STATE OF COLORADO

BEFORE THE PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ADVICE LETTER NO. 9 FILED BY BLACK HILLS COLORADO GAS, INC. TO INCREASE BASE RATE REVENUES, TO IMPLEMENT REVISED BASE RATES FOR ALL RATE SCHEDULES AND OTHER TARIFF REVISIONS EFFECTIVE JULY 2, 2021.	**Proceeding No. 21AL-0236G**

HEARING EXHIBIT NO. 601

ANSWER TESTIMONY AND ATTACHMENTS OF

PAUL L. CHERNICK

ON BEHALF OF

ENERGY OUTREACH COLORADO

Resource Insight, Inc.

NOTICE OF CONFIDENTIALITY

A PORTION OF THIS DOCUMENT HAS BEEN FILED UNDER SEAL

Confidential: Page 61, Confidential Attachment PLC-19

SEPTEMBER 10, 2021

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, where I was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, conservation program design, estimation of avoided costs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in **Attachment PLC-1**.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included planning and ratemaking for distributed resources, distributed resource planning, the benefits of load reduction on the distribution and transmission systems, utility planning, marginal costs, and related issues.

Many of those testimonies concerned planning, cost allocation, and rate design for natural gas distribution companies.

Q: Have you testified previously before this Commission?

A: Yes. I filed testimony in Proceeding No. 19AL-0268E, a Public Service Company rate case, on the management of Comanche Unit 3 outages and the prospects for Public Service's remaining coal fleet.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Energy Outreach Colorado (EOC).

Q: What is the scope of your testimony?

A: I discuss four areas:

- Avoiding uneconomic investment in expanding the distribution system and replacing deteriorated equipment in light of the policy priorities of beneficial electrification and decarbonization.
- Improving the accuracy and equity of the class cost-of-service study.
- Correcting overstatement of the residential customer charge.
- Consolidating the rate areas.

Q: Please summarize your conclusions and recommendations.

A: My major conclusions are as follows:

- Black Hills Colorado Gas, Inc. ("Black Hills Gas" or the "Company") should be prioritizing retirement of deteriorating plant, supported by electrification.
- Black Hills Gas has overstated the allocation of mains to the Residential class, by overstating the functionalization of mains to distribution and overstating the classification of distribution mains to customer number.
- The method that Black Hills Gas uses for functionalizing mains booked to Account 376 treats expensive high-capacity transmission as distribution.
- The class weighting that Black Hills Gas uses for allocating mains is unsupported.
- Black Hills Gas overstates the residential portion of service lines by improperly assigning the costs of expensive pipes of unknown diameter to the residential customers.
- Black Hills Gas overstates the cost of residential meter sets, by failing to recognize the higher costs of the non-residential meters.
- Black Hills has no basis for its weighting of customer accounting costs.
- The residential customer charges proposed by Black Hills Gas are higher than the embedded costs of serving very small customers.
- There is no reason to maintain the separate rates for the three Rate Areas.
- No infrastructure should be added in connection with consolidating the Rate Areas.

Q: What are your recommendations?

A: The Commission should reject Black Hills Gas's class cost-of-service study and proposed allocation of the revenue requirement. It should also reject Black Hills Gas's proposed residential customer charges.

The Commission should adopt my corrections to the Company's class cost-of-service study, and the resulting customer fixed charges.

Finally, the Commission should approve statewide consolidation of the rate areas, or at a minimum partial consolidation of Rate Areas 2 and 3. If consolidation is not approved, the Commission should at least mitigate the rate impacts to residential customers in RA2 such as by limiting the percentage increase of that group's revenue requirement to double the average system base-rate increase. For example, if the Commission allows a 5% increase in Black Hills Gas total non-fuel revenues, the increase in the RA2 residential revenue should be no more than 10%. Since the residential customer charges should not increase, whatever residential revenue increase the Commission allows should be recovered through an increase in the volumetric rate.

Q: Do you have any general comments on Black Hills Gas's allocation and rate design analysis?

A: Yes. With regard to some parts of the class cost-of-service study, such as the use of relative capacity measure for mains, ignoring the commodity function of distribution, and the inconsistent treatment of plant of unknown diameter, Black Hills Gas does not appear to have thought through its approach and has not provided a clear rationale for its decisions. By this, I do not just mean that I disagree with Black Hills Gas's approach, but that I do not understand why the Company thinks that approach is reasonable.

Black Hills Gas's lack of attention to the cost-allocation and rate-design portions of this proceeding is at times baffling. For example, in explaining why Irrigation customers are not allocated certain costs, Black Hills Gas says that they "[do] not operate during the very cold temperatures at the time of system peak. Therefore, these customers do not use natural gas on the peak day and thus their load factor is 0."[1] Load factor is defined as average load divided by peak load, so a customer with the same load every day has a load factor of 100%, a customer using less on average than on peak has a load factor under 100%, and a customer using more on average than on peak has a load factor over 100%.[2] A customer who uses gas only on the peak day would have a load factor of 1/365th, or about 0.3%. Low load factors are generally undesirable and impose large fixed costs per unit of consumption. When EOC pointed out Black Hills Gas's error, the Company doubled down, redefining load factor: "the formula is use on the peak day divided by the system peak on the peak day, which will always equal zero independent of the system peak value."[3]

While Black Hills Gas is not a large utility, it should be able to avoid such glaring errors in basic terminology.

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[1] Testimony of Douglas Hyatt, Hearing Exhibit 105, p. 24, lines 19–21.

[2] *See, e. g.*, https://cms.ferc.gov/sites/default/files/2020-04/cost-of-service-manual.doc, pages 35–44.

[3] **Attachment PLC-2**, Black Hills Gas Response to Discovery Request EOC 2-1(a).

III. Minimize Investment in Obsolescent Distribution System

Q: Please describe Black Hills Gas's current approach to replacement of deteriorated or vulnerable equipment on its distribution system?

A: Black Hills Gas generally replaces deteriorated equipment with new equipment, so as to be able to continue delivering gas in essentially the same manner as before. This approach is also applied to situations in which a meter is in an unsafe location; Black Hills Gas relocates the meter to the building and constructs a new service drop to replace the Customer-Owned Yard Lines (COYL).

Q: Why is this approach of concern in this proceeding?

A.: Black Hills Gas's cost claim includes a total of $63.5 million in "integrity program" investments replacing, relocating, protecting and otherwise maintaining the aging system between July 1, 2018 and December 31, 2020. Of that total, 45% ($28.8 million) was in RA2.[4] The Company seeks full recovery of these costs; in RA2, only approximately 19,000 residential customers constitute 86% of the customers and about half the sales. The result is a proposed base rate revenue increase in RA2 for the Residential class of 48%,[5] with average residential monthly bill impacts of 21%–25% in RA2.[6] This rate hike and substantial expenditure in new gas infrastructure occurs while Colorado energy policy dictates a near-term transition *away* from natural gas. Accordingly, the Commission should be concerned not only with the immediate rate impacts, but with the potential future rate impacts from stranded

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[4] *See* Black Hills Gas Response to Discovery Request EOC 2-29, attached hereto as **Attachment PLC-3**. A substantial fraction of the "reliability" projects, as listed in Direct Testimony of Kellie K. Ashcraft, Hearing Exhibit 101, Attachment KKA-2, are also related to maintaining the aging system. The "reliability" projects total $34.9 million, including $4.5 million in RA2. The so-called reliability investments are mostly for meter replacement ($23.3 million, including almost all the RA2 investment), with small amounts of service replacement, growth-related projects, and looping (Hearing Exhibit 101, Attachment KKA-2).

[5] Direct Testimony of Svetlana Atoyan, Hearing Exhibit 106, Table SVA-10.

[6] *Id.* at Table SVA-16.

assets and duplicative of energy infrastructure. EOC is especially worried about these cost burdens for RA2, which I understand to include some of the poorest areas in Colorado.

Q: Does Black Hills Gas make any exceptions to its policy of replacing aging infrastructure in kind?

A: Yes. With respect to the replacement of aging polyvinyl chloride (PVC) pipe, Kellie K. Ashcraft stated in the System Safety and Integrity Rider (SSIR) proceeding:[7]

> The Company has already replaced PVC pipe in its system located in towns and other more populated areas that serve residential and commercial customers. PVC is still used to fuel pumps and related equipment for agriculture irrigation within Rate Areas 2 and 3. Given the remote locations of these pipes, the typically extensive length of the service lines, and the seasonal nature of the service provided, the Company has delayed replacing the PVC lines in these areas until it can more fully evaluate potentially more feasible alternatives. In 2021, the Company plans to determine if the agriculture irrigation engines could be converted to an alternate energy source. The Company plans to include within the scope of this study any residential or commercial customers also served by PVC pipe in less populated areas.

In response to discovery requests, Black Hills Gas indicated that it was considering that approach more widely, at least where costs of continuing service was excessive:

> The Company is currently evaluating situations where it may be required to discontinue service to some customers due to the amount of required safety and integrity investment necessary to continue providing natural gas service. The Company continues to evaluate options of future service for these customers.[8]

It is not clear how uneconomic a replacement project would have to be for Black Hills Gas to consider that it was "required to discontinue service to some

[7] *Id.* at p. 5.
[8] Black Hills Gas Response to Discovery Request EOC 2-10(e), attached hereto as **Attachment PLC-4**.

customers." Because Black Hills Gas is just beginning to think through how to deal with these situations, Commission guidance may be particularly valuable at this time.

Q: Is Black Hills Gas's approach to abandoning long lines with limited loads and switching customers to other energy sources appropriate?

A: Yes. That approach should be applied to other situations in which the ratio of gas investment (particularly for deteriorating mains and services) for energy delivered is high, to minimize the cost of providing energy services to customers. Just as a gas utility can reduce its ratepayer's costs by replacing some natural-gas use with investments in insulation, weatherstripping or higher-efficiency furnaces, it can replace a customer's entire natural-gas consumption (and avoid a range of distribution and customer costs) by switching the customer to high-efficiency electricity equipment (such as heat pumps or radiant heat) or, in some situations, propane.

Just as power plants that cost more to run than to replace are economically obsolete, so are gas lines that cost more to refurbish and maintain than to eliminate. Replacing economically obsolete plant in kind is not beneficial to consumers.

This may also apply to COYL projects in limited circumstances, where the cost of relocating an unsafe meter exceeds the cost of converting the customer to electric service. One might expect this to be the case if the customer is mainly using gas for a single appliance, such as a water heater or stove, which can be replaced with a heat pump water heater or induction stove.

Q: Other than avoiding expensive replacements of gas lines, are there other benefits of retiring lines and shifting loads off natural gas?

A: Yes. This year, the Colorado General Assembly enacted SB21-246 (the "Beneficial Electrification Bill"), in which the legislature declared that:

> (f) … transitioning to clean electric homes and businesses is a critical strategy for improving public health and safety, saving energy, creating family-sustaining jobs, and helping the state meet its greenhouse gas emission-reduction targets;
>
> (g) Colorado has significant potential for replacing fossil gas with clean electricity; …[9]

Similarly, in passing SB21-264 (the "Clean Gas" Bill), the legislature declared its intent "to implement a performance standard that will allow Colorado gas utilities to use available tools, including…beneficial electrification of customer end uses…"[10] The Clean Gas Bill requires Black Hills Gas and other Colorado gas utilities to file a Clean Heat Plan by August 1, 2023 to achieve carbon dioxide and methane reductions.

Any lines retired, and any loads shifted from natural gas to electricity, will count toward Black Hills Gas' compliance with the emission reduction goals set out in the Clean Gas Bill. A sense of urgency for such work is also suggested in the *Colorado Greenhouse Gas Pollution Reduction Roadmap*, which calls for electrification "action in the near term to accelerate the transition."[11]

The removal of obsolete gas meters, regulators, and pipes may also reduce impediments to private or public infrastructure projects. Black Hills Gas should remove abandoned above-ground equipment, and maintain appropriate records to assist customers with identification of abandoned below-ground equipment that may be safely removed in the course of construction activities.

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[9] Colorado Senate Bill 21-246, Section 1 (1)(f).
[10] Colorado Senate Bill 21-264, Section 1 (1)(c)(I).
[11] Governor Jared Polis, *Colorado Greenhouse Gas Pollution Reduction Roadmap* (January 14, 2021), p. 32.

Q: What are the potential costs of beneficial electrification?

