ 811.3904	$ 824.4703
Commodity ($/therm)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas							
Capacity ($/therm)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer ($/month)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity ($/therm)	$ 0.2592	$ 0.5226	$ 0.5123	$ 0.4312	$ (0.0003)	$ (0.0014)	$ 0.0071
Revenues							
Capacity ($/therm)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer ($/month)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity ($/therm)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total							
TOTAL							
Capacity ($/therm)	$ 0.0407	$ 0.0595	$ 0.0608	$ 0.0216	$ 0.0019	$ 0.0248	$ 0.0224
Customer ($/month)	$ 17.0302	$ 13.6057	$ 46.8532	$ 604.2039	$ 1,698.6974	$ 811.3904	$ 824.4703
Commodity ($/therm)	$ 0.2592	$ 0.5226	$ 0.5123	$ 0.4312	$ (0.0003)	$ (0.0014)	$ 0.0071
Total ($/therm)	$ 0.4068	$ 0.8188	$ 0.7406	$ 0.4736	$ 0.0047	$ 0.0267	$ 0.0332
Therms	***651,399,403***	***212,787,060***	***107,972,664***	***6,317,560***	***39,909,287***	***284,412,832***	***324,322,119***
No. of Customers	***4,089,148***	***3,701,803***	***385,898***	***217***	***72***	***1,158***	***1,447***
Therms	***651,399,403***	***212,787,060***	***107,972,664***	***6,317,560***	***39,909,287***	***284,412,832***	***324,322,119***

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 21

Class Cost of Service Study
Account Detail

				Residential Service				General Service			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**	**CAP**	**CUS**	**COM**	**TOTAL**
RATE BASE											
Plant in Service											
	Intangible Plant										
	Organization	2,506	WEIGHTED	-	1,897	-	1,897	-	593	-	593
	Franchises & Consents	429,487	RB_PLT_??_OR	80,601	205,420	-	286,020	40,053	58,011	-	98,063
	Misc. Intangible Plant	40,650,532	RB_PLT_??_OR	7,628,763	19,442,800	-	27,071,562	3,790,934	5,490,643	-	9,281,577
	Sub-total	***41,082,525***		***7,709,363***	***19,650,117***	**-**	***27,359,480***	***3,830,986***	***5,549,247***	**-**	***9,380,233***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Storage Plant										
	Land & Land Rights LNG	292,588	PDAY	145,244	-	-	145,244	72,153	-	-	72,153
	Structures & Improvements - LNG	4,698,209	PDAY	2,332,246	-	-	2,332,246	1,158,588	-	-	1,158,588
	Gas Holders - LNG	3,698,508	PDAY	1,835,983	-	-	1,835,983	912,060	-	-	912,060
	Purification Equip - LNG	13,885,945	PDAY	6,893,145	-	-	6,893,145	3,424,303	-	-	3,424,303
	Sub-total	***22,575,250***		***11,206,618***	**-**	**-**	***11,206,618***	***5,567,103***	**-**	**-**	***5,567,103***
	Transmission Plant										
	Land & Land Rights	789,682	PDAY	392,007	-	-	392,007	194,737	-	-	194,737
	Structures & Improvements - Transmission	77,152	PDAY	38,299	-	-	38,299	19,026	-	-	19,026
	Trans Mains	68,666,886	PDAY	34,087,043	-	-	34,087,043	16,933,396	-	-	16,933,396
	Trans Compressor Sta Equip	1,730,359	PDAY	858,970	-	-	858,970	426,710	-	-	426,710
	Trans Communication Equip	714,440	PDAY	354,656	-	-	354,656	176,182	-	-	176,182
	Sub-total	***71,978,519***		***35,730,977***	**-**	**-**	***35,730,977***	***17,750,052***	**-**	**-**	***17,750,052***
	Distribution Plant										
	Dist Land & Land Rights	637,754	D_LLR	93,089	361,403	-	454,492	46,273	84,121	-	130,393
	Dist Structures & Improvements	18,864	PK_AVG	7,940	-	-	7,940	3,973	-	-	3,973
	Dist Mains	164,694,644	PDAY	43,200,052	70,312,695	-	113,512,747	21,460,459	7,329,814	-	28,790,273
	Dist Meas & Reg Sta Equip - Gen	9,529,795	PK_AVG	4,010,962	-	-	4,010,962	2,007,276	-	-	2,007,276
	Dist Services	149,255,628	WEIGHTED	-	113,007,918	-	113,007,918	-	35,340,181	-	35,340,181
	Dist Meters	44,853,911	WEIGHTED1	-	35,082,732	-	35,082,732	-	9,734,725	-	9,734,725
	Dist Meter Installations	13,955,058	WEIGHTED1	-	10,915,025	-	10,915,025	-	3,028,691	-	3,028,691
	Dist House Regulators	6,410,602	WEIGHTED1	-	5,014,087	-	5,014,087	-	1,391,304	-	1,391,304
	Dist House Regulator Install	7,047,749	WEIGHTED1	-	5,512,435	-	5,512,435	-	1,529,586	-	1,529,586
	Dist Ind Reg Sta	11,259,697	WEIGHTED2	-	-	-	-	-	9,395,790	-	9,395,790
	Sub-total	***407,663,702***		***47,312,042***	***240,206,296***	**-**	***287,518,338***	***23,517,981***	***67,834,212***	**-**	***91,352,194***
	General Plant										
	Gen Land & Land Rights	2,991,271	RB_PLT_??_OR	561,363	1,430,699	-	1,992,062	278,956	404,029	-	682,985
	Gen Struct & Imp	19,567,163	RB_PLT_??_OR	3,672,110	9,358,806	-	13,030,916	1,824,769	2,642,925	-	4,467,694
	Gen Office Furn & Imp	9,824,942	RB_PLT_??_OR	1,843,817	4,699,185	-	6,543,002	916,242	1,327,049	-	2,243,291
	Gen Trans Equip	9,122,889	RB_PLT_??_OR	1,712,065	4,363,399	-	6,075,464	850,770	1,232,223	-	2,082,994
	Gen Stores Equip	4,407	RB_PLT_??_OR	827	2,108	-	2,935	411	595	-	1,006
	Gen Tools Shop & Gar Equip	5,207,323	RB_PLT_??_OR	977,243	2,490,618	-	3,467,860	485,618	703,350	-	1,188,968
	Gen Laboratory Equip	-	RB_PLT_??_OR	-	-	-	-	-	-	-	-
	Gen Power Oper Equip	1,457,918	RB_PLT_??_OR	273,603	697,310	-	970,913	135,961	196,920	-	332,881
	Gen Communications Equip	4,589,648	RB_PLT_??_OR	861,325	2,195,189	-	3,056,515	428,015	619,921	-	1,047,936
	Gen Misc Equip	-	RB_PLT_??_OR	-	-	-	-	-	-	-	-
	Sub-total	***52,765,561***		***9,902,354***	***25,237,314***	**-**	***35,139,667***	***4,920,741***	***7,127,013***	**-**	***12,047,754***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TOTAL PLANT-IN-SERVICE	**596,065,557**		**111,861,353**	**285,093,727**	**-**	**396,955,080**	**55,586,864**	**80,510,472**	**-**	**136,097,336**

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Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
RATE BASE											
Plant in Service											
	Intangible Plant										
	Organization	2,506	WEIGHTED	-	2	-	2	-	1	-	1
	Franchises & Consents	429,487	RB_PLT_??_OR	808	269	-	1,077	223	245	-	468
	Misc. Intangible Plant	40,650,532	RB_PLT_??_OR	76,455	25,494	-	101,950	21,110	23,184	-	44,294
	Sub-total	***41,082,525***		***77,263***	***25,765***	-	***103,028***	***21,333***	***23,430***	-	***44,763***
	Sub-total	-		-	-	-	-	-	-	-	-
	Storage Plant										
	Land & Land Rights LNG	292,588	PDAY	1,413	-	-	1,413	-	-	-	-
	Structures & Improvements - LNG	4,698,209	PDAY	22,687	-	-	22,687	-	-	-	-
	Gas Holders - LNG	3,698,508	PDAY	17,860	-	-	17,860	-	-	-	-
	Purification Equip - LNG	13,885,945	PDAY	67,053	-	-	67,053	-	-	-	-
	Sub-total	***22,575,250***		***109,012***	-	-	***109,012***	-	-	-	-
	Transmission Plant										
	Land & Land Rights	789,682	PDAY	3,813	-	-	3,813	-	-	-	-
	Structures & Improvements - Transmission	77,152	PDAY	373	-	-	373	-	-	-	-
	Trans Mains	68,666,886	PDAY	331,581	-	-	331,581	-	-	-	-
	Trans Compressor Sta Equip	1,730,359	PDAY	8,356	-	-	8,356	-	-	-	-
	Trans Communication Equip	714,440	PDAY	3,450	-	-	3,450	-	-	-	-
	Sub-total	***71,978,519***		***347,573***	-	-	***347,573***	-	-	-	-
	Distribution Plant										
	Dist Land & Land Rights	637,754	D_LLR	960	205	-	1,165	513	174	-	687
	Dist Structures & Improvements	18,864	PK_AVG	132	-	-	132	514	-	-	514
	Dist Mains	164,694,644	PDAY	420,228	4,122	-	424,350	-	1,368	-	1,368
	Dist Meas & Reg Sta Equip - Gen	9,529,795	PK_AVG	66,665	-	-	66,665	259,771	-	-	259,771
	Dist Services	149,255,628	WEIGHTED	-	99,651	-	99,651	-	87,068	-	87,068
	Dist Meters	44,853,911	WEIGHTED1	-	4,024	-	4,024	-	1,266	-	1,266
	Dist Meter Installations	13,955,058	WEIGHTED1	-	1,252	-	1,252	-	394	-	394
	Dist House Regulators	6,410,602	WEIGHTED1	-	575	-	575	-	181	-	181
	Dist House Regulator Install	7,047,749	WEIGHTED1	-	632	-	632	-	199	-	199
	Dist Ind Reg Sta	11,259,697	WEIGHTED2	-	204,506	-	204,506	-	195,777	-	195,777
	Sub-total	***407,663,702***		***487,985***	***314,966***	-	***802,951***	***260,799***	***286,427***	-	***547,226***
	General Plant										
	Gen Land & Land Rights	2,991,271	RB_PLT_??_OR	5,626	1,876	-	7,502	1,553	1,706	-	3,259
	Gen Struct & Imp	19,567,163	RB_PLT_??_OR	36,802	12,272	-	49,073	10,161	11,160	-	21,321
	Gen Office Furn & Imp	9,824,942	RB_PLT_??_OR	18,479	6,162	-	24,640	5,102	5,603	-	10,705
	Gen Trans Equip	9,122,889	RB_PLT_??_OR	17,158	5,721	-	22,880	4,737	5,203	-	9,940
	Gen Stores Equip	4,407	RB_PLT_??_OR	8	3	-	11	2	3	-	5
	Gen Tools Shop & Gar Equip	5,207,323	RB_PLT_??_OR	9,794	3,266	-	13,060	2,704	2,970	-	5,674
	Gen Laboratory Equip	-	RB_PLT_??_OR	-	-	-	-	-	-	-	-
	Gen Power Oper Equip	1,457,918	RB_PLT_??_OR	2,742	914	-	3,656	757	831	-	1,589
	Gen Communications Equip	4,589,648	RB_PLT_??_OR	8,632	2,878	-	11,511	2,383	2,618	-	5,001
	Gen Misc Equip	-	RB_PLT_??_OR	-	-	-	-	-	-	-	-
	Sub-total	***52,765,561***		***99,241***	***33,092***	-	***132,333***	***27,401***	***30,094***	-	***57,494***
	Sub-total	-		-	-	-	-	-	-	-	-
	TOTAL PLANT-IN-SERVICE	**596,065,557**		**1,121,075**	**373,823**	-	**1,494,898**	**309,532**	**339,951**	-	**649,483**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Transport Service (Firm)			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**
	RATE BASE						
	Plant in Service						
	Intangible Plant						
	Organization	2,506	WEIGHTED	-	12	-	12
	Franchises & Consents	429,487	RB_PLT_??_OR	41,927	1,931	-	43,858
	Misc. Intangible Plant	40,650,532	RB_PLT_??_OR	3,968,374	182,776	-	4,151,150
	Sub-total	***41,082,525***		***4,010,301***	***184,719***	-	***4,195,020***
	Sub-total	-		-	-	-	-
	Storage Plant						
	Land & Land Rights LNG	292,588	PDAY	73,778	-	-	73,778
	Structures & Improvements - LNG	4,698,209	PDAY	1,184,688	-	-	1,184,688
	Gas Holders - LNG	3,698,508	PDAY	932,606	-	-	932,606
	Purification Equip - LNG	13,885,945	PDAY	3,501,444	-	-	3,501,444
	Sub-total	***22,575,250***		***5,692,517***	-	-	***5,692,517***
	Transmission Plant						
	Land & Land Rights	789,682	PDAY	199,124	-	-	199,124
	Structures & Improvements - Transmission	77,152	PDAY	19,454	-	-	19,454
	Trans Mains	68,666,886	PDAY	17,314,865	-	-	17,314,865
	Trans Compressor Sta Equip	1,730,359	PDAY	436,323	-	-	436,323
	Trans Communication Equip	714,440	PDAY	180,151	-	-	180,151
	Sub-total	***71,978,519***		***18,149,918***	-	-	***18,149,918***
	Distribution Plant						
	Dist Land & Land Rights	637,754	D_LLR	49,552	1,464	-	51,017
	Dist Structures & Improvements	18,864	PK_AVG	6,305	-	-	6,305
	Dist Mains	164,694,644	PDAY	21,943,911	21,995	-	21,965,907
	Dist Meas & Reg Sta Equip - Gen	9,529,795	PK_AVG	3,185,120	-	-	3,185,120
	Dist Services	149,255,628	WEIGHTED	-	720,810	-	720,810
	Dist Meters	44,853,911	WEIGHTED1	-	31,164	-	31,164
	Dist Meter Installations	13,955,058	WEIGHTED1	-	9,696	-	9,696
	Dist House Regulators	6,410,602	WEIGHTED1	-	4,454	-	4,454
	Dist House Regulator Install	7,047,749	WEIGHTED1	-	4,897	-	4,897
	Dist Ind Reg Sta	11,259,697	WEIGHTED2	-	1,463,624	-	1,463,624
	Sub-total	***407,663,702***		***25,184,889***	***2,258,104***	-	***27,442,993***
	General Plant						
	Gen Land & Land Rights	2,991,271	RB_PLT_??_OR	292,013	13,450	-	305,463
	Gen Struct & Imp	19,567,163	RB_PLT_??_OR	1,910,180	87,979	-	1,998,159
	Gen Office Furn & Imp	9,824,942	RB_PLT_??_OR	959,128	44,176	-	1,003,303
	Gen Trans Equip	9,122,889	RB_PLT_??_OR	890,592	41,019	-	931,611
	Gen Stores Equip	4,407	RB_PLT_??_OR	430	20	-	450
	Gen Tools Shop & Gar Equip	5,207,323	RB_PLT_??_OR	508,348	23,414	-	531,761
	Gen Laboratory Equip	-	RB_PLT_??_OR	-	-	-	-
	Gen Power Oper Equip	1,457,918	RB_PLT_??_OR	142,324	6,555	-	148,880
	Gen Communications Equip	4,589,648	RB_PLT_??_OR	448,049	20,636	-	468,686
	Gen Misc Equip	-	RB_PLT_??_OR	-	-	-	-
	Sub-total	***52,765,561***		***5,151,064***	***237,248***	-	***5,388,312***
	Sub-total	-		-	-	-	-
	TOTAL PLANT-IN-SERVICE	**596,065,557**		**58,188,688**	**2,680,071**	-	**60,868,760**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC
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Class Cost of Service Study
Account Detail

				Residential Service				General Service			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**	**CAP**	**CUS**	**COM**	**TOTAL**
	Accumulated Reserve for Depreciation										
	Intangible Plant										
	Amort of Intangible Plant	(4,124,482)	RB_PLTINT_OR	(773,982)	(1,972,774)	-	(2,746,756)	(384,612)	(557,117)	-	(941,729)
	Sub-total	***(4,124,482)***		***(773,982)***	***(1,972,774)***	**-**	***(2,746,756)***	***(384,612)***	***(557,117)***	**-**	***(941,729)***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Storage Plant										
	Prov For Depr-Stor Other Plant	(11,407,763)	RB_PLT_ST_OR	(5,662,947)	-	-	(5,662,947)	(2,813,178)	-	-	(2,813,178)
	Sub-total	***(11,407,763)***		***(5,662,947)***	**-**	**-**	***(5,662,947)***	***(2,813,178)***	**-**	**-**	***(2,813,178)***
	Transmission Plant										
	Prov For Depr-Trans Plant	(41,291,008)	RB_PLT_TR_ORIG	(20,497,338)	-	-	(20,497,338)	(10,182,448)	-	-	(10,182,448)
	Sub-total	***(41,291,008)***		***(20,497,338)***	**-**	**-**	***(20,497,338)***	***(10,182,448)***	**-**	**-**	***(10,182,448)***
	Distribution Plant										
	Prov For Depr-Dist Plant	(229,245,708)	RB_PLT_DI_ORIG	(26,605,466)	(135,077,668)	-	(161,683,134)	(13,225,107)	(38,145,908)	-	(51,371,015)
	Sub-total	***(229,245,708)***		***(26,605,466)***	***(135,077,668)***	**-**	***(161,683,134)***	***(13,225,107)***	***(38,145,908)***	**-**	***(51,371,015)***
	General Plant										
	Prov For Depr-Gen Plant	(22,381,886)	RB_PLTGEN_ORIG	(4,200,341)	(10,705,064)	-	(14,905,404)	(2,087,260)	(3,023,108)	-	(5,110,368)
	Prov For Depr-Plant Adj	-	RB_PLT???_ORIG	-	-	-	-	-	-	-	-
	Sub-total	***(22,381,886)***		***(4,200,341)***	***(10,705,064)***	**-**	***(14,905,404)***	***(2,087,260)***	***(3,023,108)***	**-**	***(5,110,368)***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TOTAL DEPRECIATION ACCRUAL	**(308,450,847)**		**(57,740,073)**	**(147,755,506)**	**-**	**(205,495,580)**	**(28,692,606)**	**(41,726,133)**	**-**	**(70,418,739)**
	NET PLANT	**287,614,710**		**54,121,280**	**137,338,221**	**-**	**191,459,500**	**26,894,258**	**38,784,339**	**-**	**65,678,597**
	Rate Base Adjustments										
	Other Rate Base Adjustments										
	Gas Plant Adjustment	-	RB_PLT???_ORIG	-	-	-	-	-	-	-	-
	Unamortized ITC	-	RB_PLT_?	-	-	-	-	-	-	-	-
	Deferred Income Taxes-Sp	(2,040,884)	RB_PLT_ST_OR	(1,013,119)	-	-	(1,013,119)	(503,286)	-	-	(503,286)
	Deferred Income Taxes-Tp	(6,507,119)	RB_PLT_TR_ORIG	(3,230,210)	-	-	(3,230,210)	(1,604,669)	-	-	(1,604,669)
	Deferred Income Taxes-Dp	(36,854,276)	RB_PLT_DI_ORIG	(4,277,180)	(21,715,520)	-	(25,992,700)	(2,126,111)	(6,132,459)	-	(8,258,569)
	Deferred Income Taxes-Gp	(4,770,198)	RB_PLTGEN_ORIG	(895,209)	(2,281,545)	-	(3,176,753)	(444,853)	(644,308)	-	(1,089,161)
	Zero-Interest Fin. Notes	-	RB_PLT	-	-	-	-	-	-	-	-
	Materials & Supplies	3,149,131	RB_PLT_??_OR	590,988	1,506,202	-	2,097,190	293,678	425,351	-	719,029
	Lng Inventory	3,195,613	PDAY	1,586,340	-	-	1,586,340	788,045	-	-	788,045
	Cust Adv For Const	(7,893,171)	MAIN_SERV	(1,086,113)	(4,608,949)	-	(5,695,062)	(539,547)	(1,072,786)	-	(1,612,334)
	Cash Working Capitol	1,032,688	CWC	200,488	482,598	-	683,086	99,627	137,287	-	236,914
	Sub-total	***(50,688,216)***		***(8,124,015)***	***(26,617,213)***	**-**	***(34,741,228)***	***(4,037,117)***	***(7,286,914)***	**-**	***(11,324,031)***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TOTAL RATE BASE ADJ.	**(50,688,216)**		**(8,124,015)**	**(26,617,213)**	**-**	**(34,741,228)**	**(4,037,117)**	**(7,286,914)**	**-**	**(11,324,031)**
TOTAL RATE BASE		**236,926,494**		**45,997,265**	**110,721,007**	**-**	**156,718,272**	**22,857,141**	**31,497,425**	**-**	**54,354,566**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC
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Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**	**CAP**	**CUS**	**COM**	**TOTAL**
Accumulated Reserve for Depreciation											
	Intangible Plant										
	Amort of Intangible Plant	(4,124,482)	RB_PLTINT_OR	(7,757)	(2,587)	-	(10,344)	(2,142)	(2,352)	-	(4,494)
	Sub-total	***(4,124,482)***		***(7,757)***	***(2,587)***	-	***(10,344)***	***(2,142)***	***(2,352)***	-	***(4,494)***
	Sub-total	-		-	-	-	-	-	-	-	-
	Storage Plant										
	Prov For Depr-Stor Other Plant	(11,407,763)	RB_PLT_ST_OR	(55,086)	-	-	(55,086)	-	-	-	-
	Sub-total	***(11,407,763)***		***(55,086)***	-	-	***(55,086)***	-	-	-	-
	Transmission Plant										
	Prov For Depr-Trans Plant	(41,291,008)	RB_PLT_TR_ORIG	(199,388)	-	-	(199,388)	-	-	-	-
	Sub-total	***(41,291,008)***		***(199,388)***	-	-	***(199,388)***	-	-	-	-
	Distribution Plant										
	Prov For Depr-Dist Plant	(229,245,708)	RB_PLT_DI_ORIG	(274,414)	(177,118)	-	(451,532)	(146,658)	(161,069)	-	(307,727)
	Sub-total	***(229,245,708)***		***(274,414)***	***(177,118)***	-	***(451,532)***	***(146,658)***	***(161,069)***	-	***(307,727)***
	General Plant										
	Prov For Depr-Gen Plant	(22,381,886)	RB_PLTGEN_ORIG	(42,096)	(14,037)	-	(56,133)	(11,623)	(12,765)	-	(24,388)
	Prov For Depr-Plant Adj	-	RB_PLT???_ORIG	-	-	-	-	-	-	-	-
	Sub-total	***(22,381,886)***		***(42,096)***	***(14,037)***	-	***(56,133)***	***(11,623)***	***(12,765)***	-	***(24,388)***
	Sub-total	-		-	-	-	-	-	-	-	-
	TOTAL DEPRECIATION ACCRUAL	**(308,450,847)**		**(578,740)**	**(193,742)**	-	**(772,482)**	**(160,422)**	**(176,187)**	-	**(336,609)**
	NET PLANT	**287,614,710**		**542,334**	**180,082**	-	**722,416**	**149,110**	**163,764**	-	**312,874**
Rate Base Adjustments											
	Other Rate Base Adjustments										
	Gas Plant Adjustment	-	RB_PLT???_ORIG	-	-	-	-	-	-	-	-
	Unamortized ITC	-	RB_PLT_?	-	-	-	-	-	-	-	-
	Deferred Income Taxes-Sp	(2,040,884)	RB_PLT_ST_OR	(9,855)	-	-	(9,855)	-	-	-	-
	Deferred Income Taxes-Tp	(6,507,119)	RB_PLT_TR_ORIG	(31,422)	-	-	(31,422)	-	-	-	-
	Deferred Income Taxes-Dp	(36,854,276)	RB_PLT_DI_ORIG	(44,116)	(28,474)	-	(72,590)	(23,577)	(25,894)	-	(49,471)
	Deferred Income Taxes-Gp	(4,770,198)	RB_PLTGEN_ORIG	(8,972)	(2,992)	-	(11,963)	(2,477)	(2,721)	-	(5,198)
	Zero-Interest Fin. Notes	-	RB_PLT	-	-	-	-	-	-	-	-
	Materials & Supplies	3,149,131	RB_PLT_??_OR	5,923	1,975	-	7,898	1,635	1,796	-	3,431
	Lng Inventory	3,195,613	PDAY	15,431	-	-	15,431	-	-	-	-
	Cust Adv For Const	(7,893,171)	MAIN_SERV	(10,565)	(2,609)	-	(13,174)	-	(2,223)	-	(2,223)
	Cash Working Capitol	1,032,688	CWC	2,008	648	-	2,656	546	590	-	1,136
	Sub-total	***(50,688,216)***		***(81,567)***	***(31,452)***	-	***(113,019)***	***(23,873)***	***(28,452)***	-	***(52,325)***
	Sub-total	-		-	-	-	-	-	-	-	-
	TOTAL RATE BASE ADJ.	**(50,688,216)**		**(81,567)**	**(31,452)**	-	**(113,019)**	**(23,873)**	**(28,452)**	-	**(52,325)**
TOTAL RATE BASE		**236,926,494**		**460,767**	**148,630**	-	**609,397**	**125,237**	**135,312**	-	**260,549**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC
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Class Cost of Service Study
Account Detail

				Transport Service (Firm)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL
	Accumulated Reserve for Depreciation						
	Intangible Plant						
	Amort of Intangible Plant	(4,124,482)	RB_PLTINT_OR	(402,614)	(18,545)	-	(421,159)
	Sub-total	***(4,124,482)***		***(402,614)***	***(18,545)***	**-**	***(421,159)***
	Sub-total	**-**		**-**	**-**	**-**	**-**
	Storage Plant						
	Prov For Depr-Stor Other Plant	(11,407,763)	RB_PLT_ST_OR	(2,876,552)	-	-	(2,876,552)
	Sub-total	***(11,407,763)***		***(2,876,552)***	**-**	**-**	***(2,876,552)***
	Transmission Plant						
	Prov For Depr-Trans Plant	(41,291,008)	RB_PLT_TR_ORIG	(10,411,834)	-	-	(10,411,834)
	Sub-total	***(41,291,008)***		***(10,411,834)***	**-**	**-**	***(10,411,834)***
	Distribution Plant						
	Prov For Depr-Dist Plant	(229,245,708)	RB_PLT_DI_ORIG	(14,162,477)	(1,269,823)	-	(15,432,300)
	Sub-total	***(229,245,708)***		***(14,162,477)***	***(1,269,823)***	**-**	***(15,432,300)***
	General Plant						
	Prov For Depr-Gen Plant	(22,381,886)	RB_PLTGEN_ORIG	(2,184,958)	(100,635)	-	(2,285,593)
	Prov For Depr-Plant Adj	-	RB_PLT???_ORIG	-	-	-	-
	Sub-total	***(22,381,886)***		***(2,184,958)***	***(100,635)***	**-**	***(2,285,593)***
	Sub-total	**-**		**-**	**-**	**-**	**-**
	TOTAL DEPRECIATION ACCRUAL	**(308,450,847)**		**(30,038,435)**	**(1,389,003)**	**-**	**(31,427,438)**
	NET PLANT	**287,614,710**		**28,150,253**	**1,291,069**	**-**	**29,441,322**
	Rate Base Adjustments						
	Other Rate Base Adjustments						
	Gas Plant Adjustment	-	RB_PLT???_ORIG	-	-	-	-
	Unamortized ITC	-	RB_PLT_?	-	-	-	-
	Deferred Income Taxes-Sp	(2,040,884)	RB_PLT_ST_OR	(514,624)	-	-	(514,624)
	Deferred Income Taxes-Tp	(6,507,119)	RB_PLT_TR_ORIG	(1,640,818)	-	-	(1,640,818)
	Deferred Income Taxes-Dp	(36,854,276)	RB_PLT_DI_ORIG	(2,276,805)	(204,141)	-	(2,480,946)
	Deferred Income Taxes-Gp	(4,770,198)	RB_PLTGEN_ORIG	(465,675)	(21,448)	-	(487,123)
	Zero-Interest Fin. Notes	-	RB_PLT	-	-	-	-
	Materials & Supplies	3,149,131	RB_PLT_??_OR	307,424	14,159	-	321,583
	Lng Inventory	3,195,613	PDAY	805,798	-	-	805,798
	Cust Adv For Const	(7,893,171)	MAIN_SERV	(551,702)	(18,675)	-	(570,377)
	Cash Working Capitol	1,032,688	CWC	104,251	4,645	-	108,896
	Sub-total	***(50,688,216)***		***(4,232,152)***	***(225,460)***	**-**	***(4,457,612)***
	Sub-total	**-**		**-**	**-**	**-**	**-**
	TOTAL RATE BASE ADJ.	**(50,688,216)**		**(4,232,152)**	**(225,460)**	**-**	**(4,457,612)**
	TOTAL RATE BASE	**236,926,494**		**23,918,101**	**1,065,608**	**-**	**24,983,710**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Residential Service				General Service			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**	**CAP**	**CUS**	**COM**	**TOTAL**
EXPENSES											
O & M Expenses (Total)											
	Other Gas Supply Expenses										
	Other Gas Supply Expenses	46,564	SALES	-	31,110	-	31,110	-	15,454	-	15,454
	Sub-total	***46,564***		***-***	***31,110***	***-***	***31,110***	***-***	***15,454***	***-***	***15,454***
	Sub-total	***-***		***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***
	Total ~	***46,564***		***-***	***31,110***	***-***	***31,110***	***-***	***15,454***	***-***	***15,454***
	Storage Operation Expenses										
	Operation Supervision & Engineering	(197)	PDAY	(98)	-	-	(98)	(49)	-	-	(49)
	Operation Labor & Expenses	557,574	PDAY	276,786	-	-	276,786	137,499	-	-	137,499
	Fuel	174,453	PDAY	86,600	-	-	86,600	43,020	-	-	43,020
	Power	113,643	PDAY	56,414	-	-	56,414	28,025	-	-	28,025
	Sub-total	***845,472***		***419,702***	***-***	***-***	***419,702***	***208,495***	***-***	***-***	***208,495***
	Storage Maintenance Expenses										
	Maintenance Supervision & Engineering	103,654	PDAY	51,455	-	-	51,455	25,561	-	-	25,561
	Maintenance of Structures	30,155	PDAY	14,969	-	-	14,969	7,436	-	-	7,436
	Maintenance of Gas Holders	3,323	PDAY	1,650	-	-	1,650	820	-	-	820
	Maintenance of Purification Equipment	32,228	PDAY	15,998	-	-	15,998	7,948	-	-	7,948
	Maintenance of Liquefaction Equipment	155,251	PDAY	77,069	-	-	77,069	38,285	-	-	38,285
	Maintenance of Vaporizing Equipment	75,595	PDAY	37,526	-	-	37,526	18,642	-	-	18,642
	Maintenance of Compressor Equipment	46,511	PDAY	23,089	-	-	23,089	11,470	-	-	11,470
	Maintenance of M&R Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Other Equipment	90,903	PDAY	45,125	-	-	45,125	22,417	-	-	22,417
	Sub-total	***537,621***		***266,881***	***-***	***-***	***266,881***	***132,579***	***-***	***-***	***132,579***
	Total LNG	***1,383,093***		***686,584***	***-***	***-***	***686,584***	***341,074***	***-***	***-***	***341,074***
	Transmission Operation Expenses										
	Operation Supervision & Engineering	-	PDAY	-	-	-	-	-	-	-	-
	System Control	-	PDAY	-	-	-	-	-	-	-	-
	Communication System Expenses	39,202	PDAY	19,460	-	-	19,460	9,667	-	-	9,667
	Compressor Sta. Labor & Expenses	5,532	PDAY	2,746	-	-	2,746	1,364	-	-	1,364
	Gas for Compressor Station Fuel	-	PDAY	-	-	-	-	-	-	-	-
	Mains Expenses	144,627	PDAY	71,795	-	-	71,795	35,665	-	-	35,665
	Sub-total	***189,362***		***94,001***	***-***	***-***	***94,001***	***46,697***	***-***	***-***	***46,697***
	Transmission Maintenance Expenses										
	Maintenance of Mains	13,276	PDAY	6,590	-	-	6,590	3,274	-	-	3,274
	Maintenance Pipeline Integrity	88,874	PDAY	44,118	-	-	44,118	21,916	-	-	21,916
	Maintenance of Compressor Station Equipm	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Communication Equipment	201,230	PDAY	99,893	-	-	99,893	49,624	-	-	49,624
	Sub-total	***303,380***		***150,601***	***-***	***-***	***150,601***	***74,814***	***-***	***-***	***74,814***
	Total Transmission	***492,741***		***244,602***	***-***	***-***	***244,602***	***121,511***	***-***	***-***	***121,511***

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Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
EXPENSES											
O & M Expenses (Total)											
	Other Gas Supply Expenses										
	Other Gas Supply Expenses	46,564	SALES	-	-	-	-	-	-	-	-
	Sub-total	***46,564***		-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-
	Total ~	***46,564***		-	-	-	-	-	-	-	-
	Storage Operation Expenses										
	Operation Supervision & Engineering	(197)	PDAY	(1)	-	-	(1)	-	-	-	-
	Operation Labor & Expenses	557,574	PDAY	2,692	-	-	2,692	-	-	-	-
	Fuel	174,453	PDAY	842	-	-	842	-	-	-	-
	Power	113,643	PDAY	549	-	-	549	-	-	-	-
	Sub-total	***845,472***		***4,083***	-	-	***4,083***	-	-	-	-
	Storage Maintenance Expenses										
	Maintenance Supervision & Engineering	103,654	PDAY	501	-	-	501	-	-	-	-
	Maintenance of Structures	30,155	PDAY	146	-	-	146	-	-	-	-
	Maintenance of Gas Holders	3,323	PDAY	16	-	-	16	-	-	-	-
	Maintenance of Purification Equipment	32,228	PDAY	156	-	-	156	-	-	-	-
	Maintenance of Liquefaction Equipment	155,251	PDAY	750	-	-	750	-	-	-	-
	Maintenance of Vaporizing Equipment	75,595	PDAY	365	-	-	365	-	-	-	-
	Maintenance of Compressor Equipment	46,511	PDAY	225	-	-	225	-	-	-	-
	Maintenance of M&R Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Other Equipment	90,903	PDAY	439	-	-	439	-	-	-	-
	Sub-total	***537,621***		***2,596***	-	-	***2,596***	-	-	-	-
	Total LNG	***1,383,093***		***6,679***	-	-	***6,679***	-	-	-	-
	Transmission Operation Expenses										
	Operation Supervision & Engineering	-	PDAY	-	-	-	-	-	-	-	-
	System Control	-	PDAY	-	-	-	-	-	-	-	-
	Communication System Expenses	39,202	PDAY	189	-	-	189	-	-	-	-
	Compressor Sta. Labor & Expenses	5,532	PDAY	27	-	-	27	-	-	-	-
	Gas for Compressor Station Fuel	-	PDAY	-	-	-	-	-	-	-	-
	Mains Expenses	144,627	PDAY	698	-	-	698	-	-	-	-
	Sub-total	***189,362***		***914***	-	-	***914***	-	-	-	-
	Transmission Maintenance Expenses										
	Maintenance of Mains	13,276	PDAY	64	-	-	64	-	-	-	-
	Maintenance Pipeline Integrity	88,874	PDAY	429	-	-	429	-	-	-	-
	Maintenance of Compressor Station Equipm	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Communication Equipment	201,230	PDAY	972	-	-	972	-	-	-	-
	Sub-total	***303,380***		***1,465***	-	-	***1,465***	-	-	-	-
	Total Transmission	***492,741***		***2,379***	-	-	***2,379***	-	-	-	-

