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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 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

[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

1 directly to the customer of a particular class of service. Metering costs are an
2 example of customer-related costs." (P. 137)
3 These costs vary with the number of customer and typically include,
4 beside meter reading costs, the costs of billing a customer and some distribution
5 costs. The exact make up of costs associated with "customer charges" varies with
6 the practices of the individual state commissions. That is, some states may include
7 more distribution system costs than others related to demand.
8 The reason for this is that for residential gas meters and the utility's billing
9 systems do not allow for residential and GS customers to be charged for their
10 maximum demand on the system. Therefore the next best solution is to convert
11 the expected demand charge into a customer charge, which is equitable as
12 customers in this class are similar to each other so that the customer charge
13 collects as a demand charge would.
14 The testimony of Lori B. Blattner indicates that Intermountain's unit
15 customer-related costs are estimated at $13.50 per month, while the Company's
16 monthly customer charge is only $2.50 in the summer and $6.50 in the winter
17 months. Thus, a customer going on vacation for a summer month and shutting off
18 gas appliances would pay only $2.50, which would be grossly inadequate to
19 recover the fixed cost investment in the distribution system standing by to provide
20 service for that customer during the entire month, let alone the associated meter
21 reading and billing costs. The implication of that fact is that other customers
22 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.

1 **Q. Would the shift in customer charge, as proposed by Intermountain,**
2 **discourage conservation or encourage unnecessary use of natural gas?**
3 A. I do not believe so. Correctly done the average customer should see a monthly bill
4 at the same level before the change as after. While the fixed customer charge will
5 increase, the volumetric charge will decrease, leading, on average, to a total bill
6 the same as before. Thus, there would not be any price signal indicating that
7 delivered gas service was any cheaper than before.
8 Even if the commodity price of natural is slightly lower in the future, due
9 to this shift, it is not people who use natural gas but their appliances and devices.
10 These devices do not see any price. When the weather gets colder the family
11 furnace or cooking range will not use more gas just because it is less expensive
12 than it was before. Yes, customers do control the thermostat, but is it likely that
13 small changes in gas commodity price will cause major changes in life style
14 choices (increasing thermostat settings in winter or cooking more often) for the
15 average consumer? Conversely, if the price of gas is lower, it is also highly
16 unlikely that consumers will go out and install a second furnace and a second
17 kitchen range.
18 With respect to which price signals to consumers would cause them to
19 replace lower efficiency furnaces and appliances for new ones, I believe that
20 consumers are more likely to change their furnaces and appliances due to
21 mechanical problems, age and rebates and other promotional programs than
22 changes in commodity gas costs. I doubt whether gas appliance sales have
23 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")?

1 A. Yes. It is my opinion that the FCCM presented in Mr. McGrath's testimony is a
2 necessary component of the Demand Side Management (DSM) program
3 presented in the testimony of Allison A. Spector in this proceeding.
4 Ms. Spector's testimony includes a description of the company's proposed
5 DSM program, the program direct cost and reference to a revenue decoupling
6 proposal in the form of the FCCM Tariff in Mr. McGrath's testimony. The
7 purpose of the FCCM is to mitigate revenue losses resulting from this
8 conservation program and other factors. It is my opinion that the FCCM is a
9 critical component of the DSM proposal and its acceptance by the commission
10 would be in keeping with the public interest and good regulatory practice.
11 **Q. What is the nature of the term "fixed costs" in the context of the FCCM**
12 **proposal?**
13 A. As I explained earlier, a natural gas utility incurs certain fixed costs during the
14 test year period for which the revenue requirement is estimated, and upon which
15 rates are based. These costs do not vary with the volume of natural gas delivered
16 through the Company's distribution system or taken by any individual customer.
17 An allocated cost of service study, as prepared by all natural gas utilities in
18 support of rate design, has within it a breakdown of fixed and variable costs by
19 customer class. The problem arises when natural gas distribution rates are
20 designed to predominately recover costs in the volumetric component and
21 experienced volumes fall below those expected. The result will be programmatic
22 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.

1 **Q. Is a request for a decoupling mechanism, such as the FCCM proposal**
2 **appropriate when a utility adopts a demand side management program?**
3 A. Yes, it is. The Commission recognized this with its earlier cases in the electric
4 industry. For natural gas distribution utilities, the cited NRRI paper clearly states
5 that ratemaking mechanism elements when adopting DSM "generally attempt to
6 allow recovery of investments and expenses of various options, recovery of
7 revenues caused by lost sales due to successful implementation of demand-side
8 management (DSM) options, or otherwise make supply side and DSM options
9 equally profitable, offer additional financial incentives for successful DSM
10 options, and promote overall costs minimization." (Page 3) In this case, Mr.
11 McGraths testimony on FCCM lays out a specific proposal in keeping with the
12 DSM program.
13 **Q. Is ratemaking treatment to recover lost revenues an indispensable part of a**
14 **DSM proposal?**
15 A. It is. The NRRI report is direct on this point: "Recognizing the fact that adoption
16 of cost-effective DSM options may lead to a reduction in sales, and therefore, a
17 reduction of revenues and profits, mechanisms to compensate the utility for lost
18 revenues have been proposed and used." Thus, I believe it is indispensable.
19 **Q. Is there a case where a DSM program may not lead to a reduction in**
20 **"revenues and profits"?**
21 A. In most cases DSM would lead to reduction in revenues. However, if the
22 distribution gas company rate design had all fixed costs in a monthly fixed charge,
23 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

[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.