A: In its System Safety and Integrity Rider (SSIR) proceeding, Black Hills Gas witness Otto described a study by affiliate Black Hills Colorado Electric regarding the "cost of converting a single natural gas home and the entire gas service within the community of Rocky Ford, Colorado to all-electric service."[12] Rocky Ford receives both natural gas and electric service from Black Hills Energy. The study estimated that the incremental customer bill impact would be about $100 per month in 2021, by comparing the $165/month electric bill increase for an assumed 1,036 kWh incremental usage to the assumed $65/month avoided gas bill.[13] Even if the input assumptions are correct for a customer converting to Black Hills Electric, which has some of the highest rates in Colorado, they would not be accurate in most of the Black Hills Gas territory. Most of the coops whose service territories overlap with Black Hills Gas have residential rates lower than Black Hills Electric's, so the customer economics would be much better in those areas. Table PLC-1 shows that the Black Hills Electric residential rates are in the top 10% of Colorado cooperatives' rates, weighted by either residential sales or residential customer number.

Table PLC-1: Distribution of Colorado Cooperatives' Residential Electric Rates

Price Range, $/kWh			Residential Sales	Residential Customers
	<	$0.09	0.3%	0.3%
$0.09	to	$0.10	0.0%	0.0%
$0.10	to	$0.11	0.0%	0.0%
$0.11	to	$0.12	10.6%	8.0%

[12] Alternative Fuel Analysis: Preliminary Study of Electrification of Customers within Rocky Ford, Colorado; September 2020, Black Hills Gas Response to Discovery Request EOC 2-10, Attachment EOC 2-10(d)(i), attached hereto as **Attachment PLC-5**.

[13] *Id.*, p. 28. It is not clear that these averages are comparable. The average gas bills with Black Hills Gas's requested rates range from $60/month in RA3 (the only area under $65) to $91/month in part of RA1. *See* Attachment EOC 1-9, *infra*. The average gas bills do not include all loads that Black Hills assume would be shifted, since not every customer has gas space heat, water heat, dryer, and stove. The gas bill for a fully-loaded customer would be higher than the reported average usage.

$0.12	to	$0.13	11.2%	10.3%	
$0.13	to	$0.14	44.3%	43.7%	
$0.14	to	$0.15	18.9%	19.8%	
$0.15	to	$0.16	6.9%	8.1%	
$0.16	to	$0.17	4.0%	5.0%	Black Hills Electric price
$0.17	to	$0.18	3.8%	5.0%	
$0.18	to	$0.19	0.0%	0.0%	

Source: Energy Information Administration, Form 861 data 2019, Sales to Ultimate Customers

In addition to whatever bill changes occur, the fuel-switching study estimated that replacing existing appliances and upgrading electrical wiring would cost $14,000.[14] This is a plausible value, at least in some situations, but the costs will vary widely (e.g., some customers will already have electric ranges and dryers, others will have furnaces at the end of their useful lives, and others may have adequate service capacity, due to existing inefficient air conditioners and other summer loads, such as pool pumps).

Moreover, Colorado's policy objectives regarding beneficial electrification dictate that the bulk of gas end uses will need to be electrified, so these are capital costs that will be incurred sooner or later. If electrification occurs slowly, a portion of the gas appliances would likely need to be replaced before electrification, only to be discarded when the building is electrified.

Over time, the retail price of natural gas is likely to increase, in part due to greenhouse-gas charges. Low-cost renewable energy, including behind-the-meter solar and storage, would moderate the effect of greenhouse gas reduction initiatives on the price of electricity.

[14] *Id.*, p. 5. The study does not provide a breakdown of this estimate.

Q: May there be circumstances in which it would be reasonable for Black Hills Gas to pay thousands of dollars per customer for beneficial electrification?

A: Yes. In 2020, SEMCO Energy Gas Company was authorized to abandon approximately 4.3 miles of pipelines serving just three Michigan customers. By abandoning the pipelines, SEMCO avoided $471,500 in capital expenditures with what it described as a comparatively "minimal" cost to convert three customers to propane.[15]

In this case, SEMCO could have paid $150,000 per customer and still reduced costs.

Q: Have you identified any similar opportunities in Black Hills Gas's territory?

A: Yes. In the Glenwood Spring area of RA1, Black Hills Gas spent $2.17 million to resolve low-pressure issues for 12 customers in the Singletree sub-division.[16] Black Hills Gas could have spent over $180,000 per home to switch these customers to electricity and still saved money. In all probability, taking even a small number of these customers off of gas would have solved the pressure problem, while also reducing the cost of decarbonization.

Black Hills Gas has already spent that $2.17 million, apparently unwisely. It should avoid similar errors in the future.

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[15] SEMCO Energy Gas Company, *Application for Approval of the Abandonment of Approximately 4.3 Miles of Natural Gas Pipeline Pursuant to MCL 460.6z*, Case No. U-20738 (March 11, 2020), p. 2. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000ACTwEAAX.

[16] Hearing Exhibit 101, Attachment KKA-2, page 5, Funding Project 10069903. This was the only project for which Attachment KKA-2 identifies the number of customers served.

Q: Are you recommending beneficial electrification for all customers or entire communities?

A: No. While the Commission may want to investigate that topic in the process of developing the Clean Gas Plan, it is outside the scope of this proceeding. Considering that beneficial electrification policies are coming, my recommendations are focused on ensuring that future system integrity and so-called reliability spending does not result in higher system costs than a beneficial electrification alternative.

Q: How would you suggest that Black Hills Gas pay for cost-effective beneficial electrification?

A: Costs should be recovered either as part of Black Hills Gas demand-side management (DSM) program costs or included in the Clean Heat Plan budget.

This year, the Colorado General Assembly also passed HB21-1238 (the "Gas DSM Bill") to make beneficial electrification programs eligible as demand-side management programs funded by gas utilities, as follows:

> "Beneficial electrification" means a utility's change in the energy source powering an end use from a nonelectric source to an electric source, including transportation, water heating, space heating, or industrial processes, if the change:
>
> (I) Reduces system costs for the utility's customers;
>
> (II) Reduces net carbon dioxide emissions; or
>
> (III) Provides for a more efficient utilization of grid resources.[17]

Where beneficial electrification can result in the retirement of a line and shifting the load from gas to electricity, and where those costs would be less than the cost of

[17] C.R.S. § 40-3.2-106(6)(a).

repairing or maintaining the line,[18] then the reduced system costs would justify including such projects in Black Hills Gas' DSM program.

In addition, the electric utility adding the load may be willing to contribute the difference between its additional revenues and the additional costs it incurs to serve the customer. Various parts of the Black Hills Gas system are served by Black Hills Electric, Public Service Company of Colorado, and multiple cooperatives. I recommend that as part of its Clean Heat Plan, Black Hills Gas should contact each electric utility and identify what costs each utility may be able to cover in order to make more line retirement projects feasible without increasing system costs to Black Hills Gas customers. The Commission may wish to direct further coordination of costs and revenue recovery.

Finally, the Company could look into securitization as means of reducing the overall cost of fuel switching.

Q: How could Black Hills Gas ensure that the fuel-switching program is implemented equitably?

A: There are at least two aspects of equity that should be addressed. First, all customers served by equipment that is economically obsolete should be able to participate in the program without excessive financial burden.

Black Hills Gas should cover most or even all costs of appliance replacement and any related electrical upgrades for customers with lower income and/or wealth than for better-off customers.[19] In addition, if the electrical equipment is more expensive to operate in the short term, Black Hills Gas or the electric utility may need to offset the incremental bill impacts of the fuel-switching until that premium erodes.

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[18] As noted above, beneficial electrification might also be applicable to some COYL projects.

[19] *See* Senate Bill 21-246, Section 1(2).

For customers with higher incomes and wealth, Black Hills Gas or the electric utility should provide financing for all participants for whatever part of the conversion costs they wind up bearing, so access to capital is not an issue. That financing should ideally be tied to the property (or perhaps the electric bill), to allow participants to move without taking the debt with them.

Second, the utility's program costs should be allocated among classes and recovered as the avoided costs would have been allocated. For mains, that would be largely or entirely volumetrically.

Q: What is a fair contribution to expect from customers whose gas service is being retired?

A: Since the customer would require new appliances and some new electrical work, potentially including a panel upgrade, and since the total energy bill may decline, the customer would derive significant value from the beneficial electrification project. I recommend the following general design for a customer contribution requirement.

1. A generous threshold for low-to-moderate income customers should be set using both income and property value. For customers with income or property value below the threshold, customers would not have any required contribution other than voluntary upgrades, and would receive a reasonable allowance for bill impacts, as described above.
2. For customers with incomes and property values above the threshold, Black Hills Gas could require the customers pay for 50 percent of the additional value provided by the beneficial electrification project could be required. This additional should be determined by the cost of the appliances and electrical service upgrade, net of an allowance for the remaining life of the gas appliances. Black Hills Gas should provide financing for that cost, limited to a reasonable percentage (perhaps 25 percent) of the customer's future electric bill.

Implementing these general guidelines in a specific program will be fairly complicated. In the near term, Black Hills Gas is not likely to identify very many situations where it may be required to discontinue service to some customers due to the amount of required safety and integrity investment necessary to continue providing natural gas service. And in any event, as the SEMCO example suggests, the number of customers affected by each electrification project would generally be very small.

Because such opportunities will arise infrequently, it would not be burdensome for Black Hills Gas to apply for approval of abandonment and cost recovery on a case-by-case basis. If it appears that abandonment and replacement applications may become frequent, Black Hills Gas may wish to propose an abandonment and replacement program as part of its Clean Heat Plan.

Q: Would a retirement and fuel-switching program conflict with the utility's obligation to serve?

A: No. Colorado law now provides substantial direction to the Commission to enable beneficial electrification, which must be implemented consistent with the obligation to serve.[20] While the General Assembly stated that there should not be coercion or discriminatory treatment, the obligation to serve can be satisfied by adequately covering the costs (potentially through financing) of the provision of equivalent replacement electrical service. In some limited cases where the customer's use of gas cannot reasonably be replaced by electricity, it may be reasonable to replace the service with propane.[21]

While I am not aware of any Colorado precedents on this issue, the Michigan example I mentioned above may be useful to the Commission. SEMCO's application

[20] An application for abandonment is required by Rule 4103(a). "A utility shall not extend, restrict, curtail, or abandon or discontinue without equivalent replacement any service, service area, or facility not in the ordinary course of business without authority from the Commission."

[21] If neither propane nor electricity can meet the customer's needs, then I would agree that the obligation to serve requires the replacement or repair of the line to ensure continued service.

to abandon approximately 4.3 miles of pipelines serving just three customers stated, "… the cost of replacing and maintaining this pipeline outweighs any interest in the public convenience and necessity."[22] The Michigan Public Service Commission approved the application, finding that abandonment and converting the customers to propane service was in the public interest.[23]

I recommend that the Commission give guidance to Black Hills Gas to adopt a similar standard, reflecting both cost minimization and the recently enacted bills that direct the Commission to support beneficial electrification. Specifically, the Company should be required to seek approval to abandon, rather than rehabilitating, gas infrastructure whenever the costs to maintain the gas equipment exceed the costs of replacing it with electric or other low-carbon alternatives. At a minimum, the Black Hills Gas should undertake the non-pipeline alternative analysis before investing in replacement or upgrades, and be prepared to show its analysis in future rate cases to justify that the spending was prudent and in the public interest.

Q. Why is it appropriate for the Commission to impose such standards and directives to Black Hills Gas in this proceeding?

A. The Company is spending so much money on new and replacement natural gas lines that it is putting upward pressure on rates, often to serve few customers.

While the Commission may not wish to disallow recovery of such spending that the utility considered necessary to serve under its legacy criteria, the Commission should signal that such excessive costs on a dying technology will not automatically be recoverable. In future, Black Hills Gas should be required to show that it

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[22] SEMCO Energy Gas Company, Application for Approval of the Abandonment of Approximately 4.3 Miles of Natural Gas Pipeline Pursuant to MCL 460.6z, Case No. U-20738 (March 11, 2020), p. 2.

[23] Michigan Public Service Commission, *Order Approving Settlement Agreement*, Case No. U-20738 (July 9, 2020).

reasonably analyzed whether replacement or retirement was the better option, in light of the overall costs, as well as the policy directives regarding beneficial electrification and carbon reduction. In the absence of such analysis, or some other showing of mitigating circumstances, the Commission should not allow Black Hills Gas to recover the costs.

IV. Class Cost-of-Service Study

Q: What aspects of the class cost-of-service study have you reviewed?

A: I reviewed the following:

- functionalization of mains between transmission and distribution;
- classification of distribution mains between capacity and customer numbers;
- weighting of customer number for mains;
- allocation of services; and
- allocation of meter costs, including regulators.

Q: Do you have any overarching concerns about the accuracy of the cost data used in the class cost-of-service study?