Class Cost of Service Study
Account Detail

				Transport Service (Firm)			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**
EXPENSES							
O & M Expenses (Total)							
	Other Gas Supply Expenses						
	Other Gas Supply Expenses	46,564	SALES	-	-	-	-
	Sub-total	***46,564***		**-**	**-**	**-**	**-**
	Sub-total	**-**		**-**	**-**	**-**	**-**
	Total ~	***46,564***		**-**	**-**	**-**	**-**
	Storage Operation Expenses						
	Operation Supervision & Engineering	(197)	PDAY	(50)	-	-	(50)
	Operation Labor & Expenses	557,574	PDAY	140,596	-	-	140,596
	Fuel	174,453	PDAY	43,990	-	-	43,990
	Power	113,643	PDAY	28,656	-	-	28,656
	Sub-total	***845,472***		***213,192***	**-**	**-**	***213,192***
	Storage Maintenance Expenses						
	Maintenance Supervision & Engineering	103,654	PDAY	26,137	-	-	26,137
	Maintenance of Structures	30,155	PDAY	7,604	-	-	7,604
	Maintenance of Gas Holders	3,323	PDAY	838	-	-	838
	Maintenance of Purification Equipment	32,228	PDAY	8,127	-	-	8,127
	Maintenance of Liquefaction Equipment	155,251	PDAY	39,148	-	-	39,148
	Maintenance of Vaporizing Equipment	75,595	PDAY	19,062	-	-	19,062
	Maintenance of Compressor Equipment	46,511	PDAY	11,728	-	-	11,728
	Maintenance of M&R Equipment	-	PDAY	-	-	-	-
	Maintenance of Other Equipment	90,903	PDAY	22,922	-	-	22,922
	Sub-total	***537,621***		***135,565***	**-**	**-**	***135,565***
	Total LNG	***1,383,093***		***348,757***	**-**	**-**	***348,757***
	Transmission Operation Expenses						
	Operation Supervision & Engineering	-	PDAY	-	-	-	-
	System Control	-	PDAY	-	-	-	-
	Communication System Expenses	39,202	PDAY	9,885	-	-	9,885
	Compressor Sta. Labor & Expenses	5,532	PDAY	1,395	-	-	1,395
	Gas for Compressor Station Fuel	-	PDAY	-	-	-	-
	Mains Expenses	144,627	PDAY	36,469	-	-	36,469
	Sub-total	***189,362***		***47,749***	**-**	**-**	***47,749***
	Transmission Maintenance Expenses						
	Maintenance of Mains	13,276	PDAY	3,348	-	-	3,348
	Maintenance Pipeline Integrity	88,874	PDAY	22,410	-	-	22,410
	Maintenance of Compressor Station Equipm	-	PDAY	-	-	-	-
	Maintenance of Communication Equipment	201,230	PDAY	50,742	-	-	50,742
	Sub-total	***303,380***		***76,499***	**-**	**-**	***76,499***
	Total Transmission	***492,741***		***124,248***	**-**	**-**	***124,248***

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Class Cost of Service Study
Account Detail

No.	Account Description	Amount	Alloc. Factor	Residential Service				General Service			
				CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
	Distribution Operation Expenses										
	Distrib Supervision & Engineering	2,691,872	LACA	77,189	1,431,838	-	1,509,027	38,345	982,689	-	1,021,034
	Distribution Load Dispatching	-	PK_AVG	-	-	-	-	-	-	-	-
	Compressor Station Fuel/Power	-	LACA	-	-	-	-	-	-	-	-
	Dist Oper Mains & Services Expenses	2,699,639	MAIN_SERV	371,475	1,576,362	-	1,947,837	184,537	366,917	-	551,454
	Dist Oper Meas & Reg Gen	129,611	PK_AVG	54,552	-	-	54,552	27,300	-	-	27,300
	Dist Oper Meas & Reg Ind	-	PA_GP_II	-	-	-	-	-	-	-	-
	Meter/House Regulator Expenses	226,375	WEIGHTED1	-	177,061	-	177,061	-	49,131	-	49,131
	Meter/House Regulator Expenses	(556,097)	WEIGHTED1	-	(434,955)	-	(434,955)	-	(120,691)	-	(120,691)
	Customer Installations Expenses	7,126,046	D_382_384_385	-	3,628,449	-	3,628,449	-	3,082,133	-	3,082,133
	Other Expenses	2,437,388	RB_PLT_DI_ORIG	282,875	1,436,174	-	1,719,049	140,612	405,575	-	546,187
	Rents	204,290	RB_PLT_DI_ORIG	23,709	120,373	-	144,082	11,785	33,993	-	45,779
	Sub-total	***14,959,124***		***809,799***	***7,935,302***	-	***8,745,102***	***402,580***	***4,799,747***	-	***5,202,327***
	Distribution Maintenance Expenses										
	Dist Main Supervision/Engineering	196,391	NADM	19,386	102,909	-	122,295	19,280	25,898	-	45,178
	Dist Maintenance of Mains	950,016	PDAY	249,193	405,588	-	654,781	123,791	42,281	-	166,072
	Dist Maintenance of Mains	79,382	PDAY	20,822	33,891	-	54,713	10,344	3,533	-	13,877
	Maint of Meas/Reg Station Equip-General	198,278	PK_AVG	83,452	-	-	83,452	41,764	-	-	41,764
	Maint of Meas/Reg Station Equip-City Gate (	482,877	PA_GP_II	-	-	-	-	175,629	-	-	175,629
	Maintenance of Services	1,037,443	WEIGHTED	-	785,493	-	785,493	-	245,642	-	245,642
	Maintenance of Meters/House Regulators	832,745	WEIGHTED1	-	651,336	-	651,336	-	180,732	-	180,732
	Sub-total	***3,777,132***		***372,854***	***1,979,217***	-	***2,352,071***	***370,808***	***498,086***	-	***868,893***
	Total Distribution	***18,736,256***		***1,182,653***	***9,914,519***	-	***11,097,173***	***773,388***	***5,297,832***	-	***6,071,220***
	Customer Account										
	Supervision - Customer Assistance	98,925	CUST_ACCT	-	76,162	-	76,162	-	22,211	-	22,211
	Meter Reading Expenses	715,432	CUSTS	-	647,662	-	647,662	-	67,516	-	67,516
	Customer Records and Collection Exp	7,599,357	WEIGHTED	-	5,753,803	-	5,753,803	-	1,799,347	-	1,799,347
	Customer Records and Collection Exp	-	WEIGHTED	-	-	-	-	-	-	-	-
	-	-	0	-	-	-	-	-	-	-	-
	-	-	0	-	-	-	-	-	-	-	-
	Uncollectible Accounts	853,486	UNCOL	-	737,562	-	737,562	-	115,490	-	115,490
	Uncollectable Account - Increase	36,536	UNCOL	-	31,574	-	31,574	-	4,944	-	4,944
	Sub-total	***9,303,736***		-	***7,246,763***	-	***7,246,763***	-	***2,009,508***	-	***2,009,508***
	Customer Service & Information Expenses										
	Supervision	-	CUSTS	-	-	-	-	-	-	-	-
	Customer Assistance Expenses	202,610	CUSTS	-	183,418	-	183,418	-	19,121	-	19,121
	Sub-total	***202,610***		-	***183,418***	-	***183,418***	-	***19,121***	-	***19,121***
	Sales Expenses										
	New Business-Supervision	-	SALES	-	-	-	-	-	-	-	-
	New Business-Demon & Selling	1,134,815	SALES	-	758,176	-	758,176	-	376,639	-	376,639
	New Business-Advertising	102,057	SALES	-	68,185	-	68,185	-	33,872	-	33,872
	Sub-total	***1,236,872***		-	***826,361***	-	***826,361***	-	***410,511***	-	***410,511***
	Administrative and General Expenses										
	Adm & Gen Salaries	5,665,256	OMCUSTEXP	384,863	3,269,225	-	3,654,088	225,031	1,404,273	-	1,629,304
	Adm & Gen Office Supplies	3,592,135	OMCUSTEXP	244,027	2,072,898	-	2,316,925	142,684	890,399	-	1,033,083
	Adm & Gen Transferred	-	OMCUSTEXP	-	-	-	-	-	-	-	-
	Adm & Gen Outside Services	1,048,199	RB_PLT???_OR	196,712	501,346	-	698,058	97,751	141,580	-	239,331
	Adm & Gen Property Insurance	150,398	RB_PLT???_OR	28,225	71,934	-	100,159	14,026	20,314	-	34,340
	Adm & Gen Injuries & Damage	817,559	LA	40,403	473,985	-	514,388	26,384	224,065	-	250,448
	Adm & Gen Employee Pensions & Benefits	507,190	LA	25,065	294,047	-	319,112	16,368	139,003	-	155,371
	Franchise Requirements	654,529	OMCUSTEXP	44,465	377,706	-	422,171	25,999	162,241	-	188,240
	General Advertising Exp	192,721	OMCUSTEXP	13,092	111,213	-	124,305	7,655	47,771	-	55,426
	Misc. General Expenses	208,916	OMCUSTEXP	14,192	120,559	-	134,751	8,298	51,785	-	60,084
	Misc. General Expenses	198,674	OMCUSTEXP	13,497	114,648	-	128,145	7,892	49,246	-	57,138
	Rents	784,105	RB_PLTGEN_ORIG	147,151	375,031	-	522,181	73,123	105,909	-	179,032
	Maintenance of General Plant	-	RB_PLTGEN_ORIG	-	-	-	-	-	-	-	-
	Commission Fee Increase	19,081	OMCUSTEXP	1,296	11,011	-	12,307	758	4,730	-	5,488
	Sub-total	***13,838,765***		***1,152,987***	***7,793,603***	-	***8,946,589***	***645,968***	***3,241,316***	-	***3,887,284***
	TOTAL O & M EXPENSES	**45,240,637**		**3,266,826**	**25,995,773**	-	**29,262,600**	**1,881,940**	**10,993,743**	-	**12,875,683**

Exhibit No. 21
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Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
	Distribution Operation Expenses										
	Distrib Supervision & Engineering	2,691,872	LACA	751	13,372	-	14,123	-	12,701	-	12,701
	Distribution Load Dispatching	-	PK_AVG	-	-	-	-	-	-	-	-
	Compressor Station Fuel/Power	-	LACA	-	-	-	-	-	-	-	-
	Dist Oper Mains & Services Expenses	2,699,639	MAIN_SERV	3,614	892	-	4,506	-	760	-	760
	Dist Oper Meas & Reg Gen	129,611	PK_AVG	907	-	-	907	3,533	-	-	3,533
	Dist Oper Meas & Reg Ind	-	PA_GP_II	-	-	-	-	-	-	-	-
	Meter/House Regulator Expenses	226,375	WEIGHTED1	-	20	-	20	-	6	-	6
	Meter/House Regulator Expenses	(556,097)	WEIGHTED1	-	(50)	-	(50)	-	(16)	-	(16)
	Customer Installations Expenses	7,126,046	D_382_384_385	-	45,587	-	45,587	-	43,374	-	43,374
	Other Expenses	2,437,388	RB_PLT_DI_ORIG	2,918	1,883	-	4,801	1,559	1,713	-	3,272
	Rents	204,290	RB_PLT_DI_ORIG	245	158	-	402	131	144	-	274
	Sub-total	***14,959,124***		***8,433***	***61,863***	-	***70,296***	***5,223***	***58,681***	-	***63,904***
	Distribution Maintenance Expenses										
	Dist Main Supervision/Engineering	196,391	NADM	540	43	-	584	1,543	35	-	1,578
	Dist Maintenance of Mains	950,016	PDAY	2,424	24	-	2,448	-	8	-	8
	Dist Maintenance of Mains	79,382	PDAY	203	2	-	205	-	1	-	1
	Maint of Meas/Reg Station Equip-General	198,278	PK_AVG	1,387	-	-	1,387	5,405	-	-	5,405
	Maint of Meas/Reg Station Equip-City Gate (	482,877	PA_GP_II	5,833	-	-	5,833	22,729	-	-	22,729
	Maintenance of Services	1,037,443	WEIGHTED	-	693	-	693	-	605	-	605
	Maintenance of Meters/House Regulators	832,745	WEIGHTED1	-	75	-	75	-	24	-	24
	Sub-total	***3,777,132***		***10,387***	***837***	-	***11,223***	***29,677***	***672***	-	***30,349***
	Total Distribution	***18,736,256***		***18,820***	***62,699***	-	***81,519***	***34,900***	***59,354***	-	***94,254***
	Customer Account										
	Supervision - Customer Assistance	98,925	CUST_ACCT	-	61	-	61	-	53	-	53
	Meter Reading Expenses	715,432	CUSTS	-	38	-	38	-	13	-	13
	Customer Records and Collection Exp	7,599,357	WEIGHTED	-	5,074	-	5,074	-	4,433	-	4,433
	Customer Records and Collection Exp	-	WEIGHTED	-	-	-	-	-	-	-	-
	-	-	0	-	-	-	-	-	-	-	-
	-	-	0	-	-	-	-	-	-	-	-
	Uncollectible Accounts	853,486	UNCOL	-	65	-	65	-	22	-	22
	Uncollectable Account - Increase	36,536	UNCOL	-	3	-	3	-	1	-	1
	Sub-total	***9,303,736***		-	***5,240***	-	***5,240***	-	***4,521***	-	***4,521***
	Customer Service & Information Expenses										
	Supervision	-	CUSTS	-	-	-	-	-	-	-	-
	Customer Assistance Expenses	202,610	CUSTS	-	11	-	11	-	4	-	4
	Sub-total	***202,610***		-	***11***	-	***11***	-	***4***	-	***4***
	Sales Expenses										
	New Business-Supervision	-	SALES	-	-	-	-	-	-	-	-
	New Business-Demon & Selling	1,134,815	SALES	-	-	-	-	-	-	-	-
	New Business-Advertising	102,057	SALES	-	-	-	-	-	-	-	-
	Sub-total	***1,236,872***		-	-	-	-	-	-	-	-
	Administrative and General Expenses										
	Adm & Gen Salaries	5,665,256	OMCUSTEXP	5,076	12,369	-	17,445	6,354	11,629	-	17,984
	Adm & Gen Office Supplies	3,592,135	OMCUSTEXP	3,218	7,843	-	11,061	4,029	7,374	-	11,403
	Adm & Gen Transferred	-	OMCUSTEXP	-	-	-	-	-	-	-	-
	Adm & Gen Outside Services	1,048,199	RB_PLT???_OR	1,971	657	-	2,629	544	598	-	1,142
	Adm & Gen Property Insurance	150,398	RB_PLT???_OR	283	94	-	377	78	86	-	164
	Adm & Gen Injuries & Damage	817,559	LA	622	2,167	-	2,790	1,004	2,044	-	3,048
	Adm & Gen Employee Pensions & Benefits	507,190	LA	386	1,345	-	1,731	623	1,268	-	1,891
	Franchise Requirements	654,529	OMCUSTEXP	586	1,429	-	2,015	734	1,344	-	2,078
	General Advertising Exp	192,721	OMCUSTEXP	173	421	-	593	216	396	-	612
	Misc. General Expenses	208,916	OMCUSTEXP	187	456	-	643	234	429	-	663
	Misc. General Expenses	198,674	OMCUSTEXP	178	434	-	612	223	408	-	631
	Rents	784,105	RB_PLTGEN_ORIG	1,475	492	-	1,966	407	447	-	854
	Maintenance of General Plant	-	RB_PLTGEN_ORIG	-	-	-	-	-	-	-	-
	Commission Fee Increase	19,081	OMCUSTEXP	17	42	-	59	21	39	-	61
	Sub-total	***13,838,765***		***14,173***	***27,749***	-	***41,921***	***14,468***	***26,061***	-	***40,529***
	TOTAL O & M EXPENSES	**45,240,637**		**42,051**	**95,699**	-	**137,750**	**49,368**	**89,939**	-	**139,307**

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Exhibit No. 21
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Class Cost of Service Study
Account Detail

				Transport Service (Firm)			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**
	Distribution Operation Expenses						
	Distrib Supervision & Engineering	2,691,872	LACA	39,209	95,778	-	134,987
	Distribution Load Dispatching	-	PK_AVG	-	-	-	-
	Compressor Station Fuel/Power	-	LACA	-	-	-	-
	Dist Oper Mains & Services Expenses	2,699,639	MAIN_SERV	188,694	6,387	-	195,082
	Dist Oper Meas & Reg Gen	129,611	PK_AVG	43,320	-	-	43,320
	Dist Oper Meas & Reg Ind	-	PA_GP_II	-	-	-	-
	Meter/House Regulator Expenses	226,375	WEIGHTED1	-	157	-	157
	Meter/House Regulator Expenses	(556,097)	WEIGHTED1	-	(386)	-	(386)
	Customer Installations Expenses	7,126,046	D_382_384_385	-	326,504	-	326,504
	Other Expenses	2,437,388	RB_PLT_DI_ORIG	150,578	13,501	-	164,079
	Rents	204,290	RB_PLT_DI_ORIG	12,621	1,132	-	13,752
	Sub-total	***14,959,124***		***434,422***	***443,073***	**-**	***877,495***
	Distribution Maintenance Expenses						
	Dist Main Supervision/Engineering	196,391	NADM	26,442	314	-	26,756
	Dist Maintenance of Mains	950,016	PDAY	126,580	127	-	126,707
	Dist Maintenance of Mains	79,382	PDAY	10,577	11	-	10,587
	Maint of Meas/Reg Station Equip-General	198,278	PK_AVG	66,270	-	-	66,270
	Maint of Meas/Reg Station Equip-City Gate (	482,877	PA_GP_II	278,686	-	-	278,686
	Maintenance of Services	1,037,443	WEIGHTED	-	5,010	-	5,010
	Maintenance of Meters/House Regulators	832,745	WEIGHTED1	-	579	-	579
	Sub-total	***3,777,132***		***508,555***	***6,040***	**-**	***514,595***
	Total Distribution	***18,736,256***		***942,977***	***449,113***	**-**	***1,392,090***
	Customer Account						
	Supervision - Customer Assistance	98,925	CUST_ACCT	-	439	-	439
	Meter Reading Expenses	715,432	CUSTS	-	203	-	203
	Customer Records and Collection Exp	7,599,357	WEIGHTED	-	36,700	-	36,700
	Customer Records and Collection Exp	-	WEIGHTED	-	-	-	-
	-	-	0	-	-	-	-
	-	-	0	-	-	-	-
	Uncollectible Accounts	853,486	UNCOL	-	347	-	347
	Uncollectable Account - Increase	36,536	UNCOL	-	15	-	15
	Sub-total	***9,303,736***		**-**	***37,703***	**-**	***37,703***
	Customer Service & Information Expenses						
	Supervision	-	CUSTS	-	-	-	-
	Customer Assistance Expenses	202,610	CUSTS	-	57	-	57
	Sub-total	***202,610***		**-**	***57***	**-**	***57***
	Sales Expenses						
	New Business-Supervision	-	SALES	-	-	-	-
	New Business-Demon & Selling	1,134,815	SALES	-	-	-	-
	New Business-Advertising	102,057	SALES	-	-	-	-
	Sub-total	***1,236,872***		**-**	**-**	**-**	**-**
	Administrative and General Expenses						
	Adm & Gen Salaries	5,665,256	OMCUSTEXP	257,805	88,631	-	346,436
	Adm & Gen Office Supplies	3,592,135	OMCUSTEXP	163,465	56,198	-	219,663
	Adm & Gen Transferred	-	OMCUSTEXP	-	-	-	-
	Adm & Gen Outside Services	1,048,199	RB_PLT???_OR	102,327	4,713	-	107,040
	Adm & Gen Property Insurance	150,398	RB_PLT???_OR	14,682	676	-	15,358
	Adm & Gen Injuries & Damage	817,559	LA	31,355	15,530	-	46,885
	Adm & Gen Employee Pensions & Benefits	507,190	LA	19,452	9,635	-	29,086
	Franchise Requirements	654,529	OMCUSTEXP	29,785	10,240	-	40,025
	General Advertising Exp	192,721	OMCUSTEXP	8,770	3,015	-	11,785
	Misc. General Expenses	208,916	OMCUSTEXP	9,507	3,268	-	12,775
	Misc. General Expenses	198,674	OMCUSTEXP	9,041	3,108	-	12,149
	Rents	784,105	RB_PLTGEN_ORIG	76,546	3,526	-	80,071
	Maintenance of General Plant	-	RB_PLTGEN_ORIG	-	-	-	-
	Commission Fee Increase	19,081	OMCUSTEXP	868	299	-	1,167
	Sub-total	***13,838,765***		***723,603***	***198,838***	**-**	***922,441***
	TOTAL O & M EXPENSES	**45,240,637**		**2,139,585**	**685,712**	**-**	**2,825,297**

Class Cost of Service Study
Account Detail

No.	Account Description	Amount	Alloc. Factor	Residential Service CAP	Residential Service CUS	Residential Service COM	Residential Service TOTAL	General Service CAP	General Service CUS	General Service COM	General Service TOTAL
	Labor Expense (2015 Actuals)										
	Storage Operation Expenses										
	Operation Supervision/Engineering	-	0	-	-	-	-	-	-	-	-
	Operation Labor and Exp	344,964	PDAY	171,244	-	-	171,244	85,069	-	-	85,069
	Operation Fuel	-	0	-	-	-	-	-	-	-	-
	Operation Power	-	0	-	-	-	-	-	-	-	-
	Sub-total	***344,964***		***171,244***	**-**	**-**	***171,244***	***85,069***	**-**	**-**	***85,069***
	Storage Maintenance Expenses										
	Maintenance Supervision & Engineering	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Structures	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Gas Holders	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Purification Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Liquefaction Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Vaporizing Equipment	61,718	PDAY	30,637	-	-	30,637	15,220	-	-	15,220
	Maintenance of Compressor Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of M&R Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Other Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Sub-total	***61,718***		***30,637***	**-**	**-**	***30,637***	***15,220***	**-**	**-**	***15,220***
	Total Storage	***406,682***		***201,881***	**-**	**-**	***201,881***	***100,289***	**-**	**-**	***100,289***
	Transmission Operation Expenses										
	Operation Supervision & Engineering	-	PDAY	-	-	-	-	-	-	-	-
	System Control	-	PDAY	-	-	-	-	-	-	-	-
	Communication System Expenses	-	0	-	-	-	-	-	-	-	-
	Compressor Sta. Labor & Expenses	-	0	-	-	-	-	-	-	-	-
	Gas for Compressor Station Fuel	-	0	-	-	-	-	-	-	-	-
	Mains Expenses	-	PDAY	-	-	-	-	-	-	-	-
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission Maintenance Expenses										
	Maintenance of Mains	2,388	PDAY	1,186	-	-	1,186	589	-	-	589
	Maintenance Pipeline Integrity	17,601	PDAY	8,737	-	-	8,737	4,340	-	-	4,340
	Maintenance of Compressor Station Equipm	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Communication Equipment	183,504	PDAY	91,094	-	-	91,094	45,253	-	-	45,253
	Sub-total	***203,493***		***101,016***	**-**	**-**	***101,016***	***50,182***	**-**	**-**	***50,182***
	Total Transmission	***203,493***		***101,016***	**-**	**-**	***101,016***	***50,182***	**-**	**-**	***50,182***

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
Labor Expense (2015 Actuals)											
	Storage Operation Expenses										
	Operation Supervision/Engineering	-	0	-	-	-	-	-	-	-	-
	Operation Labor and Exp	344,964	PDAY	1,666	-	-	1,666	-	-	-	-
	Operation Fuel	-	0	-	-	-	-	-	-	-	-
	Operation Power	-	0	-	-	-	-	-	-	-	-
	Sub-total	***344,964***		***1,666***	**-**	**-**	***1,666***	**-**	**-**	**-**	**-**
	Storage Maintenance Expenses										
	Maintenance Supervision & Engineering	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Structures	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Gas Holders	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Purification Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Liquefaction Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Vaporizing Equipment	61,718	PDAY	298	-	-	298	-	-	-	-
	Maintenance of Compressor Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of M&R Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Other Equipment	-	PDAY	-	-	-	-	-	-	-	-
	Sub-total	***61,718***		***298***	**-**	**-**	***298***	**-**	**-**	**-**	**-**
	Total Storage	***406,682***		***1,964***	**-**	**-**	***1,964***	**-**	**-**	**-**	**-**
	Transmission Operation Expenses										
	Operation Supervision & Engineering	-	PDAY	-	-	-	-	-	-	-	-
	System Control	-	PDAY	-	-	-	-	-	-	-	-
	Communication System Expenses	-	0	-	-	-	-	-	-	-	-
	Compressor Sta. Labor & Expenses	-	0	-	-	-	-	-	-	-	-
	Gas for Compressor Station Fuel	-	0	-	-	-	-	-	-	-	-
	Mains Expenses	-	PDAY	-	-	-	-	-	-	-	-
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission Maintenance Expenses										
	Maintenance of Mains	2,388	PDAY	12	-	-	12	-	-	-	-
	Maintenance Pipeline Integrity	17,601	PDAY	85	-	-	85	-	-	-	-
	Maintenance of Compressor Station Equipm	-	PDAY	-	-	-	-	-	-	-	-
	Maintenance of Communication Equipment	183,504	PDAY	886	-	-	886	-	-	-	-
	Sub-total	***203,493***		***983***	**-**	**-**	***983***	**-**	**-**	**-**	**-**
	Total Transmission	***203,493***		***983***	**-**	**-**	***983***	**-**	**-**	**-**	**-**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

No.	Account Description	Amount	Alloc. Factor	Transport Service (Firm)			
				CAP	CUS	COM	TOTAL
Labor Expense (2015 Actuals)							
	Storage Operation Expenses						
	Operation Supervision/Engineering	-	0	-	-	-	-
	Operation Labor and Exp	344,964	PDAY	86,985	-	-	86,985
	Operation Fuel	-	0	-	-	-	-
	Operation Power	-	0	-	-	-	-
	Sub-total	***344,964***		***86,985***	**-**	**-**	***86,985***
	Storage Maintenance Expenses						
	Maintenance Supervision & Engineering	-	PDAY	-	-	-	-
	Maintenance of Structures	-	PDAY	-	-	-	-
	Maintenance of Gas Holders	-	PDAY	-	-	-	-
	Maintenance of Purification Equipment	-	PDAY	-	-	-	-
	Maintenance of Liquefaction Equipment	-	PDAY	-	-	-	-
	Maintenance of Vaporizing Equipment	61,718	PDAY	15,563	-	-	15,563
	Maintenance of Compressor Equipment	-	PDAY	-	-	-	-
	Maintenance of M&R Equipment	-	PDAY	-	-	-	-
	Maintenance of Other Equipment	-	PDAY	-	-	-	-
	Sub-total	***61,718***		***15,563***	**-**	**-**	***15,563***
	Total Storage	***406,682***		***102,548***	**-**	**-**	***102,548***
	Transmission Operation Expenses						
	Operation Supervision & Engineering	-	PDAY	-	-	-	-
	System Control	-	PDAY	-	-	-	-
	Communication System Expenses	-	0	-	-	-	-
	Compressor Sta. Labor & Expenses	-	0	-	-	-	-
	Gas for Compressor Station Fuel	-	0	-	-	-	-
	Mains Expenses	-	PDAY	-	-	-	-
	Sub-total	**-**		**-**	**-**	**-**	**-**
	Transmission Maintenance Expenses						
	Maintenance of Mains	2,388	PDAY	602	-	-	602
	Maintenance Pipeline Integrity	17,601	PDAY	4,438	-	-	4,438
	Maintenance of Compressor Station Equipm	-	PDAY	-	-	-	-
	Maintenance of Communication Equipment	183,504	PDAY	46,272	-	-	46,272
	Sub-total	***203,493***		***51,312***	**-**	**-**	***51,312***
	Total Transmission	***203,493***		***51,312***	**-**	**-**	***51,312***

