- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Questar Gas Company to Increase Distribution Non-Gas Rates and Charges and Make Tariff Modifications	)	DOCKET NO. 07-057-13 REPORT AND ORDER ON COST OF SERVICE AND RATE DESIGN

ISSUED: December 22, 2008

SHORT TITLE

Questar Gas Company 2007 General Rate Case
Phase II Order on Cost of Service and Rate Design

SYNOPSIS

The Commission addresses cost-of-service issues, approves revenue spread to classes, and approves pricing to achieve the $11.966 million revenue increase approved in Phase I of this proceeding. Additionally, the Commission approves the elimination of the General Service South (GSS) rate schedule and revises the Extension Area Charge (EAC) calculations and approves in part, the Company's restructuring of rate schedules.

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APPEARANCES:

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I. BACKGROUND AND PROCEDURAL HISTORY

On December 27, 2007, and January 9, 2008, the Commission issued scheduling orders which bifurcated this proceeding into Phase I - Revenue Requirement and Phase II - Cost of Service. Phase I of this proceeding was completed with the issuance of the Commission's June 27, 2008, Report and Order on Revenue Requirement which increased Questar Gas Company's ("Questar" or "Company") annual distribution non-gas ("DNG") revenue requirement by $11,966,500 based on allowed rate of return on equity of 10 percent. Phase II of this proceeding, as represented by the following procedural history, decides the spread of this revenue increase to the Company's rate schedules and sets rates based on an analysis of cost-of-service issues and consideration of rate design proposals.

On December 18, 2007, the Company filed its Application in this docket which contained direct testimony on cost of service, revenue spread and rate design. On April 1, 2008, Questar filed Updated Direct Testimony and Exhibits including direct testimony on cost of service, revenue spread and rate design. On July 14, 2008, the Company notified the Commission that revised tariff sheets and an updated version of its cost-of-service model would be made available to parties by July 25, 2008. On July 25, 2008, the Company filed an updated cost-of-service model and tariff sheets, and the Commission issued a Third Amended Scheduling Order which revised the procedural schedule based upon agreed changes submitted by interested parties.

On August 18, 2008, the following parties filed written direct testimony on cost of service, revenue spread and rate design issues: the Utah Division of Public Utilities ("Division"); the Utah Committee of Consumer Services ("Committee"); the Association of Energy Users

Intervention Group ("UAE"); and by AARP, Salt Lake Community Action Program and Crossroads Urban Center (collectively, "AARP et al."). Approximately ten public comment e-mails were filed with the Commission addressing cost-of-service issues.

On September 22, 2008, the Company, the Division, the Committee, UAE, AARP et al., and Roger Ball filed rebuttal testimony in this case. On October 7, 2008, the Company, the Division, the Committee, UAE, and AARP et al. filed surrebuttal testimony. On October 8, 2008, the Company filed a joint issues list and a joint position matrix. On October 9, 2008, the Company and UAE filed a Motion to Strike Portions of Pre-Filed Surrebuttal Testimony of David E. Dismukes, Ph.D., which was denied at hearing. After due notice, a hearing was held on October 13 through 15, 2008, to address cost of service, rate design and other tariff issues.

We address the issues raised in this docket in the context of the following categories: restructuring of rate schedules, cost of service and spread of revenues; pricing and rate design; and miscellaneous policy and tariff-related issues.

II. RESTRUCTURING OF RATE SCHEDULES

A. INTRODUCTION

The Company and other parties recommend the Commission restructure the Company's customer classes and rate schedules.[1] These changes include splitting the General Service ("GS-

[1] A customer "class" is the grouping of customers with similar cost-causing characteristics for the purposes of allocating total system costs to that group based on a cost-of-service study. This class may also form a grouping of customers for which a rate schedule is defined with the specific terms, conditions and pricing of service. Alternatively, the class may be divided into multiple rate schedules. In this proceeding, the terms class and rate schedule are used interchangeably by parties because the groupings of customers into classes and rate schedules are

1") class and rate schedule into two separate rate schedules by customer type, eliminating or revising expansion area rates, combining several rate schedules into a new transportation service rate schedule, eliminating certain other rate schedules, and changing the names of rate schedules. We address these proposed changes below.

B. SPLIT OF THE GS-1 CLASS AND RATE SCHEDULE

1. Positions of the Parties

The Company proposes to split the GS-1 class into two separate classes, General Service Residential ("GSR") and General Service Commercial ("GSC"). This separation is based on the Utah State sales tax rate classification for residential and commercial customers. The Company testifies its billing system already codes whether a GS-1 customer is residential or commercial based on the state sales-tax classification and therefore, the Company proposes this method to split the GS-1 class. However, the Company testifies a split performed on this basis does not produce two separate, homogenous groups of customers and proposes to address intra-class equity through rate design.

The Division supports the Company's proposal to use state sales tax codes as a basis for splitting the GS-1 class. The Division reasons it is best to first split the class into fixed residential and commercial customer groups to better distinguish the purpose for which the natural gas is used. In a subsequent step, rates can be designed within each customer group to promote the efficient use of natural gas. This second step involves distinguishing usage patterns

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often the same.

and designing rates that reflect both cost causation and appropriate price signals to promote efficient use of natural gas.

The Division is cautious regarding a usage-based rate classification because customers may face a perverse incentive to increase the consumption of natural gas in order to qualify for a different and lower cost rate schedule. Further, the Division is concerned it may be administratively difficult to correctly classify customers based on usage because it varies over time. Therefore, the Division recommends a task force first study high volume usage patterns in order to further develop the GSC class and report the results to the Commission by May 1, 2009.

The Committee surmises the goal of the Company's proposed separation of the GS-1 class is to create two more homogenous customer classes, with similar usage levels and patterns, than exists under the current GS-1 class. The Committee supports this goal but disagrees with the Company's basis for splitting the class. The Committee testifies the proposed new GSC class will still have a considerable degree of heterogeneity since the class can represent customers ranging from a small retail establishment to a large hotel or shopping mall. Further, the split proposed by the Company and Division could result in pricing discrimination, wherein customers with similar size and usage patterns may be charged different prices.

The Committee recommends the Commission split the GS-1 class into two classes based on monthly usage. Under this proposal, all residential and small commercial customers with a maximum monthly usage of 100 decatherms or less would be eligible for service under a General Service class. Commercial-only customers with maximum use per customer greater than 100 decatherms per month would be included in a General Service-Large class. The

Committee set the 100 decatherm threshold based upon an analysis of bill frequency, customer and usage data it obtained from the Company.

AARP et al. opposes the Company's proposal to split the GS-1 class based on tax code classification. However, AARP et al. supports dividing the GS-1 class into separate classes because currently the GS-1 class comprises most of the Company's customers and 96 percent of the DNG revenue yet the only distinction in costs for customers in this class is the declining block rate that provides lower costs for larger customers.

AARP et al. testifies that dividing the GS-1 class is a rate design issue which begins with understanding and prioritizing rate design objectives. It is AARP et al.'s view that the principal objective is to design rates which reflect the cost of providing service. A secondary objective is encouraging the efficient use and conservation of resources. When designing rate classes, and deciding how to separate a class such as the GS-1 class, the primary objective is to collect customers into homogeneous groupings having similar cost characteristics.

AARP et al. argues the Company's proposal to separate the GS-1 class by tax coding does not separate the customers into homogeneous classes. Rather, it separates small commercial customers from residential customers even though the two customer groups have similar usage patterns, and it combines small and large commercial customers which do not. AARP et al. observes the Company's proposal for designing rates to address the wide variation in use by commercial customers is to use declining block rates and a basic service fee. AARP et al. argues these rate design components are antithetical to the second objective in rate design, the efficient use and conservation of resources. A further problem with the Company's proposal is its slight practical effect. The split effectively changes rates for no one.