A: Yes. Black Hills Gas's class cost-of-service study relies heavily on trended original cost (TOC), that is, the gross plant in service times the ratio of the applicable Handy-Whitman index today to that index in the plant's in-service year.[24]

When asked about why its workpapers reported that some years had a large number of regulators installed, including over 40,000 in RA1 in 1986, over 21,000 in RA2 in 2005, and over 67,000 in RA3 1989, Black Hills Gas acknowledged that:

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[24] The Handy Whitman index is a set of relative construction price data, differentiated by utility (gas, electric, etc.), region, FERC account and sometimes other factors, such as material.

> the Company has undertaken activities to improve its data records. Often these efforts include converting paper records to digital format. The Company is not certain why these regulators were designated as installed on those specific years.[25]

In other words, Black Hills Gas is acknowledging that the conversion of records from paper to digital may misstate the vintage of property, and hence the trended cost. Any part of the class cost-of-service study that relies on the relative trended cost of various sizes or types of equipment to allocate plant to classes (meters, regulators, services, mains) should therefore be taken with a grain of salt. As a result, there is reason to be skeptical of a large portion of the class cost-of-service study that uses the TOC, including meters, services, and mains.

A. Mains

Q: How does Black Hills Gas allocate mains costs among classes?

A: The allocation process for the mains investment consists of three steps:

- functionalization between transmission and distribution, based on pipe diameter;
- classification of the transmission main plant (Account 367 and part of Account 376) 50% to commodity (also known as throughput or energy) and 50% to capacity (which is allocated on the basis of class peak-day load); and
- classification of the distribution main plant 50% to capacity and 50% to customer, to be allocated on a weighted customer number.

[25] Black Hills Gas Response to Discovery Request EOC 2-6, attached hereto as **Attachment PLC-6**, at (h).

1. Functionalization

Q: Please describe Black Hills Gas's functionalization of the costs of Account 376 mains between transmission and distribution, based on pipe diameter.

A: For each Rate Area (RA), each material (plastic and steel) and each diameter category (≤1", 1–2", 3", 4" and so on), Black Hills Gas computed the length, TOC, and a "relative capacity" measure equal to the following:[26]

$$\text{length} \times (\text{nominal diameter})^{2.5}$$

Black Hills Gas then sorted the data by diameter category and selected a break point at which more than half the relative capacity was functionalized as distribution and less than half as transmission, without allowing a category to be split between distribution and transmission.[27] This process resulted in all pipe up to 4" diameter being functionalized as distribution for RA2 and the consolidated company, and all pipe up to 3" diameter, plus 4" plastic pipe, being functionalized as distribution for RA1 and RA3. Black Hills Gas wound up assigning the distribution function over 90% of the mains length, 54% to 59% of the relative capacity, and 51% to 76% of the trended original cost, as shown in Table PLC-2.

Table PLC-2: Distribution Share of Black Hills Gas Mains, Account 376

Rate Area	% of Length	% of Relative Capacity	% of TOC
1	90%	54%	51%
2	92%	56%	62%
3	93%	57%	76%
Consolidated	94%	59%	69%

[26] The 2.5 power on pipe diameter is a simplified approximation of the effect of the pipe cross-section on flow rate, given pressure differential, pipe length, pipe roughness, and other parameters.
[27] Attachments DNH-21 to DNH-24 of Hearing Exhibit 105, Direct Testimony of Douglas N. Hyatt.

Q: How did Black Hills Gas develop this methodology?

A: Black Hills Gas does not explain the origin of the methodology. When asked how it decided to set "The break point between the transmission function and distribution function …such that the relative capacity of the mains classified as transmission approximately equals that of mains classified as distribution" (Hearing Exhibit 105, Attachment DNH-14, p. 8), Black Hills Gas responded as follows:

> The Mains Analysis described in Attachment DNH-14 was developed approximately 27 years ago and used for Base Rate Areas 1 ("RA1") and 2 ("RA2") in Proceeding No. 08S-0108G. The methodology proposed in that proceeding was the same methodology the Company is proposing in the current proceeding.[28]

Black Hills Gas appears to use this method as a result of tradition dating to the early 1990s, when these rate areas were served by UtiliCorp United, the predecessor of Aquila, rather than any technical or economic analysis.

Q: Was this the only traditional methodology that Black Hills Gas could have used to allocate mains costs?

A: No. In the previous rate case, Black Hills Gas used a much simpler method for Rate Area 3.

The methodology to classify mains is different in the current proceeding from that used in the last rate proceeding for Base Rate Area 3 ("RA3"). The methodology used in the last rate proceeding for RA3 was based upon an allocation of distribution mains as 50% capacity and 50% commodity.[29]

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[28] Black Hills Gas Response to Discovery Request EOC 2-15, attached hereto as **Attachment PLC-7**, at (h).
[29] *Id.*

Q: What problems have you identified with Black Hills Gas's approach to functionalizing Account 376 mains?

A: I have identified five problems.

- Use of the relative-capacity measure to functionalize transmission from capacity.
- Misspecifying the role of pipe length in determining capacity.
- Failing to follow Black Hills Gas's stated intention to divide the relative capacity equally between transmission and distribution.
- Inconsistency between the pipe allocations of the rate areas and the consolidated system.
- Failing to properly distinguish steel from plastic pipe.

Q: What is the problem with the relative-capacity measure?

A: Black Hills Gas's use of relative capacity to split the functions is illogical and inconsistent. There is no reason to expect that the length×(nominal diameter)$^{2.5}$ of the transmission portion of Account 376 will be any particular fraction of the same computation for the entire account. A system can have long transmission lines connecting short bits of distribution lines, or short transmission lines with many long distribution lines coming off of them. Black Hills Gas did not provide any evidence in its filing or discovery response to support the assumption that the relative capacity for distribution should be higher than the relative capacity of transmission.

Q: How does the relative-capacity measure misstate the contribution of line length to capacity?

A: Multiplying the length of pipe by the flow parameter to produce some measure of flow-miles does not make sense. As Black Hills Gas acknowledges, "Capacity is also a function of length since capacity declines as the length of pipe increases due to friction losses."[30] Black Hills Gas acknowledges that the length of pipe runs reduces capacity, but treats length as increasing capacity.

Q: How does Black Hills Gas fail to follow its stated approach to functionalization of the mains in Account 376?

A: Black Hills Gas asserts that "The determination of the break point is…based upon the Cumulative Relative Capacity, which is developed using the diameter and length in feet of mains booked to FERC Account 376. The break point based upon the Cumulative Relative Capacity should be as close as practical to a 50/50% split when examining the relative capacity and cost relationships."[31] Yet Black Hills Gas actually selected Cumulative Relative Capacity break points of 54.36% for RA1, 56.44% for RA2, 57.00% for RA3 and 59.37% for the consolidated system – not a clear 50/50% split.

For the consolidated system, Black Hills Gas functionalizes as distribution all the 4" lines, plastic and steel, even though just the 1"–3" lines and the 4" plastic would constitute 54% of the Cumulative Relative Capacity.[32] Including 83% of the 4" lines as distribution would match the 50/50 split that Black Hills Gas claims it aimed for. While Black Hills Gas would functionalize 69.05% of the consolidated mains cost as distribution, the 50/50 split would functionalize only 58% as distribution.

By failing to split 4" mains of a particular type, Black Hills Gas also increased the distribution-functionalized portion of mains for each of the Rate Areas: by 3 percent points for RA1, by 10 points for RA2, and 18 points for RA3.

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[30] Black Hills Gas Response to Discovery Request EOC 2-15, attached hereto as **Attachment PLC-7**, at (b).

[31] Black Hills Gas Supplemental Response to Discovery Request EOC 2-15, attached hereto as **Attachment PLC-8.**

[32] As I explain below, the 2" and 3" steel pipes should be functionalized as transmission before the 4" plastic pipes.

Q: Please explain the inconsistency between the Rate Area results and the consolidated results.

A: The capricious nature of Black Hills Gas's approach can be seen in Table PLC-2, from the fact that the consolidated results assign distribution more of the pipe length and more of the relative capacity than any of the rate areas.

Q: How did Black Hills Gas fail to properly distinguish steel from plastic pipe?

A: Lumping plastic and steel pipe together and sorting them only by diameter ignores the much higher cost of steel and the increased capacity that high price buys. Black Hills Gas has not provided any details about its process for selecting pipe materials, but does indicate that the steel is installed so that Black Hills Gas can provide higher pressures and hence capacity:[33]

> …capacity increases with higher pressures. Each pipe diameter has pressure and capacity limitations. There are differences in pressure between steel and plastic, but the Company allocates based on end-user usage.[34]
>
> Black Hills chooses to install steel pipelines when working with system pressures greater than 200 psig. The Company follows industry standard and uses steel because it allows greater flexibility for system planning, reliability, and resilience. These 200+ psig systems lend themselves to handle varying loads and future growth, which allows the Company to use the existing steel pipe infrastructure rather than replace plastic pipe in those situations.[35]

Yet Black Hills Gas also states that its mains-allocation "methodology does not focus on whether the main is plastic or steel. Rather, it focuses on the diameter and capacity of the main in determining the function the pipe serves."[36] Note that Black

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[33] Some large customers may also require higher pressure, as well as higher volumes, for their operations.
[34] Black Hills Gas Response to Discovery Request EOC 2-15, attached hereto as **Attachment PLC-7**, at (d).
[35] *Id.* at (j).
[36] *Id*. at (h).

Hills Gas does not explain why it prefers to ignore pressure considerations (which affect capacity) and instead allocate the cost of steel pipe to customers who do not require the higher pressures or volumes that steel provides.

Table PLC-3 provides the average trended cost per foot of pipe, from Attachment DNH 23, for the consolidated system. The relationships are similar for individual rate areas.

Table PLC-3: Relative Cost of Plastic and Steel Pipe, TOC per foot

	Account 376		ratio to	Acct 367	ratio to
Diameter	Plastic	Steel	plastic	Steel	plastic
1	$9.94	$12.47	1.25		
2	$5.59	$13.68	2.45	$13.02	2.33
3	$4.35	$14.75	3.39	$10.40	2.39
4	$12.52	$39.88	3.19	$19.18	1.53
6	$34.43	$67.97	1.97	$43.71	1.27
8	$47.56	$60.64	1.27	$52.07	1.09

The Account 376 steel pipes are 25% to 239% more expensive than the plastic pipes.[37] The steel cost premium is even higher in the steel pipes installed in 2018–2020.[38]

Q: How do you suggest functionalizing the Account 376 mains?

A: By far, the simplest and most reasonable approach would be to extend the 50/50 classification of all mains between capacity and commodity, as Black Hills Gas previously used for Rate Area 3. That approach avoids the need to functionalize Account 376, as well as the need for a complicated classification of the costs functionalized to distribution.

If the Commission wants to pursue the multiple complex steps proposed by Black Hills Gas, the available information suggests that it would be appropriate to

[37] I am using Black Hills Gas's estimates of trended original cost, which may not be particularly reliable, as I note above. But I have no way to correct for Black Hills Gas's limited information on its equipment vintages.

[38] Black Hills Gas Response to Discovery Request EOC 2-8, attached hereto as **Attachment PLC-9.**

functionalize the plastic pipes up to 4" diameter and the 1" steel pipes as distribution, and the remainder as transmission. I base this recommendation on the preceding discussion of relative costs and the justification for incurring those higher costs, as well as the fact that Black Hills Gas's explicit transmission mains (Account 367) consist of 2", 3", 4", 6" and 8" steel pipe. Similar and larger steel pipe in Account 376 should also be functionalized to transmission.

Q: Have you calculated the effect on the class cost of service study if the Commission orders the Company to classify the mains 50/50 capacity and commodity for all Rate Areas?

A: Yes. This one change would reduce the consolidated allocation to the residential class by about $2 million, reducing that class's revenue deficiency by 15%.

Table PLC-4: Effect of Changing Mains Classification on Consolidated Class Cost-of-Service Study Results

	Total	Sales and Transportation			
	Gas Utility Adjusted	Residential	Small Commercial	Large Commercial	Seasonal and Irrigation
BHG Mains Classification					
Total Revenues Excluding Gas	$71,942,253	$53,368,287	$6,766,038	$11,342,982	$464,947
Net Cost of Service	$86,535,700	$67,279,177	$7,189,644	$11,578,469	$488,411
Revenue Deficiency	$14,593,447	$13,910,890	$423,606	$235,487	$23,464
As % of non-gas Revenues	20.28%	26.07%	6.26%	2.08%	5.05%
With 50/50 Commodity/Capacity Classification					
Net Cost of Service	$86,535,700	$65,184,355	$7,377,399	$13,380,358	$593,588
Revenue Deficiency	$14,593,447	$11,816,068	$611,361	$2,037,376	$128,642
As % of non-gas Revenues	20.28%	22.14%	9.04%	17.96%	27.67%

2. Classification

Q: How does Black Hills Gas classify the transmission mains function?