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

No.	Account Description	Amount	Alloc. Factor	Residential Service				General Service			
				CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
	Distribution Operation Expenses										
	Distrib Supervision & Engineering	1,995,398	LACA	57,218	1,061,376	-	1,118,593	28,424	728,436	-	756,860
	Distribution Load Dispatching	-	PK_AVG	-	-	-	-	-	-	-	-
	Compressor Station Fuel/Power	-	LACA	-	-	-	-	-	-	-	-
	Dist Oper Mains & Services Expenses	1,611,161	MAIN_SERV	221,698	940,783	-	1,162,481	110,133	218,978	-	329,111
	Dist Oper Meas & Reg Gen	-	PK_AVG	-	-	-	-	-	-	-	-
	Dist Oper Meas & Reg Ind	-	PA_GP_II	-	-	-	-	-	-	-	-
	Meter/House Regulator Expenses	202,693	WEIGHTED1	-	158,538	-	158,538	-	43,991	-	43,991
	Meter/House Regulator Expenses	-	WEIGHTED1	-	-	-	-	-	-	-	-
	Customer Installations Expenses	5,917,585	D_382_384_385	-	3,013,123	-	3,013,123	-	2,559,453	-	2,559,453
	Other Expenses	1,617,836	RB_PLT_DI_ORIG	187,760	953,272	-	1,141,033	93,332	269,204	-	362,536
	Rents	-	RB_PLT_DI_ORIG	-	-	-	-	-	-	-	-
	Sub-total	***11,344,673***		***466,677***	***6,127,091***	-	***6,593,767***	***231,889***	***3,820,062***	-	***4,051,951***
	Distribution Maintenance Expenses										
	Dist Main Supervision/Engineering	177,609	NADM	17,532	93,067	-	110,600	17,436	23,421	-	40,857
	Dist Maintenance of Mains	502,000	PDAY	131,677	214,318	-	345,994	65,413	22,342	-	87,755
	Dist Maintenance of Mains	64,436	PDAY	16,902	27,509	-	44,411	8,396	2,868	-	11,264
	Maint of Meas/Reg Station Equip-General	120,906	PK_AVG	50,888	-	-	50,888	25,467	-	-	25,467
	Maint of Meas/Reg Station Equip-City Gate (	399,141	PA_GP_II	-	-	-	-	145,173	-	-	145,173
	Maintenance of Services	357,288	WEIGHTED	-	270,518	-	270,518	-	84,597	-	84,597
	Maintenance of Meters/House Regulators	353,914	WEIGHTED1	-	276,816	-	276,816	-	76,811	-	76,811
	Sub-total	***1,975,294***		***216,999***	***882,229***	-	***1,099,227***	***261,885***	***210,039***	-	***471,924***
	Total Distribution	***13,319,967***		***683,675***	***7,009,319***	-	***7,692,995***	***493,775***	***4,030,100***	-	***4,523,875***
	Customer Account										
	Supervision - Customer Assistance	101,161	EXP_CUST_ACCTA	-	78,266	-	78,266	-	22,344	-	22,344
	Meter Reading Expenses	553,077	CUSTS	-	500,687	-	500,687	-	52,195	-	52,195
	Customer Records and Collection Exp	4,401,233	WEIGHTED	-	3,332,365	-	3,332,365	-	1,042,107	-	1,042,107
	Customer Records and Collection Exp	-	WEIGHTED	-	-	-	-	-	-	-	-
	Uncollectible Accounts	-	UNCOL	-	-	-	-	-	-	-	-
	Sub-total	***5,055,471***		-	***3,911,317***	-	***3,911,317***	-	***1,116,646***	-	***1,116,646***
	Sub-total	-		-	-	-	-	-	-	-	-
	Sales Expenses										
	New Business-Supervision	-	0	-	-	-	-	-	-	-	-
	New Business-Demon & Selling	977,913	SALES	-	653,349	-	653,349	-	324,564	-	324,564
	New Business-Advertising	-	0	-	-	-	-	-	-	-	-
	Sub-total	***977,913***		-	***653,349***	-	***653,349***	-	***324,564***	-	***324,564***
	TOTAL 2015 O & M LABOR EXP.	**19,963,525**		**986,573**	**11,573,986**	-	**12,560,559**	**644,245**	**5,471,310**	-	**6,115,555**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL	CAP	CUS	COM	TOTAL
	Distribution Operation Expenses										
	Distrib Supervision & Engineering	1,995,398	LACA	557	9,912	-	10,469	-	9,414	-	9,414
	Distribution Load Dispatching	-	PK_AVG	-	-	-	-	-	-	-	-
	Compressor Station Fuel/Power	-	LACA	-	-	-	-	-	-	-	-
	Dist Oper Mains & Services Expenses	1,611,161	MAIN_SERV	2,157	533	-	2,689	-	454	-	454
	Dist Oper Meas & Reg Gen	-	PK_AVG	-	-	-	-	-	-	-	-
	Dist Oper Meas & Reg Ind	-	PA_GP_II	-	-	-	-	-	-	-	-
	Meter/House Regulator Expenses	202,693	WEIGHTED1	-	18	-	18	-	6	-	6
	Meter/House Regulator Expenses	-	WEIGHTED1	-	-	-	-	-	-	-	-
	Customer Installations Expenses	5,917,585	D_382_384_385	-	37,856	-	37,856	-	36,018	-	36,018
	Other Expenses	1,617,836	RB_PLT_DI_ORIG	1,937	1,250	-	3,187	1,035	1,137	-	2,172
	Rents	-	RB_PLT_DI_ORIG	-	-	-	-	-	-	-	-
	Sub-total	***11,344,673***		***4,650***	***49,569***	**-**	***54,219***	***1,035***	***47,029***	**-**	***48,064***
	Distribution Maintenance Expenses										
	Dist Main Supervision/Engineering	177,609	NADM	488	39	-	528	1,395	32	-	1,427
	Dist Maintenance of Mains	502,000	PDAY	1,281	13	-	1,293	-	4	-	4
	Dist Maintenance of Mains	64,436	PDAY	164	2	-	166	-	1	-	1
	Maint of Meas/Reg Station Equip-General	120,906	PK_AVG	846	-	-	846	3,296	-	-	3,296
	Maint of Meas/Reg Station Equip-City Gate (	399,141	PA_GP_II	4,821	-	-	4,821	18,788	-	-	18,788
	Maintenance of Services	357,288	WEIGHTED	-	239	-	239	-	208	-	208
	Maintenance of Meters/House Regulators	353,914	WEIGHTED1	-	32	-	32	-	10	-	10
	Sub-total	***1,975,294***		***7,601***	***324***	**-**	***7,925***	***23,479***	***255***	**-**	***23,734***
	Total Distribution	***13,319,967***		***12,251***	***49,893***	**-**	***62,144***	***24,514***	***47,284***	**-**	***71,797***
	Customer Account										
	Supervision - Customer Assistance	101,161	EXP_CUST_ACCTA	-	61	-	61	-	53	-	53
	Meter Reading Expenses	553,077	CUSTS	-	29	-	29	-	10	-	10
	Customer Records and Collection Exp	4,401,233	WEIGHTED	-	2,938	-	2,938	-	2,567	-	2,567
	Customer Records and Collection Exp	-	WEIGHTED	-	-	-	-	-	-	-	-
	Uncollectible Accounts	-	UNCOL	-	-	-	-	-	-	-	-
	Sub-total	***5,055,471***		**-**	***3,028***	**-**	***3,028***	**-**	***2,630***	**-**	***2,630***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Sales Expenses										
	New Business-Supervision	-	0	-	-	-	-	-	-	-	-
	New Business-Demon & Selling	977,913	SALES	-	-	-	-	-	-	-	-
	New Business-Advertising	-	0	-	-	-	-	-	-	-	-
	Sub-total	***977,913***		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TOTAL 2015 O & M LABOR EXP.	**19,963,525**		**15,197**	**52,921**	**-**	**68,118**	**24,514**	**49,913**	**-**	**74,427**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Transport Service (Firm)			
No.	Account Description	Amount	Alloc. Factor	CAP	CUS	COM	TOTAL
	Distribution Operation Expenses						
	Distrib Supervision & Engineering	1,995,398	LACA	29,064	70,997	-	100,061
	Distribution Load Dispatching	-	PK_AVG	-	-	-	-
	Compressor Station Fuel/Power	-	LACA	-	-	-	-
	Dist Oper Mains & Services Expenses	1,611,161	MAIN_SERV	112,614	3,812	-	116,426
	Dist Oper Meas & Reg Gen	-	PK_AVG	-	-	-	-
	Dist Oper Meas & Reg Ind	-	PA_GP_II	-	-	-	-
	Meter/House Regulator Expenses	202,693	WEIGHTED1	-	141	-	141
	Meter/House Regulator Expenses	-	WEIGHTED1	-	-	-	-
	Customer Installations Expenses	5,917,585	D_382_384_385	-	271,134	-	271,134
	Other Expenses	1,617,836	RB_PLT_DI_ORIG	99,948	8,961	-	108,909
	Rents	-	RB_PLT_DI_ORIG	-	-	-	-
	Sub-total	***11,344,673***		***241,626***	***355,045***	**-**	***596,671***
	Distribution Maintenance Expenses						
	Dist Main Supervision/Engineering	177,609	NADM	23,913	284	-	24,197
	Dist Maintenance of Mains	502,000	PDAY	66,886	67	-	66,954
	Dist Maintenance of Mains	64,436	PDAY	8,585	9	-	8,594
	Maint of Meas/Reg Station Equip-General	120,906	PK_AVG	40,410	-	-	40,410
	Maint of Meas/Reg Station Equip-City Gate (	399,141	PA_GP_II	230,359	-	-	230,359
	Maintenance of Services	357,288	WEIGHTED	-	1,725	-	1,725
	Maintenance of Meters/House Regulators	353,914	WEIGHTED1	-	246	-	246
	Sub-total	***1,975,294***		***370,154***	***2,331***	**-**	***372,485***
	Total Distribution	***13,319,967***		***611,780***	***357,376***	**-**	***969,157***
	Customer Account						
	Supervision - Customer Assistance	101,161	EXP_CUST_ACCTA	-	437	-	437
	Meter Reading Expenses	553,077	CUSTS	-	157	-	157
	Customer Records and Collection Exp	4,401,233	WEIGHTED	-	21,255	-	21,255
	Customer Records and Collection Exp	-	WEIGHTED	-	-	-	-
	Uncollectible Accounts	-	UNCOL	-	-	-	-
	Sub-total	***5,055,471***		**-**	***21,849***	**-**	***21,849***
	Sub-total	**-**		**-**	**-**	**-**	**-**
	Sales Expenses						
	New Business-Supervision	-	0	-	-	-	-
	New Business-Demon & Selling	977,913	SALES	-	-	-	-
	New Business-Advertising	-	0	-	-	-	-
	Sub-total	***977,913***		**-**	**-**	**-**	**-**
	TOTAL 2015 O & M LABOR EXP.	**19,963,525**		**765,640**	**379,225**	**-**	**1,144,866**

Class Cost of Service Study
Account Detail

				Residential Service				General Service			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**	**CAP**	**CUS**	**COM**	**TOTAL**
Depreciation Expense											
	Intangible Plant										
	Amort Exp-Intangible Plant	3,125,359	RB_PLTINT	586,491	1,494,886	-	2,081,376	291,443	422,160	-	713,603
	Sub-total	***3,125,359***		***586,491***	***1,494,886***	-	***2,081,376***	***291,443***	***422,160***	-	***713,603***
	Sub-total	-		-	-	-	-	-	-	-	-
	Storage Plant										
	Deprec Exp-Storage Plant	682,914	RB_PLT_ST	339,006	-	-	339,006	168,408	-	-	168,408
	Sub-total	***682,914***		***339,006***	-	-	***339,006***	***168,408***	-	-	***168,408***
	Transmission Plant										
	Deprec Exp-Transmission Plant	1,977,413	RB_PLT_TR	981,611	-	-	981,611	487,634	-	-	487,634
	Sub-total	***1,977,413***		***981,611***	-	-	***981,611***	***487,634***	-	-	***487,634***
	Distribution Plant										
	Deprec Exp-Distribution Plant	12,612,078	RB_PLT_DI	1,463,714	7,431,372	-	8,895,086	727,587	2,098,618	-	2,826,205
	Sub-total	***12,612,078***		***1,463,714***	***7,431,372***	-	***8,895,086***	***727,587***	***2,098,618***	-	***2,826,205***
	General Plant Plant										
	Deprec Exp-General Plant	3,309,349	RB_PLTGEN	621,055	1,582,833	-	2,203,888	308,619	446,992	-	755,611
	Sub-total	***3,309,349***		***621,055***	***1,582,833***	-	***2,203,888***	***308,619***	***446,992***	-	***755,611***
	TOTAL DEPRECIATION EXPENSES	**21,707,112**		**3,991,878**	**10,509,090**	-	**14,500,968**	**1,983,690**	**2,967,770**	-	**4,951,460**
Interest and Other Expenses											
	Sub-total	-		-	-	-	-	-	-	-	-
	TOTAL INTEREST AND OTHER EXPENSE	-		-	-	-	-	-	-	-	-
Taxes Other Than Income Taxes											
	Payroll Taxes	1,641,942	LA	81,143	951,927	-	1,033,070	52,987	449,999	-	502,987
	Property Taxes	3,198,871	PROPTX	602,162	1,527,143	-	2,129,305	299,230	431,265	-	730,495
	Ad Valorem Taxes	-	RB_PLT	-	-	-	-	-	-	-	-
	Frchise Rev & Exp	-	RB	-	-	-	-	-	-	-	-
	Administrative Taxes Transfrd	-	RB	-	-	-	-	-	-	-	-
	Sub-total	***4,840,813***		***683,304***	***2,479,070***	-	***3,162,375***	***352,217***	***881,264***	-	***1,233,481***
		-									
	TOTAL TAXES OTHER THAN INCOME TA	**4,840,813**		**683,304**	**2,479,070**	-	**3,162,375**	**352,217**	**881,264**	-	**1,233,481**
Cost of Gas											
	Cost Of Gas - Fixed Cost Of Gas	62,387,552	FCOG	-	-	41,697,617	41,697,617	-	-	20,040,806	20,040,806
	Cost Of Gas - Commodity Cog	106,435,107	VCOG	-	-	69,499,313	69,499,313	-	-	35,271,794	35,271,794
	TOTAL	**168,822,659**		-	-	**111,196,930**	**111,196,930**	-	-	**55,312,600**	**55,312,600**
Income Taxes - Pro Forma											
	Income Taxes Pro Forma	2,750,218	RB	533,931	1,285,238	-	1,819,169	265,323	365,619	-	630,942
	TOTAL	**2,750,218**		**533,931**	**1,285,238**	-	**1,819,169**	**265,323**	**365,619**	-	**630,942**
Income Taxes - Proposed											
	Income Taxes Proposed	6,775,042	RB	1,315,317	3,166,127	-	4,481,444	653,612	900,686	-	1,554,298
	TOTAL	**6,775,042**		**1,315,317**	**3,166,127**	-	**4,481,444**	**653,612**	**900,686**	-	**1,554,298**
Operating Revenues											
	Revenue from Gas Sales	251,900,147	RS_REV	-	-	164,429,181	164,429,181	-	-	74,843,065	74,843,065
	Other Revenues	2,900,363	REV_OTHER	-	-	2,048,327	2,048,327	-	-	650,808	650,808
	Sub-total	***254,800,510***		-	-	***166,477,508***	***166,477,508***	-	-	***75,493,873***	***75,493,873***
	TOTAL	**254,800,510**		-	-	**166,477,508**	**166,477,508**	-	-	**75,493,873**	**75,493,873**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Large Volume				Transport Service (Interruptible)			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**	**CAP**	**CUS**	**COM**	**TOTAL**
Depreciation Expense											
	Intangible Plant										
	Amort Exp-Intangible Plant	3,125,359	RB_PLTINT	5,878	1,960	-	7,838	1,623	1,782	-	3,405
	Sub-total	***3,125,359***		***5,878***	***1,960***	**-**	***7,838***	***1,623***	***1,782***	**-**	***3,405***
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Storage Plant										
	Deprec Exp-Storage Plant	682,914	RB_PLT_ST	3,298	-	-	3,298	-	-	-	-
	Sub-total	***682,914***		***3,298***	**-**	**-**	***3,298***	**-**	**-**	**-**	**-**
	Transmission Plant										
	Deprec Exp-Transmission Plant	1,977,413	RB_PLT_TR	9,549	-	-	9,549	-	-	-	-
	Sub-total	***1,977,413***		***9,549***	**-**	**-**	***9,549***	**-**	**-**	**-**	**-**
	Distribution Plant										
	Deprec Exp-Distribution Plant	12,612,078	RB_PLT_DI	15,097	9,744	-	24,841	8,068	8,861	-	16,930
	Sub-total	***12,612,078***		***15,097***	***9,744***	**-**	***24,841***	***8,068***	***8,861***	**-**	***16,930***
	General Plant Plant										
	Deprec Exp-General Plant	3,309,349	RB_PLTGEN	6,224	2,075	-	8,300	1,719	1,887	-	3,606
	Sub-total	***3,309,349***		***6,224***	***2,075***	**-**	***8,300***	***1,719***	***1,887***	**-**	***3,606***
	TOTAL DEPRECIATION EXPENSES	**21,707,112**		**40,045**	**13,780**	**-**	**53,825**	**11,410**	**12,531**	**-**	**23,941**
Interest and Other Expenses											
	Sub-total	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	TOTAL INTEREST AND OTHER EXPENSE	**-**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Taxes Other Than Income Taxes											
	Payroll Taxes	1,641,942	LA	1,250	4,353	-	5,603	2,016	4,105	-	6,121
	Property Taxes	3,198,871	PROPTX	6,034	2,002	-	8,036	1,658	1,821	-	3,479
	Ad Valorem Taxes	-	RB_PLT	-	-	-	-	-	-	-	-
	Frchise Rev & Exp	-	RB	-	-	-	-	-	-	-	-
	Administrative Taxes Transfrd	-	RB	-	-	-	-	-	-	-	-
	Sub-total	***4,840,813***		***7,284***	***6,355***	**-**	***13,639***	***3,674***	***5,926***	**-**	***9,600***
		-									
	TOTAL TAXES OTHER THAN INCOME TA	**4,840,813**		**7,284**	**6,355**	**-**	**13,639**	**3,674**	**5,926**	**-**	**9,600**
Cost of Gas											
	Cost Of Gas - Fixed Cost Of Gas	62,387,552	FCOG	-	-	649,129	649,129	-	-	-	-
	Cost Of Gas - Commodity Cog	106,435,107	VCOG	-	-	2,074,834	2,074,834	-	-	(13,435)	(13,435)
	TOTAL	**168,822,659**		**-**	**-**	**2,723,963**	**2,723,963**	**-**	**-**	**(13,435)**	**(13,435)**
Income Taxes - Pro Forma											
	Income Taxes Pro Forma	2,750,218	RB	5,349	1,725	-	7,074	1,454	1,571	-	3,024
	TOTAL	**2,750,218**		**5,349**	**1,725**	**-**	**7,074**	**1,454**	**1,571**	**-**	**3,024**
Income Taxes - Proposed											
	Income Taxes Proposed	6,775,042	RB	13,176	4,250	-	17,426	3,581	3,869	-	7,451
	TOTAL	**6,775,042**		**13,176**	**4,250**	**-**	**17,426**	**3,581**	**3,869**	**-**	**7,451**
Operating Revenues											
	Revenue from Gas Sales	251,900,147	RS_REV	-	-	3,127,950	3,127,950	-	-	714,239	714,239
	Other Revenues	2,900,363	REV_OTHER	-	-	5,720	5,720	-	-	-	-
	Sub-total	***254,800,510***		**-**	**-**	***3,133,670***	***3,133,670***	**-**	**-**	***714,239***	***714,239***
	TOTAL	**254,800,510**		**-**	**-**	**3,133,670**	**3,133,670**	**-**	**-**	**714,239**	**714,239**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

Class Cost of Service Study
Account Detail

				Transport Service (Firm)			
No.	**Account Description**	**Amount**	**Alloc. Factor**	**CAP**	**CUS**	**COM**	**TOTAL**
Depreciation Expense							
	Intangible Plant						
	Amort Exp-Intangible Plant	3,125,359	RB_PLTINT	305,084	14,053	-	319,137
	Sub-total	***3,125,359***		***305,084***	***14,053***	**-**	***319,137***
	Sub-total	**-**		**-**	**-**	**-**	**-**
	Storage Plant						
	Deprec Exp-Storage Plant	682,914	RB_PLT_ST	172,202	-	-	172,202
	Sub-total	***682,914***		***172,202***	**-**	**-**	***172,202***
	Transmission Plant						
	Deprec Exp-Transmission Plant	1,977,413	RB_PLT_TR	498,619	-	-	498,619
	Sub-total	***1,977,413***		***498,619***	**-**	**-**	***498,619***
	Distribution Plant						
	Deprec Exp-Distribution Plant	12,612,078	RB_PLT_DI	779,156	69,860	-	849,016
	Sub-total	***12,612,078***		***779,156***	***69,860***	**-**	***849,016***
	General Plant Plant						
	Deprec Exp-General Plant	3,309,349	RB_PLTGEN	323,064	14,880	-	337,944
	Sub-total	***3,309,349***		***323,064***	***14,880***	**-**	***337,944***
	TOTAL DEPRECIATION EXPENSES	**21,707,112**		**2,078,126**	**98,792**	**-**	**2,176,918**
Interest and Other Expenses							
	Sub-total	**-**		**-**	**-**	**-**	**-**
	TOTAL INTEREST AND OTHER EXPENSE	**-**		**-**	**-**	**-**	**-**
Taxes Other Than Income Taxes							
	Payroll Taxes	1,641,942	LA	62,972	31,190	-	94,162
	Property Taxes	3,198,871	PROPTX	313,200	14,356	-	327,556
	Ad Valorem Taxes	-	RB_PLT	-	-	-	-
	Frchise Rev & Exp	-	RB	-	-	-	-
	Administrative Taxes Transfrd	-	RB	-	-	-	-
	Sub-total	***4,840,813***		***376,171***	***45,546***	**-**	***421,718***
		-					
	TOTAL TAXES OTHER THAN INCOME TA	**4,840,813**		**376,171**	**45,546**	**-**	**421,718**
Cost of Gas							
	Cost Of Gas - Fixed Cost Of Gas	62,387,552	FCOG	-	-	-	-
	Cost Of Gas - Commodity Cog	106,435,107	VCOG	-	-	(397,399)	(397,399)
	TOTAL	**168,822,659**		**-**	**-**	**(397,399)**	**(397,399)**
Income Taxes - Pro Forma							
	Income Taxes Pro Forma	2,750,218	RB	277,639	12,369	-	290,008
	TOTAL	**2,750,218**		**277,639**	**12,369**	**-**	**290,008**
Income Taxes - Proposed							
	Income Taxes Proposed	6,775,042	RB	683,951	30,472	-	714,423
	TOTAL	**6,775,042**		**683,951**	**30,472**	**-**	**714,423**
Operating Revenues							
	Revenue from Gas Sales	251,900,147	RS_REV	-	-	8,785,712	8,785,712
	Other Revenues	2,900,363	REV_OTHER	-	-	195,508	195,508
	Sub-total	***254,800,510***		**-**	**-**	***8,981,220***	***8,981,220***
	TOTAL	**254,800,510**		**-**	**-**	**8,981,220**	**8,981,220**

Exhibit No. 21
Case No. INT-G-16-02
L. Blattner, IGC

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 22

Class Cost of Service Study
Account Inputs

RATE BASE

Plant in Service

Acct. No.	Account Description		December 31, 2016	December 31, 2016	Function	Classifier	CAP	CUS	COM	Internal
	Intangible Plant									
1010.3010	Organization	2,506	2,506	2,506	F DISTR	CUS		WEIGHTED		
1010.3020	Franchises & Consents	429,487	429,487	429,487						RB PLT ?? OR
1010.3030	Misc. Intangible Plant	40,650,532	40,650,532	40,650,532						RB PLT ?? OR
	Sub-total	***41,082,525***	***41,082,525***	***41,082,525***						
	Storage Plant									
1010.3600	Land & Land Rights LNG	292,588	292,588	292,588	F STORG	CAP	PDAY			
1010.3610	Structures & Improvements - LNG	4,698,209	4,698,209	4,698,209	F STORG	CAP	PDAY			
1010.3620	Gas Holders - LNG	3,698,508	3,698,508	3,698,508	F STORG	CAP	PDAY			
1010.3630.0	Purification Equip - LNG	13,885,945	13,885,945	13,885,945	F STORG	CAP	PDAY			
	Sub-total	***22,575,250***	***22,575,250***	***22,575,250***						
	Transmission Plant									
1010.3651	Land & Land Rights	789,682	789,682	789,682	F TRANS	CAP	PDAY			
1010.3660	Structures & Improvements - Transmission	77,152	77,152	77,152	F TRANS	CAP	PDAY			
1010.3670	Trans Mains	68,666,886	68,666,886	68,666,886	F TRANS	CAP	PDAY			
1010.3680	Trans Compressor Sta Equip	1,730,359	1,730,359	1,730,359	F TRANS	CAP	PDAY			
1010.3700	Trans Communication Equip	714,440	714,440	714,440	F TRANS	CAP	PDAY			
	Sub-total	***71,978,519***	***71,978,519***	***71,978,519***						
	Distribution Plant									
1010.3740	Dist Land & Land Rights	637,754	637,754	637,754						D LLR
1010.3750	Dist Structures & Improvements	18,864	18,864	18,864	F DISTR	CAP	PK AVG			
1010.3760	Dist Mains	164,694,644	164,694,644	164,694,644	F DISTR	MAINS	PDAY	CUSTS		
1010.3780	Dist Meas & Reg Sta Equip - Gen	9,529,795	9,529,795	9,529,795	F DISTR	CAP	PK AVG			
1010.3800	Dist Services	149,255,628	149,255,628	149,255,628	F DISTR	CUS		WEIGHTED		
1010.3810	Dist Meters	44,853,911	44,853,911	44,853,911	F_DISTR	CUS		WEIGHTED1		
1010.3820	Dist Meter Installations	13,955,058	13,955,058	13,955,058	F DISTR	CUS		WEIGHTED1		
1010.3830	Dist House Regulators	6,410,602	6,410,602	6,410,602	F DISTR	CUS		WEIGHTED1		
1010.3840	Dist House Regulator Install	7,047,749	7,047,749	7,047,749	F DISTR	CUS		WEIGHTED1		
1010.3850	Dist Ind Reg Sta	11,259,697	11,259,697	11,259,697	F DISTR	CUS		WEIGHTED2		
	Sub-total	***407,663,702***	***407,663,702***	***407,663,702***						
	General Plant									
1010.3890	Gen Land & Land Rights	2,991,271	2,991,271	2,991,271						RB PLT ?? OR
1010.3900	Gen Struct & Imp	19,567,163	19,567,163	19,567,163						RB PLT ?? OR
1010.3910	Gen Office Furn & Imp	9,824,942	9,824,942	9,824,942						RB PLT ?? OR
1010.3920	Gen Trans Equip	9,122,889	9,122,889	9,122,889						RB PLT ?? OR
1010.3930	Gen Stores Equip	4,407	4,407	4,407						RB PLT ?? OR
1010.3940	Gen Tools Shop & Gar Equip	5,207,323	5,207,323	5,207,323						RB PLT ?? OR
1010.3950	Gen Laboratory Equip	-	-	-						RB PLT ?? OR
1010.3960	Gen Power Oper Equip	1,457,918	1,457,918	1,457,918						RB PLT ?? OR
1010.3970	Gen Communications Equip	4,589,648	4,589,648	4,589,648						RB PLT ?? OR
1010.3980	Gen Misc Equip	-	-	-						RB PLT ?? OR
	Sub-total	***52,765,561***	***52,765,561***	***52,765,561***						
	TOTAL PLANT-IN-SERVICE	**596,065,557**	**596,065,557**	**596,065,557**						

Accumulated Reserve for Depreciation

Acct. No.	Account Description		December 31, 2016	December 31, 2016	Function	Classifier	CAP	CUS	COM	Internal
	Intangible Plant									
1112.0000	Amort of Intangible Plant	(4,124,482)	(4,124,482)	(4,124,482)						RB PLTINT OR
	Sub-total	***(4,124,482)***	***(4,124,482)***	***(4,124,482)***						
	Storage Plant									
1080.0001	Prov For Depr-Stor Other Plant	(11,407,763)	(11,407,763)	(11,407,763)						RB PLT ST OR
	Sub-total	***(11,407,763)***	***(11,407,763)***	***(11,407,763)***						
	Transmission Plant									
1080.0002	Prov For Depr-Trans Plant	(41,291,008)	(41,291,008)	(41,291,008)						RB PLT TR ORIG
	Sub-total	***(41,291,008)***	***(41,291,008)***	***(41,291,008)***						
	Distribution Plant									
1080.0003	Prov For Depr-Dist Plant	(229,245,708)	(229,245,708)	(229,245,708)						RB PLT DI ORIG
	Sub-total	***(229,245,708)***	***(229,245,708)***	***(229,245,708)***						
	General Plant									
1080.0004	Prov For Depr-Gen Plant	(22,381,886)	(22,381,886)	(22,381,886)						RB PLTGEN ORIG
1080.1000	Prov For Depr-Plant Adj	-	-	-						RB PLT??? ORIG
	Sub-total	***(22,381,886)***	***(22,381,886)***	***(22,381,886)***						
	TOTAL DEPRECIATION ACCRUAL	**(308,450,847)**	**(308,450,847)**	**(308,450,847)**						
	NET PLANT	**287,614,710**	**287,614,710**	**287,614,710**						

Rate Base Adjustments

Acct. No.	Account Description		December 31, 2016	December 31, 2016	Function	Classifier	CAP	CUS	COM	Internal
	Other Rate Base Adjustments									
1010.0000	Gas Plant Adjustment	-	-	-						RB PLT??? ORIG
2550.0000	Unamortized ITC	-								RB PLT ?
1510	Deferred Income Taxes-Sp	(2,040,884)	(2,040,884)	(2,040,884)						RB PLT ST OR
1520	Deferred Income Taxes-Tp	(6,507,119)	(6,507,119)	(6,507,119)						RB PLT TR ORIG
1530	Deferred Income Taxes-Dp	(36,854,276)	(36,854,276)	(36,854,276)						RB PLT DI ORIG
1540	Deferred Income Taxes-Gp	(4,770,198)	(4,770,198)	(4,770,198)						RB PLTGEN ORIG
1240.0000	Zero-Interest Fin. Notes	-	-	-						RB PLT
1540.0000	Materials & Supplies	3,149,131	3,149,131	3,149,131						RB PLT ?? OR
1640.0000	Lng Inventory	3,195,613	3,195,613	3,195,613	F STORG	CAP	PDAY			
2520.0000	Cust Adv For Const	(7,893,171)	(7,893,171)	(7,893,171)						MAIN SERV
2600.0000	Cash Working Capitol	1,032,688	1,032,688	1,032,688						CWC
	Sub-total	***(50,688,216)***	***(50,688,216)***	***(50,688,216)***						
	TOTAL RATE BASE ADJ.	**(50,688,216)**	**(50,688,216)**	**(50,688,216)**						
TOTAL RATE BASE		**236,926,494**	**236,926,494**	**236,926,494**						

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Class Cost of Service Study
Account Inputs

Acct. No.	Account Description		December 31, 2016	December 31, 2016	Function	Classifier	CAP	CUS	COM	Internal
EXPENSES										
O & M Expenses (Total)										
	Other Gas Supply Expenses									
4010.28130	Other Gas Supply Expenses	46,564	46,564	46,564	F DISTR	CUS		SALES		
	Sub-total	***46,564***	***46,564***	***46,564***						
	Storage Operation Expenses									
4010.28400	Operation Supervision & Engineering	(197)	(197)	(197)	F STORG	CAP	PDAY			
4010.28410	Operation Labor & Expenses	557,574	557,574	557,574	F STORG	CAP	PDAY			
4010.28421	Fuel	174,453	174,453	174,453	F STORG	CAP	PDAY			
4010.28422	Power	113,643	113,643	113,643	F STORG	CAP	PDAY			
	Sub-total	***845,472***	***845,472***	***845,472***						
	Storage Maintenance Expenses									
4020.28431	Maintenance Supervision & Engineering	103,654	103,654	103,654	F STORG	CAP	PDAY			
4020.28432	Maintenance of Structures	30,155	30,155	30,155	F STORG	CAP	PDAY			
4020.28433	Maintenance of Gas Holders	3,323	3,323	3,323	F STORG	CAP	PDAY			
4020.28434	Maintenance of Purification Equipment	32,228	32,228	32,228	F STORG	CAP	PDAY			
4020.28435	Maintenance of Liquefaction Equipment	155,251	155,251	155,251	F STORG	CAP	PDAY			
4020.28436	Maintenance of Vaporizing Equipment	75,595	75,595	75,595	F STORG	CAP	PDAY			
4020.28437	Maintenance of Compressor Equipment	46,511	46,511	46,511	F STORG	CAP	PDAY			
4020.28438	Maintenance of M&R Equipment	-	-	-	F STORG	CAP	PDAY			
4020.28439	Maintenance of Other Equipment	90,903	90,903	90,903	F STORG	CAP	PDAY			
	Sub-total	***537,621***	***537,621***	***537,621***						
	Total LNG	***1,383,093***	***1,383,093***	***1,383,093***						
	Transmission Operation Expenses									
4010.28500	Operation Supervision & Engineering	-	-	-	F TRANS	CAP	PDAY			
4010.28510	System Control	-	-	-	F TRANS	CAP	PDAY			
4010.28520	Communication System Expenses	39,202	39,202	39,202	F TRANS	CAP	PDAY			
4010.28530	Compressor Sta. Labor & Expenses	5,532	5,532	5,532	F TRANS	CAP	PDAY			
4010.28540	Gas for Compressor Station Fuel	-	-	-	F TRANS	CAP	PDAY			
4010.28560	Mains Expenses	144,627	144,627	144,627	F TRANS	CAP	PDAY			
	Sub-total	***189,362***	***189,362***	***189,362***						
	Transmission Maintenance Expenses									
4020.28630	Maintenance of Mains	13,276	13,276	13,276	F TRANS	CAP	PDAY			
4020.28631	Maintenance Pipeline Integrity	88,874	88,874	88,874	F TRANS	CAP	PDAY			
4020.28640	Maintenance of Compressor Station Equipment	-	-	-	F TRANS	CAP	PDAY			
4020.28660	Maintenance of Communication Equipment	201,230	201,230	201,230	F TRANS	CAP	PDAY			
	Sub-total	***303,380***	***303,380***	***303,380***						
	Total Transmission	***492,741***	***492,741***	***492,741***						
	Distribution Operation Expenses									
4010.28700	Distrib Supervision & Engineering	2,691,872	2,691,872	2,691,872						LACA
4010.28701	Distribution Load Dispatching	-	-	-	F_DISTR	CAP	PK_AVG			
4010.28739	Compressor Station Fuel/Power	-	-	-						LACA
4010.28740	Dist Oper Mains & Services Expenses	2,699,639	2,699,639	2,699,639						MAIN SERV
4010.28750	Dist Oper Meas & Reg Gen	129,611	129,611	129,611	F DISTR	CAP	PK AVG			
4010.28760	Dist Oper Meas & Reg Ind	-	-	-	F DISTR	CAP	PA GP II			
4010.28780	Meter/House Regulator Expenses	226,375	226,375	226,375	F DISTR	CUS		WEIGHTED1		
4010.28783	Meter/House Regulator Expenses	(556,097)	(556,097)	(556,097)	F_DISTR	CUS		WEIGHTED1		
4010.28790	Customer Installations Expenses	7,126,046	7,126,046	7,126,046						D 382 384 385
4010.28800	Other Expenses	2,437,388	2,437,388	2,437,388						RB PLT DI ORIG
4010.28810	Rents	204,290	204,290	204,290						RB PLT DI ORIG
	Sub-total	***14,959,124***	***14,959,124***	***14,959,124***						
	Distribution Maintenance Expenses									
4020.28850	Dist Main Supervision/Engineering	196,391	196,391	196,391						NADM
4020.28870	Dist Maintenance of Mains	950,016	950,016	950,016	F DISTR	MAINS	PDAY	CUSTS		
4020.28871	Dist Maintenance of Mains	79,382	79,382	79,382	F DISTR	MAINS	PDAY	CUSTS		
4020.28890	Maint of Meas/Reg Station Equip-General	198,278	198,278	198,278	F DISTR	CAP	PK AVG			
4020.28900	Maint of Meas/Reg Station Equip-City Gate Check Sta	482,877	482,877	482,877	F DISTR	CAP	PA GP II			
4020.28920	Maintenance of Services	1,037,443	1,037,443	1,037,443	F DISTR	CUS		WEIGHTED		
4020.28930	Maintenance of Meters/House Regulators	832,745	832,745	832,745	F DISTR	CUS		WEIGHTED1		
	Sub-total	***3,777,132***	***3,777,132***	***3,777,132***						
	Total Distribution	***18,736,256***	***18,736,256***	***18,736,256***						

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Class Cost of Service Study
Account Inputs