AARP et al. testifies the Committee's proposal to separate the GS-1 class at 100 decatherms addresses AARP et al.'s concern with the tax code split. Further, the Division's concern with migration of customers from one class to another can be addressed by requiring customers to remain on a rate schedule for a period of time before changing to another. However, AARP et al. notes the Division also provides testimony suggesting consideration of a large class divided at 300 decatherms in the next rate case. Therefore, AARP et al. recommends the Commission defer any decision on dividing the GS-1 class until the next rate case and to encourage parties to work together to propose a manner to divide the class that satisfies all parties' concerns so the proper classification can be made up front.

UAE supports the Company's proposed separation reasoning the fundamental differences between residential and commercial usage warrant serving these customers under separate rate schedules.

2. Discussion, Findings, Conclusions

For the reasons articulated by AARP et al., we defer a decision on splitting the GS-1 class at this time and therefore do not accept the Company's proposal to rename this class or rate schedule. We are not persuaded by the Company or Division that the proposed tax code classification split brings us any closer to the rate design objectives discussed in the record, namely, cost-based rates, intra-class equity, and the promotion of energy efficiency and conservation. We concur with AARP et al. that the primary objective in rate design is to reflect the cost of providing service. To this end, rate classes should be relatively homogeneous so that total system costs can be fairly allocated to each class based on the cost of providing service. The design of appropriately specified classes promotes intra-class equity while allowing for simple and well understood rate designs that promote energy efficiency and resource conservation.

We direct the parties to examine other bases for dividing the GS-1 class. For example, they may wish to consider the following two alternatives. First, as discussed in the record and advocated by the Committee and AARP et al., a volume basis may provide for a more homogenous grouping of customers. A second candidate criterion for splitting the GS-1 class, although not advocated by any party, is meter size. The Company testifies the size of the meter is an indication of the amount of plant needed to serve a customer. As the delivery capacity for a customer increases (as measured by meter size and inlet pressure), the amount of plant required to serve that customer also increases all the way back to the city gates. In its distribution plant study, the Company first identifies all the different meter sizes and the different meter pressures. Then, irrespective of rate class, the Company analyzes the plant necessary to serve each individual meter. From this analysis, the Company identifies meter categories based on cost of service.

We also direct the parties to provide supporting analysis and evidence on how the proposed rate classes address the various rate design objectives. Given our decision to defer splitting the GS-1 class, we drop further reference to the GSR or GSC classes or rate schedules in this order unless necessary.

C. ELIMINATE GSS, IS-4, AND IT-S RATE SCHEDULES

1. Positions of the Parties

The Division recommends the Commission eliminate the General Service South (“GSS”), Interruptible South Sales #4 (“IS-4”), and Interruptible Transportation South (“IT-S”) rates schedules and move these customers into other appropriate rate schedules. These rate schedules were established to set rates for new service in rural areas over 15 years ago. There are currently about 7,100 customers in central and southwestern Utah taking service from these schedules. These GSS rates are set to expire in 2012 and 2013.

The Division advocates the elimination of the GSS rate schedule now because, in part, these rates do not follow assumptions initially used to establish a 20-year time-frame for recovery of the expansion area costs. In the original applications to set expansion area rates, the actual rates used to determine the 20-year time period were set at double the then current GS-1 rate of $1.70716 per decatherm and held constant for the rate-effective twenty-year period. However, in practice, whenever the GS-1 DNG rates have changed, the GSS rates have been increased or decreased by the same percentage as the change in the GS-1 rates. Thus, the current GSS summer rate is 2.31 times the GS-1 summer rate and 2.38 times the winter GS-1 rate. The Division believes this was not the intent of the original rate design. Further, since the revenue collected from GSS customers has not been tracked, there is no way to determine if the purported rate of return has been or will be realized at the end of the time period, regardless of whether a 10 or 20-year payoff is set as the criterion. Therefore, on a going forward basis, the Division cannot support the continuation of the GSS, IS-4, and IT-S rates as just and reasonable.

In support of its recommendation to eliminate the GSS, IS-4 and IT-S rates now, the Division demonstrates the effect on the payback period of changing the average target rate of return employed in the initial analysis establishing GSS rates from 11 percent to 6 percent. This is the same rate the Division recommends the Commission use going forward for the extension area charges ("EAC") and also going forward for customers in future service expansion areas. The original filing for GSS rates required a 20-year time period to achieve an average rate of return of 11 percent. By applying a 6 percent target, a ten to twelve year payoff would be required rather than twenty. Under this assumption, the GSS Southwestern Utah System would achieve its target average rate of return in 10 years or by 2003, and the Cleveland Elmo area would achieve a 6 percent average rate of return between 11 and 12 years or by 2005. Thus, under the 6 percent assumption, GSS rates are no longer necessary.

The Company supports the Division's analysis and use of a 6 percent target rate of return to calculate the payback period, and recommendation to eliminate, going forward, the GSS rates. The Company does not characterize this change as a refinancing of the debt for these customers but rather as a change in the analysis used by the Commission to establish the expansion area rates. The Company argues it is not the obligation for these areas to repay the Company or other ratepayers any specific amount, but to pay the rates established by the Commission. The Company neither supports nor opposes the Division's recommendation to eliminate the IS-4 and IT-S rates going forward.

Mr. Ball opposes the Division's recommendation, arguing it is not fair and is essentially a subsidy from all other ratepayers to customers in the GSS communities. Mr. Ball testifies the

Company seized a business opportunity without paying attention to the details, and therefore should bear the burden of any losses associated with its investments in these communities. Alternatively, the customers in these communities should continue to pay for the bargain to which they agreed.

To counter the Division's argument GSS customers have been inappropriately charged more than double the GS-1 rate, Mr. Ball recommends the Commission reset the rates in accordance with the original intention of the analysis rather than eliminate them. Mr. Ball also argues the Division's proposal is discriminatory to customers who, by calculation at 6 percent, have already repaid their obligation yet will receive no refund for the charges between 2003 or 2005 and today.

2. Discussion, Findings and Conclusions

We find the Division's recommendation has merit. The Division presents uncontroverted testimony that the approach taken for establishing and implementing current GSS rates is flawed because customers have been charged a higher rate than anticipated to retire the obligation within 20 years. Either correcting it going forward or conclusively verifying when the communities have met their obligation is difficult because there is no clean or unequivocal way to determine the actual revenue collected from GSS customers over the past 15 plus years.

In this case, it is the Division's opinion the GSS obligation has been met. Alternatively, Mr. Ball believes it may not have been met and further analysis should be undertaken prior to any early elimination of the GSS rates. However, we have no evidence in this record to identify what the rate going forward would be if a correction was made for the prior practice of more than doubling the GSS rate. We agree with the Division, this prior practice, if uncorrected, renders rates that are no longer just and reasonable.

Further, the Division shows us the GSS obligation was met several years ago assuming a 6 percent target rate of return. We note the Division's exhibit also shows the obligation was met in 2007 assuming an 8 percent target rate of return. This is very close to the Company's currently authorized rate of return on rate base of 8.41 percent.

In the past, we have determined it to be reasonable to change the interest rate used to calculate the time periods for EAC expansion area obligations.[2] For EAC's, this rate is currently 9.64 percent which was the Company's after-tax authorized rate of return on rate base established in the Company's prior general rate case in Docket No. 02-057-02. If we had followed this approach and considered changes to the Company's rate of return used for calculating the GSS time period, the GSS analysis would likely employ a lower target rate of return than 11 percent. The use of an updated rate of return calculation, coupled with the extra payments made by GSS customers due to the faulty implementation of setting GSS rates at more than double the GS-1 rates, leads us to reasonably conclude the GSS customers have either met their obligation at this point or otherwise have come close enough that further expenditure of time and regulatory resources is unnecessary. Therefore we determine it is in the public interest to eliminate the GSS rates going forward and approve moving these customers to the appropriate rate schedules of service.

[2] Docket No. 05-057-13, "In the Matter of the Verified Application of Questar Gas Company for a Change in the Interest Rate Used in the Extension Area Charge Calculation," Report and Order, September 30, 2005.