A: Black Hills Gas classifies transmission mains 50% to capacity and 50% to commodity. On the one hand, pipes need to be designed (in terms of size and material) to meet the peak flow they must carry. On the other hand, gas utilities generally expand their distribution systems only when the expected revenues cover their expected costs, as illustrated in Black Hills Gas discovery responses Attachments EOC 2-40(a) and 2-40(b), attached hereto as **Attachment PLC-10.** Those revenues are largely due to volumetric sales.

It is difficult to untangle these factors as drivers of transmission mains costs, so the 50/50 classification seems reasonable.

Q: How does Black Hills Gas classify distribution mains?

A: Black Hills Gas does not classify any of the distribution mains function as being commodity-related, even though the commodity carried over (and justifying) the transmission system must also be delivered through the distribution system. Until this proceeding, all mains in Rate Area 3 were classified 50/50 between capacity and commodity, as Black Hills Gas proposes for the mains functionalized to transmission. Black Hills Gas does not have a coherent rationale for abandoning this approach.

Instead, Black Hills Gas goes through a non-intuitive process, using the suspect relative capacity values I described above, to classify costs between capacity and weighted customer number. Black Hills Gas does not explain or justify its method.

Q: Is Black Hills Gas's computation the same as the archaic minimum-system approach to classification of distribution plant?

A: Not quite. Black Hills Gas' computation is conceptually the inverse of a minimum system, which estimates the cost of covering all the mileage of the system with the smallest, least expense distribution equipment, such as lines with the lowest cost per foot. Instead, Black Hills Gas estimates the cost of providing all the "relative capacity" with the 4" pipes functionalized as distribution mains.[39] So rather than estimating the cost of serving all the customers with the least-expensive hypothetical system, without considering the cost of capacity, Black Hills Gas's method estimates the cost of providing its estimate of relative capacity without considering the cost of actually delivering gas to customers.[40] Neither version reflects the reality of utility planning and cost causation.

Q: Is Black Hills Gas's approach to classifying distribution mains reasonable?

A: No. As I explained above, the relative capacity computation is not really meaningful. Black Hills Gas supposes that a distribution system composed of about 9.8 million feet of 4" blended plastic and steel line would be able to serve all its load, if only it did not have so many customers.[41] In order for that to be true, customers would not just need to consolidate into fewer but larger customers, but they would also need to move closer to Black Hills Gas's citygate delivery points. That is particularly true for the large customers for whom Black Hills Gas is willing to spend the most on expanding the distribution system.

Table PLC-5 shows the allowances Black Hills Gas currently offers for line extensions. Consumption levels are the only allowance driver for most rate schedules in RA3, and the dominant driver for customers over about 1,000 therms annual consumption in RA1 (roughly the average residential consumption) and RA2 (about 50% above the average residential consumption).

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[39] For Rate Areas 1 and 3, those are the 4" plastic pipes; for Rate Area 2 and the consolidated system, steel pipes are included in the computation.

[40] Black Hills Gas did not articulate the purpose of its computation, but I believe I have captured the intent.

[41] The 9.8 million feet is from "TOC of less than 6 inch that is Capacity Related" of $168.4 million, divided by the $17.09/ft TOC for blended 4" pipe, from Attachment DNH-23.

Table PLC-5: Black Hills Gas Line-extension Allowances

Base Rate Area	Fixed Amount	Per Dth over
Rate Area 1	$790.00	$24/Dth over 75.7 Dth
Rate Area 2	$830.00	$22/Dth over 76.0 Dth

Rate Area 3 - Class and Rate Schedule	Service Line	Main
Residential R-3	$174.00	$376.00
Small Commercial SC-3	$174.00	$512.00
Small Volume (SVF-3, SVI-3)	$0.39 / Dth	$3.08 / Dth
Large Volume (LVF-3, LVI-3, LCTS-3)	$0.03 / Dth	$2.68 / Dth
Irrigation (I/S-3)	$0.12 / Dth	$1.74 / Dth

Source: Schedule of Rates For Gas Service Available in the Entire Territory Served By Black Hills Colorado Gas, Inc., d/b/a Black Hills Energy, Colo. PUC No. 1, Sheet Nos. R40–R45

The portion of the mains costs not directly assessed to the new customers may be justified by many small customers, but it is more likely to be justified by the anticipated usage and revenue from larger customers.[42] The latter is consistent with my experience in other gas service territories.

It is difficult to exactly translate these allowances to the amount that Black Hills Gas or its predecessors would have paid to hook up the current mix of customers and loads.[43] However, making some conservative assumptions (*e.g.*, all RA3 Large Commercial load is Small Volume and all customers in a class have the average class load), to maximize the portion of costs attributable to customer number, only about 6% of the allowance statewide would have been due to the number of customers. With more realistic assumptions, such as some RA3 commercial customers being large volume and some customers having usage less than the extra-credit threshold

[42] Black Hills Gas explained in discovery that "non-refundable contributions in advance to construction are credited against the asset cost in determining the book value of services." Black Hills Gas Response to Discovery Request EOC 2-39. Thus, only the costs within the allowance limits are in the data used for functionalizing, classifying, and allocating costs.

[43] For example, Black Hills Gas does not provide customer number, peak load, or consumption separately for the Small Volume and Large Volume groups in the RA3 Large Commercial class. And for RA1 and RA2, I do not have data on the amount of usage by customers larger than the dekatherm cut-off limits.

(resulting in more usage being eligible for usage-related credits), the customer-related portion would be even lower.

Q: What do you recommend regarding the classification of the distribution mains?

A: I recommend that no more than 6% be classified as customer-related, with the remainder split evenly between capacity and commodity. For a 6% customer classification, a 47% share would be assigned to each of capacity and commodity. The customer classification should probably be even lower, but I do not have the bill-frequency data or the breakdown of the RA3 large-commercial sales.

More simply, the customer classification may reasonably be set to zero, as has been the practice for RA3.

3. Allocation

Q: How does Black Hills Gas propose to allocate the customer-classified distribution mains costs?

A: Black Hills Gas uses the customer weighting it developed for services, as discussed in the next section.

Q: Is that use of the services allocators reasonable?

A: No. As I explain below, Black Hills Gas's services allocators grossly overstate the residential share of service costs, by assigning all the costs of the services of unknown diameter (and very high cost) to the smallest services. Even if those were reasonable service allocators, there is little obvious relationship between the cost of distribution mains and the cost of services. It does make sense to assume higher mains costs for a large customer than a small one, since many of the small customers are clustered in towns, with several customer to a block, while large commercial gas customer (a hospital, high school, large church, courthouse, supermarket, or the like) may take up much of the block, substantially increasing the pipe run between customers.

Q: How do you propose that the customer-classified distribution mains costs be allocated?

A: The simplest approach would be to recognize that mains have historically been extended primarily because of the potential for sales, and thus classify those costs entirely to capacity and commodity. This is the approach used in previous proceedings for RA3, and it is entirely reasonable.

If the Commission decides to classify a small portion of the mains as customer-related, it could use the corrected service allocator I develop below, for lack of a better alternative. However, 50/50% allocation to capacity and commodity is more reasonable and preferred.

B. Services Weighting

Q: How does Black Hills Gas allocate the costs of service lines among classes?

A: Black Hills Gas treats service lines as entirely customer-related, but recognizes that larger customers have larger-diameter services.[44] For each Rate Area (RA), each material (plastic and steel) and each diameter (≤1”, 1–2”, 2–4”, 4–8” and “unknown”), Black Hills Gas compiled the TOC and the DOT number of services. Black Hills Gas then aggregated those data into two groups, without distinguishing material: group A was ≤1” lines plus lines with unknown diameter, and group B all the lines with known diameters over 1”, and computed the average TOC per service.[45] Finally, Black Hills Gas assigned services to classes, with Residential and Small

[44] Larger customers probably also have longer services, on average, since their lots are larger and the service may need to traverse a parking lot, but I do not have any data on that effect.
[45] Attachments DNH-16 to DNH-19 to Hearing Exhibit 105, Direct Testimony of Douglas N. Hyatt.

Commercial getting all group A services, and the larger customers (Large Commercial and Irrigation/Seasonal) getting a prorated mix of the remaining group A and the group B services.[46] The resulting relative weights are shown in Attachment DNH-1 p. 6, after some idiosyncratic rounding.

Q: Is this approach reasonable?

A: Yes, except for the inclusion of the services of unknown diameter in group A, with the ≤1” services.

Black Hills Gas’s data are spotty and inconsistent. The DOT data on number of service by size do not distinguish between RA1 and RA2, so Black Hills Gas assigned numbers of services between those rate areas in proportion to residential customer number for the unknown and ≤1” services, and in proportion to the large-commercial customer number for the larger services.

For an unexplained reason, Black Hills Gas divided the number of services between 1 and 2 inches by a factor of 10 for both RA1 and RA2; those services do not appear to have moved anywhere, they just disappear.[47] Black Hills Gas reports “DOT Number of Feet” for each pipe diameter, but that is just the number of services from the DOT report times the average service length for the 2019 aggregations (RA1 and RA2 as BH Gas Distribution and RA3 as BH Gas Utility).[48] Fortunately, the “DOT Number of Feet” for services does not appear to be used in the computation.

[46] The number of residential services is appropriately reduced to reflect the number of multi-family buildings in which customers share a single service.

[47] I do not correct this anomaly, since doing so would result in more services than customers.

[48] The average number of feet for services statewide is inconsistent with the data provided for the two reporting areas.

Q: What is the effect of including the unknown-diameter services in group A, and treating them as if they were small services, mostly used by residential customers?

A: The unknown-diameter services are very expensive, and drive up the cost assigned to the small customers. Table PLC-6 summarizes the cost per service from Attachments DNH-16 to DNH-19, with the corrections I mentioned above.

Table PLC-6: Cost per Service by Rate Area and Diameter

Diameter	RA1	RA2	RA3	Consolidated
unknown	$10,522	$13,217		$11,085
1" or less	$103	$167	$463	$275
>1" thru 2"	$396	$283	$2,800	$554
>2" thru 4"	$21,799	$18,456	$13,246	$20,322
>4" thru 8"	$93,022			$93,022

The unknown-diameter services are not only 20 to 100 times more expensive than the services up to 1”, and 1”–2”, but are closer to the magnitude of the >2” inch costs. Clearly, the unknown services, if they must be included for the methodology, should be in the groups with the largest services, not the smallest ones.

Table PLC-7 shows the cost per unit (Black Hills Gas does not define “quantity,” but I assume that means “feet”) for the ≤1” lines, the unknown diameter lines, and the combination (which Black Hills Gas treats as ≤1”) for RA1 and RA2. Not only are the unknown lines much more expensive than the ≤1” lines, but the costs of the actual ≤1” lines in RA1 and RA2 are much closer to the cost of the lines in RA3, which are not contaminated with the unknown-diameter lines.

Table PLC-7: Effect of removing Unknown from the ≤1" Services

	Quantity	TOC	$/unit
Rate Area 1			
≤1"	687,487	$9,337,382	$13.58
Unknown	36,812	$43,766,925	$1,188.93
Combined	724,299	$53,104,306	$73.32
Ratio of ≤1" to Combined			18.5%
Rate Area 2			
	Quantity	TOC	$/unit
≤1"	176,645	$3,588,708	$20.32
Unknown	20,704	$14,493,633	$700.04
Combined	197,349	$18,082,341	$91.63
Ratio of ≤1" to Combined			22.2%
Rate Area 3			
	Quantity	TOC	$/unit
≤1"	4,252,549	$38,203,492	$8.98

Notes: includes plastic and steel

RA1 includes data that Black Hills Gas lists as "RA1-WW," which I take to be the Whitewater area.

Data from Services FERC 380 tab of Mains Services Weighting Study workpaper

Q: Have you found any other errors in Black Hills Gas's treatment of the ≤1" service lines?

A: Yes. While most of the ≤1" services are plastic, a small portion are much more expensive steel pipe, which Black Hills Gas acknowledges are installed to carry higher pressure gas and provide higher capacity. In Table PLC-8, I compare the cost of the plastic pipe to steel pipe and the combination, which Black Hills Gas uses in its class cost-of-service study.

Table PLC-8: Cost per Unit of ≤1" Services

Rate Area	Plastic $/unit	Steel $/unit	Plastic + Steel $/unit	Ratio of Plastic to P+L
1	$12.13	$132.66	$13.58	89.3%
2	$17.75	$70.12	$20.32	87.3%
3	$7.80	$23.08	$8.98	86.8%

Data from Services FERC 380 tab of Mains Services Weighting Study workpaper

The plastic pipes are about 12% less expensive than the combined plastic and steel.

Q: What is the result of correcting these errors?

A: The share of the service costs allocated to residential customers is reduced by about half on a consolidated basis.