Acct. No.	Account Description		December 31, 2016	December 31, 2016	Function	Classifier	CAP	CUS	COM	Internal
	Customer Account									
4010.29010	Supervision - Customer Assistance	98,925	98,925	98,925						CUST ACCT
4010.29020	Meter Reading Expenses	715,432	715,432	715,432	F DISTR	CUS		CUSTS		
4010.29030	Customer Records and Collection Exp	7,599,357	7,599,357	7,599,357	F DISTR	CUS		WEIGHTED		
4010.29031	Customer Records and Collection Exp	-	-	-	F DISTR	CUS		WEIGHTED		
		-								
		-								
4010.29040	Uncollectible Accounts	853,486	853,486	853,486	F DISTR	CUS		UNCOL		
4010.29040	Uncollectable Account - Increase	36,536	36,536	36,536	F DISTR	CUS		UNCOL		
	Sub-total	***9,303,736***	***9,303,736***	***9,303,736***						
	Customer Service & Information Expenses									
4010.29070	Supervision	-	-	-	F DISTR	CUS		CUSTS		
4010.29080	Customer Assistance Expenses	202,610	202,610	202,610	F DISTR	CUS		CUSTS		
	Sub-total	***202,610***	***202,610***	***202,610***						
	Sales Expenses									
4010.29110	New Business-Supervision	-	-	-	F DISTR	CUS		SALES		
4010.29120	New Business-Demon & Selling	1,134,815	1,134,815	1,134,815	F DISTR	CUS		SALES		
4010.29130	New Business-Advertising	102,057	102,057	102,057	F_DISTR	CUS		SALES		
	Sub-total	***1,236,872***	***1,236,872***	***1,236,872***						
	Administrative and General Expenses									
4010.29200	Adm & Gen Salaries	5,665,256	5,665,256	5,665,256						OMCUSTEXP
4010.29210	Adm & Gen Office Supplies	3,592,135	3,592,135	3,592,135						OMCUSTEXP
4010.29220	Adm & Gen Transferred	-	-	-						OMCUSTEXP
4010.29230	Adm & Gen Outside Services	1,048,199	1,048,199	1,048,199						RB PLT??? OR
4010.29240	Adm & Gen Property Insurance	150,398	150,398	150,398						RB PLT??? OR
4010.29250	Adm & Gen Injuries & Damage	817,559	817,559	817,559						LA
4010.29260	Adm & Gen Employee Pensions & Benefits	507,190	507,190	507,190						LA
4010.29280	Franchise Requirements	654,529	654,529	654,529						OMCUSTEXP
4010.29301	General Advertising Exp	192,721	192,721	192,721						OMCUSTEXP
4010.29302	Misc. General Expenses	208,916	208,916	208,916						OMCUSTEXP
4010.29307	Misc. General Expenses	198,674	198,674	198,674						OMCUSTEXP
4010.29310	Rents	784,105	784,105	784,105						RB PLTGEN ORIG
4010.29320	Maintenance of General Plant	-	-	-						RB PLTGEN ORIG
4010.29280	Commission Fee Increase	19,081	19,081	19,081						OMCUSTEXP
	Sub-total	***13,838,765***	***13,838,765***	***13,838,765***						
	TOTAL O & M EXPENSES	**45,240,637**	**45,240,637**	**45,240,637**						
			45,185,020							
Labor Expense										
	Storage Operation Expenses									
4010.28400	Operation Supervision/Engineering	-	-	-						
4010.28410	Operation Labor and Exp	344,964	344,964	344,964	F STORG	CAP	PDAY			
4010.28421	Operation Fuel	-	-	-						
4010.28422	Operation Power	-	-	-						
	Sub-total	***344,964***	***344,964***	***344,964***						
	Storage Maintenance Expenses									
4020.28431	Maintenance Supervision & Engineering	-	-	-	F STORG	CAP	PDAY			
4020.28432	Maintenance of Structures	-	-	-	F STORG	CAP	PDAY			
4020.28433	Maintenance of Gas Holders	-	-	-	F STORG	CAP	PDAY			
4020.28434	Maintenance of Purification Equipment	-	-	-	F STORG	CAP	PDAY			
4020.28435	Maintenance of Liquefaction Equipment	-	-	-	F STORG	CAP	PDAY			
4020.28436	Maintenance of Vaporizing Equipment	61,718	61,718	61,718	F STORG	CAP	PDAY			
4020.28437	Maintenance of Compressor Equipment	-	-	-	F STORG	CAP	PDAY			
4020.28438	Maintenance of M&R Equipment	-	-	-	F STORG	CAP	PDAY			
4020.28439	Maintenance of Other Equipment	-	-	-	F STORG	CAP	PDAY			
	Sub-total	***61,718***	***61,718***	***61,718***						
	Total Storage	***406,682***	***406,682***	***406,682***						
	Transmission Operation Expenses									
4010.2850	Operation Supervision & Engineering	-	-	-	F TRANS	CAP	PDAY			
4010.2851	System Control	-	-	-	F TRANS	CAP	PDAY			
4010.2852	Communication System Expenses	-	-	-						
4010.2853	Compressor Sta. Labor & Expenses	-	-	-						
4010.2854	Gas for Compressor Station Fuel	-	-	-						
4010.2856	Mains Expenses	-	-	-	F TRANS	CAP	PDAY			
	Sub-total	**-**	**-**	**-**						
	Transmission Maintenance Expenses									
4020.2863	Maintenance of Mains	2,388	2,388	2,388	F TRANS	CAP	PDAY			
4020.2863	Maintenance Pipeline Integrity	17,601	17,601	17,601	F TRANS	CAP	PDAY			
4020.2864	Maintenance of Compressor Station Equipment	-	-	-	F TRANS	CAP	PDAY			
4020.2866	Maintenance of Communication Equipment	183,504	183,504	183,504	F TRANS	CAP	PDAY			
	Sub-total	***203,493***	***203,493***	***203,493***						
	Total Transmission	***203,493***	***203,493***	***203,493***						

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Class Cost of Service Study
Account Inputs

Acct. No.	Account Description		December 31, 2016	December 31, 2016	Function	Classifier	CAP	CUS	COM	Internal
	Distribution Operation Expenses									
4010.28700	Distrib Supervision & Engineering	1,995,398	1,995,398	1,995,398						LACA
4010.28701	Distribution Load Dispatching	-	-	-	F DISTR	CAP	PK AVG			
4010.28739	Compressor Station Fuel/Power	-	-	-						LACA
4010.28740	Dist Oper Mains & Services Expenses	1,611,161	1,611,161	1,611,161						MAIN SERV
4010.28750	Dist Oper Meas & Reg Gen	-	-	-	F DISTR	CAP	PK AVG			
4010.28760	Dist Oper Meas & Reg Ind	-	-	-	F DISTR	CAP	PA GP II			
4010.28780	Meter/House Regulator Expenses	202,693	202,693	202,693	F DISTR	CUS		WEIGHTED1		
4010.28783	Meter/House Regulator Expenses	-	-	-	F DISTR	CUS		WEIGHTED1		
4010.28790	Customer Installations Expenses	5,917,585	5,917,585	5,917,585						D 382 384 385
4010.28800	Other Expenses	1,617,836	1,617,836	1,617,836						RB PLT DI ORIG
4010.28810	Rents	-	-	-						RB PLT DI ORIG
	Sub-total	***11,344,673***	***11,344,673***	***11,344,673***						
	Distribution Maintenance Expenses									
4020.2885	Dist Main Supervision/Engineering	177,609	177,609	177,609						NADM
4020.2887	Dist Maintenance of Mains	502,000	502,000	502,000	F DISTR	MAINS	PDAY	CUSTS		
4020.2887	Dist Maintenance of Mains	64,436	64,436	64,436	F DISTR	MAINS	PDAY	CUSTS		
4020.2889	Maint of Meas/Reg Station Equip-General	120,906	120,906	120,906	F DISTR	CAP	PK AVG			
4020.2890	Maint of Meas/Reg Station Equip-City Gate Check Sta	399,141	399,141	399,141	F DISTR	CAP	PA GP II			
4020.2892	Maintenance of Services	357,288	357,288	357,288	F DISTR	CUS		WEIGHTED		
4020.2893	Maintenance of Meters/House Regulators	353,914	353,914	353,914	F_DISTR	CUS		WEIGHTED1		
	Sub-total	***1,975,294***	***1,975,294***	***1,975,294***						
	Total Distribution	***13,319,967***	***13,319,967***	***13,319,967***						
	Customer Account									
4010.29010	Supervision - Customer Assistance	101,161	101,161	101,161						EXP CUST ACCTA
4010.29020	Meter Reading Expenses	553,077	553,077	553,077	F DISTR	CUS		CUSTS		
4010.29030	Customer Records and Collection Exp	4,401,233	4,401,233	4,401,233	F DISTR	CUS		WEIGHTED		
4010.29031	Customer Records and Collection Exp	-	-	-	F DISTR	CUS		WEIGHTED		
4010.29040	Uncollectible Accounts	-	-	-	F DISTR	CUS		UNCOL		
	Sub-total	***5,055,471***	***5,055,471***	***5,055,471***						
	Sales Expenses									
4010.29110	New Business-Supervision	-	-	-						
4010.29120	New Business-Demon & Selling	977,913	977,913	977,913	F DISTR	CUS		SALES		
4010.29130	New Business-Advertising	-	-	-						
	Sub-total	***977,913***	***977,913***	***977,913***						
	TOTAL 2015 O & M LABOR EXP.	**19,963,525**	**19,963,525**	**19,963,525**						
Depreciation Expense										
	Intangible Plant									
4050.0000	Amort Exp-Intangible Plant	3,125,359	3,125,359	3,125,359						RB PLTINT
	Sub-total	***3,125,359***	***3,125,359***	***3,125,359***						
	Storage Plant									
4030.0003	Deprec Exp-Storage Plant	682,914	682,914	682,914						RB PLT ST
	Sub-total	***682,914***	***682,914***	***682,914***						
	Transmission Plant									
4030.0004	Deprec Exp-Transmission Plant	1,977,413	1,977,413	1,977,413						RB PLT TR
	Sub-total	***1,977,413***	***1,977,413***	***1,977,413***						
	Distribution Plant									
4030.0005	Deprec Exp-Distribution Plant	12,612,078	12,612,078	12,612,078						RB PLT DI
	Sub-total	***12,612,078***	***12,612,078***	***12,612,078***						
	General Plant Plant									
4030.0006	Deprec Exp-General Plant	3,309,349	3,309,349	3,309,349						RB PLTGEN
	Sub-total	***3,309,349***	***3,309,349***	***3,309,349***						
	TOTAL DEPRECIATION EXPENSES	**21,707,112**	**21,707,112**	**21,707,112**						
				18,581,753						
Interest and Other Expenses										
	Sub-total	**-**	**-**	**-**						
	TOTAL INTEREST AND OTHER EXPENSES	**-**	**-**	**-**						
Taxes Other Than Income Taxes										
408.1	Payroll Taxes	1,641,942	1,641,942	1,641,942						LA
408.2	Property Taxes	3,198,871	3,198,871	3,198,871						PROPTX
408.5	Ad Valorem Taxes	-								RB PLT
408.3	Frchise Rev & Exp	-	-	-						RB
408.4	Administrative Taxes Transfrd	-	-	-						RB
	Sub-total	***4,840,813***	***4,840,813***	***4,840,813***						
	TOTAL TAXES OTHER THAN INCOME TAX	**4,840,813**	**4,840,813**	**4,840,813**						
Cost of Gas										
804.1	Cost Of Gas - Fixed Cost Of Gas	62,387,552	62,387,552	62,387,552	F COSGA	DIRECT COG			FCOG	
804.2	Cost Of Gas - Commodity Cog	106,435,107	106,435,107	106,435,107	F COSGA	DIRECT COMM			VCOG	
	TOTAL	**168,822,659**	**168,822,659**	**168,822,659**						
Income Taxes - Pro Forma										
	Income Taxes Pro Forma	2,750,218	2,750,218	2,750,218						RB
	TOTAL	**2,750,218**	**2,750,218**	**2,750,218**						
Income Taxes - Proposed										
	Income Taxes Proposed	6,775,042	6,775,042	6,775,042						RB
	TOTAL	**6,775,042**	**6,775,042**	**6,775,042**						
Operating Revenues										
480	Revenue from Gas Sales	251,900,147	251,900,147	251,900,147	F REVNU	COM			RS REV	
488	Other Revenues	2,900,363	2,900,363	2,900,363	F REVNU	COM			REV OTHER	
	Sub-total	***254,800,510***	***254,800,510***	***254,800,510***						
	TOTAL	**254,800,510**								

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 23

Class Cost of Service Study
External Allocation Factors

Name	Description		Total	RS	GS	LV-1	T-3	T-4
DEMAND ALLOCATORS								
PDAY	Peak Day	CAP		49.64%	24.66%	0.48%	0.00%	25.22%
	December 31, 2016		4,011,191	1,991,202	989,168	19,369	-	1,011,452
PK_AVG	Peak & Average	CAP		42.09%	21.06%	0.70%	2.73%	33.42%
	December 31, 2016		1	0.42	0.21	0.01	0.03	0.33
PA_GP_II	Peak & Average Group II	CAP		0.00%	36.37%	1.21%	4.71%	57.71%
	December 31, 2016		1	-	0.21	0.01	0.03	0.33
CUSTOMER ALLOCATORS								
WEIGHTED	Weighted customer (meter cost)	CUS		75.71%	23.68%	0.07%	0.06%	0.48%
	December 31, 2016		1	0.76	0.24	0.00	0.001	0.005
WEIGHTED2	Weighted customer group 2	CUS		0.00%	83.45%	1.82%	1.74%	13.00%
	December 31, 2016		0	-	0.03	0.00	0.001	0.004
WEIGHTED1	Weighted customer group 1	CUS		78.22%	21.70%	0.01%	0.00%	0.07%
	December 31, 2016		1	0.76	0.21	0.00	0.00003	0.00067
SALES	SALES	CUS		66.81%	33.19%	0.00%	0.00%	0.00%
	December 31, 2016		2,980,370	1,991,202	989,168	-	-	-
CUSTS	No. of Customers	CUS		90.53%	9.44%	0.01%	0.00%	0.028%
	December 31, 2016		4,089,148	3,701,803	385,898	217	72	1,158
UNCOL	Uncollectible Expense	CUS		86.42%	13.53%	0.01%	0.00%	0.04%
	December 31, 2016		1	0.86	0.14	0.00	0.00	0.00
COMMODITY ALLOCATORS								
FCOG	Fixed Cost of Gas	COM		66.84%	32.12%	1.04%	0.00%	0.00%
	December 31, 2016		62,387,552	41,697,617	20,040,806	649,129	-	-
VCOG	Variable Cost of Gas	COM		65.30%	33.14%	1.95%	-0.01%	-0.37%
	December 31, 2016		106,435,107	69,499,313	35,271,794	2,074,834	(13,435)	(397,399)
THERMS	Therms	COM		32.67%	16.58%	0.97%	6.13%	43.66%
	December 31, 2016		651,399,403	212,787,060	107,972,664	6,317,560	39,909,287	284,412,832
		-	-					
RS_REV	Revenues	COM		65.28%	29.71%	1.24%	0.28%	3.49%
	December 31, 2016		251,900,147	164,429,181	74,843,065	3,127,950	714,239	8,785,712
REV_OTHER	Other Revenue	COM		70.62%	22.44%	0.20%	0.00%	6.74%
	December 31, 2016		407,116,476	287,518,338	91,352,194	802,951	-	27,442,993

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Class Cost of Service Study
Internal Allocators

Internal Allocators

Allocator Name	Description	Total	RS	GS	LV-1	T-3	T-4
RB_PLT_ST_OR	Storage Plant	22,575,250	11,206,618	5,567,103	109,012	-	5,692,517
	Percent	100.00%	49.64%	24.66%	0.48%	0.00%	25.22%
RB_PLT_TR_ORIG	Transmission Plant	71,978,519	35,730,977	17,750,052	347,573	-	18,149,918
	Percent	100.00%	49.64%	24.66%	0.48%	0.00%	25.22%
RB_PLT_DI_ORIG	Distribution Plant	407,663,702	287,518,338	91,352,194	802,951	547,226	27,442,993
	Percent	100.00%	70.53%	22.41%	0.20%	0.13%	6.73%
RB_PLT_??_OR	Stor., Trans., Distr. Plant	502,217,471	334,455,932	114,669,349	1,259,536	547,226	51,285,428
	Percent	100.00%	66.60%	22.83%	0.25%	0.11%	10.21%
RB_PLTINT_OR	Intangible Plant	41,082,525	27,359,480	9,380,233	103,028	44,763	4,195,020
	Percent	100.00%	66.60%	22.83%	0.25%	0.11%	10.21%
RB_PLTGEN_ORIG	General Plant	52,765,561	35,139,667	12,047,754	132,333	57,494	5,388,312
	Percent	100.00%	66.60%	22.83%	0.25%	0.11%	10.21%
RB_PLT???_OR	Total Plant	596,065,557	396,955,080	136,097,336	1,494,898	649,483	60,868,760
	Percent	100.00%	66.60%	22.83%	0.25%	0.11%	10.21%
RB_PLT???_ORIG	Trans., Distr., Gen. Plant	532,407,782	358,388,982	121,149,999	1,282,857	604,720	50,981,223
	Percent	100.00%	67.31%	22.76%	0.24%	0.11%	9.58%
RB_PLT_ST	Storage Plant less depr.	11,167,487	5,543,671	2,753,925	53,926	-	2,815,965
	Percent	100.00%	49.64%	24.66%	0.48%	0.00%	25.22%
RB_PLT_TR	Transmission Plant less depr.	30,687,511	15,233,639	7,567,604	148,185	-	7,738,084
	Percent	100.00%	49.64%	24.66%	0.48%	0.00%	25.22%
RB_PLT_DI	Distribution Plant less depr.	178,417,994	125,835,204	39,981,178	351,419	239,499	12,010,694
	Percent	100.00%	70.53%	22.41%	0.20%	0.13%	6.73%
RB_PLT_?	Stor, Trans, Distr. less depr.	220,272,992	146,612,513	50,302,707	553,531	239,499	22,564,742
	Percent	100.00%	66.56%	22.84%	0.25%	0.11%	10.24%
RB_PLTINT	Intangible less depr.	36,958,043	24,612,724	8,438,504	92,685	40,269	3,773,861
	Percent	100.00%	66.60%	22.83%	0.25%	0.11%	10.21%
RB_PLTGEN	General less depr.	30,383,675	20,234,263	6,937,386	76,201	33,107	3,102,719
	Percent	100.00%	66.60%	22.83%	0.25%	0.11%	10.21%
RB	Total Rate Base	236,926,494	156,718,272	54,354,566	609,397	260,549	24,983,710
	Percent	100.00%	66.15%	22.94%	0.26%	0.11%	10.54%
RB_PLT	Plant-in-service less depr.	287,614,710	191,459,500	65,678,597	722,416	312,874	29,441,322
	Percent	100.00%	66.57%	22.84%	0.25%	0.11%	10.24%
CUSTOM	Customer O & M	86,874,739	56,292,553	23,937,754	259,690	237,675	6,147,066
	Percent	100.00%	64.80%	27.55%	0.30%	0.27%	7.08%
EXP_CUST_ACCTA	Customer Accounts Labor Expense	12,000,590	9,086,168	2,841,454	8,012	7,001	57,955
	Percent	100.00%	75.71%	23.68%	0.07%	0.06%	0.48%
LA	Labor	19,963,525	12,560,559	6,115,555	68,118	74,427	1,144,866
	Percent	100.00%	62.92%	30.63%	0.34%	0.37%	5.73%
LACA	Labor - Operations	7,731,439	4,334,142	2,932,555	40,563	36,478	387,701
	Percent	100.00%	56.06%	37.93%	0.52%	0.47%	5.01%
LADA	Labor - Maintenance	1,797,685	988,627	431,066	7,397	22,306	348,288
	Percent	100.00%	54.99%	23.98%	0.41%	1.24%	19.37%
OMCUSTEXP	O&M	72,786,799	47,131,436	20,015,895	217,758	197,142	5,224,568
	Percent	100.00%	64.75%	27.50%	0.30%	0.27%	7.18%
NADM	Non labor Maintenance	3,580,741	2,229,776	823,716	10,640	28,771	487,839
	Percent	100.00%	62.27%	23.00%	0.30%	0.80%	13.62%

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 24

Intermountain Gas Company
Rate Design Analysis and Calculations

Line	(X)	Residential Service Rate Schedule RS (A)	General Service Rate Schedule GS-1 (B)	Large Volume Rate Schedule LV-1 (C)	Transport Service (Interruptible) Rate Schedule T-3 (D)	Transport Service (Firm) Rate Schedule T-4 (E)	Company Total (F)	Explanation (G)
1	**A. Proforma Normalized Calendar Month Revenues at Current Rates**							
2								
3	Company Total Distribution Base Revenues							
4	Distribution Revenues: Customer Charge	$14,184,240	$1,738,418	$0	$0	$0	$15,922,658	Company Records
5	Revenues: Volumetric Charge	$39,048,014	$17,792,045	$403,987	$727,673	$8,731,332	$66,703,050	Company Records
6	Revenues: Demand Charge					$451,781	$451,781	Company Records
7	Company Total Base Revenues	$53,232,253	$19,530,463	$403,987	$727,673	$9,183,113	$83,077,489	Σ Line 4 to Line 6
8	**B. Billing Determinants**							
9	Customer Bill Count							
10	Customers - Summer	2,469,370	256,991				2,726,361	
11	Customers - Winter	1,232,433	128,888				1,361,321	
12	Customers - Total	3,701,803	385,879				4,087,682	Company Records
13	Energy Consumption (Therms)							
14	Summer							
15	Distribution Quantity - Summer	75,158,465					75,158,465	Company Records
16	Distribution Quantity Block 1 - Summer		13,965,447	3,962,764	5,210,862	65,858,113	88,997,186	Company Records
17	Distribution Quantity Block 2 - Summer		17,972,029	0	2,000,000	54,169,505	74,141,534	Company Records
18	Distribution Quantity Block 3 - Summer		8,083,256	0	17,946,368	33,682,695	59,712,319	Company Records
19	Distribution Quantity Block 4 - Summer						0	Company Records
20	Distribution Quantity - Firm - Summer					10,383,817	10,383,817	Company Records
21	Distribution Quantity - Interruptible - Summer					2,898,285	2,898,285	Company Records
22	TOTAL Summer Distribution Consumption (Therms)	75,158,465	40,020,732	3,962,764	25,157,230	166,992,415	311,291,606	Company Records
23	Winter							
24	Distribution Quantity - Winter	137,628,595					137,628,595	Company Records
25	Distribution Quantity Block 1 - Winter		17,087,083	2,354,796	2,402,389	39,790,793	61,635,061	Company Records
26	Distribution Quantity Block 2 - Winter		33,412,251	0	1,000,000	34,747,263	69,159,514	Company Records
27	Distribution Quantity Block 3 - Winter		17,452,598	0	11,349,668	36,388,303	65,190,569	Company Records
28	Distribution Quantity Block 4 - Winter						0	
29	Distribution Quantity - Firm - Winter					5,271,535	5,271,535	Company Records
30	Distribution Quantity - Interruptible - Winter					1,222,523	1,222,523	Company Records
31	TOTAL Winter Distribution Consumption (Therms)	137,628,595	67,951,932	2,354,796	14,752,057	117,420,417	340,107,797	Company Records
32	Demand (Therms / day contract Demand)							
33	Billing Demand			432,960		18,236,364	18,669,324	Company Records
34	Rate Blocks: Upper Limit (Therms per Month)							
35	Block 1 - Summer		200	250,000	100,000	250,000		
36	Block 2 - Summer		2,000	750,000	150,000	750,000		
37	Block 3 - Summer		9,999,999	9,999,999	9,999,999	9,999,999		
38	Block 4 - Summer		9,999,999	9,999,999	9,999,999	9,999,999		
39	Block 1 - Winter		200	250,000	100,000	250,000		
40	Block 2 - Winter		2,000	750,000	150,000	750,000		
41	Block 3 - Winter		9,999,999	9,999,999	9,999,999	9,999,999		
42	Block 4 - Winter		9,999,999	9,999,999	9,999,999	9,999,999		

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Intermountain Gas Company
Rate Design Analysis and Calculations

Line	(X)	Residential Service Rate Schedule RS (A)	General Service Rate Schedule GS-1 (B)	Large Volume Rate Schedule LV-1 (C)	Transport Service (Interruptible) Rate Schedule T-3 (D)	Transport Service (Firm) Rate Schedule T-4 (E)	Company Total (F)	Explanation (G)
43	**C. CLASS REVENUE TARGETS**							
44	Cost Study Results							
45	Total Delivery Service Costs							
46	Total Customer-related Costs							Functional Revenue requirement at equal ROR
47	Total Capacity-related Costs							Functional Revenue requirement at equal ROR
48	Total Commodity-related Costs							Functional Revenue requirement at equal ROR
49	Rate Schedule Revenue Requirement at Equal ROR	$60,987,556	$23,997,224	$262,137	$199,632	$7,796,639	$93,243,187	Lines 46 to 48
50	Distribution Service Unit Costs							
51	Capacity ($/therm)	$0.0576	$0.0592	$0.0212	$0.0019	$0.0242		Unit Costs from ACOSS
52	Customer ($/month)	$13.16	$45.62	$0.00	$0.00	$0.00		Unit Costs from ACOSS
53	Commodity ($/therm)							Unit Costs from ACOSS
54	**Delivery Revenue Requirement**							
55	Total Revenue Requirement	$60,987,556	$23,997,224	$262,137	$199,632	$7,796,639	**93,243,187**	
56	% Increase (Revenue Requirement - Normalized revenues)	14.57%	22.87%	-35.11%	-72.57%	-15.10%	**12.24%**	Line 55 / Line 7 - 1
57	Development of Class Revenue Target							
58	Proforma Total Revenues (Base Revenues at Current Rates)							
59	Base Proforma Revenues	$53,232,253	$19,530,463	$403,987	$727,673	$9,183,113	$83,077,489	Line 7
60	Allocated Revenue Targets at Proposed ROR							
61	Capacity-related Revenue Requirement at Proposed ROR	$12,258,605	$6,394,052	$133,824	$77,326	$6,880,033	$25,743,841	Line 49
62	Customer-related Revenue Requirement at Proposed ROR	$48,728,951	$17,603,172	$128,312	$122,306	$916,605	$67,499,346	Line 50
63	Commodity-related Revenue Requirement at Proposed ROR							Line 51
64	Total Revenue Requirement at Equal ROR	$60,987,556	$23,997,224	$262,137	$199,632	$7,796,639	$93,243,187	Line 61 + Line 62
65	FINAL BASE REVENUE TARGET	$60,987,556	$23,997,224	$262,137	$199,632	$7,796,639	$93,243,187	Line 64
66	**D. RATE DESIGN**							
67	Current Customer charge - Summer	$2.50	$2.00					Company tariffs
68	Current Customer charge - Winter	$6.50	$9.50					Company tariffs
69	Unit Customer Cost	$13.61	$46.85	58.76%				ACOSS
70	**Proposed Customer Charge**	**$10.00**	**$35.00**					Company rate design decision
71	Proposed Customer charge as a % of unit costs	73.5%	74.7%					Line 70 / Line 69
72	Customer Charge Revenue, Proposed Customer Charge							
73	Customer Revenues	$37,018,030	$13,505,765				$50,523,795	Line 70 * Line 12
74	Demand-Related Charges							
75	Current Demand Charge			$0.00		$0.84253		Company Tariffs
76	Demand-Related Billing Units							
77	Billing Demand Contract Demand, Therms			432,960		18,236,364	18,669,324	Company Records
78	**Proposed Demand-Related Charges**							
79	Proposed Demand Charge			**$0.3000**		**$0.30000**		Company decision
80	Demand Revenues at Proposed Rates			$129,888		$5,470,909	$5,600,797	Line 79 x Line 77
81	Remaining Revenues	$23,969,526	$10,491,459	$132,249	$199,632	$2,325,730	$37,118,595	Line 65- Line 73 - Line 80

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Intermountain Gas Company
Rate Design Analysis and Calculations

Line		Residential Service Rate Schedule RS	General Service Rate Schedule GS-1	Large Volume Rate Schedule LV-1	Transport Service (Interruptible) Rate Schedule T-3	Transport Service (Firm) Rate Schedule T-4	Company Total	Explanation
	(X)	(A)	(B)	(C)	(D)	(E)	(F)	(G)
82	Volumetric Revenue Target	$23,969,526	$10,491,459	$132,249	$199,632	$2,325,730	$37,118,595	Line 81
				49.5%				
83	Current Volumetric Charge ($/Therm) - Summer	$0.31617						Company Tariffs
84	Current Volumetric Charge ($/Therm) - Winter	$0.20361						Company Tariffs
85	Current Volumetric Charge ($/Therm) - Summer	$0.19539						Company Tariffs
86	Current Volumetric Charge ($/Therm) - Winter	$0.16176						Company Tariffs
87	Current Volumetric Charge ($/Therm) - Summer Block 1		$0.21690	$0.06395	$0.05499	$0.05922		Company Tariffs
88	Current Volumetric Charge ($/Therm) - Summer Block 2		$0.19517	$0.02546	$0.02239	$0.02073		Company Tariffs
89	Current Volumetric Charge ($/Therm) - Summer Block 3		$0.17415	$0.00600	$0.00826	$0.00600		Company Tariffs
90	Current Volumetric Charge ($/Therm) - Winter Block 1		$0.16605	$0.06395	$0.05499	$0.05922		Company Tariffs
91	Current Volumetric Charge ($/Therm) - Winter Block 2		$0.14485	$0.02546	$0.02239	$0.02073		Company Tariffs
92	Current Volumetric Charge ($/Therm) - Winter Block 3		$0.12439	$0.00600	$0.00826	$0.00600		Company Tariffs
93	Current Volumetric Charges (per Therm) Commodity Rate					$0.00185		Company Tariffs
94	Current Volumetric Charges (per Therm) Overrun					$0.04444		Company Tariffs
95	Proposed Rate Blocks: Upper Limit (Therms per Month)							
96	Annual							
97	Distribution Quantity							
98	Distribution Quantity Block 1		200	250000	100000	250000		Yellow: Company rate design decision
99	Distribution Quantity Block 2		2000	750000	150000	750000		All other: Company records
100	Distribution Quantity Block 3		10000	999999999	999999999	999999999		
101	Distribution Quantity Block 4		999999999	999999999	999999999	999999999		
102	Proposed Volumetric Billing Units (Therms)							
103	Annual							
104	Distribution Quantity	212,787,060					212,787,060	Orange: calculated based on Company decision
105	Distribution Quantity Block 1		31,052,530	6,317,560	7,613,251	115,948,332	160,931,673	All other: Company records
106	Distribution Quantity Block 2		51,384,280		3,000,000	96,712,653	151,096,933	
107	Distribution Quantity Block 3		21,640,519		29,296,036	71,751,847	122,688,402	
108	Distribution Quantity Block 4		3,895,335				3,895,335	
109	TOTAL Annual Distribution Consumption (Therms)	212,787,060	107,972,664	6,317,560	39,909,287	284,412,832	651,399,403	Σ Lines 65 to 69

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Intermountain Gas Company
Rate Design Analysis and Calculations

Line		Residential Service Rate Schedule RS	General Service Rate Schedule GS-1	Large Volume Rate Schedule LV-1	Transport Service (Interruptible) Rate Schedule T-3	Transport Service (Firm) Rate Schedule T-4	Company Total	Explanation
	(X)	(A)	(B)	(C)	(D)	(E)	(F)	(G)
110	**Proposed Volumetric Charges**							
111	Revenues at Current rates	$39,048,014	$17,792,045	$403,987	$727,673	$8,731,332	$66,703,050	Line 5
112	Volumetric revenue target	$23,969,526	$10,491,459	$132,249	$199,632	$2,325,730	$37,118,595	Line 82
113	% change in Volumetric Rates	-38.62%	-41.03%	-67.26%	-72.57%	-73.36%		Line 112 / Line 111
114	**Proposed Volumetric Charges per therm**							
115	Proposed Volumetric Charge	$0.11265						Line 82 / Line 109
116	Proposed Volumetric Charge Block 1		$0.11076	$0.02093	$0.01509	$0.01473		
117	Proposed Volumetric Charge Block 2		$0.09662	$0.00833	$0.00614	$0.00520		
118	Proposed Volumetric Charge Block 3		$0.08297	$0.00196	$0.00227	$0.00160		
119	Proposed Volumetric Charge Block 4		$0.07500					Company rate design decision
120	**Base Rates Revenue Proof**							
121	**Proposed Customer Charge Revenues**							
122	Total Customer Charge Revenues	$37,018,030	$13,505,765				$50,523,795	Line 70 x Line 12
123	**Proposed Demand-Related Revenues**							
124	Total Demand Charge Revenues			$129,888		$5,470,909	$5,600,797	Line 79 x Line 33
125	**Proposed Volumetric Revenues**							
126	Proposed Volumetric Charge	$23,970,462					$23,970,462	Line 115 x Line 104
127	Proposed Volumetric Charge Block 1		$3,439,378	$132,227	$114,884	$1,707,919	$5,394,408	Line 116 x Line 105
128	Proposed Volumetric Charge Block 2		$4,964,749	$0	$18,420	$503,115	$5,486,284	Line 117 x Line 106
129	Proposed Volumetric Charge Block 3		$1,795,514	$0	$66,502	$114,803	$1,976,819	Line 118 x Line 107
130	Proposed Volumetric Charge Block 4		$292,150	$0	$0	$0	$292,150	Line 119 x Line 108
131	Total Volumetric Revenues	$23,970,462	$10,491,791	$132,227	$199,806	$2,325,837	$37,120,123	Σ Lines 126 to 130
132	**Total Proposed Revenues**	$60,988,492	$23,997,556	$262,115	$199,806	$7,796,746	$93,244,715	Σ Lines 122, 124, 131
133		$937	$332	-$22	$174	$107	$1,528	

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
____	)	

DIRECT TESTIMONY OF DAVID SWENSON

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is David Swenson. I am Manager of Industrial Services at Intermountain Gas Company ("Intermountain" or "the Company"). My business address is 555 S. Cole Road, Boise, Idaho 83707.

Q. Mr. Swenson, please summarize your educational and professional experience.

A. I have been working in the natural gas industry for 33 years. I have been at Intermountain Gas for over 26 years where I started as an analyst in Pricing and Special Studies. I also previously worked for IGI resources Inc., a natural gas marketing company where I held several positions including Manager of Gas Supply and Business Development. I was named Manager, Industrial Services for Intermountain in January 2013. Prior to this role, I held various positions in Intermountain's accounting, regulatory and gas supply departments. In my current assignment, I am responsible for the retention and growth strategies for all large-volume market segments and to build strong, strategic relationships with these customers and other trade allies. I am also responsible to manage policies and procedures, oversee forecasting and planning, and conduct contract negotiations. I also manage the company's Liquefied Natural Gas sales efforts. I am a graduate of Brigham Young University with a Bachelor of Science degree in finance and a minor in accounting and economics. Currently, I also serve as a member of the board of directors of the Boise Valley Economic Partnership.

Q. Please describe the purpose of your testimony.

A. In this testimony, I describe and explain the Company's proposals to:

(1) Charge all Large Volume Contract (“Industrial”) firm service customers a demand charge for the capacity on the Company’s distribution system that is made available to these industrial customers.

(2) Combine current rate schedules T-4 and T-5 into a new rate schedule, also designated as Rate Schedule T-4

(3) Eliminate of the Exit Fee provision in the LV-1 Rate Schedule and the historic high provision that determined access to block three of the T-4 Rate Schedule.

II. INDUSTRIAL RATE SCHEDULES

A. Introduction: Description of Industrial Rate Schedules

Q. As a preliminary matter, please describe and explain the rate schedules that are available to the Company’s Industrial customers.

A. Intermountain provides service to its largest natural gas consumers (hereinafter referred to as “Large Volume Industrial”) through one fully bundled sales tariff and three distribution-only transportation tariffs. The Company provides firm sales service to the Large Volume Industrial customers that meet the eligibility conditions of and elect to be served under Rate Schedule LV-1. Firm distribution system-only transportation service is provided to Large Volume Industrial customers that meet the eligibility conditions of and elect to be served under Rate Schedules T-4 or T-5. The Company also offers a distribution system-only interruptible transportation service to Large Volume Industrial customers that meet the eligibility conditions of and elect to be served under Rate Schedule T-3. I have prepared Table DS-1, below, which provides the availability provisions for the Company’s current industrial Rate Schedules.