With respect to the IS-4, and IT-S rates, no party provides testimony opposing the Division's proposal to also eliminate these rates and to move the five IS-4 customers and the one IT-S customer to their respective non-expansion schedules. In the interest of equity among southwestern expansion area customers, and lacking any basis for alternative action, we accept the Division's proposal.

D. CHANGES TO EACs

Subsequent to setting GSS rates, the Commission adopted a different method to set rates for the Company's expansion into new service territory. Rather than producing a rate with a fixed time period as in the GSS areas, EACs were developed for each community based, in part, on an assumption of customer growth in the community. An EAC is a monthly, per-customer charge to customers in eight expansion areas in rural communities throughout the state of Utah. The amount of the monthly EAC varies from $16.50 to $30.00 per customer. There are currently about 1,400 customers paying an EAC in addition to regular GS-1 rates. The projected dates for completion of these payments were established based, in part, on customer growth projections. Because the projected growth in many of these communities has not materialized, the expected date has now extended beyond the originally projected date for many of these communities.

1. Positions of the Parties

The Division argues the extension of the payoff date beyond the originally projected date because of slower customer growth is unfair to the customers who have signed up for service and expected to pay the EAC until the original date of payoff was reached. Customers signing up for service under the originally expected payoff dates are dependent on other customers also signing up. In the event other customers do not sign up as originally expected, the entire area falls behind and, as is the case with Brian Head, the payoff date may never be reached.

The Division recommends the Commission change the interest rate used to calculate the payoff of the original balance for expansion area costs. The original rate was 13.86 percent and was based on the Company's pre-tax rate of return at that point in time. In Docket No. 05-057-13, the Commission approved use of the Company's after-tax rate of return which was 9.64 percent at that time. This change made the rate more consistent with GSS rates which were also based on an after-tax rather than pre-tax rate of return. With this change, the projected payoff date was sooner than estimated based on 13.86 percent but still exceeded the originally projected payoff date for many communities. The Division now advocates the rate be set at 6 percent which is the rate Questar is authorized to charge as a carrying charge in the Account 191 balance accrual. It is also the interest rate Questar pays to customers if those customers are required to provide a cash deposit in order to receive service.

Assuming the 6 percent interest rate, five of the communities will achieve payout dates earlier than the original payout date, two communities are estimated to payout later than the original date but much sooner than the current estimated payout date calculated assuming a 9.64 percent interest rate. However, even with a 6 percent interest rate Brian Head is never expected to reach a payoff date given current customer growth expectations.

The Division also recommends customers currently paying a monthly EAC charge should, at a minimum, pay no longer than the date originally estimated, irrespective of whether or not the Company has earned its target rate of return. This recommendation addresses the situation facing Brian Head.

The Division calculates the revenue impact of its EAC recommendations in this case is $24,738. This amount arises from the loss of one year of EAC revenue from New Harmony which results if applying either a 6 percent interest rate or the recommendation communities pay no longer than the original expiration date, which is January 2008 or November 2007, respectively.

The Company supports the Division's recommendation to recalculate the payback period for each of the EAC areas using 6 percent from the date each area came on the system and agrees with the analysis presented by the Division. The Company testifies this analysis is consistent with what was done when the rate of return for these areas was reduced from a pre-tax rate of return, 13.86 percent, to an after-tax rate of return, 9.64 percent, in Docket No. 05-057-13. The Company testifies this is not a refinancing of debt for any of these communities. The obligation for these areas is not to repay the Company or other ratepayers any specific amount, but to pay the rates established by the Commission. The Commission established the expansion area rates, both GSS rates and the EACs, based on analyses that assume an interest rate or rate of return. Changing the assumed interest rate does not refinance anything, but changes the analyses used by the Commission to establish those rates. For both GSS rates and EACs, the Commission relied on analyses to determine the time frame that expansion area customers would pay a premium rate or additional charges. As in Docket No. 05-057-13, the Commission is well within its authority now to revisit these assumptions and recalculate time periods based on a different set of assumptions if the resulting rates are deemed just and reasonable. Thus, the Company argues, all of these interest rates, 13.86, 9.64 and 6 percent, are within a range of reasonableness and have been used in setting rates by this Commission.

The Company contends the Commission must make subjective decisions to balance the interests of all customers and the issues are not black and white. For example, EACs are not designed to recover all of the capital costs the Company actually incurs by extending service into the expansion areas because the charges are based on a minimum system design rather than the system the Company actually builds which includes the potential for growth. This is the same practice that is undertaken when mains are extended to subdivisions anywhere within the Company's service territory. Developers or builders are responsible for paying a contribution in aid of construction ("CIAC") for all the costs exceeding allowances set in the Company's Utah Natural Gas Tariff ("Tariff") governing the extension of mains. The costs used in determining the CIAC are also based on the minimum system to serve those customers even though the Company builds a system that includes the potential for growth.

Mr. Ball opposes the Division's proposal and argues the interest rate used for determining the EAC payoff date should track the Company's cost of capital. Mr. Ball recommends the Commission use the after-tax cost of capital most recently set in its June 27, 2008 Report and Order in this docket.

Mr. Ball argues the Division's proposal is inconsistent with the Commission's order in Docket No. 06-057-T04 because it is not about refinancing the charges over a longer period of time but is simply a lowering of the rate. Mr. Ball states every single dollar not collected in

EACs from the communities affected, will instead be collected from ratepayers at large. Mr. Ball argues ratepayers are already paying for the actual costs of expanding plant into the new communities, which is greater than the estimated cost based on a minimum system design and ratepayers have been paying for this at the Company's rate of return, not some other rate. Mr. Ball agrees a developer may be able to pass connection charges in excess of the line extension allowance on to a home buyer in the price of the house, and the homeowner may be able to finance this through a mortgage, but disagrees this is the same debt service that is being covered by all ratepayers which Mr. Ball argues is at the Company's earned rate of return.

Mr. Ball recommends the Commission require the Company to back out the capital costs and interest associated with expansion to the EAC communities from rate base and account for these costs and all EAC revenues separately. Any losses shown to remain should be attributed to the Company which should write off the deficits at the expense of its stock-holder in order to end the charges. Then, EAC charges may be removed. This approach should be taken for future extension areas as well. Specifically, for future extensions, Mr. Ball recommends the Company be required to manage and account for the whole period of the project, as a separate project, so that expenses, contributions to Questar's rate of return, and revenues are distinguishable from the accounts that pertain to ratepayers at large.

2. Discussion, Findings and Conclusions

We last addressed this issue in considering a stipulation by parties in Docket No. 06-057-T04. We then determined the proposed stipulation ran counter to well established regulatory principles of fairness and non-discriminatory treatment of similarly situated customers. We invited the parties to consider several alternatives we identified that neither violate the preferences statute nor offend rate-making principles and invited parties to develop additional alternatives for our consideration.

While not an exact match with our suggestions for an alternative method, the Division's proposal has merit. For example, it does not drop all remaining charges in EAC areas as in the rejected stipulation, but rather shortens the time period for payments. Secondly, it applies the same interest rate for new expansion areas, thus treating similarly situated customers or potential customers, similarly, going forward. The recommended 6 percent interest rate is a commonly used interest rate in ratemaking. Also, as noted in the record, the cost of line extensions in neighborhoods can be pooled and included in the price of the house, meaning a mortgage interest rate may be used in these cases which is similar to the 6 percent rate the Division advocates.

Mr. Ball argues ratepayers at large do not benefit from the facilities built to provide service to the EAC communities and therefore these costs ought not to be shifted to them. We note one of the key drivers in the rate increase granted in this case is for feeder line investment in the Salt Lake area, which EAC communities pay for in the GS-1 rate but from which they receive no direct benefit. We concur with the Company, there is not always a clear line for identifying the amount of investment cost to be shared and allocated across all customers and the amount which is directly assigned. We also take public policy and fairness into account in rendering any ratemaking decision.