Table PLC-9 corrects Black Hills Gas's services weights for the misassignment of the lines of unknown diameter.

Table PLC-9: Correction of Service Weighting for Unknown-Diameter Lines

Rate Area 1 (Attachment DNH-16)

	Black Hills Gas								Corrected				
Customer Class	Customers	Service Lines	≤1"	>1"	Unit Cost	Relative Cost	Weight	class share	≤1"	>1"	Unit Cost	Weight	class share
Residential	73,039	70,509	70,509		$636	1.00	1	84.7%	70,509		$100	1	13.4%
Small Commercial	6,392	6,392	6,392		$659	1.04	1.1	8.2%	3,281	3,111	$4,939	49.6	58.2%
Large Commercial	1,532	1,532	1,046	486	$2,331	3.66	4	7.1%		1,532	$10,041	100.9	28.4%
Seasonal/ Irrigation	4	4	3	1	$2,331	3.66	4	0.02%		4	$10,041	100.9	0.1%

Rate Area 2 (Attachment DNH-17)

	Black Hills Gas								Corrected				
Customer Class	Customers	Service Lines	≤1"	>1"	Unit Cost	Relative Cost	Weight	class share	≤1"	>1"	Unit Cost	Weight	class share
Residential	19,256	17,673	17,673		$792	1.00	1	82.4%	17,673		$153	1	16.1%
Small Commercial	2,594	2,594	2,594		$863	1.09	1.1	12.2%	1,781	813	$3,949	25.8	56.0%
Large Commercial	380	380	258	122	$1,947	2.46	3	4.9%		380	$12,237	80.0	25.4%
Seasonal/ Irrigation	38	38	26	12	$1,947	2.46	3	0.5%		38	$12,237	80.0	2.5%

Consolidated (Attachment DNH-19)

	Black Hills Gas								Corrected				
Customer Class	Customers	Service Lines	≤1"	>1"	Unit Cost	Relative Cost	Weight	class share	≤1"	>1"	Unit Cost	Weight	class share
Residential	178,417	168,979	168,979		$414	1.00	1	86.1%	168,979		$261	1.0	41.9%
Small Commercial	12,251	12,251	12,251		$438	1.06	1.1	6.5%	3,258	8,993	$3,935	15.1	43.5%
Large Commercial	2,793	2,793	1,397	1,397	$2,038	4.92	5	6.7%		2,793	$5,261	20.2	13.3%
Seasonal/ Irrigation	278	278	139	139	$2,038	4.92	5	0.7%		278	$5,261	20.2	1.3%

The correction for plastic versus higher-capacity steel services would further reduce the residential share of service costs.

C. *Meter Weights*

Q: How did Black Hills Gas allocate meter costs to customers?

A: Black Hills Gas appears to have accounting data tracking meter costs and installations by customer, which it aggregates on the class level.[49] This is the gold standard in cost assignment.

[49] Hearing Exhibit 105, Attachment DNH-15, Meter Weighting Factor Study, CIS+ Meter Data tab.

Q: So did Black Hills Gas allocate meter costs correctly?

A: Yes, it appears so, for the meters themselves.

However, in addition to the meters, Black Hills Gas includes in the meter costs the regulators that control pressure to protect user equipment and prevent over-pressurization leaks. Regulators cost about as much as meters on a system basis. In contrast to the meters, Black Hills Gas has limited information about its regulators, their cost, and which customers they serve. Black Hills Gas ignores much of the data it has, and does not relate the size of regulators (in terms of service line diameter, supply pressure, and flow rate) to the size of the customers. Instead, Black Hills Gas uses the costs for just a portion of the regulators and allocates those costs to classes in proportion to the meter costs.[50] Since the meter computation is only used to compute a weighting factor by class, and since Black Hills Gas assumes the regulator cost for each class is proportional to the cost of the class's meters, the inclusion of regulators does not change the weights or the class cost allocations.

While Black Hills Gas says that "Plant investment in meters and regulators (Accounts 381 - 385) is allocated to customer classes on the basis of the number of customers weighted to recognize relative differences in the unit investment cost of the different types and sizes of meter and regulator sets used to connect customers in that class…," it does not use any data on the "relative differences in the unit investment cost of the different types and sizes of…regulator sets."[51] Black Hills Gas does not identify the type or size of regulators used by any class.

[50] Attachment DNH-15 workpaper, "Regulator TOC" tab.
[51] Hearing Exhibit 105, Attachment DNH-14, at p. 3.

Table PLC-10 summarizes the data that Black Hills Gas has provided on the number and cost of regulators.[52]

[52] As it does with all other book costs, Black Hills Gas inflates the recorded book costs to present dollars, as TOC.

Table PLC-10: Summary of Regulator Data

	RA1			RA2			RA3			Consolidated		
Retirement Unit	**Count**	**TOC**	**$/reg**	**Count**	**TOC**	**$/reg**	**Count**	**TOC**	**$/reg**	**Count**	**TOC**	**$/reg**
Regulator - Unavailable	72,525	$7,557,183	$104	23,118	$2,430,174	$105	1	$262	$262	95,644	$9,987,619	$104
Regulator Assembly <2"	8,383	$6,256,863	$746	1,931	$1,401,087	$726	116,477	$24,870,276	$214	126,791	$32,528,226	$257
Regulator <2"	1,457	$634,472	$435	888	$1,066,183	$1,201	15,601	$2,072,542	$133	17,946	$3,773,197	$210
Regulator Assembly 2"	45	$72,345	$1,608	-16	$6,856	($428)	37	$93,373	$2,524	66	$172,575	$2,615
Regulator 2"	-9	$92,807	($10,312)	2	$2,552	$1,276	198	$299,083	$1,511	191	$394,442	$2,065
Regulator Assembly ≥3"				7	$834	$119				7	$834	$119
Regulator ≥3"	0	$6,632	Undefined				1	$14,251	$14,251	1	$20,883	$20,883
Total Regulators	82,401	$14,620,303	$177	25,930	$4,907,685	$189	132,315	$27,349,787	$207	240,646	$46,877,775	$195
Regulators in BHG COSS	9,885			2,828			132,314			145,027		
Total Meters	81,774			23,263			91,820			196,857		
% unavailable	88%	0%		89%	0%		0.001%			40%		
% of meters	101%			111%			144%			122%		

Q: Do you see any problems with the regulator data provided in Table PLC-8?

A: A number of problems are evident in Table PLC-10:

- Black Hills Gas does not provide any information on the number and cost of regulators with diameters less than 2”. Since most services are 1” or less, it is likely that many regulators are also much smaller than 2”.
- Black Hills Gas uses only about 12% of total regulators in RA1 and RA2, and about 60% on a consolidated basis.
- Even aggregated to the retirement unit level for a rate area, some equipment types show zero or negative units in service but positive costs. In the raw annual data, there are entries with positive units, but negative book value.
- The reported regulator counts are 101% of the meter count in RA1, 111% in RA2, and 144% in RA3, but Black Hills Gas does not account for the which classes use the extra regulators.

Q: Which regulators does Black Hills Gas omit from its computations?

A: Black Hills Gas excludes the regulators for which it does not know the inlet diameter. Those regulators are 88% to 89% of the total regulators in RA1 and RA2.

Q: What does Black Hills Gas know about those regulators?

A: The regulators with unknown diameters are much less expensive than the regulators with known diameters, as shown in Table PLC-10. If those regulators are the ones with the lowest capacity, smallest diameter, and the lowest pressure, they would be the types used by residential and the smallest commercial customers. As for service lines, the smallest, least expensive regulators should be allocated to the smallest customers.

Q: How does Black Hills Gas explain the inconsistency between the number and costs of some categories of regulators?

A: In discovery, Black Hills Gas provided the following explanations:

> The number of items can be negative while book costs remain positive when dealing with Plant Accounting. As an example, when assets that were part of a blanket work order, but have retirements as part of the work order. When the Company unitizes a blanket work order, classification of capital assets, retirements of capital assets, cost of removal and salvage value for retired assets are assigned from account 106000 to account 101000 (Plant In-Service) and the creation of a new asset. The blanket work order remains active on the books, showing negative balances that are netted against the newly created asset that was developed at the time of the unitization to account 101000.[53]

> Negative [service or main] book costs or quantity values…could be due to the following reasons: (1) asset has contribution in aid of construction (extension costs in excess of Regular Construction Allowance) applied to the total cost of the asset; or (2) asset was part of a blanket work order and had retirements as part of the work order.[54]

These explanations appear to imply that Black Hills Gas records the net change in units in service and the investment for the year, so if it adds 40 regulators in some category for $6,000 ($150/regulator) and retires 30 regulators in that category, it would report that the 10 regulators cost $6,000 ($600/regulator). And if it retired 50 regulators, the net –10 regulators would be assigned the $6,000 (–$600/regulator). This means that the unit cost for the group of items (regulators, in this case) can be inflated due to retirements, especially when they result in negative item counts.

[53] Black Hills Gas Response to Discovery Request EOC 2-6, attached as **Attachment PLC-6**, at (e).
[54] Black Hills Gas Response to Discovery Request EOC 2-37(c), attached as **Attachment PLC-11**.

Q: What accounts for the variation in the number of regulators per customer from just over 1.0 to 1.44 in the various Rate Areas?

A: That is not clear. Black Hills Gas could not "explain why adding a customer would require adding more than one regulator" without "a detailed study."[55] Black Hills Gas does hint at an explanation in EOC 2-6h, which indicates that "Regulators can be replaced at a rate of more than one for one, especially when uprates occur. It is difficult to identify the circumstances to lead to each replacement.… In certain cases, additional regulation may be preferred or even required when adding a new meter set (customer) to provide adequate over pressure protection in accordance with standards." Thus, it appears that larger customers may require more than a single regulator.[56]

It is also possible that Black Hills Gas uses a single regulator for multiple customers, such that adding a new customer to an existing property may require "additional regulation." If multi-family buildings use a single regulator for multiple metes, the residential regulator number should be reduced proportional to the number of service lines.

Q: What would be the effect of eliminating these problems in Black Hills Gas's allocation of regulators among classes?

A: Table PLC-11 summarizes the allocation of meters (including regulators) as used in Black Hills Gas's class cost-of-service studies and as corrected by:

- including the regulators of unknown size, and
- assigning regulators to classes in the same manner as Black Hills Gas's assignment of services, with excess regulators assigned to the largest customers.

[55] Black Hills Gas Response to Discovery Request EOC 2-6, **Attachment PLC-6**, at (i).

[56] Confidential Attachment EOC 2-6_G-DN4001 Meter Set Design, pp. 28–29, indicates that Black Hills Gas sometimes used two regulators in series for a single high-pressure location.

Table PLC-11: Meter Cost Allocation as Proposed by Black Hills Gas and Corrected

	RA1		RA2		RA3		Consolidated	
	BHG	Corrected	BHG	Corrected	BHG	Corrected	BHK	Corrected
Residential	74%	56%	66%	52%	86%	73%	80%	65%
Small Commercial	13%	19%	18%	11%	7%	4%	11%	10%
Large Commercial	13%	25%	15%	34%	6%	18%	8%	22%
Seasonal/Irrigation	0.1%	0.1%	1%	4%	1%	5%	1%	3%

The corrections reduce the meters allocation to the Residential class by 15% to 24% for the various rate areas, and 19% on a consolidated basis. The Commission should order the Company to undertake these corrections.

Q: Please summarize the results of your corrections to the class cost-of-service study.

A: Table PLC-12 summarizes some statistics from the Black Hills Gas class cost-of-service study to the same outputs from the Black Hills Gas model with the changes in allocations of mains, services, and meters that I discuss above. Higher return and lower revenue deficiency for a class argue for lower rate increases for that class.

Table PLC-12: Summary of Class Cost-of-Service Study Changes

	Black Hills Gas			Corrected	
	System	Residential	% of System	Residential	% of System
RA1, Attachment DNH-25					
Rate of Return Under Current Rates	4.51%	3.92%		8.21%	
Revenue Deficiency	$5,331,687	$4,763,180	89%	($1,565,155)	-29%
Percent of Total Non-fuel Cost	5.41%	6.87%		-2.26%	
RA2, Attachment DNH-29					
Rate of Return Under Current Rates	1.93%	1.73%		4.78%	
Revenue Deficiency	$4,547,943	$3,070,364	68%	$992,097	22%
Percent of Total Non-fuel Cost	31.83%	32.66%		13.55%	
RA3, Attachment DNH-33					
Rate of Return Under Current Rates	3.74%	3.13%		3.55%	
Revenue Deficiency	$4,699,179	$4,741,179	101%	$4,078,181	87%
Percent of Total Non-fuel Cost	17.63%	21.61%		18.59%	

Consolidated, Attachment DNH-37					
Rate of Return Under Current Rates	3.75%	2.98%		5.35%	
Revenue Deficiency	14,593,447	13,910,890	95%	4,788,070	33%
Percent of Total Non-fuel Cost	16.86%	20.68%		8.23%	

With the Black Hills Gas inputs, the residential class has a lower return under current rates than the system as a whole, for each rate area and for the consolidated system. The computed residential revenue deficiency is 68% to more than 100% of the system deficiency for the various rate areas.