Table DS-1 Intermountain Gas Company Industrial Rate Classifications

Rate Schedule	Title	Availability Provision[1]
LV-1	Large Volume Firm Sales Service	Available to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under rate schedule LV-1 whose usage does not exceed 500,000 therms annually, for firm sales service in excess of 200,000 therms per year.
T-3	Interruptible Distribution Transportation Service	Available to any customer.
T-4	Firm Distribution Only Transportation Service	Available for firm distribution transportation service in excess of 200,000 therms per year.
T-5	Firm Distribution Service with Maximum Daily Demands	Available to any existing T-5 customer whose daily contract demand on any given days meets or exceeds a predetermines level agreed to by the customer and the Company for firm distribution service in excess of 200,000 therms per year.

Q. Please describe how the Company charges interruptible industrial customers served on Rate Schedule T-3.

A. Currently, the Company charges a Volumetric Rate to T-3 customers for interruptible transportation service.

Table DS-2 Currently Effective T-3 Rates[2]

Commodity Charge per therm		
Block 1	1st 250,000 therms	$0.49512
Block 2	Next 500,000 therms	$0.45663
Block 3	Over 750,000 therms	$0.33442

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[1] In addition, applicable to all industrial customers, service will only be provided upon execution of a one year minimum written service contract and, specifically relating to customers receiving transport service, any customer delivery of natural gas must occur at any mutually agreeable delivery point on the Company's distribution system.

[2] Rate Schedule T-3 Interruptible Distribution Transportation Service, Eleventh Revised Sheet No. 8, Effective: October 1, 2015

Q. Please describe how the Company charges firm industrial customers served on Rate Schedule T-4.

A. Currently, the Company charges a Volumetric Rate to T-4 customers for firm distribution only transportation service.

Table DS-3 Currently Effective T-4 Rates[3]

Commodity Charge per therm		
Block 1	1st 250,000 therms	$0.05777
Block 2	Next 500,000 therms	$0.01928
Block 3	Over 750,000 therms	$0.00455

Q. Please describe how the Company charges firm industrial customers served on Rate Schedule T-5.

A. Differing from the rate schedules described above, the T-5 customers are billed monthly under a two-part rate: a demand charge and a volumetric rate. The demand charge is the product of the T-5 demand rate times the effective Maximum Daily Firm Quantity ("MDFQ"). The MDFQ is more fully described below. In addition to the demand charge, T-5 customers are also charged a Volumetric Rate for all firm therms transported and, when applicable, an overrun rate for all therms transported in excess of the maximum monthly firm amount. The Company's currently effective T-5 rates are shown in Table DS-5, below.

Table DS-4 Currently Effective T-5 Rates[4]

Firm Service		
Demand Charge	Firm Daily Demand (Therms)	$0.84253
Commodity Charge	Firm Therms Transported	$0.00111
Over-Run (non-Firm) Service		
Commodity Charge	Therms Transported in Excess of MDFQ	$0.04370

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[3] Rate Schedule T-4 Firm Distribution Only Transportation Service, Tenth Revised Sheet No. 9, Effective: October 1, 2015

[4] Rate Schedule T-5 Firm Distribution Service with Maximum Daily Demands, Effective: October 1, 2015

B. Industrial Demand Charge Proposal

Q. Please describe the Company's proposal to bill a demand charge to all Industrial customers taking firm transportation service.

A. The testimony of Company Witness Branko Terzic provides support for demand charges for large industrial customers. Specifically, Mr. Terzic makes the points that it is a fundamental rate making principle that the capacity of a gas distribution system is designed to meet customers' cumulative demands when the system peak demand occurs and that customers should pay their proportionate share of costs in meeting that system peak demand.

Based on the Company's experience with the current Rate Schedule T-5 demand charge, the Company is proposing to add a demand charge to all firm industrial rate schedules, to equitably charge all firm industrial customers for their use of the Company's distribution capacity. Similar to the rate structure for the current Rate Schedule T-5, all firm industrial customers will also be charged volumetric rates, in addition to the demand rate. The calculation of the proposed demand and volumetric rates for Intermountain's firm industrial rate schedules is described and explained in the testimony of Witness Blattner. The demand charge for all firm industrial customers in Intermountain's proposed firm Rate Schedules will be based on the effective MDFQ.

Q. Please explain how a firm industrial customer's Maximum Daily Firm Quantity is determined.

A. Delivery capacity on Northwest Pipeline's interstate transportation system, as well as the Company's distribution system, are finite resources and so there must be a methodology to allocate that the resource fairly. All firm service, large volume industrial customer contracts include a mutually agreed upon MDFQ. The Company utilizes daily usage data from its SCADA (Supervisory Control and Data Acquisition) system along with connected load ratings from the customer's natural gas fired equipment to determine a recommended MDFQ. Upon confirmation from the engineering and measurement departments that Intermountain can, in fact, provide that level of peak service to the customer, and upon agreement with the customer, that MDFQ is written into the customer's contract. Once the contract is executed, Intermountain commits to the LV-1 customers that it can provide each day during the contract a level of interstate transportation capacity, gas supply and distribution capacity equal to the customer's MDFQ. Similarly, Intermountain commits to the firm transport customers that it can provide that level of daily distribution capacity equal to the customer's MDFQ.

All daily natural gas deliveries above the customer's MDFQ are on an "as available" basis and, during periods of Entitlement, Intermountain could restrict a customer's usage to no more than the customer's MDFQ. Knowing that natural gas deliveries to their factories and places of business can be capped by the contracted MDFQ, industrial customers are generally careful to nominate an MDFQ that will satisfy their peak delivery needs.

C. Proposal to Combine Rate Schedules T-4 and T-5

Q. Please describe the Company's proposal to combine current rate schedules T-4 and T-5 into a new rate schedule, also designated as Rate Schedule T-4.

A. The current Rate Schedules T-4 and T-5 are almost identical, except that current Rate Schedule T-5 includes both a demand charge and a volumetric charge, and current schedule T-4 includes only a volumetric charge. As shown in Table DS-1, above, the availability provisions for both Rate Schedules are the same, and as shown in Table DS-6, below, typical T-4 and T-5 customers are structurally similar. Thus, after adding a demand charge to Schedule T-4, there is no remaining distinguishing differences between the two rate schedules and therefore no purpose to be served by continuing to offer both T-4 and T-5.

Table DS-5 Current Rate Schedules T-4, T-5: Customer data (Actual 2015)

Current Rate Schedule	Customers	Therms		MDFQ	
		Total	Average	Total	Average
T-4	82	246,066,376	3,000,809	1,447,697	17,655
T-5	13	26,054,206	2,004,170	72,750	5,596
Combined	95	272,120,582	2,864,427	1,520,447	16,005

D. Industrial Proposed Rates to Industrial Rate Schedules

Q. Have you reviewed the proposed rates to Industrial Rate Schedules, as described and explained in the testimony of Witness Blattner?

A. Yes, I have.

Q. What are your general observations related to the proposed Rate Schedule LV-1 rates?

A. Under the proposed LV-1 rates, as explained by Witness Blattner, the typical (average) LV-1 customer will experience a small decrease in annual bills. Based on my review of projected LV-1 customer charges using 2015 billed consumption, current MDFQs and the proposed LV-1 demand and volumetric rates, customers that consume gas more evenly from day-to-day and month-to-month (i.e. a high “Load Factor”[5]) will experience larger decreases and customers

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[5] Load Factor is a commonly used measure to describe day-to-day and month-to-month gas consumption patterns. Load Factor is the ratio of the average daily therm use divided by some

that have relatively large differences in gas consumption by day and by month will experience smaller decreases. Some LV-1 customers with relatively large differences in gas consumption by day and by month may experience small increases in annual bills.

Q. Why do some Industrial customers have lower load factors than others?

A. In most instances, industrial customers that utilize natural gas largely for heating load will show relatively less usage during non-heating load periods and therefore have a lower than average load factor. In some instances however, customers have knowingly elect an MDFQ higher than needed, when compared to current gas consumption, in order to protect future growth expectations. In a few cases, the customer may have elected an MDFQ that does not reflect current or future expected consumption and the Company continues its efforts to educate such customers regarding the economic and operational value of a properly set MDFQ. It is my belief that the inclusion of a demand charge in all firm industrial large volume rate schedules will provide the necessary price signals for industrial customers to better manage their contracted peak day requirements. As a result, the Company will be better able to optimize the use of its distribution system.

Q. What are your general observations related to the new proposed rate Schedule T-4 and the proposed Rate Schedule T-4 rates?

A. In general, the proposal to combine current Rate Schedules T-4 and T-5, and to charge a demand rate to customers in this class has similar impacts on these

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measure of the peak day or, in this case, the MDFQ. The greater the difference between the MDFQ and the average daily use, the lower the Load Factor. For customers that are charged a demand rate and a volumetric rate, total charges are inversely related to a customer's load factor, for a given level of consumption.

customers as the LV-1 impacts that I described above. That is, under the proposed T-4 rates as explained by Witness Blattner, the typical (average) T-4 customer will experience a small decrease in annual bills. Based on my review of projected T-4 customer billing based on 2015 billed consumption, current MDFQs and the proposed demand and volumetric rates, T-4 customers with relatively high load factors will experience larger decreases, customers with lower load factors will experience smaller decreases and, in some cases, T-4 customers with the lowest load factors may experience small increases in annual bills.

Q. Please explain the Firm Demand Relief provision, which is included in the proposed LV-1 and T-4 Tariffs.

A. The Firm Demand Relief provision states, "Demand charge relief will be afforded to those LV-1 (or T-4) customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter." The Company has included this provision to provide a mechanism to refund the affected portion of a customer's demand charge in the unlikely event that the company cannot deliver the customer's full MDFQ for any days during a given month. This provision does not provide for refunds to a customer that cannot arrange for delivery of its full MDFQ or otherwise fails to deliver the needed amount of natural gas to one of the Company's city gates.

Q. Please explain the removal of the Exit Fee provision formerly found in the LV-1 Rate Schedule.

A. When the Company first implemented the T-4 Rate Schedule, it was believed that many customers would desire to switch to T-4 service and in fact, the majority of the large volume industrials did switch to T-4. In order to not saddle remaining customers with the cost of interstate capacity that Intermountain held on behalf of those customers migrating to T-4, the Exit Fee provision required those T-4 customers to pay for some of that capacity cost over a two-year period. Since most of the large volume industrials migrated to transport years ago and most of the remaining LV-1 customer are relatively small, the amount of capacity that would be freed up by one of the customers migrating to transport if largely insignificant and so the Company proposes to eliminate this provision.

Q. Please explain why LV-1 customers were removed from eligibility to use the T-3 tariff as an overrun service.

A. LV-1 customers utilize Intermountain’s WACOG supply. In the unlikely event of Entitlement, curtailment or during periods of managing a T-3 imbalance, it would be difficult, if not impossible, to identify the source of gas supplies used by an LV-1 customer.

Q. Please explain the removal of the historic high therm use provision from the T-4 Rate Schedule.

A. Because the Company is proposing the inclusion of a demand charge for the T-4 Tariff, there is no longer any concern that customers growing in the lowest price tail block or those with unusually high usage for just a short period of time, would cause other customers to bear fixed costs belonging to those growing customers. So the Company proposes to eliminate this provision.

Q. Does this conclude your testimony?

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

DIRECT TESTIMONY OF DAN KIRSCHNER

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name, title and business address.

A. My name is Dan Kirschner. I am the Executive Director of the Northwest Gas Association (NWGA). My business address is 1914 Willamette Falls Dr., Suite 260, West Linn, OR 97068.

Q. Would you please describe the NWGA.

A. The NWGA is a bi-national trade association of the Pacific Northwest natural gas industry. We are a 501(c)6, non-profit organization whose mission is to promote natural gas as a cornerstone of the region's energy, economic and environmental foundation. The NWGA accomplishes its mission by producing timely and regionally relevant information relating to natural gas**;** by shaping and communicating the industry's perspective; through policy analysis and advocacy and by facilitating high quality interactions among industry stakeholders. NWGA members include six local distribution companies serving communities throughout Idaho, Oregon, Washington and British Columbia, and three transmission pipelines that transport natural gas from production areas in Alberta, British Columbia and the U.S. Rockies into and through the Pacific Northwest.

Q. Would you please summarize your educational and professional experience.

A. I graduated from Eastern Washington University with a Bachelor of Arts Degree in Government and Economics. I also have an MBA from the University of Washington. I spent several years on the staff of the Washington State Legislature and of U.S Senator Slade Gorton. I worked for a number of years as the Vice President of Public Policy and Public Affairs at the Spokane Regional Chamber of

Commerce. I have been the Executive Director of the NWGA for the past fourteen years.

Q. What are your duties and responsibilities and accountabilities at the NWGA?

A. I am accountable for the successful execution of the NWGA's mission, its financial status and staff management. I report to a Board of Directors that includes representatives of each of the NWGA's nine member companies. I am the chief spokesperson and advocate for the industry and a resource for information about natural gas in the Pacific Northwest. I work to foster understanding and informed decision-making on relevant issues in the region.

Q. What is the purpose of your testimony?

A. I will describe the national and regional trend toward using natural gas as a fuel to generate electricity, replacing coal-fired generation and supporting intermittent renewable generation. I will also discuss the relative benefits of burning natural gas directly in end-use applications.

Q. Why is natural gas increasingly used to generate electricity?

A. In short, natural gas is abundant, clean and affordable. Gas-fired generation is economic, clean, reliable and flexible.

It has been less than ten years since North American producers first achieved economic production of hydrocarbons, including natural gas and oil, from shale formations deep underground. Since then, the amount of natural gas that can be produced has more than doubled and production has soared. We haven't found more natural gas, we found out how to produce natural gas that was previously inaccessible.

Furthermore, producers are continuously improving extraction technologies, allowing more natural gas to be produced at lower and lower prices. Today we are producing more natural gas than ever before utilizing 75% fewer drilling rigs than were in operation less than five years ago.

This phenomenon has had a dramatic effect on the price of natural gas. From 1981 to 2000, the average price of natural gas at the wellhead was $4.40/Mdth in real dollars. In 2015, the average wellhead price was $2.62. In 2008 Idaho residential consumers paid more than $200 million for natural gas delivered to the city gate. In 2015, those same consumers paid almost $100 million less for the same volume of gas.

The low price of natural gas makes it more attractive as a fuel for electrical generation. In the mid-2000s, natural gas was out of favor as a generation fuel because the fuel price risk was so high. While still a risk consideration, that risk has moderated to the point that gas-fired generation appears to be the preferred option as both a base load or energy resource, as well as the flexible, on-demand or capacity resource required to support the significant quantities of intermittent renewable generation built to serve this region over the last decade.

Finally, natural gas is the cleanest on-demand generation option that is both economic and can be permitted and built within a reasonable time frame. Compared to coal, natural gas can reduce CO2 emissions by 45% or more, produces 80% fewer nitrous oxide emissions and virtually eliminates sulphur dioxide, mercury and particulate emissions. The shift from coal to natural gas generation is widely credited with a 12% reduction in U.S. energy-related CO2 emissions from 2005 to 2015.

Q. What are the trends regarding natural gas-fired generation?

A. Abundance, affordability and a cleaner environmental profile, these are the same dynamics are driving the growth of gas-fired generation. Nationally, natural gas-fired generation is supplanting coal as older coal plants are replaced by new, cleaner natural gas plants, and as the low price of natural gas makes running existing gas plants more economical than existing coal facilities.

The shift from coal to gas has happened with astonishing speed. In 2010, coal-fired generation was the dominant electricity resource in the U.S., producing twice as much electricity as natural gas. In contrast, natural gas generation is projected by the U.S. Energy Information Administration, or EIA, to exceed coal for the first time ever during the 2016 calendar year. State and federal regulations, like the EPA's Clean Power Plan, will only accelerate this national trend.

We are experiencing the same trends in our region. In the NWGA's 2016 Natural Gas Market Outlook ("Outlook"), we are projecting 1.8% compounded annual growth rate in gas use for generation purposes from 2016-17 to 2025-26, exceeding the expected growth in gas demand from the residential (0.6%), commercial (0.8%) and industrial (0.1%) sectors. Natural gas is the marginal generation resource in our region. The projected growth is expected to come from a combination of additional baseload (energy) generation and increased utilization of flexible plants (capacity) to support renewable resources.

Natural gas is also supplanting coal-fired generation capacity in the Northwest. Recent regional coal plant retirements include the 130 MW JE Corette Plant in Montana, owned by Talen Energy, and the 170 MW Carbon Plant in Carbon, UT owned by PacifiCorp. Currently planned closures include the 250 MW Reid Gardner plant in Nevada, to be closed by the end of 2017; the 550 MW Boardman coal plant in Oregon, 10 percent of which is owned by Idaho Power, mandated to close in 2020; and one of two 670 MW coal-fired units at Centralia in Washington by the end of 2020. There is also increasing pressure to close other regional coal plants before the end of their useful lives, most notably Colstrip units 1 & 2 in Montana, co-owned by Puget Sound Energy and Talen Energy, and North Valmy Unit 1 in Utah, co-owned by Idaho Power and NV Energy.

Natural gas generation can be expected to replace some portion of regional coal retirements because it is dispatchable, economic and a cleaner generation resource. Consequently, the Outlook contemplates a scenario outside of the Expected Demand forecast replacing about two-thirds (800 MW) of the planned Boardman and Centralia retirements with natural gas.

Q. What is the Northwest Natural Gas Market Outlook you referenced?

A. The Outlook is the consensus view of NWGA members of the dynamics driving the natural gas market in the Pacific Northwest. It includes a 10-year demand forecast by sector and an analysis of the capability of the region’s infrastructure to serve that demand. It also includes discussions on North American and regional sources of natural gas supply, as well as commodity price trends. It is an aggregation of the integrated Resource Plans (IRPs) and long range planning analyses of our member companies. The NWGA publishes the Outlook annually and it can be found on our website at www.nwga.org/outlook.

Q. Does natural gas-fired generation make effective use of the available energy?

A. Natural gas is an excellent electric generation fuel for all of the reasons I've mentioned to this point. Langley Gulch is the region's most recent gas-fired generation facility and one of its most efficient. According to the Northwest Power and Conservation Council, it requires about 7,100 Btu of gas to generate 3,413 Btu of electricity (1KW), so it converts only about 48% of the available energy to useful energy. When combined with line losses from transmission and distribution, about 40% of the available energy makes it to homes and businesses, while 60% is wasted.

Q. What are the benefits of using natural gas directly for space and water heat?

A. Using natural gas directly is the most efficient use of this high quality energy resource. By all accounts, more than 90% of the available energy makes it from the well head to homes and businesses where it is burned in highly efficient appliances. In its recent whitepaper, *Dispatching Direct Use: Achieving Greenhouse Gas Reductions with Natural Gas in Homes and Businesses*, the American Gas Association asserts that a typical gas water heater uses 50% less energy than an electric resistance hot water heater; emits half the CO2 and costs less than half as much to operate on an annual basis. The same characteristics apply to electric furnaces and air-source heat pumps.

The NWGA Outlook Expected Demand forecast projects that under normal weather conditions the region will burn 15 percent or about 32 million Dth/year more gas to generate electricity in ten years than it does today. The

Outlook Expected Case forecast includes only the growth in utilization of existing natural gas plants in the region for energy or capacity. It does not include the potential for natural gas to replace soon-to-be-shuttered coal generation in the region. If the projected 32 million Dth of incremental growth in gas used to generate electricity at about 40 percent efficiency were used instead directly in homes and businesses at 90 percent efficiency, the region's consumers would save tens of millions of dollars, reduce CO2 emissions by more than a million tons and, most importantly, preserve and extend this valuable resource.

Q. Do you have any concluding thoughts or comment?

A. Natural gas is an abundant, reliable, clean and affordable source of energy. It is and will continue to be key to satisfying our region's energy needs going forward as a fuel for electricity generation, in industrial applications and to heat homes and businesses. Energy efficiency and demand side management programs should contemplate the direct use of natural gas as a strategy that is in the consumer's best interest; a strategy that reduces environmental impacts and saves dollars while preserving and extending a vital natural resource.

Q. Does this conclude your direct testimony?

A. Yes. Thank you.

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____)

DIRECT TESTIMONY OF ALLISON SPECTOR

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Allison A. Spector. My business address is 400 North Fourth Street, Bismarck, ND 58501. My e-mail address is allison.spector@intgas.com.

Q. By whom are you employed and in what capacity?

A. My corporate role is Manager of Conservation Policy as a shared employee of the Montana-Dakota Utilities Group of which Intermountain Gas Company is a part. I am actively providing Demand Side Management program development support to IGC and am additionally responsible for support and development of policy, and standards and guidelines regarding Intermountain's environmental and conservation efforts.

Q. How long have you been employed by the Utility Group?

A. I have been employed within the Utility Group since June 2008 where I served as a Conservation Analyst, then Conservation Manager, then Manager of Energy Efficiency and Community Outreach for Cascade Natural Gas Corporation. In June 2014, I took on the role of Manager of Demand Side Management for Montana-Dakota Utilities. In January 2016, I was offered the role of Conservation Policy Manager for Cascade and was additionally tasked with providing support services to Intermountain in matters related to Demand Side Management. Prior to joining MDU, I was employed by the National Association for State Community Services Programs (NASCSP) in Washington, DC. I served NASCSP as a Program Assistant, later as a Program Coordinator, and lastly as the Associate Director of Weatherization Services.

Q. What are your educational and professional qualifications?

A. I graduated from Goucher College 2005, with a Bachelor of Arts degree in Communications and Media Studies with an emphasis in policy communications; and a Bachelor of Arts degree in Political Science, degree of distinction.

I have eight years' experience designing and implementing utility-run energy efficiency programs, and an additional three years in energy policy & advocacy.

I am experienced in the design and implementation of viable, cost-effective Demand Side Management (DSM) portfolios. I have performed analysis of the cost effectiveness of DSM portfolios under both the Utility Cost Test and Total Resource Cost Test. I have designed conservation rebate programs at all stages from planning through implementation; designed tariff filings in support of these programs; selected and hired program implementation staff; developed requests for proposals for program delivery and evaluation contractors; and have developed and filed annual program performance reports.

I also co-authored a peer-reviewed paper published by the American Association for an Energy Efficient Economy titled, "Natural Selection: The Evolution of DSM Valuation and Use of the UCT" which discusses the importance of natural gas demand side management efforts and optimal methods of program valuation. The paper also addresses the importance of applying a relevant discount rate to any DSM analysis performed.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this docket?

A. My testimony will cover four primary areas. First, I will define the purpose of natural gas Demand Side Management and the current conditions influencing Intermountain

Gas Company's decision to engage in DSM. Second, I will describe the modeling utilized by the Company to assess its DSM potential and the development of associated targets. The third section will describe how Intermountain's conservation rebate portfolio was designed and how appropriate rebate levels were determined. In the last section I will present Intermountain's targeted approach to program delivery and implementation, as more fully described in the testimony of Ms. Imlach.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits, which are described in my testimony:

Exhibit 25	Demand Side Management Potential Assessment
Exhibit 26	Portfolio Design Analysis

III. PURPOSE OF NATURAL GAS DEMAND SIDE MANAGEMENT

Q. What is the purpose of Demand Side Management?

A. Demand Side Management (DSM) is a strategy used by utilities in order to optimize their consumers' energy use. When paired with supply side resources, demand side management helps ensure reliability and affordability of a resource.

In the case of a natural gas local distribution company like Intermountain Gas Company, DSM means finding opportunities to purchase therms through conservation as opposed to purchasing through a natural gas supplier. This transaction considers both commodity and transportation costs and includes encouraging voluntary reductions to natural gas usage by offering conservation incentives to its customers.

As stated in the earlier testimony provided by Mr. Kirschner, Natural gas is an abundant, affordable, and clean burning resource. Using this 90% efficient resource directly for space and water heat end use applications in the residential sector is the most efficient application of natural gas. Conservation incentives associated with high-efficiency natural gas space and water heating equipment would provide the Company with the two-fold benefit of acquiring essential DSM resources while allowing natural gas to serve the role it performs best, as a direct space and water heating fuel.

Oak Ridge National Laboratories, and others have acknowledged the value of Demand Side Management as a best-cost resource for utilities. Intermountain will be utilizing this resource to operate a program whose ultimate intent is to produce energy savings that result in lower overall rates than if the program were not in place.

Q. Does the Company intend to file for approval to recover the costs associated with a natural gas Demand Side Management Program with the Idaho Public Utilities Commission?

A. Yes. The Company is seeking approval of a new Energy Efficiency Rebate Program in support of its DSM efforts, and has submitted proposed Original Tariff Sheet No. 16 (DSM Tariff), which is supported by the testimony of Company witness Imlach. This proposed DSM Tariff sheet is part of Exhibits 30 and 31 sponsored by Company witness Michael McGrath.

The Company is simultaneously seeking recovery in the form of a fixed cost collection mechanism (FCCM), which will accompany its Demand Side Management program. More information regarding this mechanism can be found in the testimony of Mr. McGrath.

Finally, the Company intends to submit a filing following program approval to obtain deferred treatment of incremental staffing expenses (salaries associated with employees that would not otherwise have been hired in the absence of a DSM program) and administrative/outreach costs resulting from operation of a Company run Demand Side Management Program.

Q. Please summarize the type of program you are proposing to operate.

A. Intermountain is proposing to operate a natural gas conservation incentive program for residential customers. This program will provide rebates for the installation of high-efficiency natural gas equipment, and natural gas ENERGY Star certified homes. The rebates will help bridge the up-front cost of higher efficiency equipment and thus optimize the amount of energy being used in participants' homes.

Q. Why is this program focused on residential equipment rebates and ENERGY Star homes?

A. Rebates have been proven to be an effective means of encouraging the use of energy efficient equipment in the residential sector, and for the construction of energy efficient natural gas homes.

As the region's local distribution company that is providing fuel for space and water heating applications, it is intuitive that the Company focus on natural gas space and water heating equipment, and ENERGY Star homes in the residential sector. As described in both this testimony, and the testimony of Ms. Imlach, the Company is well positioned to leverage existing experience in the operation of an equipment rebate program, and build partnerships with builders and contractors for the purpose of introducing them to the value and benefits of energy efficiency.

Likewise, Intermountain's conservation potential modeling has demonstrated that focusing on the residential sector is a viable strategy for the Company to achieve meaningful energy conservation results. The program will therefore allow the Company to effectively engage in utility-operated DSM efforts.

Q. Are other Idaho utilities successfully using rebate programs in support of their Demand Side Management efforts?

A. Absolutely. Both Avista and Idaho Power offer rebates for high-efficiency residential equipment, and other energy conservation measures. Both programs are filed with the Idaho Public Utility Commission and are ratepayer recovered. Both programs result in energy savings for their companies and customers.

Intermountain Gas reviewed the design of both of these Idaho-focused programs, and examined their associated efficiency and rebate levels. This information was taken into account as IGC developed its potential assessment. The Company also solicited employee feedback, and gathered other IGC specific research to refine its conservation portfolio and gauge program feasibility and value to Intermountain's service area.

Q. Will the Company consider expanding measure offerings and sectors served at a later time?

A. Absolutely. Intermountain intends to treat DSM ramp-up as a phased approach, with its first priority being conservation achievements in the residential sector. Following the successful launch of its residential conservation program, the Company will develop efforts including a targeted rebate portfolio of prescriptive conservation measures for its commercial sector customers.

Q. What does the Company anticipate as the benefits of engaging in natural gas DSM at this time?

A. The Company sees natural gas DSM as a natural fit for the utility, its customers, and the surrounding community. A conservation incentive program utilizing rebates for high-efficiency natural gas equipment offers an environmentally beneficial, cost-effective supplement to supply side resources, while optimizing regional energy usage through the direct use of natural gas.

With Idaho regulators now accepting the Utility Cost Test (UCT) as a viable method of program valuation, and with growing in-house expertise in this area, the Company is positioned to offer cost-effective rebates to its customers.

Ultimately, everyone benefits when utilities acknowledge the environmental and economic importance of allowing natural gas to do what it does best—provide a fuel for space and water heat directly in customers' homes— as efficiently as possible. The full benefit of using natural gas directly for space and water heat is described in detail in the testimony of Mr. Kirschner.

Q. Are there any rate impacts associated with the operation of a DSM program?

A. A Demand Side Management program operated through rebates for energy efficient space and water heat equipment is a strategic investment in energy resources that would otherwise be wasted through inefficiency. As described earlier, the direct use of natural gas for space and water heating is an efficient application of this resource. Achieving DSM in combination with direct use increases the value of the Company's investment in this effort. The Company's DSM program is designed to maximize the potential of the natural gas on its system to serve as many homes as possible as cost effectively as possible.

It is Intermountain's goal to cost-effectively acquire demand side resources based on Intermountain's most recently acknowledged avoided costs. This provides value to both the Company and its ratepayers. Rates will be influenced by two factors associated with the program: the recovery of fixed costs, and the recovery of administrative program expenses.

Rate impacts associated with the recovery of fixed costs will be carefully designed as to make the Company whole for reductions to usage associated with the implementation of a DSM program.

Administrative program expenses related to the operation of the Company's DSM effort have been designed as not to exceed the threshold past which such an investment would not be cost-effective to the Company and its customers.

Q. Can you please elaborate on what you mean by "fixed cost recovery?"

A. Gladly. In this case Intermountain is filing for fixed cost recovery to mitigate losses to margin resulting from its conservation efforts. This mechanism will allow the Company to remain whole as it actively pursues cost-effective forms of conservation to maximize natural gas efficiency and bring value to its customers.

Q. Can you elaborate on what you mean by "administrative program expenses?"

A. There will be reasonable costs associated with the operation of Intermountain's DSM program. The Company anticipates an initial budget of approximately $225,000, which will include funding for program outreach; and for the hiring of a dedicated staff for program support and implementation. The Company will also leverage existing staff resources, which will not be included as part of its program delivery budget. Intermountain's rebate portfolio has been designed to shoulder these costs while still maintaining cost effectiveness under the Utility Cost Test (UCT). The Company anticipates that rebate payments will be in the range of $200,000 - $600,000 in the first program year based on customer interest and the effectiveness of its program outreach efforts.

As stated earlier, it is the Company's intention that DSM effort procure therms through investment in natural gas molecules and their associated transportation costs at a cost lower than that of alternative resources. Therefore, the program design will ensure that energy efficiency purchased by the utility through DSM efforts will result in lower overall rates to customers than would be experienced if the program was not in operation.

Q. Does the Company intend to file a follow-on application to seek recovery of program expenses?

A. Yes. It is the Company's intention to file a follow-on application to seek recovery of all rebate costs associated with its DSM effort, as well as its program delivery budget and the salaries of staff that would have not otherwise been hired without the presence of the Company's Demand Side Management rebate program. Program expenses have been balanced against the associated therm savings of the rebate portfolio and have been assessed as cost effective under Exhibit 26 associated with this filing.

Q. Have you prepared an exhibit summarizing the fixed cost collection mechanism accompanying the design of your DSM program?

A. Yes. Details and exhibits supporting the FCCM can be found in the testimony of Mr. McGrath.

Q. What are the benefits to ratepayers if the Commission approves this recovery of programmatic expenses, including the staff positions you describe?

A. A well-designed DSM program, like the one the Company is proposing, results in both electric and natural gas savings. Electric savings comes from the customers' decision to use natural gas directly for space and water heating, as opposed to the reduced efficiency of using natural gas to generate the electricity to power equipment for the same end use. As the testimony of Mr. Kirschner has indicated, by the time a customer turns on an electric appliance, up to 62% of the energy from the original fuel has been lost. The full fuel cycle efficiency of natural gas equipment is about 92%. Therefore using natural gas space and water heating equipment directly, as opposed to using electricity for these end uses, results in meaningful conservation of energy resources. Natural gas savings is then achieved through Intermountain's program by providing rebates for extremely energy-efficient models of natural gas space and water heating equipment. The installation of high-performance natural gas equipment and proliferation of ENERGY Star natural gas homes results in a carbon footprint reduction, which is good for the environment, and the entire community.

The program is beneficial to all ratepayers because it secures a long-term supply (16-30 years) of demand side resources in the form of quantifiable natural gas conservation. This resource helps supplement traditional supply side resources at a cost equal to or lower than traditional supply when factoring for both the avoided molecule cost and the transportation to deliver the resource. It also helps mitigate future capacity constraints to ensure ongoing reliability.

Intermountain's program is beneficial from a customer standpoint, because it helps mitigate the upfront cost of high-efficiency equipment run on natural gas— a clean-burning, reliable, and affordable resource. By incentivizing for high performance natural gas equipment and ENERGY Star Homes, the Company is working to ensure that natural gas is being used as efficiently as possible within that customer's home. This provides economic savings for the customer.

IV. DMS POTENTIAL ASSESSMENT

Q. Could you please describe the contents of Exhibit 25 "Demand Side Management Potential Assessment" of your testimony?

A. Absolutely. Exhibit 25 provides an examination of the total demand side management potential available to Intermountain's residential sector. This was modeled through an analysis tool called TEAPot, which was developed by Nexant for IGC's sister company, Cascade Natural Gas Corporation in 2014. TEAPot refers to the acronym, Technical, Economic, and Achievable Potential. The model incorporates an analysis of available technologies, climate zone, load forecasts, and market segments.

Intermountain utilized the TEAPot tool in order to better understand the DSM potential in its service area under both the Utility Cost Test (UCT) and the Total Resource Cost (TRC) test.

Based from Intermountain's data for both usage and premise counts, the TEAPot was first run with the following assumptions: 3.69% discount rate; 1.0 cost benefit ratio; 2.60% inflation rate. Two separate scenarios were modeled, gauging potential under both the Utility Cost Test (UCT) and Total Resource Cost (TRC) test.

All scenarios were operated using a portfolio of energy efficient natural gas DSM measures. The resulting analysis provides the Company with a range of therm savings under the lens of Technical, Economic, and Achievable potential. This has allowed the Company to better understand the total conservation potential associated with its proposed portfolio of high-efficiency residential equipment measures.