In addition, we agree with the Division, the originally projected payoff date should be the latest expiration date for EACs regardless of changes to the assumptions upon which the initial rates are set. Scrutiny of the reasonableness of these assumptions should be made up front and customers in the rural areas, relying on these factors and signing up, should not be individually penalized when the future unfolds differently than anyone expected. We find this a reasonable balance between averaging rates across all customers and directly assigning costs when possible.

Based on the foregoing, we approve use of a 6 percent interest rate for determining the payoff date for the existing EAC communities and the latest payoff date for any community shall be its originally estimated payoff date. These dates shall be reflected in the Company's Tariff Section 9.02, New or Additional Service. The Company is also directed to propose language changes in this Section 9.02, item (3) to effect this decision.

E. OTHER RATE SCHEDULE RESTRUCTURING CHANGES

1. Position of the Parties

The Company proposes name, service, and blocking changes to several rate schedules. Specifically, the Company proposes to: rename Firm Service #1 ("F-1") to Firm Service ("FS"), and to revise firm sales service limitations; rename Interruptible Sales #4 ("I-4") to Interruptible Service ("IS"), rename Firm Transportation #1 ("FT-1") to Firm Transportation ("FT"); combine Firm Transportation #2 ("FT-2") and Interruptible Transportation ("IT") into a new Transportation Service ("TS"); eliminate Firm Service #3 ("F-3"); eliminate Firm Service #4 ("F-4"), moving its one customer to the new TS; eliminate Temporary Service #1 ("T-1"); eliminate Natural Gas Vehicle ("NGV") Equipment Leasing for future customers; and rename the Emergency #1 ("E-1") to Emergency Service ("ES").

In renaming rate schedules, the Company is proposing to make the names more consistent and representative of the service being provided. No party opposes the Company's renaming and combining proposals.

The Company is proposing to revise firm sales service limitations in order to provide firm sales service to customers who have a maximum daily use greater than 1,250 decatherms and a load factor less than 80 percent. Currently, such a customer must qualify for firm transportation service on either the FT-1 or FT-2 rate schedules in order to obtain firm service, yet these schedules contain additional limitations which preclude some customers from firm service. To remedy this situation, in its new FS schedule the Company proposes raising the F-1 schedule's maximum daily usage limit of 1,250 decatherms to 2,500 decatherms, but retaining the F-1 schedule's 40 percent load factor requirement. No party opposes the Company's proposed change.

The F-3 schedule is currently used for interruptible sales and transportation customers to buy firm standby service on the Company's distribution system. With the proposed changes to the transportation schedules, the Company argues the need for transportation customers to use the F-3 rate schedule will be eliminated and therefore proposes to eliminate the schedule. By eliminating the F-3 rate schedule, the I-4/IS customers currently using the F-3 for firm standby service will need to contract for a level of "ribboned" firm service on the new FS rate schedule.[3] The Company also proposes to eliminate the T-1 schedule for service of a temporary nature

[3] Tariff Section 8.01 allows customers using a combination of services to be billed for usage based on the rates of different rate schedules for usage on the same meter.

determined at the discretion of the Company. No party opposes the elimination of the F-3 or T-1 schedules.

The Company proposes to eliminate the NGV Equipment Leasing program on a going-forward basis because it is no longer needed. The Company testifies this program was implemented to help “jump-start” the use of natural gas as an alternative fuel for vehicles and to promote the development of the refueling infrastructure necessary to serve the local NGV market. Now the refueling infrastructure is in place and customers are able to purchase NGV equipment and procure related services from other parties. The Company has NGV equipment leases with eight customers and will continue to honor the terms of these leases. The Company has not had a new NGV lease agreement for over 7 years. No party opposes the Company’s proposal to eliminate the NGV Equipment Lease program going forward.

The Company also proposes to eliminate the F-4 rate schedule which currently provides industrial firm sales to one customer. This proposal is directly linked to the Company’s proposal to eliminate ribboning between sales and transportation service. This customer currently uses the provisions in Section 8.01 to ribbon usage between sales and transportation service and has the first 1,000 decatherms usage per day billed at the F-4 rate and the remainder of the usage in any given day on the IT rate. The Company is proposing to charge transportation customers directly for their firm demand on the new TS rate schedule. As a result, transportation customers will not be allowed to ribbon usage between a firm sales rate and the TS rate which the Company has proposed in its modification to Section 8.01 of its Tariff. The Company states this will eliminate the need for the F-4 rate schedule. The Company proposes to maintain the allowance for sales customers to ribbon their usage in Section 8.01 of the Tariff. Thus, if the current F-4 customer desired, it could ribbon its usage on the proposed IS and FS rate schedules instead of remaining a transportation customer.

The Company argues this change is appropriate because customers that have chosen to purchase their own gas and use transportation service should do so exclusively without having access to firm sales schedules. This restriction will protect the Company-owned production for firm sales customers and insulate these customers from the imposition of additional gas costs caused by transportation customers buying firm sales service.

UAE opposes the Company's proposal to eliminate the F-4 rate schedule and to expressly prohibit customers from receiving both sales and transportation service through one meter. UAE argues the Company's reasoning is circular and unpersuasive. It appears to UAE the Company wants to prevent some customers from remaining or becoming firm sales customers in order to protect the Company-owned production for firm sales customers. But the customer who would be kicked off firm sales service are themselves firm sales customers, hence the circularity. UAE does not accept that a firm sales customer also taking transportation service is not worthy of firm sales service in the first instance. UAE concludes the prohibition is arbitrary and unduly restricts the options available to customers and recommends the Commission reject the Company's proposal. No other party opposes the Company's proposal.

In addition to renaming the I-4 rate schedule to IS, the Company proposes to change the block structure for IS rates because the usage characteristics of customers now taking service from this schedule is much different from the customers taking service on this rate schedule when the current blocks were designed years ago.

Although the Division does not directly address the Company's proposal or rationale for changing the blocking structure in the I-4/IS rate schedule, it does not support any blocks but rather proposes a flat rate. The Division notes the price differential between the current billing blocks is only about 1.5 cents per decatherm and proposes a flat volumetric rate for all usage. No other party opposes the Company's proposal to change the I-4/IS block structure.

The Company also proposes to restructure the transportation rate schedules. These changes involve rate design considerations which are more appropriately addressed in the context of a full rate design discussion and therefore, we address these changes in the rate design section of this order.

2. Discussion, Findings and Conclusions

We accept the Company's position that new names of rate schedules will be more consistent and representative of the service being provided, and approve the renaming and combining of rate schedules, with one exception. We do not accept the renaming of FT-1 to FT, Firm Transportation. This schedule is for bypass firm transportation service only. Non-bypass firm transportation service is actually provided through the new TS schedule. For clarity to customers, who might find it confusing when looking for firm transportation service, we do not approve this name change. We use the approved new names for rate schedules for the remainder of this order, referencing the old names when necessary. Absent any opposition or evidence to the contrary, we accept the Company's proposal to revise firm sales service, eliminate the F-3 and T-1 rate schedules, and eliminate the NGV Equipment Leasing program to new customers going forward.

We are persuaded by the Company's arguments regarding the change in block breaks for the IS schedule and leave to further debate the necessity of having any blocks in this schedule. The record is inadequate in this case to go further at this time. Here, we simply conclude that if blocks are to be used, they should be related to the existing customers' usage characteristics, rather than the usage characteristics of customers served under this schedule long ago.

We are persuaded by the Company that the prohibition on ribboning between sales and transportation customers is appropriate and therefore we also approve elimination of the F-4 rate schedule. However we require this schedule to be maintained until the Company's next DNG rate case at which time it shall be eliminated. This provides the customer adequate time to evaluate options and make alternative arrangements. Therefore, the allowance for ribboning between firm sales and transportation customers will also continue until that time. However, we address other modifications to the Company's proposed changes to Tariff Section 8.01 in Part V of this order on Miscellaneous Policy and Tariff-Related Issues.