With my corrections, the residential class is actually overearning in RA1, providing more than the system average return in RA2 and the consolidated system, and providing close to the average return in RA3. These results support increasing the residential revenue requirement by less than the average increases (or in the case of RA3, by very close to the average increase).

Q: Should the Commission order the use of this revised class cost-of-service study for all cost-allocation purposes?

A: No, for three reasons. First, the final cost inputs (especially return and taxes, but also some expenses) will be different than those used in the current Black Hills Gas model. Thus, the final level and mix of class costs will vary from those in Table PLC-12.

Second, the problems with Black Hills Gas's cost data, as I describe above, limits the confidence that the Commission should place on any result based on those data. That includes the lack of a consistent basis for the functionalization, classification, and allocation of mains, and Black Hills Gas's inability to relate the number of regulators to the number of customers in each class.

Third, I have concentrated on the allocation of costs (such as regulators and services) between the residential class and the three non-residential classes (small commercial, large commercial, and irrigation/seasonal), not the allocation among the non-residential classes. The costs of equipment serving small commercial are likely to be lower than the costs of equipment serving the other non-residential classes. Thus, I do not recommend using my results to allocate the revenue increase among the non-residential classes.

Nonetheless, my corrections provide the best guidance regarding the allocation to the residential class of whatever rate increase the Commission orders.

V. Residential Customer Charge

Q: How did Black Hills Gas determine its proposed customer charges?

A: Black Hills Gas computes its customer-charge proposal in two steps. First, for each Rate Area and class, Black Hills Gas adds up the service, meter and regulator, and customer accounting cost from the class cost-of-service study, in Attachments DNH-26, 30 and 34. As summarized in Table PLC-13, the supposedly cost-based rates round off to $17/month for RA1, $21/month for RA2, and $13/month for RA3. For its proposed rates, Black Hills Gas accepts its study results for RA1 and RA3, but limits the charge for RA2 to $16/month. The RA2 customer charge would increase another 40% if Black Hills Gas were successful in raising it to the computed rate in a future proceeding,

Table PLC-13: Existing, BHG-Computed and BHG-Proposed Customer Charges

				Proposed			Increase
	Existing	Computed	Rounded	Charge	Increase	Percent Increase	to Computed
RA1	$10.28	$17.40	$17.00	$17.00	$6.72	65%	69%
RA2	$11.70	$20.67	$21.00	$16.00	$4.30	37%	77%
RA3	$9.44	$13.18	$13.00	$13.00	$3.56	38%	40%

Q: How do these proposed charges compare with other gas utilities' customer charges?

A: These increases would result in higher residential natural-gas customer charges in all three rate areas than in Colorado Springs, Xcel, or Atmos, with RA1 having the highest charge in the state, and RA2 being tied with Colorado Gas's Eastern Colorado District for second place, as shown in Table PLC-14.[57]

Table PLC-14: Natural Gas Residential Customer Charges in Colorado ($/month)

Utility	Customer Charge
Fort Morgan	$7.90
Atmos	$11.60
Colorado Springs	$11.95
Xcel	$12.77
Colorado Gas-East	$14.00
Colorado Gas-Mountain	$16.00
Black Hills Gas RA1	$17.00
Black Hills Gas RA2	$16.00
Black Hills Gas RA3	$13.00

In Hearing Exhibit 105, Attachment DNH-40, Black Hills Gas lists customer charges for most of the investor-owned gas utilities in the states in which Black Hills Energy has gas distribution systems: Colorado, Kansas, Nebraska, and Wyoming. Black Hills Gas also lists some municipal, coop, and privately-held utilities in Wyoming, but not for the other states. Black Hills Gas omits one IOU in Kansas (Midwest Energy, at $19.42) and Nebraska (MidAmerican, at $10).

More importantly, Black Hills Gas ignores the other states contiguous to Colorado, such as New Mexico (New Mexico Gas, $12), Utah (Dominion, $6.75), and Arizona (Southwest Gas, $7.50 to $10.70; UNS, $7 to $10).

[57] I was not able to find rate information for most of the smaller municipal gas companies (Aguilar, Center, Trinidad, or Walsenburg). Ignacio has a $23.90 customer charge and Rangeley has no fixed charge.

Black Hills Gas's proposed residential customer charges are high compared to other investor-owned utilities in Colorado, Nebraska, Utah, New Mexico, Arizona, and low for Kansas. Both the existing and proposed Black Hills Gas customer charges fall within the range of charges in Wyoming.

Q: Do you disagree with Black Hills Gas's computation of the costs for the customer charges?

A: Yes. There are two groups of problems with the Black Hills Gas computation. First, as discussed above, Black Hills Gas over-allocated services and meter costs for residential customers. Second, the Black Hills Gas methodology estimates the customer-related costs for the average size customer and overstates the cost to serve a customer with minimal demand.

Q: Please explain how correcting the service allocation would affect the computed customer charge.

A: Table PLC-15 shows the effect of correcting the assignment of pipe with unknown diameter from the smallest services to larger services.

Table PLC-15: Residential Service Allocation, Correcting for Unknown Diameter Pipe ($/customer-month)

	BHG	Corrected
RA1	$6.92	$1.09
RA2	$9.48	$1.85
RA3	$4.84	$4.84
Consolidated	$6.30	$3.07

This computation does not include the effect of removing the small steel pipes (which are used to support higher pressures and/or volume of gas delivery) from the services used for minimal-usage residential customers. Nor does it account for the fact that many of the smallest gas consumers would be those living in multi-family buildings, sharing a service drop. Accordingly, there is a reasonable basis to reduce the residential service allocation even further.

Q: Please explain how correcting the meter and regulator allocation would affect the computed customer charge.

A: Table PLC-16 shows the effect on the allocation of meters and regulators to the residential customer charge, accounting for Black Hills Gas's failure to account for the use of higher-cost and multiple regulators to serve larger non-residential customers.

Table PLC-16: Residential Meter Allocation Corrected for Assignment of Regulator Cost

	BHG	With Regulator Assignment
RA1	$5.57	$4.17
RA2	$5.84	$4.47
RA3	$4.26	$3.62
Consolidated	$5.24	$4.21

Q: What is the difference between the equipment required for the smallest residential customer and the equipment required for the average residential customer?

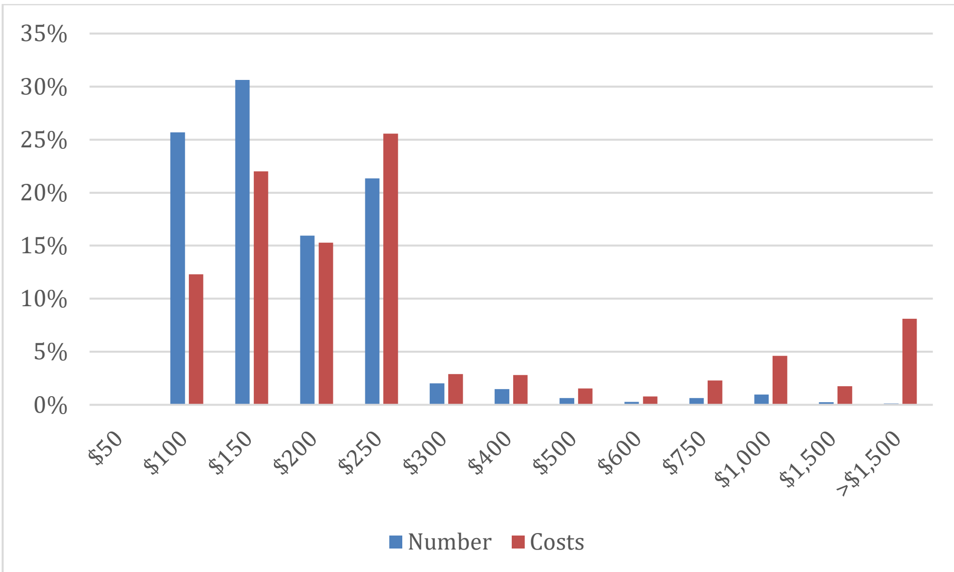
A: The customer charge should be reflect the customer-related cost of serving the smallest customers. Larger customers within a class will have higher customer-related costs, reflecting the use of services, meters and regulators that can deliver higher quantities at gas, perhaps at higher pressure. Those additional size-related customer costs, which rise with demand levels, should be collected through the volumetric charge.

Compared to the average residential customer, the smallest customers would tend to be in multi-family buildings, sharing service lines; served by low-pressure plastic services, rather than more expensive steel; and using the simplest and least expensive meters within the residential class.

Q: How did you account for these factors in analyzing the customer charges?

A: I made only one more adjustment, for the variation in cost within the meters identified as residential. Figure PLC-1 shows the distribution of Black Hills Gas's residential meter costs, both in number of meters and the total cost of the meters within each cost interval.[58]

Figure PLC-1: Distribution of Residential Meters, by Number and Cost



The average meter TOC is $186, but that average includes the costs of many meters that are much more expensive. The median meter cost $126, just 67% of the average cost. I used that ratio to reduce the meter cost for the customer charge, and calculated the meter costs shown in Table PLC-17.

[58] The data are from the CIS+ Meter Data tab of the workpaper for Attachment DNH-15. Note that the horizontal scale for Figure PLC-1 is not linear.

Table PLC-17: Residential Meter Costs for Customer Charge

		Corrected	
	BHG	For Regulators	Median Meter
RA1	$5.57	$4.17	$3.41
RA2	$5.84	$4.47	$3.75
RA3	$4.26	$3.62	$3.02
Consolidated	$5.24	$4.21	$3.53

Q: What do these corrections imply for the customer charges?

A: Table PLC-18 summarizes the effects of the corrections I describe above. Again, these adjustments do not account for the greater sharing of services by the smallest residential customers, the use of plastic pipe for low-volume customers, or the likely lower usage of customer services by the smallest customers, and are therefore conservative.

Table PLC-18: Corrected Residential Customer Charges

	RA1	RA2	RA3	Consolidated
Services	$1.09	$1.85	$4.84	$3.07
Meters & Regulators	$3.41	$3.75	$3.02	$3.53
Customer Accounting	$4.92	$5.35	$4.07	$4.06
Total	$9.42	$10.95	$11.93	$10.66

Table PLC-19 summarizes the existing residential customer charges, the charges proposed by Black Hills Gas, and those I derived above.

Table PLC-19: Comparisons of Existing and Proposed Residential Customer Charges

	Existing	BHG Proposed	Corrected
RA1	$10.28	$17.00	$9.42
RA2	$11.70	$16.00	$10.95
RA3	$9.44	$13.00	$11.93
Consolidated	$10.03	$15.60	$10.66

With these corrections, the residential customer charge would decrease for RA1 and RA2, increase about 30% less than Black Hills Gas proposes for RA3, and increase only about 6% for the consolidated system.

Q: Please summarize why your proposed customer charge results in more fair and efficient rate design.

A: First, my proposal results in cost-based rates. Second, higher fixed charges are inefficient rate design in my opinion. They remove incentives for conservation, remove the ability of customers to control their bills, and on average give lower income customers who tend to consume less power higher rate impacts than customers with higher incomes. EOC witness Andrew Bennett discusses these policy considerations in more detail in his testimony.

Q: What are the disadvantages of high customer charges?

A: Customer charges do not encourage conservation, because they cannot be avoided. They fall disproportionately on smaller customers, who are often the least able to pay higher bills. Hence, higher customer charges damage the state's environmental and energy goals, while making the system less equitable.

VI. Rate-Area Consolidation

Q: Mr. Bennett has recommended consolidation of the Company's service territory. Please review the options for consolidation.

A: The Commission could either fully consolidate all three rate areas, or it could consolidate any pair of rate areas. Mr. Bennett makes a persuasive case that full statewide consolidation of Black Hills Gas service territories is in the public interest. The next best alternative is consolidation of RA2 and RA3. My analysis below further supports statewide consolidation, or at least consolidation of RA2 and RA3. As Mr.

Bennett discusses in his testimony, in Decision No. C20-0372 (Proceeding No. 19AL-0075G), the Commission described factors that guided its review of consolidation proposals. The facts and policy considerations support consolidation better than the Commission thought in Decision No. C20-0372. I discuss the three factors in more detail below.

Q: Does the record contain revenue requirement studies and class cost of service studies for statewide consolidation, or for partial consolidation of RA2 and RA3?