Q. What data was input by the Company in order to operate the TEAPot model?

A. Intermountain specific assumptions programmed into the TEAPot modeling tool can be found on Exhibit 25.

Q. Who ran the TEAPot model and from where were the inputs derived?

A. The TEAPot modeling tool was operated by Intermountain staff for the purposes of assessing the Company's DSM potential and assisting in the design of the measures comprising the proposed conservation rebate portfolio. Inputs were derived from Intermountain's data as described above.

Q. Can you please describe the difference between Technical, Economic, Achievable, and Program Potential?

A. Technical Potential refers to the savings that could be achieved if all homes theoretically eligible to receive high-efficiency natural gas equipment did so without regards to economics or personal preference. If the Company could make all qualified homes upgrade to all possible measures, the Technical Potential would be the result. The only limitation is technical feasibility and the applicability of the measure to be installed.

Economic Potential examines the savings that could be achieved through measures that pass a cost effectiveness test. It considers what would be achieved if everyone who could *theoretically* afford to install pre-screened high-efficiency natural gas equipment did so without regards to personal preference or alternative priorities. In other words, economic potential looks at a high-level cost-effectiveness under current economic conditions, but does not consider customer interest, priorities, or perceptions of energy conservation.

Achievable Potential further refines the Company's understanding of DSM potential by examining it under the lens of economic and social realities. It asks "how much savings will result from *this* portfolio of utility rebate measures based on real-world conditions in Intermountain's service area, and customer awareness?"

There is also a fourth level of potential, which is not directly modeled under TEAPot, but has been considered by the Company, called Programmatic Potential. Programmatic Potential further refines Achievable Potential by examining what level of savings can be realistically accomplished within the current staffing, budgetary, and regulatory parameters of the utility operating the program.

While the model is unable to examine this final level of potential, Nexant, the architects of the TEAPot model, recognized its significance. In the written narrative provided for the study that was performed for Cascade in 2014, they stated that "Program Potential reflects the realistic quantity of energy savings the utility can realize through DSM programs during the horizon defined in the study. Savings delivered by program potential is often less than achievable potential, due to real-world constraints, such as utility program budgets, cost-effectiveness thresholds, regulatory and policy statements, and decisions on which subset of cost-effective measures a utility ultimately decides to include in its portfolio" (Assessment of Achievable Potential & Program Evaluation, V2, Section 2.2, p15).

Intermountain has therefore developed initial programmatic targets as a number blended between the Achievable Potential estimates modeled in its analysis, and further refined by in-depth discussions with IGC distract staff regarding the on-the-ground realities of Intermountain's service area.

Q. What measures were included in your analysis, and why were these selected?

A. Intermountain's analysis included a range of high-efficiency residential sector measures including ENERGY Star certified homes, energy efficient natural gas furnaces, fireplace inserts (an important air-quality and woodstove replacement measure), and water heaters. The Company examined several efficiency ranges, eventually narrowing in on the highest tiers available within the market in which Intermountain operates and for which it had valid data.

The Company examined the viability, and associated energy savings potential, of portfolio measures under several conditions including: (1) conversions from non-gas to high-efficiency natural gas equipment, as well as installations in the new construction sector; (2) replacement of broken lower-efficiency natural gas equipment with high efficiency natural gas equipment; and (3) replacement of functioning lower-efficiency natural gas equipment with high-efficiency natural gas equipment before the end of the measure's useful life. Analysis concentrated on space and water heating applications in new and existing construction, as well as on the viability of rebates for ENERGY Star homes.

Q. Could this analysis be further refined or expanded to other measures at a later date, if warranted?

A. Absolutely. The Company intends to explore a range of conservation options on an ongoing basis, continuing to expand and refine its analysis based on available resources.

V. CONSERVATION REBATE PORTFOLIO

Q. What circumstances have changed that has resulted in the Company's interest and ability to develop a conservation rebate program?

A. Three primary factors have precipitated the Company's interest in achieving demand side management through the use of a conservation rebate program.

First, I read the Commission's Order No. 33444 in Avista's 2015 general rate case as sanctioning Avista's proposal to adopt the Utility Cost Test (UCT) as a reasonable method of valuation of natural gas DSM. Following that lead, Intermountain has utilized the UTC alongside other tests, which has allowed the Company to assess the viability of natural gas DSM options, identify multiple cost-effective measures that would attain greater DSM value clarity, and result in a more viable DSM portfolio under the Utility Cost Test (UCT). The UCT reflects the Company's perspective as an investor-owned LDC, and results in the identification of a robust portfolio of natural gas DSM measures.

Second, conservation is an issue of public importance. This means conserving electricity through the direct use of natural gas for space and water heat, as well as maximizing the efficiency of natural gas equipment used in residential customers' homes. The Company continues to promote the direct use of natural gas and supports the adoption of energy conservation and DSM programs.

Third, Intermountain has the opportunity to positively influence the energy mix in its service area to ensure that natural gas is being used with maximum efficiency as a space and water heating fuel in the residential sector. Pairing direct use with high-efficiency natural gas equipment is a win-win for the Company, the environment, and ratepayers. Intermountain is glad to have the opportunity to pursue a program to encourage responsible use at this time.

In light of the above, the Company has developed in-house expertise necessary to fully assess its DSM potential, viable conservation measures, and to support the design and implementation of a fully articulated energy-efficiency residential rebate program. Company staff will continue to perform this work and will be actively engaged in supporting this program on an ongoing basis and ramping up additional staffing resources as cost-effective and appropriate.

Q. Could you please further elaborate on how a rebate program results in DSM and the efficient use of natural gas directly for space and water heat applications?

A. Rebates will result in the efficient use of natural gas directly for space and water heating applications by driving the sales of high-efficiency natural gas equipment and ENERGY Star natural gas homes. Natural gas fired energy efficiency upgrades from standard efficiency (code level) equipment results in a reduction to the amount of therms utilized for a given end use. This savings will then be recorded as energy conservation attributable to this program. The direct use of natural gas further reduces the strain on electric load which could better be applied to alternative end uses in a home.

Q. Has Intermountain developed an exhibit detailing the rebate program portfolio it has developed?

A. Yes. A full summary of Intermountain's rebate portfolio and associated details can be found in Exhibit 26: "DSM Rebate Program Analysis," which offers the full cost analysis that went into the Company's program design.

Q. Can you please further describe how your rebate program will operate?

A. Gladly. As explained in greater detail in the testimony of Ms. Imlach, the Company's conservation rebate program will be open to all customers on its residential rate schedule. Intermountain will be providing rebates for a range of cost-effective natural gas high-efficiency HVAC and water heat equipment, as well as for ENERGY Star natural gas homes.

There will be two tiers of rebates—one for upgrades from standard efficiency to high-efficiency natural gas equipment. The second tier will provide incentives for natural gas ENERGY Star homes, and for upgrades from standard electric to high-efficiency natural gas equipment. Rebates will be administered by the Company and issued in the form of a check following receipt of a completed and valid rebate application; which includes proof of sale and installation of associated equipment, or certification documentation in the case of Energy Star homes. Rebates will be advertised via bill inserts, through education to area contractors, via programmatic and district staff, and through other media as appropriate.

An annual report of expenditures, activities, therm savings, and overall cost effectiveness will be provided at the end of each program year.

Q. What measures will be included in the Company's rebate portfolio and how were they selected?

A. The Company is proposing a rebate portfolio comprised of the following measures:

<u>ENERGY Star Certified Natural Gas Homes</u>

($1,200 rebate)

<u>95%+ AFUE Natural Gas Furnace</u>

Tier 1: ($350 rebate), Tier 2: ($500 rebate)

<u>High Efficiency 90%+ Natural Gas Combo Radiant Heat System</u>

Tier 1: ($1,000 rebate), Tier 2: ($1,200 rebate)

<u>80%+ AFUE Natural Gas Fireplace Insert</u>

Tier 1: ($200 rebate) Tier 2: ($250 rebate)

<u>70%+ FE Natural Gas Fireplace Insert</u>

Tier 1: ($100 rebate), Tier 2: ($200 rebate)

<u>.67+ Energy Factor Natural Gas Water Heater</u>

Tier 1: ($50 rebate), Tier 2: ($75 rebate)

<u>.91+ Energy Factor Natural Gas Tankless Water Heater</u>

Tier 1: ($150 rebate) Tier 2, ($200 rebate)

These measures were selected based on the following factors: (1) identified viability in the TEAPot modeling tool; (2) overall cost effectiveness when modeled in the conservation portfolio development tool; (3) general availability of these measures in Intermountain's service area and an (4) opportunity for greater penetration of these measures within IGC's service territory as demonstrated through both TEAPot and observed directly by the Company's staff operating the field at the district level and; (5) the presence of similar measures in established natural gas conservation programs in the Northwest.

Q. Why is the Company proposing two levels of rebates?

A. Intermountain is proposing two cost-effective tiers of rebates: one for converting from standard to high efficiency natural gas equipment, and one for converting from standard electric to high efficiency natural gas equipment. A higher incentive will be provided for electric-to-gas equipment upgrades in acknowledgement of the higher up-front equipment costs and logistical costs of conversion. The program will begin with the baseline assumption of a 25% cost increase between gas and electric equipment measures of the same end use. Rebates will be set at as close to 30% of incremental cost as possible without exceeding levelized cost thresholds.

Intermountain agrees with the testimony of Mr. Kirschner that the direct use of natural gas for space and water heating is the best application of this fuel source. The higher-level rebate acknowledges this value, while helping a small increase in rebate amount to further bridge the incremental cost difference between electric and natural gas equipment.

Q. Can you please describe the assumptions utilized in the development of your rebate portfolio?

A. Yes. A description of each assumption used to model the viability of Intermountain's conservation portfolio has been outlined in detail below:

Therm Savings: Therm savings inputs were based from the zonal assumptions coded into the model which fall within the average of Intermountain Gas Company's Eastern and Western climate zones. Current assumed therm savings are in the conservative range and are based upon an averaged savings resulting from the installation of measures within new construction, existing construction, manufactured, replacement, and as a turnover measure.

Conservation Targets: After careful consideration, and guidance from both the TEAPot model and Company personnel, Intermountain is setting a program year target of 65,000 therms, reflecting the Achievable Potential that can be acquired through Intermountain's proposed portfolio of conservation measures. It was developed by running the TEAPot model with IGC forecasting data, assessing the volume of incentives needed to achieve the various potential levels, and reviewing the outcomes with district staff. More details behind the conservation targets can be found in Exhibit 25.

Basing Intermountain's portfolio design from a target of 65,000 therms ensures that the Company is able to maintain cost-effectiveness upon a strong foundation of realistic expectations. That said, it is also the Company's desire to push beyond the existing market and drive positive change in equipment purchasing behavior within Intermountain's communities. The Company is therefore setting a "stretch" goal of 97,825 therms based on its TEAPOT modeled Technical Potential, which is aspirational rather than achievable. Because IGC is not certain this stretch goal is realistic, program cost-effectiveness is not dependent upon this aspirational target, but rather upon the realistic achievable target developed by the Company.

However, Intermountain will aspire to achieve this goal with planned staffing and budget levels, in order to attain the greatest value possible for the Company and its customers, through the Company's investment in DSM.

Target Levelized Cost: The Company has developed a levelized cost target of $0.531 which was based from the following inputs:

Commodity Cost of Gas (WACOG) = $0.32764

Fixed Cost of Gas (Pipeline + Storage Fixed + Commodity Costs) = $0.20418

These two numbers added together equal $0.53182, which is the threshold used in determining which measures would be cost-effective to include in Intermountain's program. Intermountain will reassess avoided costs on an ongoing annual basis to ensure that the cost-effectiveness threshold is up-to-date and reflects the current avoided costs of the Company.

Program Expenses: The Company anticipates a programmatic budget of $225,000 for program outreach and operational expenses including two FTE staff to deliver the program. This is a preliminary estimate of the Company's staffing and administrative needs, and it is subject to change as necessary to ensure appropriate program delivery and cost effectiveness. However, any adjustments made to this original assumption will be placed within the confines of the program's cost-effectiveness modeling to ensure the portfolio does not exceed the $0.531 threshold. Anticipated total rebate expenditures for the program year will vary based upon the measures that drive customer participation. However, preliminary estimates are in the $200k - $600k range for rebates paid in association with the portfolio of measures pre-screened from program cost effectiveness and modeled under the associated spreadsheets.

Rebate Levels: Rebate levels were based on similar natural gas offerings and equivalent electric measures within IGC’s service areas and surrounding regions. Rebate levels have been set to be as close to 30% of incremental cost as possible, and higher where cost-effective, in order to ensure that they are sufficient to attracting customer interest and avoiding free ridership. Thoughtfully constructed incentive levels will help kick-start natural gas DSM efforts in Intermountain’s service area and drive customers towards environmentally beneficial equipment choices while mitigating the risk of free ridership.

Incremental Costs: Incremental cost levels were shaped by the baseline market assumptions developed during the design of the TEAPot model, and refined with on-the-ground market research performed by the Company. Intermountain will be monitoring installed measure costs on an ongoing basis and will make adjustments to these assumptions as appropriate.

Measure Life: Measure life assumptions were based from the figures utilized by Nexant in its modeling tool, engineering best practices, and the standard measure life assumed for the same piece of equipment in comparable utility programs.

Discount Rate: The model utilizes a 20-year mortgage rate reflecting the averaged lifespan of the measures within Intermountain’s rebate portfolio with an APR of 3.69%. This approach acknowledges the low-risk, long-term value, and reliability of home-based energy efficiency investments. It likewise acknowledges the utility's investment in demand side resources through a long-lived energy efficiency portfolio as a viable supplement to supply side resources.

The Company shall regularly monitor, and update program variables on an annual basis, in order to make adjustments, as appropriate to the program design.

Q. Is the Company considering cost effectiveness at the individual measure level, the portfolio, or both, and why was this approach taken?

A. The Company is considering cost-effectiveness at the portfolio level. In addition, the discrete measures within the Company's proposed conservation portfolio are generally viable at the individual level, with minor variations in cost effectiveness taking place from measure to measure.

All measures within the portfolio developed by the Company have strong UCT results and were screened via the TEAPot model. The Company is confident that the real world application of its rebate portfolio is cost effective.

Q. Under what cost test/s are these measures deemed to be cost effective and what were the underlying inputs that lead to that conclusion?

A. The proposed conservation program portfolio as designed is cost-effective to the Company under the Utility Cost Test.

The main drivers of cost-effectiveness of the Utility Cost Test are utility rebate payment levels and administrative expenses which are balanced out against total energy savings. This approach treats supply and demand side resources as equally valuable. Under the UCT, the customer is seen as a supplier from which the Company is purchasing natural gas. The Company "purchases" unused therms and their associated transportation costs from customers resulting from the use of

Company-driven purchases of energy-efficient natural gas equipment. A cost effective DSM rebate program under the UCT must ensure that the Company pays the same amount or less for demand side resources as it does for supply side resources. In the case of Intermountain's proposed portfolio, the UCT result is below the $0.531 levelized cost threshold, meaning that the portfolio is cost effective since it cost the same or less to "purchase" unused therms, with their associated transportation costs, from the customer via IGC's conservation portfolio than it does to purchase energy from traditional suppliers.

The Company also performed analysis of its proposed conservation portfolio under the Total Resource Cost Test. The main drivers of the TRC are the cost of the energy savings equipment purchased by the customer and the Company's associated administrative costs, balanced against the total energy savings. The test scrutinizes the customer's purchasing decision, focusing on whether the investment in energy savings yields adequate payment to the customer under current energy prices. However, this level of analysis is not typically conducted when assessing a supplier from which natural gas will be purchased. And the customer from which DSM is purchased may see additional benefits and value beyond energy savings that, when paired with the rebate offered by the utility, may motivate them to purchase high-efficiency natural gas equipment.

Furthermore, lower natural gas costs today will not necessarily translate into lower natural gas costs in the future. It is when natural gas is the lowest priced that consumers are more likely to be driven towards use of the product. Encouraging conservation during lower natural gas costs by providing an additional economic motivation through rebates, is essential to proper management of this precious natural resource and to maintain reliability for the Company. Therefore, even though the TRC result does exceed the Company's levelized cost threshold, Intermountain believes that portfolio is still cost effective, and worth pursuing.

Q. Will the Company be utilizing the same discount rate for the development of its conservation portfolio as it did for its DSM potential analysis?

A. Yes. Intermountain's program design was informed by its TEAPot DSM analysis and all inputs have been synchronized accordingly.

Q. Does the Company intend to calculate total annual therm savings achievements on a net or gross basis?

A. The Company intends to calculate savings on a gross basis, based on the program's deemed therm savings.

Q. Please describe the ways the Company intends to mitigate free ridership as part of this program?

A. The Company will be working to mitigate free ridership in several ways through the development and implementation phases of its program.

First, Intermountain has taken free ridership risks into account in the development of its program portfolio. For example, the Company had initially considered lower efficiency levels for furnace and water heat incentives. However, after consulting with district staff throughout IGC's service area, Intermountain's DSM development team learned these measures were already being sold without the need for further incentive. The Company took this feedback seriously as measures were selected.

Second, the Company is following guidance developed by Nexant during the development of the TEAPot model that suggests rebate levels of at least 30% of the incremental cost of a measure are more likely to result in program participation. Intermountain will bring out rebates as close to, or higher, than these levels as possible while maintaining program cost-effectiveness.

Third, the Company will gather information, where available, on the efficiency levels of equipment installed in customers' homes pre and post program implementation where available, to determine the influence the program has on customer purchasing decisions.

Fourth, the Company will make program updates on an ongoing basis to ensure that rebates are only provided for measures that are not already saturating the market so that they serve their intended purpose—as an incentive that drive positive consumer behavior.

Finally, it is important to note that in addition to free ridership, there will be a certain percentage of homeowners that will purchase Energy Star homes and high-efficiency natural gas equipment as a direct result of Company marketing and outreach that will *not* apply for a conservation incentive. This will result in therm savings directly attributable to Intermountain's program that is left unquantified. However, the Company believes that both these savings, and free ridership will likely be minimal.

Q. Are there any other energy benefits associated with this program?

A. Yes. Utilizing high performance natural gas equipment in place of electric equipment results in the direct use of natural gas, which is a more efficient use of the resource for providing home space and water heating. The Department of Energy recognizes source efficiency as the optimal measure of efficiency, and therefore electric savings resulting from the use of energy-efficient natural gas equipment should be considered when evaluating the merits of a natural gas DSM program.

Q. What actions will the Company take to help ensure the program operates as anticipated?

A. Intermountain has developed a cost-effective, low risk conservation portfolio. The Company has selected proven measures with known therm savings values and has estimated program participation levels via the TEAPot model which has been updated with Intermountain specific inputs. Intermountain further refined this figure with direct input from district staff to provide the most realistic estimate possible for therm savings achieved during its ramp-up phase. In addition, IGC developed a modest, but realistic budget, minimizing sunk costs to two FTE employees in order to balance having adequate staff to deliver the rebate program, and cautiously managing program expenditures prior to demonstrated performance.

Quite simply, the Company has planned its portfolio design to ensure customers are offered an attractive, well-staffed, and successful program. Rebates have been set at levels designed to drive customer interest, while balancing against the law of diminishing returns. If the program does not perform as anticipated, Intermountain will examine the root cause of this underperformance and will adjust. The Company is confident that in the event of unforeseen problems, the program could withstand lower than anticipated participation, or the need for additional expenditures if absolutely necessary.

Q. What impact will failing to achieve annual therm savings targets have on program cost effectiveness and operation?

A. If the Company fails to achieve its annual therm savings targets, the overall cost effectiveness of its program portfolio will be lowered. However, the conservation portfolio was designed to withstand lower participation levels if necessary. This was done by prudently budgeting program ramp-up costs, while maintaining rebates at levels comparable to other natural gas utility programs. In the event that program participation was low enough to result in cost-effectiveness below Intermountain's $.531 threshold, the Company would reexamine its rebate levels, portfolio design, and outreach strategy for following years.

Q. What impact will exceeding annual therm savings targets have on program cost effectiveness and operation?

A. If the Company were to exceed its annual therm savings targets, the portfolio as a whole would become even more cost effective than anticipated since more therms would be saved for the same budgeted level of investment. In such a case, the Company would assess if participation levels were sustainable, and if so, would work within the parameters of its TEAPot analysis and feedback from district staff, to expand its program and raise associated targets as appropriate.

VI. PROGRAM DELIEVERY AND IMPLEMENTATION

Q. Can you describe how the conservation/DSM program proposed by the Company will be implemented?

A. Absolutely. With this general rate case, the Company seeks to implement its first ever Demand Side Management Program (DSM) for the residential sector with a request for cost recovery to be filed pending approval of the DSM program. This program will be implemented in-house, and led by Intermountain's Manager of Energy Utilization. The Company anticipates that two additional positions will be developed in association with this program. This includes an FTE position designed to process and verify rebates, perform all required data tracking and reporting, and to serve as an energy advisor to IGC customers. The second anticipated position would provide deeper analysis of energy conservation measures and potential and would support training and technical assistance to area HVAC contractors in regards to Intermountain's program, and would perform quality control inspections as needed. The Company will also leverage existing staff resources such as its Consumer Sales Representatives who are positioned to reach out directly to customers to encourage program participation.

The Company also intends to reach out to local builders and contractors to introduce them to high-efficiency natural gas equipment options and increase the proliferation of these technologies in the communities served by IGC. Intermountain's goal will be to build a robust Trade Ally network comprised of carefully screened equipment dealers and installers whom it will work with to encourage greater participation in this program.

Additional detail regarding program structure and delivery can be found in the testimony of Ms. Imlach.

Q. How will the Company publicize and promote its DSM rebate program?

A. The Company intends to publicize and promote its DSM program through as many channels as possible, which may include: bill inserts; utility newsletter messaging;

information on the Company’s website; word-of-mouth by existing Consumer Sales Representatives; flyers and brochures; co-op advertising with local contractors; billboards; home and garden shows; home builder association meetings; radio, print, and television ads; and other media and methods as cost-effective and appropriate.

Q. Will the Company consider expanding its program, or adding additional measures following program ramp-up?

A. Yes. As stated earlier, it is the Company’s intention to explore additional DSM opportunities following its initial ramp-up. Program changes and expansions will be based from the on-the-ground results of its DSM program, as well as ongoing feedback from district staff, area contractors, and Intermountain’s customers.

Q. Does this conclude your testimony?

A. Yes it does.

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 25

Line No.	Measure Type	Name	Description	Baseline Description	Vintage	Segment	End Use	Applicability
1	Equipment	Condensing High Efficiency Natural Gas Tankless Water Heater (0.91 EF)	Condensing High Efficiency Natural Gas Tankless Water Heater (0.91 EF)	0.62 EF 40-gallon tank water heater	New, Early Retirement , Turnover	Single Family, Multifamily, Manufactured	Water Heating	90%
2	Equipment	Conventional High Efficiency Natural Gas Water Heater (EF=.67)	40 Gallon High Efficiency Natural Gas Water Heater (0.67 EF)	Code 0.59, Stock 0.54 EF Gas Water Heater, 40 gallon	New, Early Retirement , Turnover	Single Family, Multifamily, Manufactured	Water Heating	90%
3	Equipment	High efficiency combination domestic hot water and hydronic space heating system using pre-approved tankless water heater	Tankless water heater with mean capacity of 108 MBTU/hr	Standard furnace and water heater setup. Furnace details: Stock: 90% Efficient, Code 92% Efficient. Water heater details: 0.62 EF.	New, Early Retirement , Turnover	Single Family, Multifamily, Manufactured	Space Heating	76%
4	Equipment	High Efficiency Furnace 95 AFUE	High-efficiency (condensing) furnace = AFUE 95	Gas-fired furnace = AFUE 76 (existing) or AFUE 80 (code)	New, Early Retirement , Turnover	Single Family, Multifamily, Manufactured	Space Heating	90%
5	Equipment	High Efficiency Hearth - 80% AFUE	High efficiency natural gas fireplace hearth; AFUE 80%	The hearth replaces a log fireplace. The heat provided offsets furnace heat and the fireplace insert reduces air infiltration. Both these components provide furnace consumption savings. Baseline is therefore a Standard efficiency forced air furnace (72% AFUE)	New, Early Retirement , Turnover	Single Family, Multifamily, Manufactured	Room Heating	2%
6	Nonequipment	Energy Star Home	HERS 75	2006 IECC Zone 5 (Denver) - adjusted	New, Early Retirement , Turnover	Single Family, Multifamily, Manufactured	Space Heating	2.5%

Exhibit No. 25
Case No. INT-G-16-02
A. Spector, IGC

Exhibit No. 25
Case No. INT-G-16-02
A. Spector, IGC
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Line No.			
1			
2	**Incentive Level**	**Cost Benefit Threshold**	**Inflation Rate**
3	30%	1.00	2.60%
4			
5	**Discount Rate**	**Transmission Loss Rate**	
6	3.69%	0.1959%	
7			
8			
9			

Start Year Sales Distribution by Segment (%)

Segment	% of Start Yr Sales
Single Family	92.00%
Multi Family	7.50%
Manufactured	0.50%

Line No.						
10	**End Use Saturation**					
11		Space Heating	Room Heating	Water Heati	Clothes Drying	Other
12	Single Family	87.40%	9.10%	99.60%	94.50%	100.00%
13	Multi Family	70.90%	20.40%	87.90%	71.00%	100.00%
14	Manufactured	88.60%	5.90%	99.50%	91.00%	100.00%
15						
16	**End Use Fuel Share (Natural Gas)**					
17		Space Heating	Room Heating	Water Heati	Clothes Drying	Other
18	Single Family	99.00%	60.52%	83.46%	6.30%	100.00%
19	Multi Family	99.00%	37.33%	18.36%	3.85%	100.00%
20	Manufactured	99.00%	46.81%	59.78%	2.85%	100.00%
21						
22	**Start Year Sales Distribution by End Use (%)**					
23		Space Heating	Room Heating	Water Heati	Clothes Drying	Other
24	Single Family	70.90%	4.31%	23.32%	0.24%	1.23%
25	Multi Family	62.00%	6.51%	30.74%	0.19%	0.57%
26	Manufactured	71.68%	2.30%	21.09%	0.13%	4.80%

SALES FORECAST INPUTS

Residential Sector Forecast (Therms)	
2016	227,521,380
2017	234,742,301
2018	242,227,419
2019	250,037,327
2020	258,010,605
2021	264,582,135

PREMISE FORECAST INPUTS

Start Year (2016) Premise Count	
Single Family	289,690
Multi Family	23,617
Manufactured	1,584

Premise Count Growth Rates	
2016	2.5%
2017	2.5%
2018	2.5%
2019	2.5%
2020	2.5%
2021	2.5%

Line No.

1 TEAPOT Scenario Results: Utility Cost Test, 3.69% Discount Rate

Line No.								
2	**Annual Incremental Energy Savings by Scenario (Thm)**				**Cumulative Energy Savings by Scenario (Thm)**			
3		Tech	Econ	Ach1		Tech	Econ	Ach1
4	2016	2,773,527	2,446,984	97,825	2016	2,773,527	2,446,984	97,825
5	2017	2,913,533	2,567,969	140,116	2017	5,687,059	5,014,953	237,940
6	2018	3,027,354	2,670,882	196,979	2018	8,714,413	7,685,835	434,920
7	2019	3,148,472	2,780,391	273,857	2019	11,862,885	10,466,226	708,776
8	2020	3,273,715	2,893,774	374,292	2020	15,136,600	13,360,000	1,083,069
9	2021	3,383,183	2,993,436	496,496	2021	18,519,782	16,353,436	1,579,564

10

11 TEAPOT Scenario Results: Total Resource Cost Test, 3.69% Discount Rate

Line No.								
12	**Annual Incremental Energy Savings by Scenario (Thm)**				**Cumulative Energy Savings by Scenario (Thm)**			
13		Tech	Econ	Ach1		Tech	Econ	Ach1
14	2016	2,773,527	162,496	5,621	2016	2,773,527	162,496	5,621
15	2017	2,913,533	167,678	7,974	2017	5,687,059	330,174	13,595
16	2018	3,027,354	177,277	11,471	2018	8,714,413	507,451	25,066
17	2019	3,148,472	187,488	16,284	2019	11,862,885	694,938	41,350
18	2020	3,273,715	198,216	22,713	2020	15,136,600	893,154	64,063
19	2021	3,383,183	208,253	30,821	2021	18,519,782	1,101,407	94,884

20

Line No.								
21	**Utility Cost Test**				**Total Resource Cost Test**			
22	**Potential Savings as a Percentage of Sales by Scenario (annual incremental savings)**				**Potential Savings as a Percentage of Sales by Scenario (annual incremental savings)**			
23		Tech	Econ	Ach1		Tech	Econ	Ach1
24	2016	1.22%	1.08%	0.04%	2016	1.22%	0.07%	0.00%
25	2017	1.24%	1.09%	0.06%	2017	1.24%	0.07%	0.00%
26	2018	1.25%	1.10%	0.08%	2018	1.25%	0.07%	0.00%
27	2019	1.26%	1.11%	0.11%	2019	1.26%	0.07%	0.01%
28	2020	1.27%	1.12%	0.15%	2020	1.27%	0.08%	0.01%
29	2021	1.28%	1.13%	0.19%	2021	1.28%	0.08%	0.01%

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 26

Intermountain Gas Company
DSM Rebate Program Analysis

LINE NO.			
1	**Inflation rate**		2.60%
2	**DISCOUNT RATE**		3.69%
3	**Program Admin Costs (est. delievery & salary costs)**	$	225,000
4	**Program Target**		65,000
5	**Estimated Program Cost per Therm**		$3.46
6	**Cost Effectiveness Threshold = $0.53182**		
7			
8			
9			
10			

11 12 13	MEASURE		EFFICIENCY RATING	ANNUAL THERM SAVINGS	INCREMENTAL COST	MEASURE LIFE	DISCOUNTED THERM SAVINGS UCT	ESTIMATED PROGRAM ADMIN COSTS PER MEASURE
14	**Energy * Certified Home (BOP 1)**		92% AFUE Rating	204	$ 4,000.00	30	3,664	$ 706
15	**95% AFUE Gas Furn (Existing)**		95% AFUE Rating	112	$ 1,307.00	18	1,454	$ 388
16	**High Efficiency Combination Radiant Heat**		90% Eff Condensing Tankless Combo w/ WH	451	$ 2,500.00	21	6,512	$ 1,561
17	**80% AFUE Hearth**		80% AFUE Rating	76	$ 600.00	20	1,062	$ 263
18	**70% FE Hearth with Int Ignition**		70% FE Rating	56	$ 425.00	20	782	$ 194
19	**.67 Water Heater**		0.67 Energy Factor or Greater	22	$ 349.00	16	262	$ 76
20	**.91 EF Tankless Water Heater**		.91 Energy Factor or Greater	58	$ 1,360.00	18	753	$ 201

21
22
23
24
25

26 **STANDARD REBATE UNDER UTILITY COST TEST**

27 28 29	MEASURE		PROGRAM REBATE	UTILITY COST TEST (UCT) OUTCOMES	UCT WITH PROGRAM ADMIN COSTS	UCT COST/ BENEFIT RATIOS
30	**Energy * Certified Home (BOP 1)**			$ -		
31	**95% AFUE Gas Furn (Existing)**		$ 350.00	$ 0.241	$ 0.507	1.635
32	**High Efficiency Combination Radiant Heat**		$ 1,000.00	$ 0.154	$ 0.393	2.549
33	**80% AFUE Hearth**		$ 200.00	$ 0.188	$ 0.436	2.082
34	**70% FE Hearth with Int Ignition**		$ 100.00	$ 0.128	$ 0.376	3.068
35	**.67 Water Heater**		$ 50.00	$ 0.191	$ 0.481	2.072

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.91 EF Tankless Water Heater		$ 150.00	$ 0.199	$ 0.466	1.976
				$ 0.3799	

DIRECT USE REBATE UNDER UTILITY COST TEST

MEASURE		PROGRAM REBATE	UCT OUTCOMES	UCT WITH PROGRAM ADMIN COSTS	UCT COST/ BENEFIT
Energy * Certified Home (BOP 1)		$ 1,200.00	$ 0.327	$ 0.520	1.172
95% AFUE Gas Furn (Existing)		$ 500.00	$ 0.344	$ 0.610	1.144
High Efficiency Combination Radiant Heat		$ 1,200.00	$ 0.184	$ 0.424	2.125
80% AFUE Hearth		$ 250.00	$ 0.235	$ 0.483	1.665
70% FE Hearth with Int Ignition		$ 200.00	$ 0.256	$ 0.503	1.534
.67 Water Heater		$ 75.00	$ 0.286	$ 0.576	1.381
.91 EF Tankless Water Heater		$ 200.00	$ 0.266	$ 0.532	1.482
				$ 0.5214	

REBATES UNDER TOTAL RESOURCE COST TEST

MEASURE			TOTAL RESOURCE OUTCOMES	TRC WITH PROGRAM ADMIN COSTS	COST/BENEFIT
Energy * Certified Home (BOP 1)			$ 1.092	$ 1.284	0.352
95% AFUE Gas Furn (Existing)			$ 0.899	$ 1.165	0.438
High Efficiency Combination Radiant Heat			$ 0.384	$ 0.624	1.020
80% AFUE Hearth			$ 0.565	$ 0.813	0.694
70% FE Hearth with Int Ignition			$ 0.543	$ 0.791	0.722
.67 Water Heater			$ 1.330	$ 1.621	0.297
.91 EF Tankless Water Heater			$ 1.806	$ 2.072	0.218
				$ 0.9456	

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A. Spector, IGC

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THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
______________________________________	)	

DIRECT TESTIMONY OF CHERYL IMLACH

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

I. INTRODCUTION

Q. Please state your name and business address.

A. My name is Cheryl Imlach. My business address is 555 S. Cole Road, Boise, Idaho. My e-mail address is Cheryl.Imlach@intgas.com.

Q. By whom are you employed and in what capacity?

A. I am employed by Intermountain Gas Company ("Intermountain" or the "Company") as the Manager of Energy Utilization. In this capacity, I have been tasked with leading the operation and tactical implementation of the Company's emergent Demand Side Management (DSM) efforts and associated rebate program. I lead the Company's economic and technological development efforts. I am also in charge of forecasting customer growth for integrated resource planning.