III. COST OF SERVICE AND REVENUE SPREAD

A. INTRODUCTION

In the Company's last DNG rate case, the Commission approved a stipulation settling all cost allocation and rate design issues.[4] Among the many items included in this stipulation was the establishment of a task force to study several cost allocation and rate design issues. The task force was chaired by the Division and met 18 times over a period of 18 months beginning January 2003.[5] During the task force meetings, the Company provided a new, more detailed cost-of-service model. No agreement was reached on the use of specific allocation factors. However, there was a general consensus among the parties to use the Company's new model in future rate cases as the basis for allocating costs to rate schedules.

The Company, Division, Committee and UAE provide testimony in this case on issues relating to the cost of service of rate schedules, including the Company's study of distribution plant, the development of allocation factors and the application of factors to specific accounts. These parties also address the concept of "gradualism" in spreading the revenue change to rate schedules. Issues addressed by the parties include the development of the peak day factor, the extent to which throughput is reflected in the calculation of several factors, the allocation of the costs of small diameter mains, feeder lines, service lines, compressors, and meters, regulators (i.e., distribution plant), contributions in aid of construction, revenue credits, the value of gas

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[4] Docket No. 02-057-02, "In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges." "Allocation and Rate-Design Stipulation and Settlement," referred to as Stipulation No. 2, is attached to the Report and Order issued December 30, 2002.

[5] A report summarizing the discussions held by the task force was filed by the Division on June 19, 2004, in Docket No. 02-057-02.

purchased from interruptible and transportation customers, and administration and general expenses. Several of these issues are discussed below.

B. COST-OF-SERVICE STUDY/ALLOCATION FACTORS

The Company provides an electronic model responding to the issues raised in the task force which follows the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts. The FERC account detail is also presented in financial reporting and the development of test year revenue requirement. The Company's new model integrates cost of service with revenue requirement. It extends the account detail from revenue requirement to the development of the cost of serving the Company's proposed five rate classes listed below and allocates distribution non-gas revenues and costs to the proposed rate classes. The Company's model also classifies DNG costs into four groups, namely Peak Demand, Throughput, Network, and Customer, and it allocates DNG income taxes, earned income and revenue changes to these four groups based upon relative rate base of the four groups. It then allocates the total costs for the four groups to the proposed classes.

The Company's class cost-of-service study allocates DNG costs to five classes, GSR, GSC, FS, IS, and TS. These five classes then serve as the basis for the development of the Company's major rate schedules which have been given the same names.[6] These five classes, however, do not include all of the Company's rate schedules. The model spreads the GS-1 and GSS rate schedules to the GSR and GSC classes. The IS class includes both the I-4 rate

[6] Note that the abbreviated names of the five classes and schedules which are the same, are distinguished by the addition of "class" or "schedule" after the abbreviation.

schedule and IS-4 rate schedule which the Company proposes to rename ISE. The TS class includes the FT-2, the IT and the IT-S rate schedules. The FS class consists of the current F-1 rate schedule. The study does not include two transportation contracts ("FT-1L" and "FT-2C"), the by-pass transportation schedule FT-1, the natural gas vehicle schedule ("NGV"), and the municipal transportation schedule ("MT"), but rather applies the revenues from these schedules as revenue credits to the five classes. The Company proposes to eliminate two sales schedules, F-3 and F-4, and includes the associated costs in the TS class. The Company also proposes to eliminate T-1 and therefore it is also not included in the study.

Supporting its cost-of-service study, the Company presents a Distribution Plant Factor Study ("DPFS"). This study of distribution plant is used to develop three factors: Small Diameter Mains, Service Lines, and Meters & Regulators. Along with factors based on peak day and annual use, the bulk of distribution non-gas costs are apportioned to the Company's five proposed classes.

The Division, the Committee, and UAE present cost-of-service studies using the Company's model. These studies differ from the Company's in the formation of some allocation factors and the application of factors to specific accounts. The Company testifies it has been probably 20 years since parties have brought before us contested cost-of-service issues. For many of these issues the parties have not provided us with sufficient evidence to make definitive conclusions in this case. Therefore, of the many disputes regarding the cost-of-service studies and associated allocation factors raised in this case,[7] we resolve or provide guidance on three: inclusion of all rate schedules in future cost-of-service studies, the development of the peak-day allocation factor, and the use of a gross plant factor to allocate Administrative and General ("A&G") Expenses. We await more comprehensive discussion of the remaining issues in future DNG proceedings.

Rate Schedules Included in Cost-of-Service Study

The Company excludes the FT-1, NGV and MT rate schedules and the FT-2C and FT-1L contracts from its cost-of-service study. The Company excludes the FT-1 schedule and explains this rate, established in Docket No. 99-057-20,[8] was designed as a discount rate to keep large industrial customers that are close to an interstate pipeline from bypassing the Questar Gas system. The revenues required of this schedule reflect the theory that it is better to have these customers on the system and making a contribution, even if it is less than cost of service, than for these customers to leave the system entirely. The Company excludes the FT-2C schedule because this schedule is applicable to a contract obtained in the purchase of the Utah Gas system and cannot be changed until the contract expires. At hearing, the Company agrees to include the FT-1, NGV, and MT schedules in its next cost-of-service study, but makes no agreement with respect to the FT-1L and FT-2C contracts.

[7] Disputed allocation factors include the allocation of small diameter mains, allocation of feeder lines and large diameter mains, allocation of service lines and allocation of meters and regulators.

[8] Docket No. 99-057-20, "In the Matter of the Application of Questar Gas Company for a general increase in Rates and Charges."

The Division and UAE recommend all major rate schedules should be included in the cost-of-service study. The Division contends the cost-of-service study is a basic tool of ratemaking necessary to identify costs the utility incurs to serve various classes of customers and individual customers within the class. The Division maintains the study supports the broadly accepted ratemaking principle that rates should be based upon costs. The Division also recommends the interruptible and firm transportation components of the TS schedule be separated in cost-of-service studies for future rate cases because these two services are distinct.

The Committee recommends future cost-of-service studies include all rate schedules. In addition, the Committee recommends that in its next rate case the Company provide a cost-of-service study that includes all customers and all customer classes as separate rate classes. This will enable a full examination of the cost of serving the various schedules and weigh the costs against the benefits provided. In addition, the Committee insists current, not just proposed, rate schedules be included in future class cost-of-service studies. The Committee contends that only providing proposed schedule restructuring information, as the Company has done in this case, results in the parties' inability to determine the rate of return achieved by each class under the current rate schedules.

We agree with the Division, UAE and Committee. We find the cost-of-service study critical for assessing the performance of any given rate schedule or contract and hence for determining just and reasonable rates. We direct the Company to include each rate schedule separately, including the FT-1L and FT-2C contracts, in future cost-of-service studies. We also agree with the Division, the interruptible and firm transportation components of the TS schedule should be separated in future cost-of-service studies, as these two services are distinct.

Peak-Day Allocation Factor

There are two issues with respect to the peak-day allocation factor. First, the treatment of firm sales and firm transportation customers, and second, the treatment of interruptible sales customers. Regarding the first issue, the Company bases its peak-day allocation factor for the GSR, GSC, and FS schedules on the design-day demand from the 2007 Integrated Resource Plan ("IRP"), adjusted for known changes. The IRP bases its design-day demand on a one-in-20 year weather event.[9] The peak-day allocation factor for the firm transportation schedules, however, is based on contract demand. The Company does not include the interruptible sales and interruptible transportation schedules in the peak demand calculation, nor does it include the by-pass transportation schedule, FT-1.