A. The Company provided historical test year (HTY) and 13-month average revenue requirement studies for statewide consolidation as Attachments MCC-4 and MCC-8, respectively. Attachment DNH-37 contains the consolidated class cost of service study, with other attachments of Mr. Hyatt supporting this model. As I discuss above, I have concerns with the class cost of service study as presented, for any rate area individually or consolidated.

In discovery, EOC requested and the Company provided revenue requirement studies and class cost of service studies for the partially consolidated rate areas. Attached as **Attachments PLC-12, PLC-13, and PLC-14** are the produced HTY revenue requirement study (Attachment to Black Hills Discovery Response EOC 1-6), the 13-month average revenue requirement study (Attachment to Black Hills Discovery Response EOC 1-7), and the class cost of service study (Attachment to Black Hills Discovery Response EOC 1-8) for consolidated RA2 and RA3.

Q: Why do you favor consolidation of RA2 and RA3 to consolidation of RA1 and RA2, if the Commission decides not to fully consolidate the Black Hills Gas service territory statewide?

A: While statewide consolidation seems most equitable, there are greater similarities between RA2 and RA3 than between any other pair. In some ways, RA1 is distinct from the other rate areas in that much more of its service territory is mountainous, and thus perhaps more expensive to install new or replacement infrastructure. Rate Area 1 is also the only rate area served by the Western Slope gas supplies.

In contrast, RA2 and RA3 share the Central region gas supplies, while RA2 and RA3 are clustered together, with the service territories (although not lines) abutting one another along the border between Kit Carson and Yuma counties.

Finally, RA2 is under the most rate pressure from legacy costs, while RA3 has the lowest existing rates and can maintain reasonable rates even after consolidation with RA2.

A. Legacy Criteria

Q: What factors did the Commission identify in Decision No. C20-0372?

A: The Commission identified three factors that, if present, would provide support for base rate area consolidation. The factors are (1) an absence of a substantial rate disparity between the existing base rate areas; (2) evidence of present or future physical connection between systems serving each base rate area; and (3) potential future operational efficiencies from consolidation yielding cost savings.[59]

[59] Proceeding No. 19AL-0075G, Decision No. C20-0372, ¶22 (mailed May 19, 2020).

1. Absence of Substantial Rate Disparity

Q: Are there currently substantial rate disparity between the base rate areas?

A: There certainly are differences in base rates. For 89 therms/month, for example, the 2020 non-fuel charge was $32 in RA1, $36 in RA2, and $24 in RA3. However, the variation in the GCA was much larger, ranging from under $32 in the Central CGA region to almost $52 in the North/Southwest region, a swing of more than $20.[60]

I understand that RA2 is likely to experience continued SSIR rate increases in the future, in which case the rate disparities are likely to grow unless the rate areas are consolidated or the tariff differences are otherwise mitigated.

Q: How do the base rate components currently differ among the rate areas?

A: Table PLC-20 shows each rate area's current volumetric rates, the proposed rate the and consolidated rate. There is currently a difference of 11¢/therm between the volumetric rates for residential customers in RA2 and RA3. If Black Hills' proposed rates are approved, that difference would grow to 24¢/therm.

Table PLC-20: Effect of Consolidation on Volumetric Base Rates ($/therm)[61]

Base Rate Area	Current	Proposed	Consolidated Statewide
Residential Rate			
1	*$0.23*	$0.22	$0.20
2	*$0.26*	$0.40	$0.20
3	*$0.15*	$0.16	$0.20
Change from Current			
1	-	-6.4%	-13.7%
2	-	53.1%	-23.2%
3	-	7.6%	31.9%

See **Attachment PLC-21** for further detail.

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[60] There are also separate GCA rates for the North and Southwest regions (parts of RA1 and RA2) and Western Slope without storage (part of RA1).

[61] Hearing Exhibit 106, Direct Testimony of Svetlana V. Atoyan, Attachments SVA-3 and SVA-4; Black Hills Gas Response to Discovery Request EOC 1-9, including Att EOC 1-9_YE Bill Impacts (Based on CCOSS for EOC 1-5).xlsx and Att. EOC 1-9_YE Bill Impacts (Based on CCOSS for EOC 1-8).xlsx, attached as **Attachment PLC-15.**

There are similar and growing disparities in the monthly customer charge, as shown in Table PLC-21.

Table PLC-21: Existing and Proposed Customer Charges ($/month)

	Existing	Proposed	Increase	Percent Increase
RA1	$10.28	$17.00	$6.72	65%
RA2	$11.70	$16.00	$4.30	37%
RA3	$9.44	$13.00	$3.56	38%

Q: Would any rate disparity be mitigated by consolidating rate areas?

A: Yes. If rates are consolidated statewide, then there would be no difference in rates across areas.

Q: What was the Commission's past concern with consolidating base rate areas where there is substantial rate disparity?

A: The Commission identified two problems with consolidating base rate areas where there is a substantial rate disparity. First, the Commission expressed concern that the resulting rates would result in subsidies among the existing rate areas, causing "ratepayers in high-cost areas to make economically inefficient choices regarding consumption and investment that will, in turn, place upward pressure on overall system costs." Second, the Commission concluded that the resulting rates would "also increase the likelihood of over-collection of revenues, as the proposed rates in [RA3] substantially exceed the cost of delivering service in that area and the highest anticipated growth is in that area."[62]

The Decision relies on "Staff testimony that the wrong price signals cause ratepayers in high-cost areas to over-consume and may prevent ratepayers from switching to a less costly fuel source that would reduce the overall system cost."[63]

[62] Proceeding No. 19AL-0075G, Decision No. C20-0372, at ¶23.
[63] *Id.* at p. 17, note 33.

Q: Would consolidating the rate areas cause ratepayers in high-cost areas to make economically inefficient choices to over-consume and under-invest in efficiency?

A: No. The Staff testimony in Proceeding No. 19AL-0075G, at least as interpreted by the Decision, conflates the historical embedded cost in a rate area, which drives the unconsolidated rates, and the marginal costs that are avoided when a customer reduces usage or avoids an increase in usage.[64] I have not seen any evidence that, in terms of the costs recovered through base rates, there is any difference between the costs of continuing to serve a therm of existing load, or serving a therm of new load, in RA2, compared to RA1 and RA3. Continuing to serve an individual with an at-risk meter, or located on a long deteriorated line, is expensive no matter which rate area the customer is in; as explained in Section III, Black Hills Gas should be giving those customers incentives to electrify and reduce uneconomic utility investments.

The primary driver of costs that are being added to rates are investments in integrity and reliability, not in additional capacity to meet volumetric demand. As shown in Table PLC-20, customers in RA2 are facing a volumetric base rate increase of 53 percent, and are likely to reduce their already low consumption even further in response. But customers in RA2 do not impose higher or lower costs, just because that rate area has higher legacy costs than RA3, for example.[65]

If Black Hills Gas is allowed to increase rates, customers will have increased incentives to increase efficiency, reduce gas use, and even switch energy supplies; consolidation would change the distribution of the increases across the rate areas, but not the total effect. It is unlikely that efficiency investments in response to these

[64] The same distinction should be made between the historical embedded costs that are generally allocated as customer-related, and the marginal cost of adding a customer or the marginal saving of removing a customer.

[65] The rate areas are not compact or consistent, with RA2, for example, abutting the northern and eastern borders of the state, as well as the southern border, and reaching nearly to the western border.

increase in base rates would be excessive.[66] Colorado's decarbonization plan relies on end-use energy efficiency and electrification to reduce emissions. Higher volumetric retail rates for natural gas will facilitate state- and utility-sponsored programs for efficiency, and higher total natural gas bills will encourage beneficial electrification.

Even after reducing consumption, most RA2 customers would face increased bills with Black Hills Gas's proposed rate increase without consolidation. The consumption reductions will make little difference to the upward pressure on overall system costs driven by system integrity and reliability investment.

Consolidating rate areas statewide would raise the currently low volumetric rates in RA3 by about 30 percent. Those customers would be more likely to undertake efficiency and electrification with consolidated rates, contributing to meeting Black Hills Gas' compliance obligations under the Clean Heat Bill and reducing the cost of compliance for all customers.

Implementing programs for efficiency and electrification will be easier if all Black Hills Gas residential customers face the same rates, allowing consistent incentive structures and marketing.

Q: Would consolidating the rate areas increase the likelihood of over-collection of revenues, as higher rates in RA3 would substantially exceed the cost of delivering service in an area of high anticipated growth?

A: No. If load grows, so will the costs of the building and operating the distribution system. While one area may have higher embedded costs per customer or per therm than another, it is not clear that the costs of serving new load would vary in the same

[66] Of course, some customers may make unwise choices, such as undertaking efficiency investments that are ineffectual, or converting from natural gas to resistance electric heat. Good utility efficiency programs will help customers select appropriate measures and competent installers.

manner. It is not clear that the difference between the additional revenue and the additional cost would be higher in one area than another.

2. Present or Future Physical Interconnection

Q: Are the physical connections within each Rate Area different qualitatively than the physical connections among the Rate Areas?

A: No. Black Hills Gas points out that although the "rate areas are not directly connected through Black Hills owned and operated infrastructure," the rate areas "share present physical connections."[67] These connections are in the form of transportation on seven upstream pipelines.

These pipelines provide connections not only between the three rate areas, but within them.

Each of the existing Rate Areas have multiple distribution systems, connected only by the use of third-party or Black Hills Gas transmission pipelines. In **Attachment PLC-17**, I list some of those separations, derived from Hearing Exhibit 101, Attachment KKA-1. Additional discrete distribution pockets can be seen in **Attachment PLC-18**, which is Black Hills Gas Response to Discovery Request EOC 2-14, including Attachment EOC 2-14, and **Confidential Attachment PLC-19**, which is Black Hills Gas Response to Discovery Request EOC 2-19.

As listed in Attachment PLC-14, well over a hundred distribution segments are **not** connected to each other through any form of Black Hills infrastructure. In addition, about two dozen segments are connected only by Black Hills Gas transmission lines.

In several cases, the distribution segments within a Rate Area are not even connected by transmission lines within the Rate Area. For example, in Rate Area 2:

[67] Black Hills Gas Response to Discovery Request EOC 2-19, attached as **Attachment PLC-16.**

- the [redacted] segments [redacted] are connected only by pipelines running through RA1,

- those distribution segments are connected to the [redacted] distribution system by pipelines running through both RA1 and RA 3,

- the [redacted] distribution segments are connected to the [redacted] segments by transmission lines running through RA3, and to the southwestern pockets by pipelines running through RA1.

As Black Hills Gas noted in a response to discovery, "As a result [of the proximity of portions of rate areas], customers are charged different rates when in close geographical proximity just because they are in a legacy rate area that differ[s]."[68]

Direct connections of the distribution system are not necessary for the operation of the existing Rate Areas, and the entire service territory is connected by the integrated regional gas transmission system. Any definition of "connection" under which each Rate Area is considered to be physically connected would also define the three rate areas to already be physically inter-connected. If the three Rate Areas are not deemed physically connected presently, then none of the three Rate Areas is internally connected. In conclusion, either all of Black Hills Gas' rate areas are presently physically connected, or that the concept has no useful meaning in terms of determining whether costs are allocated fairly on a geographic basis. The Commission should not deny rate consolidation based on this factor.

[68] From Black Hills Gas Response to Discovery Request EOC 2-20.

Q: Is there any reason to add distribution equipment to more directly connect portions of the Black Hills Gas distribution system, either within an existing Rate Area or between Rate Areas?

A: Not for the purpose of rate consolidation, for which direct distribution connections are irrelevant. In general, it would be imprudent to add infrastructure to a system whose throughput must decline to reduce carbon emissions (and upstream methane emissions) and whose physical extent must decline to reduce methane leakage.

Additions can only be justified if there is an imminent shortage of deliverability for existing customers that cannot be solved less expensively by fuel-switching, or an opportunity to produce near-term fuel savings exceeding the capital cost. No infrastructure investments should be undertaken to accommodate an arbitrary (and currently ignored) requirement that the parts of the system in a rate area must be physically interconnected.

3. Operational Efficiencies

Q: Are there potential future operational efficiencies from consolidation yielding cost savings?

A: Yes, there should be opportunities for cost savings. Significantly, most of the operational efficiency have already taken effect, as Black Hills Gas is operating now as "a single entity with integrated operations," even though the Commission did not approve service area consolidation in the last proceeding. Further, Black Hills Gas did identify several additional opportunities for operational efficiencies, as follows.[69]

> Base rate area consolidation would result in a simplified tariff and certain administrative efficiencies. Consolidation would eliminate the complexity of having three separate rate areas in the tariffs, filings,

[69] Black Hills Gas Response to Discovery Request EOC 2-21, attached hereto as **Attachment PLC-20**.