Q. How long have you been employed by the Utility Group?

A. I have been with Intermountain for 24 years starting first as a Consumer Specialist in the Southeast section of IGC's service territory. In 2005, I was promoted to Manager of Treasury Services. In 2007, I became the Manager of Revenue Accounting. My current title is Manager of Energy Utilization, a role which I began in 2016.

Q. What are your educational and professional qualifications?

A. I am a graduate of Idaho State University where I earned a bachelor's degree in business administration in 1992 and an M.B.A in 2002. I have extensive experience in both financial management and fiscal oversight in the utility sector.

I am also well versed in the tactical implementation of efforts designed to encourage efficiencies through the direct use of natural gas.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this docket?

A. My testimony will cover three primary areas. First, I will discuss the feasibility of operating a residential conservation rebate program and the preparations Intermountain has made to launch this effort. Next, I will offer a detailed description of our proposed program ramp-up. Lastly, I will describe anticipated program benefits and predicted results.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, although I participated in the preparation of Original Tariff Sheet No. 16, Rate Schedule DSM (DSM Tariff), which is the Company's proposed Tariff that would obtain demand side resources through rebates for select energy efficiency equipment and upgrades. This proposed DSM Tariff sheet is part of Exhibits 30 and 31 sponsored by Company witness Michael McGrath.

III. FEASIBILITY OF DEMAND SIDE MANAGEMENT AND ASSOCIATED PREPARATIONS

Q. What steps has the Company taken in preparation of the launch of a residential conservation rebate program in Intermountain's service area?

A. As explained in the testimony of Ms. Spector, the Company has performed an assessment of both its total DSM potential and the cost effectiveness of offering rebates for residential conservation measures. In addition, the Company has also performed a desk audit of similar rebate programs in the State of Idaho including both Avista and Idaho Power's energy conservation efforts.

Intermountain has also held meetings with its district employees to ensure that the measures in its portfolio were not already saturated in the local markets, and that rebate levels are meaningful from an "on-the-ground" perspective. Feedback from district staff ultimately drove the Company to make changes to their initial program design, raising minimal efficiency levels from .64 to .67 for water heaters and for 91% Annual Fuel Utilization Efficiency (AFUE) to 95% AFUE for furnaces. Feedback from the districts also provided a better understanding of the incremental costs associated with upgrades from standard efficiency to high efficiency natural gas equipment in Intermountain's service area.

The Company has also met with local area HVAC contractors and builders to better understand what natural gas equipment is available on the market today and how to assist those contractors and builders in the selection of more energy efficient measures and equipment.

Finally, Intermountain has developed a comprehensive set of trade ally and rebate eligibility guidelines that will be used to govern the program, after hoped-for approval by the Commission.

Q. What is the current demand for high-efficiency natural gas equipment and ENERGY Star homes in Intermountain's service are?

A. Within the residential market, there is currently a mix of older equipment, and lower-grade energy efficiency measures being utilized by customers. While energy efficient upgrades are not uncommon in the Boise metropolitan area, anecdotal feedback suggests that penetration is inconsistent, and lower efficiency equipment is still readily available to IGC customers, contractors and builder. There is likewise a strong opportunity to increase the presence of energy efficient equipment and ENERGY Star homes in other parts of the service area as well.

Q. What impacts do you anticipate your program will have on the residential sector?

A. Making rebates available for energy-efficient natural gas equipment and ENERGY Star homes will drive increased sales of these essential upgrades, leading to energy savings that would have not been otherwise achieved without the program. Other gas utilities in the northwest have achieved consistent energy savings through rebates for energy efficiency measures. The Company believes this momentum can be replicated in Intermountain's service area in Idaho. More specifically, based on the Company's TEAPot modeling results, blended with feedback from district staff, and area contractors, Intermountain believes it can achieve a therm savings target of 65,000 therms with a stretch goal of 97,8235 as described in the testimony of Ms. Spector. This savings will be achieved by using rebates to encourage the purchase of energy efficient natural gas space and water heating equipment and ENERGY Star homes in the residential sector.

Q. How will success resulting from this program be measured?

A. Success means that the Company has met or exceeded its programmatic therm savings targets, and that the program's pre-screened measures have been performed safely, in accordance with industry best practices.

The program metrics that will be used to determine performance will include total therm savings achieved; Utility Cost Test (UCT) results in relation to the $0.531 threshold; total conversions to high-efficiency natural gas equipment directly attributable to the Company's rebate program; total number of ENERGY Star homes directly attributable to the Company's rebate program; and the results of any quality assurance inspection outcomes.

Q. How does the Company intend to directly attribute natural gas savings to your conservation rebate program?

A. Natural gas savings will be considered directly attributable to the Company's natural gas conservation program if it is associated with a successfully completed conservation incentive application for a rebate eligible measure. The Company will be using deemed therm savings based from the appropriate climate zone programmed in the TEAPot model. The risk of free ridership associated with customers applying for incentives for equipment they would have otherwise installed will be mitigated in the ways described within the testimony offered by Ms. Spector.

Q. What will the Company do once the measures in its portfolio achieve market transformation in Intermountain's service area?

A. Measures eligible for incentive as part of the Company's conservation rebate program will be examined on an ongoing basis to ensure that they support the most efficient technologies available on the market within Intermountain's service area. In the event that a measure becomes saturated into the local market, or becomes mandated by code, the Company will replace it with a higher-tier energy savings measure as they become available.

IV. PROGRAM RAMP UP AND DELIEVERY

Q. Please describe the first 90 days of operation for your conservation rebate program, if approved.

A. Following the approval of the Company's DSM program, Intermountain will file for the collection of costs as described in Ms. Spector's testimony. Upon approval of the recovery mechanism, the Company will issue a solicitation for two new staff to support daily program operation and implementation.

As Manager of Energy Utilization, I will oversee this process and provide ongoing management and oversight to the DSM team. We will meet with our district team to finalize all program terms and conditions, and to ensure that they have the resources necessary to explain the program to customers and area contractors. We will provide easy-to-complete rebate applications for distribution by our district and program staff, and for distribution to local contractors. We will convene meetings with area contractors to launch a residential trade ally program to encourage partnership with the HVAC and builder communities on the sale of high-efficiency natural gas equipment and ENERGY Star homes over standard-efficiency alternatives. We will have an enrollment campaign to invite all well-qualified contractors to participate in our trade ally program. We will perform ongoing monitoring of work and will gather customer feedback to ensure that the program operates as intended.

While program ramp-up is taking place, the Company will concurrently implement internal best-practices for rebate processing and data collection to ensure that customer rebate requests are processed in a timely manner, and that we are able to report all program findings and outcomes with maximum transparency and clarity. We will also train our call center staff to ensure they are prepared to answer customer questions about our energy efficiency rebate program and to refer customers to the appropriate departmental contacts.

Q. Please describe the guidelines that will be associated with this program and how they will be enforced.

A. Intermountain has developed terms and conditions that will govern the operation of its rebate program. The program will be available to residential customers who use natural gas as their primary space or water heating fuel. Natural gas must be the space heat fuel for all space heating applications. Natural gas must be the water heat fuel for all water heating applications. Energy savings equipment must meet the program requirements specified in the program’s terms and conditions. Rebate eligible measures will be performed through licensed & bonded contractors. A Trade Ally program will help enforce best practices in equipment installation, and ensure a commitment to assisting customers through the rebate application process.

All rebate applications will be subject to verification and review, including a review of all associated invoices. Staff will be available to perform both randomized and targeted quality assurance inspections as appropriate. Trade

Allies whose work does not pass QC inspection will be removed from the program.

Q What existing resources are available to the Company for program delivery?

A. In addition to the in-house expertise harnessed for our DSM analysis and the design of our rebate portfolio, we have the following resources available to support our rebate program:

First, we have an Energy Utilization management position, which I now hold with the Company. In this capacity, I will be overseeing the practical implementation and daily operation of our program.

Second, we have customer-facing Company staff in each district served by the Utility that have been instrumental in providing feedback to ensure the smooth integration of this effort into their day-to-day operations. They will be thoroughly trained on all rebate program guidelines and requirements and will be available to answer customer questions, and provide support to area contractors.

Third, we have an existing program that has been used to promote efficient natural gas equipment in partnership with area contractors. We intend to increase the focus of this program to focus on the measures available under our DSM rebate portfolio. This will serve as a starting point from which we will be able to launch a more comprehensive trade ally program effort.

Fourth, as stated earlier, Intermountain’s Customer Service team will be trained on all aspects of our rebate program and will be available to answer customer questions and refer them to the appropriate program contacts.

Finally, we have ongoing customer outreach materials such as our monthly bill-stuffers that will contain messaging designed to encourage additional program participation.

V. ANTICIPATED BENEFITS AND OUTCOMES

Q. What are the anticipated outcomes & associated benefits of the Company's conservation rebate program?

A. The anticipated outcome of the Company's rebate program is an energy savings achievement 65,000 therms in the first year with a stretch target of 97,825 therms based on the TEAPot's model of Achievable potential. Intermountain also anticipates a gradual increase in the availability of high-efficiency natural gas space and water heating equipment and ENERGY Star homes in its service area, which will be encouraged through partnership with area contractors.

Benefits associated with the Company's rebate program include the cost-effective acquisition of demand side resources for load management; environmental benefits and increased efficiencies associated with the direct use of natural gas that was described in detail in the testimony of Mr. Kirschner; and direct benefits to participating homeowners such as increased comfort and lower energy bills than if the program were not in existence.

Q. Does the Company anticipate a limit to the amount of DSM potential in its service area?

A. While there is a finite level of DSM potential for any given measure within an energy conservation portfolio, housing stock will continue to age over time, and technologies will continue to evolve, offering additional opportunities for energy efficiency, which the Company will explore on an ongoing basis.

Q. Does this conclude your testimony?

A. Yes it does.

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR THE AUTHORITY TO CHANGE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE TO NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)))))))	Case No. INT-G-16-02

DIRECT TESTIMONY OF MICHAEL MCGRATH

FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

Q. Please state your name, title and business address.

A. My name is Michael McGrath. I am the Director of Regulatory Affairs at Intermountain Gas Company. My business address is 555 S. Cole Road, Boise, Idaho 83707.

Q. Mr. McGrath, please summarize your educational and professional experience.

A. I graduated from Brigham Young University with a Bachelor of Science Degree in Business. I also have an MBA from Boise State University. I have attended, and graduated from, numerous educational opportunities that focused on regulatory ratemaking sponsored by the American Gas Association. I have been with Intermountain Gas Company for over 30 years serving in progressively responsible positions that included regulatory rate making, financial forecasting and planning, industrial marketing and gas supply.

Q. What is the purpose of your testimony?

A. First I will discuss Intermountain's proposal to implement a fixed cost collection mechanism, in order to bring a level of consistency or stability to Company revenues, from year-to-year. Second, I will discuss the tariffs that are attached to the Application, pointing out tariff changes as well as describing the new tariffs.

Q. Addressing your first point, please describe the Company's proposed approach to fixed cost collection.

A. The Company is proposing to implement a Fixed Cost Collection Mechanism ("FCCM") that will break the link between Intermountain's (a) margin from its residential and commercial customers and, (b) the natural gas deliveries to these same core market customers. As a result of the FCCM, the traditional link between Intermountain's gas deliveries and earnings will be broken. Therefore, Intermountain's revenues and earnings will be unaffected by variations in the quantities of gas that it delivers to its residential and commercial customers. Each month, the Company will reconcile the difference between (1) the Company's actual Fixed Cost Collection Margin per customer, by rate class, and (2) the Company's Allowed Fixed Cost Collection Margin per customer for that month for the same rate class, as approved by the Commission in this proceeding.

Q. Please explain the term that you used, "Fixed Cost Collection Margin."

A. The term Fixed Cost Collection Margin refers to the distribution margin that the Company relies on to pay for the fixed costs of providing safe and reliable service to its customers. The Fixed Cost Collection Margin is the margin associated with the distribution cost per therm for the applicable rate schedules. Equivalently, the Fixed Cost Collection Margin can also be calculated as total sales service margin less PGA revenues and less revenues recovered from the customer charge for the applicable rate schedules.

Q. Which rate schedules will be effected by the Company's proposed Fixed Cost Collection Mechanism?

A. The Company's proposed FCCM will apply to Rate Schedules RS, Residential Service; GS-1, General Service; IS-R, Residential Interruptible Snowmelt Service; and IS-C, Small Commercial Interruptible Snowmelt Service.

In this testimony, references to Rate Schedule RS or Residential Service will also include Rate Schedule IS-R, Residential Interruptible Snowmelt Service and references to Rate Schedule GS-1 or General Service will also include Rate Schedule IS-C, Small Commercial Interruptible Snowmelt Service.

Q. Please explain why the Company is proposing to implement this FCCM.

A. The margin that the Company relies on to pay for the Company's fixed costs to (1) operate and maintain its system and (2) expand and replace aging portions of its distribution system has been declining over time, as our customer's homes and businesses continue to use progressively less natural gas as a result of revisions to building code standards, more efficient appliances as well as other customer behaviors that conserve energy. While the Company's proposal to implement a Demand Side Management (DSM) program adds measurable value to our customers and the environment, these same DSM programs will, nonetheless, exacerbate an already decreasing usage, and therefore margin, per customer. The FCCM that the Company is proposing will allow the Company to effectively promote and advocate for its proposed DSM program without the financial disincentives that currently exist, with margins directly connected to sales volumes.

Q. In addition to the declining usage per customer resulting from energy conservation measures, are there other determinants or factors than can also influence the natural gas sales to the Company's Rate Schedule RS and GS-1 customers?

A. Yes. The Company's RS and GS-1 Fixed Cost Collection Margin can vary from year-to-year due to fluctuations in the deliveries of natural gas (measured in therms) caused by variability in the weather as well as changes in the local, regional, and national economy. The deviations in deliveries caused by these determinants, however, are generally erratic and short-term in nature.

Q. How will the Allowed Fixed Cost Collection Margin per customer for Rate Schedules RS and GS-1 be determined?

A. Each month, the Company will reconcile the difference between (1) the Company’s actual Fixed Cost Collection Margin per customer, by the aforementioned rate classes and, (2) the Company’s Allowed Fixed Cost Collection Margin per customer for that month for those same rate classes, as approved by the Idaho Commission in this proceeding. The initial Allowed Fixed Cost Collection Margin per customer for each month will be calculated as the monthly Fixed Cost Collection Margin divided by monthly billed customers, separately for Rate Schedules RS and GS-1, based on the Distribution Cost per therm rates and billing determinants[1] that are approved in this proceeding, as determined by the Idaho Commission, and calculated in the Company’s compliance filing.

If the Distribution Cost per therm rates for Rate Schedule RS or Rate Schedule GS-1 are revised at any time after the rates in this proceeding are approved, the Allowed Fixed Cost Collection Margin per customer will be accordingly revised based on the new Distribution Cost per therm rates for Rate Schedule RS and Rate Schedule GS-1, and the billing determinants that are approved in this proceeding.

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[1] For these rate schedules, “Billing Determinants” is the count of monthly bills (or customers) and the total therms (and therms by rate block, if appropriate) that are used in a rate case, such as this proceeding INT-G-16-02, to determine the rates that are approved by the Idaho Commission.

The derivation of the initial Allowed Fixed Cost Collection Margin per customer for Rate Schedules RS and GS-1, based on the Company's proposed rates, is shown in Exhibit 27.

Q. Please explain Exhibit 27.

A. The calculation of the Monthly RS Allowed Cost Collection Margin per customer is shown on lines 1 to 9, and the calculation of the Monthly GS-1 Allowed Cost Collection Margin per customer is shown on lines 10 to 30. Because the methodologies that I used to calculate the RS and GS-1 Allowed Cost Collection Margin per customer are identical I will only explain the RS methodology. Rate Schedule RS customers and Therm sales are shown on Lines 1 and 2. Company Witness Lori Blattner also used this data to calculate the Company's proposed RS and GS-1 rates and the annual totals on Exhibit 27 are also shown on Ms. Blattner's Exhibit 20. The Company's proposed RS customer charge and volumetric rate are shown on Exhibit 27, lines 4 and 5, and the calculated margins associated with the customer charge and volumetric charge are shown on Exhibit 27, lines 7 and 8. Lastly, the monthly Allowed Cost Collection Margins per customer are shown on line 9.

Q. Please explain (a) why the FCCM will apply only to Rate Schedules RS and GS-1, and (b) why the FCCM will not apply to Rate Schedules LV-1, T-3 and T-4.

A. The Company proposes to apply the FCCM to Rate Schedules RS and GS-1 because (1) the Company's proposed DSM energy efficiency programs will initially apply to residential and general service customers, but not to the customers served by rate schedules LV-1, T-3, and T-4; (2) most of the variability in year-to-year FCCM margin that the Company experiences is associated with sales to these two rate classes; and (3) these two customer groups represent a significant portion of the Company's allocated fixed costs and, therefore, distribution margin.

I have prepared Table MM.1 below to show 2016 weather normalized deliveries and distribution margin for Intermountain's rate classes.

Table MM.1 2016 Weather Normalized Deliveries and Distribution Margin

	RS IS-R	GS-1 IS-C	LV-1	T-3	T-4	Total
Distribution margin	$53,232,253	$19,530,463	$403,987	$727,673	$9,183,113	$83,077,489
as % of total	64.1%	23.5%	0.5%	0.9%	11.1%	100.0%
Deliveries (MMBtu)	21,278,706	10,797,266	631,756	3,990,929	28,441,283	65,139,940
as % of total	32.7%	16.6%	1.0%	6.1%	43.7%	100.0%

Note: Proposed Rate Schedule RS includes current Rate Schedules RS-1 and RS-2. Proposed Rate Schedule T-4 includes current Rate Schedules T-4 and T-5.

I have prepared Table MM.2 below to show total distribution margin and volumetric margin by class, based on current rates and 2016 rate case billing determinants.

Table MM. 2 Distribution Margin and FCCM Margin at Current Rates by Proposed Class

	RS IS-R	GS-1 IS-C CNG	LV-1	T-3	T-4	Total
Distribution Margin	$53,232,253	$19,530,463	$403,987	$727,673	$9,183,113	$83,077,489
Volumetric margin	$39,048,014	$17,792,045	$403,987	$727,673	$8,731,332	$66,703,050
Volumetric as % distribution margin	73.9%	91.1%	100.0%	100.0%	95.1%	80.3%

Note: Proposed Rate Schedule RS includes current Rate Schedules RS-1 and RS-2. Proposed Rate Schedule T-4 includes current Rate Schedules T-4 and T-5.

Table 1 demonstrates that 87.6 percent of total Company distribution margin are provided by Residential Rate RS and General Service Rate GS-1 and 49.2 percent of total deliveries are made to Residential Rate RS and General Service Rate GS-1.

Q. Please describe specific elements of the FCCM.

A. The Company's proposed FCCM will recover or return annual RS and GS-1 FCCM margin shortfalls or surpluses for each FCCM Year period, defined as the 12 months October through September. The RS and GS-1 FCCM adjustment rates to be applied in the upcoming FCCM Year are calculated as the annual margin shortfalls or surpluses for the 12 months ended September plus the final reconciliation balance for the prior (October through September) FCCM Year divided by projected annual RS and GS-1 therm deliveries for the upcoming 12 months ended September. The Company will file an annual FCCM calculation prior to October 1st, using, as available, actual data and projected data for the October through September period.

Q. Please describe the FCCM calculations that you mentioned in your prior response.

A. I have prepared Exhibit 28 to provide an example of the calculations that I will explain below. Example FCCM calculations for Rate Schedules RS and GS-1 are provided on Exhibit 28, pages 1 and 2, respectively. The example "actual" monthly customers and therms that are shown on lines 1 and 2 of both pages are numbers that I created.

The Company will determine the Fixed Cost Collection Adjustment Factor ("FCCAF") prior to the start of each annual FCCM year, i.e. each 12-month period, October through September, according to the following process:

(1) For each month of the FCCM Year, the Company will calculate the monthly actual FCCM margin per customer for Rate Schedules RS and GS-1 by dividing monthly actual FCCM margin for Rate Schedules RS and GS-1 by monthly billed customers for Rate Schedules RS and GS-1. Referring to the FCCM calculations for Rate Schedule RS on Exhibit 28, page 1, monthly actual FCCM margins are shown on line 8, and the monthly actual calculated values of FCCM per customer are shown on line 11.

(2) For each month of the FCCM Year, the Company will calculate the difference between Allowed and actual FCCM margin per customer, for Rate Schedules RS and GS-1. The calculated monthly differences between allowed and actual FCCM margin per customer Rate Schedule RS are shown on Exhibit 28, page 1, line 12.

(3) For each month of the FCCM Year period, the Company will calculate FCCM margin shortfalls or surpluses by multiplying the margin per customer differences times actual customers for each rate group, by month. The calculated monthly FCCM margin shortfalls or surpluses for Rate Schedule RS are shown on Exhibit 28, page 1, line 13.

(4) The Company will calculate RS and GS-1 FCCAFs by dividing the total FCCM Year Rate Schedule-specific margin shortfall or surplus by projected therm deliveries for the upcoming FCCM Year, October through September.

The RS and GS-1 FCCAFs will also include a reconciliation of (a) the prior FCCM Year (i.e., October through September) final FCCM margin shortfall or surplus and (b) the prior FCCM Year adjustment charges or credits. Referring to Exhibit 28, page 1, the Company would calculate the FCCM Year 1 RS FCCAF by dividing the 12-month total deficiency, ($177,213; Column (M), line 13) by projected FCCM Year 2 RS therms.

Q. Please explain how actual FCCM margin per customer will be calculated.

A. Every month, actual FCCM Margin, for RS and GS-1 separately, will be determined directly from the actual booked base distribution margin on a billing month basis, minus calculated customer charge margin.

Q. Please describe the timing of FCCM calculations, filings and rate adjustments.

A. The FCCM Year adjustment factor that is in effect starting October 1st of each year will be based on the calculations related to the prior FCCM Year, that is, FCCM calculations for the prior October through September period. Each FCCM filing will also include a final reconciliation of actual and allowed FCCM margin, two FCCM Years ago. I have prepared Exhibit 29 to illustrate the timing of FCCM calculations and FCCAFs. Referring to Exhibit 29, the FCCAFs that will be in effect starting October 1 for FCCM Year 3 will be calculated based on (a) FCCM Year 2 margin shortfalls or surpluses plus (b) a final reconciliation of FCCM Year 1 margin shortfalls or surpluses and FCCM Year 1 FCCAF revenues, (c) divided by FCCM Year 3 projected delivery volumes (therms).

Q. Will the calculation of the first FCCAFs after the FCCM is approved be as depicted in Exhibit 29?

A. It is not likely that the timing of the first FCCAF will be as depicted in Exhibit 29, unless the FCCM is approved effective October 1. The initial FCCAF will become effective upon Commission approval, on the first October 1 following the effective date of the FCCM. That initial FCCAF will recover the actual and projected margin surpluses and shortfalls for each month starting with the effective date of the FCCM, through September. For example, if new rates and the FCCM are approved in this proceeding effective February 1, 2017, the first RS and GS-1 FCCAFs would become effective October 1, 2017 based on FCCM margin surpluses and shortfalls for the eight months February through September, 2017, divided by projected therm sales for October 2017 through September 2018.

Q. If the Company's base distribution rates are modified before new base rates in the Company's next base rate case become effective, will any of the FCCM calculations be modified?

A. Yes. If the Company's base distribution rates are modified before the Company's next base rate case, the Company will make a corresponding revision to the Allowed Fixed Cost Collection Margins per customer, by month. The Company will include the revised Allowed Fixed Cost Collection Margins per customer, with supporting documentation, with between-rate-case rate change filings.

Q. Has the Company prepared an FCCM tariff?

A. Yes. The Company's proposed a FCCM Tariff which is shown as Original Tariff Sheet No. 17, pages 1 through 4, which are shown on both Exhibit 30 and 31.

Q. Could you briefly describe the tariff package that implements the rates proposed by Intermountain in this case?

A. Yes. Exhibit 30, which I am sponsoring, shows the changes to Intermountain's tariffs, by striking over proposed deletions to existing tariffs and underlining additions or amendments to those existing tariffs. Exhibit 31, which I am also sponsoring, shows these same tariffs, both existing and new, in a clean format. Exhibit 31 is also shown as Attachment A to the Application.

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 27

Intermountain Gas Company
FCCM Volumetric Margin per Customer

Line		January	February	March	April	May	June	July	August	September	October	November	December	Total
	Residential Service Rate Schedule RS													
1	Customers	306,609	307,092	307,494	307,485	307,442	307,348	308,056	308,736	309,381	310,196	310,726	311,238	3,701,803
2	Therms	41,719,618	35,232,888	27,241,788	20,361,892	10,810,492	7,216,469	4,908,481	4,210,576	4,695,896	7,048,415	15,906,244	33,434,301	212,787,060
3	Proposed Rates													
4	Customer Charge	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	
5	Volumetric rate	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	
6	Total RS Margin	$7,765,805	$7,039,905	$6,143,727	$5,368,617	$4,292,222	$3,886,415	$3,633,500	$3,561,681	$3,622,803	$3,895,964	$4,899,098	$6,878,754	$60,988,492
7	Margin - Customer Charges	$3,066,090	$3,070,920	$3,074,940	$3,074,850	$3,074,420	$3,073,480	$3,080,560	$3,087,360	$3,093,810	$3,101,960	$3,107,260	$3,112,380	$37,018,030
8	Margin - Volumetric Charges	$4,699,715	$3,968,985	$3,068,787	$2,293,767	$1,217,802	$812,935	$552,940	$474,321	$528,993	$794,004	$1,791,838	$3,766,374	$23,970,462
9	**RS FCC Per Customer**	**$15.33**	**$12.92**	**$9.98**	**$7.46**	**$3.96**	**$2.64**	**$1.79**	**$1.54**	**$1.71**	**$2.56**	**$5.77**	**$12.10**	**$77.77**
	General Service Rate Schedule GS-1													
10	Customers	32,185	32,182	32,157	32,099	32,053	31,992	32,058	32,111	32,160	32,250	32,291	32,341	385,879
11	Therms	20,491,820	17,307,643	13,512,119	9,525,516	5,393,149	4,400,418	2,922,361	2,531,991	3,143,475	3,599,361	8,513,032	16,631,779	107,972,664
12	**Therms by Proposed blocks**													
13	Block 1 Therms	4,329,816	4,551,715	3,997,212	3,499,150	2,007,285	1,403,444	858,663	703,209	932,645	1,170,904	3,391,936	4,206,551	31,052,530
14	Block 2 Therms	10,221,192	8,528,558	6,424,005	4,438,632	2,461,188	2,138,009	1,334,563	1,137,925	1,514,277	1,367,342	3,580,287	8,238,302	51,384,280
15	Block 3 Therms	5,092,883	3,854,091	2,841,831	1,425,248	755,482	733,935	487,627	526,107	338,938	752,886	1,297,721	3,533,770	21,640,519
16	Block 4 Therms	847,929	373,279	249,071	162,486	169,194	125,030	241,508	164,750	357,615	308,229	243,088	653,156	3,895,335
		20,491,820	17,307,643	13,512,119	9,525,516	5,393,149	4,400,418	2,922,361	2,531,991	3,143,475	3,599,361	8,513,032	16,631,779	107,972,664
17	Proposed Rates													
18	Customer Charge	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	
19	Volumetric Rate Block 1	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	
20	Volumetric Rate Block 2	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	
21	Volumetric Rate Block 3	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	
22	Volumetric Rate Block 4	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	
23	Total GS-1 Margin	3,079,768	2,802,317	2,443,381	2,070,331	1,657,354	1,552,012	1,404,653	1,367,726	1,430,152	1,476,136	1,977,707	2,736,021	$23,997,556
24	Margin - Customer Charges	$1,126,475	$1,126,370	$1,125,495	$1,123,465	$1,121,855	$1,119,720	$1,122,030	$1,123,885	$1,125,600	$1,128,750	$1,130,185	$1,131,935	$13,505,765
25	Margin - Volumetric Charges	$1,953,293	$1,675,947	$1,317,886	$946,866	$535,499	$432,292	$282,623	$243,841	$304,552	$347,386	$847,522	$1,604,086	$10,491,791
26	Margin - Volumetric Charges Block 1	$479,570	$504,148	$442,731	$387,566	$222,327	$155,445	$95,106	$77,887	$103,300	$129,689	$375,691	$465,918	$3,439,378
27	Margin - Volumetric Charges Block 2	$987,572	$824,029	$620,687	$428,861	$237,800	$206,574	$128,945	$109,946	$146,309	$132,113	$345,927	$795,985	$4,964,749
28	Margin - Volumetric Charges Block 3	$422,556	$319,774	$235,787	$118,253	$62,682	$60,895	$40,458	$43,651	$28,122	$62,467	$107,672	$293,197	$1,795,514
29	Margin - Volumetric Charges Block 4	$63,595	$27,996	$18,680	$12,186	$12,690	$9,377	$18,113	$12,356	$26,821	$23,117	$18,232	$48,987	$292,150
30	**GS-1 FCC Per Customer**	**$60.69**	**$52.08**	**$40.98**	**$29.50**	**$16.71**	**$13.51**	**$8.82**	**$7.59**	**$9.47**	**$10.77**	**$26.25**	**$49.60**	**$325.96**

Exhibit No. 27
Case No. INT-G-16-02
M. McGrath, IGC

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IN THE STATE OF IDAHO)
)

EXHIBIT 28

Intermountain Gas Company
FCCM Monthly Example Rate Schedule RS Calculations

EXAMPLE RATE SCHEDULE RS FCC ACTUAL CALCULATIONS FCCM YEAR 1

		January (A)	February (B)	March (C)	April (D)	May (E)	June (F)	July (G)	August (H)	September (I)	October (J)	November (K)	December (L)	Total (M)	Explanation (N)
1	Example "Actual" RS Customers	312,741	313,234	313,644	313,635	313,591	313,495	314,217	314,911	315,569	316,400	316,941	317,463	3,775,839	Example "booked" customers
2	Example "Actual" RS Therms	43,830,631	35,218,795	26,397,293	20,872,975	10,971,568	7,360,798	5,006,651	4,294,788	4,789,814	7,243,304	16,062,125	33,420,927	215,469,668	Example "booked" therms
3	"Approved" Rates														
4	Customer Charge	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00		For example, "Approved" rates set at
5	Volumetric rate	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265	$0.11265		proposed rates in this proceeding
6	Total Actual RS Margin	$8,064,932	$7,099,736	$6,110,094	$5,487,688	$4,371,856	$3,964,144	$3,706,170	$3,632,915	$3,695,259	$3,979,957	$4,978,804	$6,939,495	$62,031,049	Line 7 + Line 8
7	Actual Margin - Customer Charges	$3,127,412	$3,132,338	$3,136,439	$3,136,347	$3,135,908	$3,134,950	$3,142,171	$3,149,107	$3,155,686	$3,163,999	$3,169,405	$3,174,628	$37,758,391	Line 1 x Line 4
8	Actual Margin - Volumetric Charges	$4,937,521	$3,967,397	$2,973,655	$2,351,341	$1,235,947	$829,194	$563,999	$483,808	$539,573	$815,958	$1,809,398	$3,764,867	$24,272,658	Line 2 x Line 5
9	FCCM Calculations														
10	**Target FCC RS Margin / Customer**	**$15.33**	**$12.92**	**$9.98**	**$7.46**	**$3.96**	**$2.64**	**$1.79**	**$1.54**	**$1.71**	**$2.56**	**$5.77**	**$12.10**		Target FCC margin / customer as determined in this proceeding
11	Actual Volumetric Margin / Customer	$15.79	$12.67	$9.48	$7.50	$3.94	$2.64	$1.79	$1.54	$1.71	$2.58	$5.71	$11.86		Line 8 / Line 1
12	Difference: Actual - FCC Target Margin / Customer (Surplus, (Deficiency))	$0.46	($0.26)	($0.50)	$0.04	($0.02)	$0.00	$0.00	$0.00	$0.00	$0.02	($0.06)	($0.24)		Line 11 - Line 10
13	Margin: Surplus, (Deficiency)	$143,811	($80,967)	($156,508)	$11,698	($6,211)	$0	$0	$0	$0	$6,074	($18,277)	($76,834)	($177,213)	Line 12 x Line 1

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Intermountain Gas Company
FCCM Monthly Example Rate Schedule GS-1 Calculations

EXAMPLE RATE SCHEDULE GS FCC ACTUAL CALCULATIONS FCCM YEAR 1

		January (A)	February (B)	March (C)	April (D)	May (E)	June (F)	July (G)	August (H)	September (I)	October (J)	November (K)	December (L)	Total (M)	Explanation (N)
1	Example "Actual" Customers	32,829	32,826	32,800	32,741	32,694	32,632	32,699	32,753	32,803	32,895	32,937	32,988	393,597	Example "booked" customers
2	Example "Actual" Therms	21,528,706	17,300,720	13,093,243	9,764,606	5,473,507	4,488,426	2,980,808	2,582,631	3,206,345	3,698,883	8,596,460	16,625,126	109,339,462	Example "booked" therms
3	Example Actual Block 1 Therms	4,548,905	4,549,894	3,873,298	3,586,979	2,037,194	1,431,513	875,836	717,273	951,298	1,203,279	3,425,177	4,204,868	31,405,515	Example "booked" therms: Block 1
4	Example Actual Block 2 Therms	10,738,384	8,525,147	6,224,861	4,550,042	2,497,860	2,180,769	1,361,254	1,160,684	1,544,563	1,405,149	3,615,374	8,235,007	52,039,092	Example "booked" therms: Block 2
5	Example Actual Block 3 Therms	5,350,582	3,852,550	2,753,734	1,461,021	766,739	748,614	497,380	536,629	345,717	773,703	1,310,439	3,532,357	21,929,464	Example "booked" therms: Block 3
6	Example Actual Block 4 Therms	890,835	373,129	241,350	166,565	171,715	127,531	246,338	168,045	364,767	316,752	245,470	652,894	3,965,391	Example "booked" therms: Block 4
7	"Approved" Rates														
8	Customer Charge	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00		
9	Volumetric rate: Block 1	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076	$0.11076		For this example, "Approved" rates
10	Volumetric rate: Block 2	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662	$0.09662		set at proposed rates in this
11	Volumetric rate: Block 3	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297	$0.08297		proceeding
12	Volumetric rate: Block 4	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500	$0.07500		
13	Total Actual RS Margin	$3,201,134	$2,824,174	$2,425,036	$2,116,566	$1,687,770	$1,583,052	$1,432,746	$1,395,081	$1,458,755	$1,508,316	$2,008,616	$2,758,018	$24,399,264	Line 14 + Line 15
14	Actual Margin - Customer Charges	$1,149,005	$1,148,897	$1,148,005	$1,145,934	$1,144,292	$1,142,114	$1,144,471	$1,146,363	$1,148,112	$1,151,325	$1,152,789	$1,154,574	$13,775,880	Line 1 x Line 5
15	Actual Margin - Volumetric Charges	$2,052,130	$1,675,277	$1,277,031	$970,632	$543,478	$440,938	$288,275	$248,718	$310,643	$356,991	$855,827	$1,603,444	$10,623,384	Σ (Lines 3 to 6) x (Lines 9 to 12)
16	FCCM Calculations														
17	Actual Volumetric Margin / Customer	$62.51	$51.04	$38.93	$29.65	$16.62	$13.51	$8.82	$7.59	$9.47	$10.85	$25.98	$48.61		Line 15 / Line 1
18	Difference: Actual - FCC Target Margin / Customer (Surplus, (Deficiency))	$1.82	($1.04)	($2.05)	$0.15	($0.08)	$0.00	$0.00	$0.00	$0.00	$0.08	($0.26)	($0.99)		Line 17 - Line
19	Margin: Surplus, (Deficiency)	$59,771	($34,189)	($67,212)	$4,829	($2,731)	$0	$0	$0	$0	$2,658	($8,645)	($32,723)	($78,243)	Line 18 x Line 1

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INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 29

Intermountain Gas Company
FCCM Timeline

Line																																					
1		FCCM Year 1												FCCM Year 2												FCCM Year 3											
2		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
3	**FCCM Year 3 Adjustment factors charged to RS, GS-1 customers**																									■	■	■	■	■	■	■	■	■	■	■	■
4	**FCCM Year 3 Adjustment factor:**																																				
5	Prior year revenue shortfall, surplus calculations																																				
6	Actual monthly FCCM revenue, customer data													■	■	■	■	■	■	■	■	■															
7	Projected monthly FCCM revenue, customer data																						▨	▨	▨												
8	Second prior year Final reconciliation																																				
9	Actual monthly FCCM revenue, customer data	■	■	■	■	■	■	■	■	■	■	■	■																								
10	Projected monthly FCCM revenue, customer data	■	■	■	■	■	■	■	■	■	■	■	■																								
11	Actual FCCM adjustment factor revenues	■	■	■	■	■	■	■	■	■	■	■	■																								

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
INTERMOUNTAIN GAS COMPANY FOR)
THE AUTHORITY TO CHANGE ITS RATES) Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS)
SERVICE TO NATURAL GAS CUSTOMERS)
IN THE STATE OF IDAHO)
)

EXHIBIT 30

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
June 20, 2016 July 1, 2016
Jean D. Jewell Secretary

Rate Schedule RS-1
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, who does not have both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Per Therm Charge - $0.87267*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Per Therm Charge - $0.76011*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00085)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.22910
Distribution Cost:	April through November	$0.31678
	December through March	$0.20422

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

I.P.U.C. Gas Tariff
Rate Schedules
Fiftieth Revised Sheet No. 02 (Page 1 of 1)

Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
June 20, 2016 July 1, 2016
Jean D. Jewell Secretary

Rate Schedule RS-2
RESIDENTIAL SERVICE- SPACE AND WATER HEATING

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes, which must include at a minimum, both natural gas water heating and natural gas space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Per Therm Charge - $0.71185*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Per Therm Charge - $0.67822*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00968)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19789
Distribution Cost:	April through November	$0.19600
	December through March	$0.16237

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

I.P.U.C. Gas Tariff
Rate Schedules
Fifty-~~Second~~ Revised Third Sheet No. 03 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the customer charge.