Both the Committee and UAE use the Company's peak-day allocation factor in their cost-of-service studies. The Division uses the actual deliveries on the 2007 peak day, January 15th, in its peak day calculation for both firm sales and firm transportation schedules. The Division argues using contract demand for transportation customers and the coldest recorded day in the last 20 years for residential and commercial customers is a mismatch resulting in residential and commercial customers being assigned a greater share of the peak-day demand than appropriate. The Division testifies that on January 15, 2007, the Company delivered a

[9] The 2007 IRP defines a one-in-twenty year weather event as one where the mean temperature is -5 degrees Fahrenheit at the Salt Lake Airport weather station and correspondingly cold temperatures are seen coincidentally across the Company's service territory. See Company's IRP dated May 1, 2007 to April 30, 2008.

record 1,091,289 decatherms, including 59,713 decatherms for firm transportation customers and 75,589 decatherms for interruptible transportation customers. Although the capacity and capability of the system were severely tested, sufficient capacity existed to serve all customers without interruption. The Division maintains the Company's total peak-day demand used in this factor for transportation customers is far less than the deliveries needed to serve these customers on the Company's actual peak day of January 15, 2007.

The Company argues the Division uses coincident peak delivery for firm sales customers, non-coincident peak for interruptible customers, design peak for firm transportation customers and commodity throughput for the entire system resulting in an allocation factor that achieves what the Division desires but cannot be said to improve the allocation of the costs in question. UAE maintains it is entirely appropriate to allocate peak-day-related costs of the system in a manner reflecting the expected usage on the design peak day, since the peak-day capacity is built to meet firm requirements on extremely cold days.

Regarding the second issue associated with the peak-day allocation factor, the Division proposes the peak-day contributions of the interruptible service schedule be measured by its average annual usage, a method used by the FERC and other state jurisdictions. This number represents approximately 60 percent of the amount interruptible customers used on the most recent historic peak day, a share the Division considers to be fair. The Company and UAE maintain the interruptible service schedule should have no peak demand responsibility.

With respect to the first issue, we find the Company's approach to the allocation of peak-day demand flawed insofar as firm sales and firm transportation customers are not treated on a consistent basis. For firm sales, the Company uses the coldest day in the past 20 years, while for firm transportation it uses contract demand. We view the Company's system as an evolving set of investments whereby allocation factors should be related to a measure of actual demand. Therefore we require the Company to use a measure of actual demand for the peak-day allocation factor in its cost-of-service study in the next DNG rate case.

With respect to the second issue, we are persuaded by the Division that interruptible customers contribute to peak demand and therefore these customers should receive some allocation of peak demand in the Company's next cost-of-service study.

Allocation of A&G Expenses

Regarding allocation of A&G expenses, accounts 920 through 935, the Company allocates these expenses based on its traditional method using relative gross plant. Since providing natural gas distribution service is a highly plant-intensive operation, the Company argues A&G expenses are best allocated based on the plant required to provide service. Finally the Company notes Rocky Mountain Power also uses a gross plant allocation factor to allocate A&G expenses.

The Committee recommends the allocation of A&G expenses based on a factor consisting of 75 percent of operations and maintenance expenses and 25 percent distribution throughput. The Committee contends A&G expenses include costs such as the president's salary, insurance expenses, planning, purchasing, payroll, human resources, regulatory expenses, and advertising expenses. These functions support the entire operations of the Company, including gas purchasing operations, which are a function of throughput requirements of its customers. The Committee maintains its allocation factor represents the diversity of the types of expenses included in the A&G account.

We agree A&G expenses support the entire operation of the Company, including gas purchasing activities. However, some amount of throughput is already reflected in the allocation of gross plant. Given the record, we find the Company's method to allocate A&G expenses based on relative gross plant reasonable for this case. This does not preclude parties from proposing other allocation factors specific to particular A&G accounts in future rate cases.

C. RATE OF RETURN INDEX

Cost-of-service studies can be summarized and presented by the ratio of the earned rate of return of a particular rate schedule to the earned rate of return of the system, also known as a rate of return index. The results of the parties' cost-of-service studies are presented in this format in Table 1 below. The "class" names in the Table 1 are written out such that they may be distinguished from the names given to the new schedules.

Table 1. Cost-of-service Results - Rate of Return Index[10]

Party	Residential Firm Sales	Commercial Firm Sales	Firm Sales	Interruptible Sales	Firm & Interruptible Transport	Bypass Transport
Company	0.97	1.36	0.76	-0.01	0.05	n.a.
Division	1.00	1.21	0.59	-0.02	0.15	0.53
Committee	1.14	1.17	0.05	-0.69	-0.56	n.a.
UAE	0.94	1.39	0.97	0.29	0.60	n.a.

[10] Sources: QGC 7.2R, DPU 7.4SR, CCS 5.5, and UAE COS 1.2. The abbreviation "n.a." stands for "not available."

Despite the differences regarding the calculation and use of allocation factors, the parties' cost-of-service studies indicate a somewhat similar set of results. We observe in all studies the GSC schedule performs above a 10 percent band around the system average return, i.e., above 1.10. In general, the GSR schedule performs close to the system average return, i.e., within the 0.90 to 1.10 band, with the exception of the Committee's study which shows a 1.14 rate of return index. There is a wide variation in the FS schedule, from 0.05 for the Committee to 0.97 for UAE. For both the interruptible sales and transportation service schedules, the results of the rate of return indices are close to zero with the exception of UAE, which shows higher results, 0.29 and 0.60, respectively. Only the Division calculated results for the transportation by-pass schedule, FT-1, resulting in only approximately half of the system average rate of return. From this data we conclude there is above satisfactory earnings performance by the GSC schedule, approximately satisfactory performance by the GSR schedule, mixed results from the FS and FT-1 schedules, and unsatisfactory performance by the IS and TS schedules. This leads to our conclusion a non-uniform spread of revenues is supported by the record. The parties use these costs of service results as a guide to forming their revenue spread proposals to which we now turn.

D. REVENUE SPREAD

1. Positions of the Parties

Parties' revenue spread recommendations are presented in Table 2 below. We discuss the bases for parties' proposals for each rate schedule in the order the rate schedule is presented in Table 2.

Table 2. Proposed Percent Revenue Changes[11]

Schedule	Company	Division	Committee	UAE
FT-1L	0%	0%	0%	0%
FT-2C	0%	0%	0%	0%
NGV	94%	94%	94%	7.95%
FT-1	12.5%	12.5%	n.a.	7.95%
MT	25%	0%	n.a.	7.95%
F-1 (FS)	10%	10%	67%	10.78%
I-4 (IS), IS-4 (ISE)	25%	0%	152%	10.78%
F-3, F-4, FT-2, IT (TS), ITS (TSE)	25%	25%	172%	10.78%
GS-1R (GSR), share of GSS (GSE)	5.07%	4.51%	0%	6.43%
GS-1C (GSC), share of GSS (GSE)	3.04%	4.47%	0%	0%

The Company proposes no change to the transportation contract FT-1L and a slight increase to the FT-2C contract arising from its proposed changes to basic service fees and administrative charges. Other parties propose no changes to these contracts.

The NGV schedule is designed to recover a portion of the cost of service for refueling vehicles powered by compressed natural gas at Company-owned stations. The original rate was established in Docket No. 89-057-15. When the program was established, the rate was a cost-based rate related to the levelized cost of NGV compression facilities over their expected life. Since then, the NGV revenues have been treated as a revenue credit in prior cost-of-service studies and the NGV schedule rate has not been based on cost of service but instead has been

[11] Sources: Revised QGC 7.8R; DPU 7.1SR; CCS 5.5, CCS Direct 5D, p. 33, lines 692-694; CCS Direct 1D, lines 248-249; and UAE COS 1.1R. The new names for rate schedules proposed by the Company appear in parentheses in the first column. The abbreviation "n.a." stands for "not available."

changed by each DNG rate case's overall average percentage change since it was first introduced.