> customer notices, rates, etc. (customer service representatives must be familiar with rate differences by rate area when responding to customer calls on their bills). Additionally, consolidation would result in administrative efficiencies (tariffs for each rate area would not have to be separately maintained and updated; internal accounting would no longer need to separately track capital, labor and non-labor O&M by rate area). Consolidation would reduce the administrative burden of all parties and the Commission in future BHCG regulatory proceedings (rate reviews would no longer require multiple models for each potential proposal). Because rate case complexity will be reduced, rate case expenses would likely be reduced.

Furthermore, as Mr. Bennett discusses, Black Hills Gas will need to develop new programs to implement its Clean Gas Plan. While the costs of beneficial electrification will be incurred in specific service areas, Black Hills Gas has a system-wide requirement to comply with the greenhouse gas emission reduction requirements of the Clean Heat Bill. Even though compliance costs may be incurred in one rate area, they benefit all customers.

The Clean Heat Bill directs the Commission to "maximize greenhouse gas emission reductions and benefits to customers, with particular attention to residential customers who participate in income-qualified programs, while managing costs and risks to customers, including stranded-asset cost risks …"[70] In Section **Error! Reference source not found.**, I recommend the Commission direct Black Hills Gas to begin applying for beneficial electrification projects that include abandonment of uneconomic pipelines. Conditions conducive to those cost-effective beneficial electrification projects are more likely to occur in rural areas with mountainous terrain where it is more costly to maintain connections to supply sources.[71] It would not make sense for compliance to be segregated by rate area, since that might require more expensive projects in RA3 to go forward while less expensive projects in RA2

[70] SB 21-264, Section 1(1)(c)(III).
[71] Decision No. C20-0372, ¶26.

are deferred. Nor would it make sense for one rate area to bear the costs disproportionately. Because compliance with the Clean Heat Bill is the responsibility of the utility, and not individual rate areas, the public interest in managing the costs of implementation further favors at least partial, if not statewide, consolidation.

Q: Did the Decision in Proceeding No. 19AL-0075G raise any other reasons for not consolidating rates in that case?

A: Yes. On pp. 29-30 of Decision No. C20-0372, the Commission pointed out that, "In the decision approving the SourceGas acquisition in Proceeding No. 15A-0667G, the Commission required that the settling parties show the proposed merger will result in no net harm to customers, while balancing ratepayer and utility interests…. In this first rate case following the Company's acquisition of SourceGas, we conclude it is proper to require Black Hills to show why higher costs from legacy SourceGas areas should be spread across all of Black Hills' customers…"

Q: How does that observation apply in the current proceeding?

A: I do not believe that the rationale for the initial SourceGas acquisition should impede the Commission doing the right thing today. This is not "first rate case following the Company's acquisition of SourceGas," conditions have changed from those expected in 2015 (such as the emergence of large SSIR costs), and the standard of "net harm to customers" should now include all Black Hills Gas customers.

B. Partial Consolidation

Q: Is there a partial consolidation of RA2 and RA3, if the Commission decides not to fully consolidate the service territory?

A: If the Commission decides not to fully consolidate the service territory, it should consolidate RA2 and RA3 because of the high proximity of service in geographically similar areas, as shown in **Confidential Attachment PLC-19** (which is Black Hills Gas Response to Discovery Request EOC 2-19, Confidential Attachment EOC 2-19).

Consolidation of RA2 and RA3 is to achieve alignment between rates and economic incentives. As discussed above, in terms of the costs recovered through base rates, there does not appear to be any difference between the costs of continuing to serve a therm of existing or new load, or serving an existing or new customer, in RA2, compared to RA1 and RA3.[72] And as I recommended above, consolidating the rates of Black Hills Gas on a statewide would eliminate this uneconomic disparity.

The next most optimal alternative is to consolidate RA2 and RA3. As shown in Table PLC-22, if RA1 and RA2 were consolidated, the disparity in volumetric rates would be 10 ¢/therm instead of 24 ¢/therm. If RA2 and RA3 were consolidated, the disparity would be only 3 ¢/therm.

Table PLC-22: Effect of Consolidation on Residential Volumetric Base Rates ($/therm)[73]

			Consolidated		
Base Rate Area	***Current***	**Proposed**	**Statewide**	**RA-1 & RA-2**	**RA-2 & RA-3**
1	*$0.23*	$0.22	$0.20	$0.26	$0.22
2	*$0.26*	$0.40	$0.20	$0.26	$0.19
3	*$0.15*	$0.16	$0.20	$0.16	$0.19

As shown in Table PLC-23, the rates proposed by Black Hills Gas would result in a 53 percent increase in volumetric rates (excluding commodity and pipeline charges) for residential customers. This proposed increase far exceeds those for any

[72] The cost of gas does appear to differ among the GCA areas, since different areas are served by different pipelines. But Black Hills Gas purchases its pipes and meters from the same manufacturers statewide, so the base-rate price signals should be the same across rate areas. Unless the marginal costs of distribution are shown to be higher in the mountainous portions of RA1 than in the rest of the system, there is unlikely to be any efficiency rationale for differences in distribution rates.

[73] From Hearing Exhibit 106, Attachments SVA-3 and SVA-4; **Attachment PLC-15**, Black Hills Gas Response to Discovery Request EOC 1-9, including Att EOC 1-9_YE Bill Impacts (Based on CCOSS for EOC 1-5).xlsx; Att EOC 1-9_YE Bill Impacts (Based on CCOSS for EOC 1-8).xlsx. See **Attachment PLC-21** for further detail.

rate area under any consolidation scenario. Considering that the total requested rate increase is about 20% (an increase of $14.6 million on non-gas costs of $71.9 million), rate increases exceeding 50 percent are unreasonable and must be mitigated.

Table PLC-23: Effect of Consolidation on Residential Volumetric Base Rates Changes (percent)

			Consolidated		
Base Rate Area	***Current***	**Proposed**	**Statewide**	**RA-1 & RA-2**	**RA-2 & RA-3**
1	-	-6.4%	-13.7%	11.9%	-6.4%
2	-	53.1%	-23.2%	-0.5%	-26.9%
3	-	7.6%	31.9%	7.6%	25.6%

See **Attachment PLC-21** for further detail.

This consolidation analysis includes only volumetric charges, for ease of presentation. The actual consolidation should be based on the total base rates, including the customer charge.

C. Consolidation Mechanism

Q: How would consolidation affect the SSIR?

A: The Commission approved the SSIR to apply to three years of system safety and integrity costs for RA2 and RA3, beginning with either 2021 or 2022 costs, depending on what Black Hills Gas elects. Costs for RA1 would be recovered through a future rate case. As a result, customers in RA2 and RA3 will be paying for post-test-year integrity and reliability costs prior to the next rate case, while customers in RA1 will not. So while the non-GCA costs would start fully consolidated when the rates from this proceeding become effective, they will drift apart over time.

I recommend that the Commission restore the consolidation in the next general rate case, either by consolidating the SSIR across rate areas or by adjusting the base rates so that the total of base rate plus SSIR is equal across rate areas. In the next SSIR proceeding, the Commission could determine how to consolidate the riders.

If the Commission approves consolidate of RA2 and RA3, then it could choose to direct Black Hills Gas to consolidate the SSIR as well.

D. Mitigating Revenue Allocations

Q: Is it appropriate to flow the results of a class cost-of-service study directly into the allocation of revenue requirements among classes?

A: No. Any cost-of-service study, even one done with the greatest of care, based on very good data, is just one input into the allocation of revenue requirements and rate changes among classes. The embedded cost-of-service study answers the question "Given historical investments and commitments, what is an equitable sharing of the costs among customer groups with their current usage patterns?" Regulators usually consider additional factors, including other perspectives on equity, gradualism and rate stability. Those other factors are particularly important when the class cost-of-service study relies on low-quality data and on functionalization, classification and allocation methods inconsistent with cost causation. The Black Hills Gas class cost-of-service study is replete with those problems.

Q: How do regulators mitigate the effects of cost-of-service study results on revenue allocation?

A: Various jurisdictions use a variety of approaches, including limiting:

- Percentage or point movement towards equal indicated return,
- Percentage or point change in indicated return,
- Percentage or point change in class revenue allocation.

For example, a regulator may limit the increase in the return for a class that is currently producing a return less than 95% of the system average to the system average in increase plus half the return shortfall, so a class currently earning 90% of the system average would be a 5% increase, plus the system increase.[74] Another may decree that no class shall have an increase more than three percentage points above the system average increase, and none shall have a decrease if the system revenues are increasing. Still another may limit the rate at which the percentage of costs allocated to a class approaches the results from the cost-of-service study.

Some regulators have consistent guidelines for rate mitigation across all utilities, others have differing precedents for differing utilities, and some adapt their mitigation rules to the circumstances of individual proceedings.

Q: If the Commission does not consolidate rate areas, how should rate impacts on RA2 be mitigated?

A: Once the Commission has approved a revenue requirement, there are only two ways to mitigate the rate impacts on particular groups. Cost recovery may be shifted among the rate areas or between customer classes. However, shifting costs from residential to commercial customers would exacerbate the already substantial rate increase proposed for commercial customers. Thus, it would be more equitable to shift cost recovery from RA2 to RA1 and/or RA3.

If consolidation is not approved, the Commission should at least mitigate the rate impacts to residential customers in RA2 by limiting the percentage increase of that group's revenue requirement to two times the average system base-rate increase. For example, if the Commission allows a 10% increase in Black Hills Gas total non-fuel revenues, the increase in the RA2 residential revenue should be no more than 20%. Since the residential customer charges should not increase, whatever residential

[74] These issues most often arise among rate classes or rate schedules, but sometimes among geographic areas, especially following mergers and acquisitions.

revenue increase the Commission allows should be recovered through an increase in the volumetric rate.

In Table PLC-24, I present an example of how such a cap could be implemented for residential customers, using the Company's proposed volumetric rates. (These rates should not be adopted, as they do not reflect the recommendations made elsewhere in this testimony.)

Table PLC-24: Volumetric Residential Rate Cap ($/therm)

			A	B	C	D	E
			RA1	**RA2**	**RA3**	**Total**	**Average**
1	Current Rate	(note A)	0.2133	0.2422	0.1332		0.1754
2	Proposed Rate	(note A)	0.1984	0.3809	0.1448		0.1865
3	Therms per Year	(note B)	75,405,039	14,975,452	91,501,085	181,881,576	
4	Current Revenues	1 x 3	16,086,911	3,627,653	12,184,284	31,898,849	
5	Proposed Revenues	2 x 3	14,961,114	5,704,599	13,247,527	33,913,240	
6	Proposed Increase	5 / 4 - 1	(7.0%)	57.3%	8.7%		6.3%
7	Capped Revenues	(1 + E6) * 4	18,118,666	4,085,821	13,723,143		
8	Revenue Shortfall	7 – 4		1,618,778			
9	Revenue Excess @Cap	7 – 4	3,157,552		475,616	3,633,169	
10	Shortfall Allocation Factor	9 / D9	87%		13%		
11	Shortfall Allocation	10 * B8	1,406,864		211,913		
12	Reallocated Revenues	5 + 11, B12 = B7	16,367,978	4,085,821	13,459,440	33,913,240	
13	Reallocated Proposed Rate	12 / 3	0.2171	0.2728	0.1471		0.1865
14	Reallocated Increase	14 / 4 – 1	1.7%	12.6%	10.5%		6.3%

(A) Workpaper_Figure NAW-2 - Average Residential Monthly Bill by Rate Component.xlsx
(B) Hearing Exhibit 105, Attachments DNH-8, DNH-9, DNH-10, Column C, Row 13

In my rate cap example, the rate increase for RA2 is reduced from 57 percent to 12.6 percent, double the statewide rate increase proposed by Black Hills Gas. The rate increases for RA1 and RA3 are increased, but remain below the RA2 increase.

It should also be noted that due to the likelihood that the SSIR for RA2 will increase significantly over the three-year SSIR period, overall non-fuel rates for RA2 will continue to grow faster than for the other rate areas under this mitigation proposal.

Q: How do you see mitigation interacting with consolidation of the rate areas?

A: I believe that it is appropriate for the Commission to at least start the process of consolidating rates across the rate areas, for both equity and efficiency reasons. I present the mitigation option principally in the event that the Commission rejects consolidation.

If consolidation results in excessive rate shifts, the Commission should consider mitigating those shifts. The magnitude of the overall rate increase and other results of this proceeding should inform the Commission's decision on mitigation. As a general rule, if the system revenue requirement increases, it is probably inappropriate for any group (class, rate area, for class in a rate area) to be allocated revenue responsibility lower than its current rates would produce.

Q: Does this conclude your testimony?

A: Yes.