~~For billing periods ending April through November~~

Customer Charge - $~~2.00~~ per bill $35.00

Block One:	Per Therm Charge -	First	200 therms per bill @ $~~0.72918~~*	$0.62243
Block Two:		Next	1,800 therms per bill @ $~~0.70745~~*	$0.60829
Block Three:	Next 8,000	~~Over~~	~~2,000~~ therms per bill @ $~~0.68643~~*	$0.59464
Block Four:		Over 10,000 therms per bill @ $0.58667		

~~For billing periods ending December through March~~

~~Customer Charge -~~ ~~$9.50 per bill~~

~~Per Therm Charge -~~	~~First~~	~~200 therms per bill @ $0.67833*~~
	~~Next~~	~~1,800 therms per bill @ $0.65713*~~
	~~Over~~	~~2,000 therms per bill @ $0.63667*~~

*****Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726

Distribution Cost:		~~April through November:~~		
Block One:		First 200 therms per bill @	$~~0.21751~~	$0.11076
Block Two:		Next 1,800 therms per bill @	$~~0.19578~~	$0.09662
Block Three:	Next 8,000	~~Over~~ ~~2,000~~ therms per bill @	$~~0.17476~~	$0.08297
Block Four:		Over 10,000 therms per bill @	$0.07500	
		~~December through March~~		
		~~First 200 therms per bill @~~	~~$0.16666~~	
		~~Next 1,800 therms per bill @~~	~~$0.14546~~	
		~~Over 2,000 therms per bill @~~	~~$0.12500~~	

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Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ 2016 September 12

I.P.U.C. Gas Tariff
Rate Schedules
Fifty-~~Second~~ Revised Third Sheet No. 03 (Page 2 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge - ~~$9.50~~ per bill $35.00

Per Therm Charge - ~~$0.63667~~ *

Block One: First 10,000 therms per bill @ $0.59464*

Block Two: Over 10,000 therms per bill @$0.58667*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726
Distribution Cost:	Block One: First 10,000 therms per bill @$0.08297 Block Two: Over 10,000 therms per bill @ $0.07500	~~$0.12500~~

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July~~ 1, 2016 September 12

I.P.U.C. Gas Tariff
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~~Ninth~~ Tenth Revised Sheet No. 4 (Page 1 of 2)

Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS~~-1 or RS-2~~ who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

~~For billing periods ending April through November~~

Customer Charge - $~~2.50~~ per bill $10.00

Per Therm Charge - $~~0.67822~~* $0.63476

~~For billing periods ending December through March~~

~~Customer Charge - $6.50 per bill~~

~~Per Therm Charge - $0.67822*~~

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($~~0.00968~~)	($0.00828)
	2) Weighted average cost of gas	$0.32764	
	3) Gas transportation cost	$~~0.19789~~	$0.20275
Distribution Cost:		$~~0.16237~~	$0.11265

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ September 12 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Ninth~~ Revised Tenth Sheet No. 5 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

~~For billing periods ending April through November~~

Customer Charge – $~~2.00~~ per bill $35.00

Block One: Per Therm Charge – First 200 therms per bill @ ~~$0.67833~~* $0.62243
Block Two: Next 1,800 therms per bill @ ~~$0.65713~~* $0.60829
Block Three: Next 8,000 ~~Over~~ ~~2,000~~ therms per bill @ ~~$0.63667~~* $0.59464
Block Four: Over 10,000 therms per bill @ $0.58667

~~For billing periods ending December through March~~

~~Customer Charge – $9.50 per bill~~

~~Per Therm Charge – First 200 therms per bill @ $0.67833*~~
~~Next 1,800 therms per bill @ $0.65713*~~
~~Over 2,000 therms per bill @ $0.63667*~~

*Includes the following:

Cost of Gas:
1) Temporary purchased gas cost adjustment ($0.01323)
2) Weighted average cost of gas $0.32764
3) Gas transportation cost $0.19726

Distribution Cost:
Block One: First 200 therms per bill @ $~~0.16666~~ $0.11076
Block Two: Next 1,800 therms per bill @ $~~0.14546~~ $0.09662
Block Three: Next 8,000 ~~Over~~ ~~2,000~~ therms per bill @ $~~0.12500~~ $0.08297
Block Four: Over 10,000 therms per bill @ $0.07500

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ September 12 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Sixtieth~~ Sixty-First Revised Sheet No. 7 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.30000 per MDFQ therm

Per Therm Charge:

Block One:	First	250,000 therms per bill @ ~~$0.49512~~*	$0.45149
Block Two:	Next	500,000 therms per bill @ ~~$0.45663~~*	$0.43889
Block Three:	~~Amount~~ Over	750,000 therms per bill @ ~~$0.33442~~*	$0.32977

*****Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	
	Block One and Two	($0.02707)
	Block Three	$0.00017
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost (Block One and Two only)	$0.12999

Distribution Cost:	Block One: First	250,000 therms per bill @	~~$0.06456~~	$0.02093
	Block Two: Next	.500,000 therms per bill @	~~$0.02607~~	$0.00833
	Block Three: Over	750,000 therms per bill @	~~$0.00661~~	$0.00196

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such excess usage ~~may~~ will be ~~transported and~~ billed under ~~either secondary~~ rate schedule ~~T-3 or T-4.~~ LV-1. ~~The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.~~ Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1,~~ September 12 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Third~~ Fourth Revised Sheet No. 7 (Page 2 of 2)

Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~June 20, 2016~~ ~~July 1, 2016~~
Jean D. Jewell Secretary

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE
(Continued)

3.The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those LV-1 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

~~3.~~ 4. Embedded in this service is the cost of purchased gas per the Company's PGA, firm interstate pipeline reservation charges, and distribution system costs.

BILLING ADJUSTMENTS:

1. Any LV-1 customer who exits the LV-1 service ~~at any time (including, but not limited to, the expiration of the contract term)~~ will pay to Intermountain Gas Company, upon exiting the LV-1 service, all ~~gas~~ Purchased Gas Cost ("PGA") ~~and/or interstate transportation~~ related costs incurred on the customer's behalf ~~to serve the customer during the LV-1 contract period~~ not paid by the customer during the LV-1 contract period. Any LV-1 customer who has exited the LV-1 service will have refunded to them, upon exiting the LV-1 service, any ~~excess gas and/or interstate transportation related payments made by the~~ PGA related credits attributable to the customer during the ~~LV-1~~ said contract period.

2. In the event that total deliveries to any existing customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the LV-1 Block 1 rate adjusted for the removal of variable gas costs. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

   In the event that total deliveries to any new customer did not meet the 200,000 therm threshold during the current contract period, an additional amount shall be billed. The additional amount shall be calculated by billing the customer's total usage during that contract period at the Rate Schedule GS-1 Block 3 rate, and then subtracting the amounts previously billed during the annual contract period. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

~~EXIT FEE PROVISIONS:~~

~~1.~~ ~~Any LV-1 customer, upon subsequent execution of a T-3 or T-4 contract, will pay to Intermountain each month for a period of two (2) years, an Interstate Pipeline fixed cost collection rate of $0.015 per therm times the customer's monthly T-3 or T-4 usage, up to and including 750,000 therms, not to exceed the customer's historic high usage for that same month, such usage as measured by the most recent three (3) year period.~~

~~2.~~ ~~In lieu of paying the Exit Fee Provision, as stated in the above paragraph #1, the existing LV-1 customer will provide to Intermountain a one year or more advanced written notice of the customer's intent to contract for T-3 or T-4 service.~~

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Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~July 1~~ September 12, 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Eleventh~~ Revised Twelfth Sheet No. 8 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~Sept. 29, 2015~~ ~~Oct. 1, 2015~~
~~Per O.N. 33386~~
Jean D. Jewell Secretary

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Per Therm Charge:

Block One:	First	100,000 therms transported @ $~~0.05465~~*	$0.01414
Block Two:	Next	50,000 therms transported @ $~~0.02205~~*	$0.00519
Block Three:	~~Amount~~ Over	150,000 therms transported @ $~~0.00792~~*	$0.00132

*Includes temporary purchased gas cost adjustment of $(0.00095)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.

2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.

4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company's distribution system.

5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.

6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.
7. An existing ~~LV-1,~~ T-4, ~~or T-5~~ customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

Exhibit No. 30
Case No. INT-G-16-02
M. McGrath, IGC
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Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~October 1, 2015~~September 12, 2016

I.P.U.C. Gas Tariff
Rate Schedules
~~Tenth~~ Revised Eleventh Sheet No. 9 (Page 1 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~Sept. 29, 2015~~ ~~Oct. 1, 2015~~
~~Per O.N. 33386~~
Jean D. Jewell Secretary

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.27923 per MDFQ therm*

~~Commodity~~ Charge:

Per Therm	Block One:	First	250,000 therms transported @ ~~$0.05777~~*	$0.01473
	Block Two:	Next	500,000 therms transported @ ~~$0.01928~~*	$0.00520
	Block Three:	~~Amount over~~ Over	750,000 therms transported @ ~~$0.00455~~*	$0.00160

*Includes temporary purchased gas cost adjustment of $(~~0.00206~~) $(0.02077)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

4. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in the contract and in effect throughout the term of the service contract.

5. The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

~~5.~~ 6. An existing LV-1~~,~~ or T-3, ~~or T-5~~ customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer's same or contiguous property.

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-4 customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

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Case No. INT-G-16-02
M. McGrath, IGC
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Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE
(Continued)

In the event that total deliveries to any new T-4 customer did not meet the 200,000 therm threshold during the current contract period, an additional amount shall be billed. The additional amount shall be calculated by billing the customer's total usage during that contract period at the Rate Schedule GS-1 Block 3 rate, adjusted for the cost of gas, and then subtracting the amounts previously billed during the annual contract period. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

~~2. Usage above 750,000 therms in any given month which is in excess of the customer's historical maximum above 750,000 therms for that same month will be billed at the currently effective T-4 Block 2 price. The historical maximum is the maximum usage by the customer during that same month measured over the previous three (3) year contract period.~~

2 ~~3~~. Any T-4 customer who exits the T-4 service will pay to Intermountain Gas Company, upon exiting the T-4 service, all Purchased Gas Cost ("PGA") related costs incurred on the customers behalf not paid by the customer during the T-4 contract period. Any T-4 customer who has exited the T-4 service will have refunded to them, upon exiting the T-4 service, any PGA related credits attributable to the customer during said contract period.

3. In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm distribution capacity to serve Intermountain's system, all such excess usage will be billed under rate schedule T-4. Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

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I.P.U.C. Gas Tariff
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Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
Sept. 29, 2015 Oct. 1, 2015
Per O.N. 33386
Jean D. Jewell Secretary

Rate Schedule T-5
FIRM DISTRIBUTION SERVICE WITH MAXIMUM DAILY DEMANDS

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing T-5 customer whose daily contract demand on any given day meets or exceeds a predetermined level agreed to by the customer and the Company upon execution of a one-year minimum written service contract for firm distribution service in excess of 200,000 therms per year.

MONTHLY RATE:

Firm Service	Rate Per Therm
Demand Charge:	
Firm Daily Demand	$0.84253
Commodity Charge:	
For Firm Therms Transported	$0.00111*
Over-Run Service	
Commodity Charge:	
For Therms Transported In Excess Of MDFQ:	$0.04370*

*Includes temporary purchased gas cost adjustment of $(0.00135)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in and will be in effect throughout the term of the service contract.

3. The monthly Demand Charge will be equal to the MDFQ times the Firm Daily Demand rate. Firm demand relief will be afforded to those T-5 customers paying both demand and commodity charges for gas when, in the Company's judgment, such relief is warranted.

4. The actual therm usage for the month or the MDFQ times the number of days in the billing month, whichever is less, will be billed at the applicable commodity charge for firm therms.

5. All therms not billed at the commodity charge for firm therms transported rate will be billed at the Overrun Service rate.

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: October 1, 2015

I.P.U.C. Gas Tariff
Rate Schedules
First Revised Sheet No. 10 (Page 2 of 2)
Name of Utility **Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
March 23, 2015 April 1, 2015
Jean D. Jewell Secretary

Rate Schedule T-5
FIRM DISTRIBUTION SERVICE WITH MAXIMUM DAILY DEMANDS
(Continued)

6. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule.

7. Under the overrun portion of the service contract, the customer expressly agrees to interrupt its operations during periods of curtailment.

8. Embedded in this service is the cost of firm distribution capacity.

9. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and scheduled for delivery by the interstate pipeline.

10. The customer shall negotiate a Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract. The MDFQ shall not exceed the customer's historical maximum daily usage, as agreed to by the Company.

    In the event the Customer requires daily usage in excess of the MDFQ, all such usage may be transported and billed under either secondary rate schedule T-3 or T-4. The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-5 customer within the three most recent contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-5 Rate Schedule will be renegotiated with the Company.

2. Any T-5 customer who exits the T-5 service at any time (including, but not limited to, the expiration of the contract term) will pay to Intermountain Gas Company, upon exiting the T-5 service, all Purchase Gas Cost Adjustment ("PGA") related costs incurred on the customer's behalf not paid by the customer during the T-5 contract period. Any exiting T-5 customer will have refunded to them upon exiting the T-5 service any PGA related credits attributed to the customer during the T-5 contract period.

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Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
INTERMOUNTAIN GAS COMPANY FOR	)	
THE AUTHORITY TO CHANGE ITS RATES	)	Case No. INT-G-16-02
AND CHARGES FOR NATURAL GAS	)	
SERVICE TO NATURAL GAS CUSTOMERS	)	
IN THE STATE OF IDAHO	)	
	)	

EXHIBIT 31

Rate Schedule RS
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes.

RATE:

Monthly minimum charge is the customer charge.

Customer Charge:	$10.00 per bill
Per Therm Charge:	$0.63476*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00828)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.20275
Distribution Cost:		$0.11265

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

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I.P.U.C. Gas Tariff
Rate Schedules
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Name of Utility **Intermountain Gas Company**

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the customer charge.

Customer Charge: $35.00 per bill

Per Therm Charge:	Block One:	First	200 therms per bill @	$0.62243*
	Block Two:	Next	1,800 therms per bill @	$0.60829*
	Block Three:	Next	8,000 therms per bill @	$0.59464*
	Block Four:	Over	10,000 therms per bill @	$0.58667*

*****Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726

Distribution Cost:	Block One:	First	200 therms per bill @	$0.11076
	Block Two:	Next	1,800 therms per bill @	$0.09662
	Block Three:	Next	8,000 therms per bill @	$0.08297
	Block Four:	Over	10,000 therms per bill @	$0.07500

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M. McGrath, IGC

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: September 12, 2016

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge: $35.00 per bill

Per Therm Charge:	Block One:	First 10,000 therms per bill @	$0.59464*
	Block Two:	Over 10,000 therms per bill @	$0.58667*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment		($0.01323)
	2) Weighted average cost of gas		$0.32764
	3) Gas transportation cost		$0.19726
Distribution Cost:	Block One:	First 10,000 therms per bill @	$0.08297
	Block Two:	Over 10,000 therms per bill @	$0.07500

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$10.00 per bill
Per Therm Charge:	$0.63476*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00828)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.20275
Distribution Cost:		$0.11265

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company**.**

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$35.00 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$0.62243*
	Block Two:	Next	1,800 therms per bill @	$0.60829*
	Block Three:	Next	8,000 therms per bill @	$0.59464*
	Block Four:	Over	10,000 therms per bill @	$0.58667*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.01323)
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost	$0.19726

Distribution Charge:	Block One:	First	200 therms per bill @	$0.11076*
	Block Two:	Next	1,800 therms per bill @	$0.09662*
	Block Three:	Next	8,000 therms per bill @	$0.08297*
	Block Four:	Over	10,000 therms per bill @	$0.07500*

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.30000 per MDFQ therm

Per Therm Charge:	Block One:	First	250,000 therms per bill @	$0.45149*
	Block Two:	Next	500,000 therms per bill @	$0.43889*
	Block Three:	Over	750,000 therms per bill @	$0.32977*

*****Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	
	Block One and Two	($0.02707)
	Block Three	$0.00017
	2) Weighted average cost of gas	$0.32764
	3) Gas transportation cost (Block One and Two only)	$0.12999

Distribution Cost:	Block One:	First	250,000 therms per bill @	$0.02093
	Block Two:	Next	500,000 therms per bill @	$0.00833
	Block Three:	Over	750,000 therms per bill @	$0.00196

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such excess usage will be billed under rate schedule LV-1. Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE
(Continued)

3. The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those LV-1 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

4. Embedded in this service is the cost of purchased gas per the Company's PGA, firm interstate pipeline reservation charges, and distribution system costs.

BILLING ADJUSTMENTS:

1. Any LV-1 customer who exits the LV-1 service will pay to Intermountain Gas Company, upon exiting the LV-1 service, all Purchased Gas Cost ("PGA") related costs incurred on the customer's behalf not paid by the customer during the LV-1 contract period. Any LV-1 customer who has exited the LV-1 service will have refunded to them, upon exiting the LV-1 service, any PGA related credits attributable to the customer during the said contract period.

2. In the event that total deliveries to any existing customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the LV-1 Block 1 rate adjusted for the removal of variable gas costs. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

   In the event that total deliveries to any new customer did not meet the 200,000 therm threshold during the current contract period, an additional amount shall be billed. The additional amount shall be calculated by billing the customer's total usage during that contract period at the Rate Schedule GS-1 Block 3 rate, and then subtracting the amounts previously billed during the annual contract period. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Per Therm Charge:	Block One:	First	100,000 therms transported @ $0.01414*
	Block Two:	Next	50,000 therms transported @ $0.00519*
	Block Three:	Over	150,000 therms transported @ $0.00132*

*Includes temporary purchased gas cost adjustment of $(0.00095)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.
2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.
3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.
4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company’s distribution system.
5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.
6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.
7. An existing T-4 customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year**.**

MONTHLY RATE:

Demand Charge:	$0.27923 per MDFQ therm*		
Per Therm Charge:	Block One:	First	250,000 therms transported @ $0.01473
	Block Two:	Next	500,000 therms transported @ $0.00520
	Block Three:	Over	750,000 therms transported @ $0.00160

*Includes temporary purchased gas cost adjustment of $(0.02077)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule**.**

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company’s Tariff, of which this Rate Schedule is a part.

4. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

5. The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer’s meter.

6. An existing LV-1 or T-3 customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer’s same or contiguous property.

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE
(Continued)

BILLING ADJUSTMENTS:

1. In the event that total deliveries to any existing T-4 customer within the most recent three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-4 Block 1 rate. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

   In the event that total deliveries to any new T-4 customer did not meet the 200,000 therm threshold during the current contract period, an additional amount shall be billed. The additional amount shall be calculated by billing the customer's total usage during that contract period at the Rate Schedule GS-1 Block 3 rate, adjusted for the cost of gas, and then subtracting the amounts previously billed during the annual contract period. The customer's future eligibility for the T-4 Rate Schedule will be renegotiated with the Company.

2. Any T-4 customer who exits the T-4 service will pay to Intermountain Gas Company, upon exiting the T-4 service, all Purchased Gas Cost (“PGA”) related costs incurred on the customer’s behalf not paid by the customer during the T-4 contract period. Any T-4 customer who has exited the T-4 service will have refunded to them, upon exiting the T-4 service, any PGA related credits attributable to the customer during said contract period.

3. In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm distribution capacity to serve Intermountain’s system, all such excess usage will be billed under rate schedule T-4. Additionally, all excess MDFQ above the customer’s contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

Rate Schedule DSM
RESIDENTIAL ENERGY EFFICIENCY REBATE PROGRAM

AVAILABILITY:

The Intermountain Gas Company Energy Efficiency Rebate Program (EE Program) is available throughout Intermountain's service territory to qualifying residential account holders served on the Company's Residential rate schedule upon meeting the requirements contained in the following eligibility section.

PROGRAM DESCRIPTION:

The EE Program was designed for the purpose of acquiring cost-effective DSM resources in the form of natural gas therm savings. This will be achieved through the use of rebates, offered towards the purchase and installation of qualified energy-efficient natural gas equipment and ENERGY Star homes. All energy efficiency upgrades must take place within Intermountain's service area and will be provided only to account holders on the Company's residential rate schedule.

ELIGIBILITY:

To qualify for incentives, customers must meet the end-use qualifications identified in the Measures/Incentive Table below.

The purpose of the program is to encourage upgrades from standard efficiency to high efficiency natural gas equipment. Customers currently using high-efficiency natural gas HVAC or water heating equipment are not eligible for rebates under this program.

Customers are eligible for the following tiers of incentives:

- **Tier One** (Energy Efficiency Rebates)
  Designated for customers upgrading from standard efficiency to high-efficiency natural gas equipment

- **Tier Two** (Direct Use Rebates)
  Designated for customers upgrading from standard non-gas equipment to high-efficiency natural gas equipment and for qualified energy efficiency upgrades in the new construction sector

To qualify for space heating rebates, a dwelling must use natural gas as the sole heat source upon installation of rebate-qualified equipment.

To qualify for water heating rebates, a dwelling must utilize natural gas for water heating upon installation of rebate-qualified equipment.

Rebates for furnaces and water heating equipment for new construction may not be combined with the Energy STAR whole home package rebates as they are already included as part of the Energy STAR home.

Rate Schedule DSM
RESIDENTIAL ENERGY EFFICIENCY REBATE PROGRAM
(Continued)

MEASURES/INCENTIVES:

Whole Home Package (for new construction)	**Description**		**Rebate Amount**
Energy Star Certified Home	Energy Star Verified Home with Natural Gas Space and Water Heat		$1200
Stand Alone Measures (for new & existing construction)	**Description**	**Tier One: Energy Efficiency Rebate**	**Tier Two: Direct Use Rebate**
95% AFUE Natural Gas Furnace	95% or Greater Thermal Efficiency Rating	$350	$500
High Efficiency Combination Radiant Heat System	90% or Greater Efficiency Condensing Tank-less Combo System For Space and Water Heat	$1000	$1,200
80% AFUE NG Fireplace Insert	80% AFUE Rating or Greater	$200	$250
70% FE NG Fireplace Insert	70% FE Rating or Greater	$100	$200
.67 Natural Gas Water Heater	.67 Energy Factor or Greater	$50	$75
.91 EF Condensing Tank-less Water Heater	.91 Energy Factor or Greater	$150	$200

GENERAL PROVISIONS:

The Company will track all programmatic costs, savings, and equipment installations associated with this effort and will use this information to refine the program on an annual basis. An annual report shall be issued for each year of the program with data including, but not limited to: number of participants, cost effectiveness under the utility cost and total resource cost tests, total program expenditures, and other information as appropriate.

All installations of equipment must comply with all codes and permit requirements applicable in the state of Idaho and must be properly inspected, if required, by appropriate agencies. Customers must submit required documentation of purchase and installation to the Company under the terms and instructions of the current rebate form. The Company reserves the right to verify installation prior to the payment of any rebates.

Rate Schedule FCCM
FIXED COST COLLECTION MECHANISM

PURPOSE:

The purpose of the Fixed Cost Collection Mechanism (“FCCM”) is to establish procedures that allow Intermountain Gas Company (the "Company"), subject to the jurisdiction of the Idaho Public Utilities Commission ("Commission") to adjust, on an annual basis, its rates for distribution service in order to reconcile Actual Fixed Cost Collection Margin per Customer with Allowed Fixed Cost Collection Margin per Customer. The FCCM separates the recovery of the Company’s Commission-authorized revenues from therm deliveries to customers served under the applicable natural gas service tariffs.

APPLICABILITY:

The FCCM shall apply to all retail customers taking service under Rate Schedule RS, Residential Service; Rate Schedule GS-1, General Service; Rate Schedule IS-R, Residential Interruptible Snowmelt Service; and Rate Schedule IS-C, Small Commercial Interruptible Snowmelt Service.

DEFINITIONS:

The following definitions shall apply throughout the provisions of this FCCM tariff:

1. For each of the applicable Rate Schedules, Actual Fixed Cost Collection Margin per Customer (“Actual FCC MPC”) is the (a) amounts booked each month by the Company for Distribution Cost per therm divided by (b) the number of customers as measured by bills rendered in the same month. Actual FCC MPC excludes revenue from the Fixed Cost Collection Adjustment Factor.

2. For each of the applicable Rate Schedules, Monthly Allowed Fixed Cost Collection Margin per Customer (“Allowed FCC MPC”) is (a) the class-specific Fixed Cost Collection Margin for each month as approved by the Commission in the Company’s base rate case, Docket No. INT-G-16-02, divided by (b) the class-specific number of customers for each month, also as approved by the Commission in the Company’s base rate case, Docket No. INT-G-16-02. The Allowed Fixed Cost Collection Margin per Customer is subject to adjustment and approval by the Commission in any proceeding in which the Company’s allowed Distribution Cost per therm rates are revised by Commission order.

3. Forecasted therms is the forecasted amount of natural gas, as measured in therms, to be delivered by the Company for the twelve month period, October through September, during which the proposed Fixed Cost Calculation Adjustment Factor will be in effect (see Calculation of the Fixed Cost Collection Adjustment Factor on Page 2).

Rate Schedule FCCM
FIXED COST COLLECTION MECHANISM
(Continued)

DETERMINATION OF MONTHLY ALLOWED FIXED COST COLLECTION MARGIN

1. The Monthly Allowed FCC MPC for each applicable Rate Schedule shall consist of the class-specific margin associated with the Distribution Cost per therm rates for each of the 12 months of the Rate Year as approved by the Commission in the Company’s base rate case, INT-G-16-02, unless otherwise adjusted and approved by the Commission.

2. For the period beginning with the date that new rates become effective in Docket No. INT-G-16-02, the Allowed FCC MPC shall be calculated as the product of the approved class-specific Distribution Cost per therm rates and the class-specific volumetric billing determinants, divided by the class-specific number of customers as approved in Docket No. INT-G-16-02. The approved Distribution Cost per therm rates, volumetric billing determinants, number of customers and Allowed FCC MPC are as follows:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Allowed FCC MPC: Rate Schedule RS												
Therms (000)	41,720	35,233	27,242	20,362	10,810	7,216	4,908	4,211	4,696	7,048	15,906	33,434
Customers	306,609	307,092	307,494	307,485	307,442	307,348	308,056	308,736	309,381	310,196	310,726	311,238
Allowed FCC MPC	$15.33	$12.92	$9.98	$7.46	$3.96	$2.64	$1.79	$1.54	$1.71	$2.56	$5.77	$12.10
Allowed FCC MPC Rate Schedule GS-1												
Therms (000)	20,492	17,308	13,512	9,526	5,393	4,400	2,922	2,532	3,143	3,599	8,513	16,632
Customers	32,185	32,182	32,157	32,099	32,053	31,992	32,058	32,111	32,160	32,250	32,291	32,341
Allowed FCC MPC	$60.69	$52.08	$40.98	$29.50	$16.71	$13.51	$8.82	$7.59	$9.47	$10.77	$26.25	$49.60

3. If the Commission-approved Distribution Cost per therm rates for Rate Schedule RS or GS-1 are changed after the date that new rates become effective in Docket No. INT-G-16-02, the revised Allowed FCC MPC shall be calculated as the product of the revised approved class-specific Distribution Cost per therm rates and the volumetric billing determinants (therms), divided by the number of customers. The revised Allowed FCC MPC shall become effective on the date that the revised Commission-approved Distribution Cost per therm rates for Rate Schedule RS or GS-1 become effective.

CALCULATION OF THE FIXED COST COLLECTION ADJUSTMENT FACTOR

1. **Description of Fixed Cost Collection Adjustment Factor**
   Annually, the Company shall calculate a Fixed Cost Collection Adjustment Factor (“FCCAF”) to be applied to customer bills for the upcoming 12 month period, October through September. For billing purposes, the FCCAF shall be included in the Distribution Cost per therm rates.

Rate Schedule FCCM
FIXED COST COLLECTION MECHANISM
(Continued)

The FCCAF shall be calculated monthly by subtracting (a) the Actual Fixed Cost Collection Margin per customer from (b) the Allowed Fixed Cost Collection Margin per customer, and multiplying the resulting difference times the actual number of customers for that month, for each applicable rate class. The resulting differences will be summed to develop a total 12 month shortfall (if the summed difference is positive) or surplus (if the summed difference is negative) for each applicable rate class. The total, including reconciliation, shall be divided by projected therm deliveries for the next October through September period.

2. **FIXED COST COLLECTION ADJUSTMENT FACTOR FORMULA**

$$\mathrm{FCCAF}_s = \frac{\mathrm{FCCA}_s + \mathrm{R}_S}{\mathrm{FTherm}_s}$$

And

$$FCCA_s = \sum_{Mnth1}^{Mnth12} [(Allowed\ FCC\ MPC_S - \ Actual\ FCC\ MPC_s)\ x\ Actual\ \ C_S]$$

Where:

$Allowed\ FCC\ MPC_S$	is calculated as set forth on Page 2
$Actual\ FCC\ MPC_S$	is calculated as set forth on Page 1
FCCAF_S	The Fixed Cost Collection Adjustment Factor for class s.
$FCCA_S$	The Fixed Cost Collection Adjustment equals the difference between Allowed FCC MPC and Actual FCC MPC, by month, times Actual number of Customers, by month, and summed for the 12 months, October through September. The FCCA shall include actual data for October through June and estimated data for July through September.
R_s	Fixed Cost Collection Mechanism Reconciliation – Balance in Account 191, inclusive of the associated interest.
$FTherm_S$	Forecasted Therms for class s as defined on Page 2.
s	The Rate Schedules for which this Schedule FCCM is applicable: (a) Rate Schedules RS and IS-R and (b) Rate Schedules GS-1 and IS-C.

3. **FIXED COST COLLECTION MECHANISM RECONCILIATION**

Intermountain shall maintain FCCM Balancing Accounts for each applicable rate schedule. Entries shall be made to these accounts each month as follows:

   a. A debit or credit entry equal to the difference between (a) Allowed FCC MPC times the actual number of customers and (b) the therms billed during the month multiplied by the FCCAF charged during the month.

Exhibit No. 31
Case No. INT-G-16-02
M. McGrath, IGC

Rate Schedule FCCM
FIXED COST COLLECTION MECHANISM
(Continued)

b. The FCCM Balancing Account for each applicable rate schedule shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge which shall be computed at Intermountain's average monthly investment rate. The rate of the carrying charge shall be applied to the average monthly balance in the FCCM Balancing Account. Contra entries for the carrying charge shall be made to FERC Account Nos. 431 and 419.

EFFECTIVE DATE

The FCCAF shall be effective on October 1 of each 12 month period, unless otherwise ordered by the Commission.

INTERIM FILINGS

The Company may file for a mid-period adjustment.

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