The NGV schedule is designed to recover a portion of the cost of service for refueling vehicles powered by compressed natural gas ("CNG") at Company-owned stations. The original rate was established in Docket No. 89-057-15. When the program was established, the rate was a cost-based rate related to the levelized cost of NGV compression facilities over their expected life. Since then, the NGV revenues have been treated as a revenue credit in prior cost-of-service studies and the NGV schedule rate has not been based on cost of service but instead has been changed by each DNG rate case's overall average percentage change.

The Division, and Committee recommend the revenues from the NGV schedule be raised to 50 percent of cost of service in this rate case. The Company agrees with this proposal. The Division and Committee further recommend movement to 100 percent of cost of service in the next DNG rate case. The Division maintains that, because of the recent disparity between the price for a gallon of regular gasoline compared to a gallon of NGV, the demand for NGVs and improvements to the current NGV distribution infrastructure has increased and now is the time to begin eliminating any existing inter-class subsidy. The Division, however, feels discussions regarding the role natural gas will play in the future as a vehicle fuel source and how best to balance the supply-demand paradigm needs to be deferred to a much broader policy discussion held outside the context of this docket.[12]

[12] Docket No. 08-057-21, "In the Matter of the Investigation of Questar Gas Company's Service Associated with Natural Gas Vehicles" is an open docket to consider broader policy issues..

The Committee contends the tremendous interest in NGVs and increased demand removes any need to support this market by providing a jump start through subsidized rates. The Committee believes that, whereas the Commission's original order on this issue suggested that the NGV industry would not develop without the assistance of the regulated gas utility, the NGV industry now cannot further develop unless the rates reflect a full cost of service. The currently subsidized rate will ensure that Questar will continue as a near-monopoly provider of natural gas filling stations as no other provider can compete with such artificially low prices. Further, the Committee also recommends the Commission order the Company to work with interested parties to develop a fact sheet regarding the partial removal of the subsidy and the intent to move the NGV schedule to full cost of service to ensure that NGV customers are fully informed regarding the rate change. Finally, the Committee recommends that, as the NGV industry has changed significantly in the last eighteen years, several NGV-associated issues should be closely examined.

UAE recommends the NGV schedule revenues be increased by 7.95 percent which is UAE's system average rate increase subject to providing pro-rata funding of its 200 percent rate increase cap to the FS, IS, and TS schedules and its treatment of GSR and GSC schedules. UAE characterizes this service as analogous to the "gas station" business. However, in rebuttal testimony, UAE also supports a more aggressive move to cost of service and supports the Company's and Division's recommendation.

Mr. Ball recommends the NGV rate be set at full cost of service in this case. It is far better, he contends, to send a realistic price signal based on full cost now and allow the infrastructure to develop in a sensible, open-market fashion. He further recommends that the NGV rate should reflect market, not Wexpro, prices. At hearing, Governor Huntsman's Energy Advisor recommends that the NGV rate be increased by no more than 50 percent of cost of service at this time. Furthermore, she supports the opportunity provided by the Commission to consider services associated with NGV as well as other natural gas, fuel, and vehicle factors, in Docket No. 08-057-21, prior to additional changes in the NGV rate. The Commission also received many public comments both directly and indirectly associated with the pricing of the NGV schedule.[13] Many of these comments expressed the benefits and importance of natural gas as a vehicle fuel to both the user and the public in general.

The Division recommends and the Company agrees to increase the revenues from the by-pass transportation schedule, FT-1 by 12.5 percent while UAE recommends the same 7.95 percent increase it advocates for the NGV schedule. The Committee does not address this schedule.

The Company recommends the revenues from the MT schedule be raised by 25 percent, similar to its recommendation for the transportation service schedule. UAE recommends the revenues from the MT schedule be increased by the same 7.95 percent it advocates for the NGV and FT-1 schedules. The Division recommends no change to the MT schedule revenues and provides no explanation for this position. However, in its pricing recommendations, it proposes

[13] Public comments addressed the use of the federal excise tax, maintenance and expansion of CNG infrastructure, ownership of CNG stations, the appropriate price increase, and the use of money collected by price increases.

a volumetric price increase which offsets its proposed decrease in administrative fees resulting in no change in overall revenues to this schedule. The Committee does not address this schedule.

Regarding the Company's proposed FS and TS schedules, the Committee proposes these be moved to the Committee's view of full cost of service. This results in a revenue increase of 67 percent for the firm service schedule, 152 percent for the interruptible service schedule, and 172 percent for the transportation service schedule. At the other extreme, UAE proposes to limit the increases to these schedules to two times the system average percent revenue increase, or approximately 10.78 percent each. In between these two extremes lie the Company and the Division. Both of these parties propose a 10 percent increase to the FS schedule and a 25 percent increase to TS schedules. These increases represent a movement of approximately 50 percent towards cost of service deemed reasonable by both parties.

As presented in Table 2 above, the Company proposes a 25 percent increase to the IS class. This includes the I-4/IS schedule and the IS-4/ISE schedule. To achieve its targeted increase, the Company increases the I-4/IS schedule by 28.5 percent and increases the IS-4/ISE schedule by 17.6 percent. The Division proposes no increase to the IS class. To achieve its targeted increase, the Division increases the I-4/IS schedule by approximately 25 percent with no change to the IS-4/ISE schedule.

In order to mitigate dramatic rate increases, most parties have generally embraced the concept of 'gradualism' whereby a particular rate schedule is required to move towards but not completely to its full cost of service. By limiting the increases in the schedules discussed above through gradualism, the remainder of the test year revenue deficiency becomes the obligation of the General Service schedules, to which we now turn.

Consistent with the Company's proposal to split the GS-1 schedule into residential and commercial components, and based on each parties respective cost-of-service study, parties present percent revenue changes for the general service schedules as shown in Table 2, above. The Company proposes a 5.07 percent increase to residential customers and a 3.04 percent increase to commercial customers. The Division proposes a 4.51 percent increase to residential customers and a 4.47 percent increase to commercial customers. The Committee proposes no change to either residential or commercial customers. UAE proposes a 6.43 percent increase to residential customers and no change for commercial customers.

We have not accepted the Company's proposal to split the GS-1 schedule. In addition, we have accepted the Division's proposal to move the customers on the GSS schedule to the GS-1 schedule. Based upon these decisions and for the test year revenue deficiency of $11.966 million, we take the GS-1 and GSS schedules as a whole and calculate the results of the parties' revenue spread proposals. Our calculations show revenue increases of 4.7 percent for the Company, 4.5 percent for the Division, 5.2 percent for UAE, and none for the Committee. All four of these parties include an additional $11.2 million revenue increase, or 5.4 percent, to account for the Company's projected imbalance in the CET account.

2. Discussion, Findings and Conclusions

Absent any opposition, we agree with the Company's proposal to leave the revenues in the FT-1L transportation contract unchanged in this case and no additional decisions on this contract are necessary. The slight increase to the FT-2C contract in the Company's proposal arises from the its proposed increase to basic service fees and reduced administration charges, the net effect which is a slight increase. We address this contract in the pricing section below.

We now take up the NGV schedule. Some individuals make an economic decision to either purchase or convert to a CNG-fueled vehicle based, in part, upon the NGV rate. The decision is akin to hedging against petroleum-based fuel volatility. For others, the decision to purchase a CNG-fueled vehicle may be based on reasons other than the price of CNG, including concerns about energy security and air quality, which we fully support. For others, it may be a combination of all of the above. In any event, the investment decision can be a costly one and it should be based upon the most up-to-date information.

Our decision on the NGV schedule is three-fold. First, we observe the original NGV rate was fundamentally cost-based. Since its origination, however, the cost basis for this schedule has not been re-examined until now. Based upon the testimony provided in this case, the NGV schedule is substantially below cost of service and the rate must be increased to recover its required revenue. All parties generally agree, the price of CNG vehicle fuel should not be subsidized by other utility customers. We agree, especially since CNG sales are not a traditional utility service. Recognizing the value of CNG with respect to air quality and energy security, and in order to provide proper market price signals to present and future owners of natural gasfueled vehicles, we find it reasonable to adjust the NGV schedule to recover 50 percent of its cost of service as calculated by the Company. Also, we do not find it appropriate to include the benefits of Questar's Wexpro gas resource in the pricing of this non-traditional utility service, especially since CNG is available to the general public and is not limited to Questar Gas Company customers. Therefore, we require the NGV schedule to reflect the price of natural gas, exclusive of the Wexpro resource. This is the gasoline gallon equivalent of moving the price of CNG for vehicles from $.80 per gallon to $1.14 per gallon.

Second, we observe that during the pendency of this case the cost per gallon spread between gasoline and CNG fuel has dramatically decreased and that our decision brings the price of CNG close to that of regular gasoline. As the prices of both of these commodities have demonstrated extreme volatility in the past and will likely do so in the future, the relative price spread of the two fuels will continue to vary through time. In addition, for those who have purchased a CNG-fueled vehicle to address energy security and/or air quality concerns, the contribution to resolving these issues remains regardless of the price of CNG. We are compelled by the broader public interest, however, to completely eliminate the subsidy discovered in this rate case, which has kept the price of CNG artificially low at the expense of other ratepayers, sooner rather than later and direct the Company to increase the rates associated with CNG to full cost of service on July 1, 2009. This is the gasoline gallon equivalent of moving the price of CNG for vehicles to $1.43 per gallon in 6 months time.

Finally, we find it important for the public to understand the costs and benefits of CNG when making a vehicle choice decision. We agree with the Committee's recommendation that the Company work with interested parties to develop a fact sheet regarding the partial removal of the subsidy and the intent to move the NGV schedule to full cost of service by July 1, 2009, to ensure that NGV customers are fully informed regarding the rate change. We direct the Company to generate and circulate such fact sheet by February 28, 2009. We also agree that the discussion of NGV issues should continue and will convene a technical conference in Docket 08-057-21 during the first quarter of 2009 to facilitate such discussion.

We agree with the Company and the Division to increase the revenues for the FT-1 schedule by 12.5 percent. For this transportation by-pass schedule, this 12.5 percent increase represents one half the movement required of the TS schedule. Given this schedule's relationship to the other transportation service schedule, and the lack of testimony on the price at which the customers served on this schedule will leave the system, we accept, for this case, the proposal of the Company and the Division. Similarly, we agree with the Company to raise revenue from the MT schedule by 25 percent, consistent with its recommendation for the transportation service schedule.

We agree with the gradualism to cost of service proposed by the Company and the Division and increase the revenues for the FS schedule by 10 percent and the TS schedule by 25 percent. The proposal by UAE does not provide sufficient movement toward cost of service, whereas the Committee's proposal contains no gradualism and moves directly to its view of full cost of service. Regarding the IS schedule, we agree with the Division's proposal. Based on our decision to eliminate the IS-4 schedule and move these customers to the I-4/IS schedule, this results in a 27 percent increase to the current customers in the I-4/IS schedule. In this sense, the

Division's proposal is not very different from the Company's proposal for a 25 percent increase to this rate schedule. It has been such a long time since the revenues required of these schedules have been related to cost of service that a significant movement towards cost of service is warranted in this case.

Given our decision to retain the F-4 schedule until the next DNG rate case, we treat this schedule similarly to the FS schedule by increasing the F-4 revenues by 10 percent.

The decisions we have made to this point, shown in Table 3, result in a $2.419 million revenue increase. The difference between this and the $11.966 million revenue shortfall in test year revenue requirement, or $9.547 million, is to be recovered from the General Service schedule. This represents a 4.6 percent increase.

Table 3: Final Spread of Revenue Requirement

Schedule	Current Revenue	Final Revenue	$ Change	% Change
FT-1L	$2,976,000	$2,976,000	$0	0.0%
FT-2C	$22,530	$22,530	$0	0.0%
NGV	$351,339	$861,023	$509,684	145.1%
FT-1	$1,481,696	$1,666,907	$185,211	12.5%
MT	$15,229	$19,037	$3,808	25.0%
FS	$3,866,562	$4,253,230	$386,668	10.0%
F-4	$107,182	$117,900	$10,718	10.0%
IS	$510,598	$510,598	$0	0.0%
TS	$4,687,434	$5,859,423	$1,171,989	25.0%
GS-1	$207,926,605	$217,625,016	$9,698,411	4.7%
Total	**$221,945,175**	**$233,911,664**	**$11,966,489**	**5.39%**

In Table 3, the current I-4 and IS-4 schedules are combined into the new IS schedule. At the new IS rates, the five customers taking service under the IS-4 schedule collectively receive a 56 percent revenue reduction, while the revenues from customers taking service under the I-4 schedule increase by 26.9 percent, as compared with a target increase of 25 percent. For the combined new schedule, IS, there is no net revenue change.

The current F-3, FT-2, IT and IT-S schedules are combined into the new TS schedule. At the new TS rates, the sole customer taking service under the IT-S schedule receives a 65 percent reduction, but has only a negligible effect on the customers taking service under the F-3, FT-2 and IT schedules, whose revenues collectively increase by 25.6 percent, as compared to the target increase of 25 percent for the combined new schedule, TS.

Finally, the current GSS schedule is eliminated and the customers on this schedule are moved to the GS-1 schedule. The customers taking service under the GSS schedule receive a 35.3 percent decrease, while the percent increases to the residential and commercial components of the GS-1 schedule receive 5.0 and 5.5 percent increases, respectively, as compared to the overall DNG increase of 5.39 percent. For the GS-1 schedule as a whole, the revenue change is 4.6 percent. This shows the expansion schedules can be eliminated without significant adverse impacts to other customers.

IV. PRICING/RATE DESIGN

A. INTRODUCTION

We now address proposed changes to basic service fees and administrative fees, review parties' price recommendations and provide our pricing decisions for each pricing component or rate schedule in the order the rate schedules are presented in Table 3. The new rates, as determined by the Commission, are presented in Appendix A to this Order.

B. BASIC SERVICE FEES

The Company proposes three changes to the basic service fees ("BSF"). First, as shown below, the Company proposes to increase the number of BSF categories from four to five. Second, the Company proposes to increase the meter capacity (measured in cubic feet per hour) for the respective meter categories. Third, the Company proposes to modify the fee structure.

Table 4. Company Proposed BSF Modifications

Current Category	Current Meter Capacity	Current Fee*	Proposed Category	Proposed Meter Capacity	Proposed Fee*
1	0 to 700	$5	1	0 to 1,000	$6
2	701 to 2,000	$21/$29	2	0 to 1,000	$8
3	2,001 to 30,000	$55/$67	3	1,001 to 23,000	$33/$40
4	> 30,000	$244/$274	4	23,001 to 60,000	$125/$128
			5	> 60,000	$383/$422

* The first number represents the BSF for all schedules other than the I-4, IS-4, IT and IT-S schedules which are represented by the second number.

Proposed Category 1 is limited to multi-family dwellings served under the Company's proposed GSR rate schedule (i.e., individually-metered residential apartments). Meters served by intermediate high pressure lines ("IHP") are included in Category 4 and meters served by high pressure lines are included in Category 5.

With respect to the addition of a new meter category applicable to multi-family dwellings, the Company reasons individually-metered apartments tend to have a lower investment in mains and service lines than other small customers. This lower investment results from the sharing of a single service line and slightly higher density on the IHP system. With respect to the calculation of the BSF, the Company proposes to include approximately 50 percent of the average investment in mains justifying that nearly every customer requires some main. In addition, another motivating factor is the combination of the interruptible and firm transportation customers into one rate class/schedule. With respect to the Company's proposed changes to the meter capacity ranges, these have been adjusted based upon the Company's cost-of-service study and reflect the grouping of meters with similar cost characteristics. Overall, the Company maintains the relative level of recovery of customers costs through fixed charges does not lend itself to a single definitive solution and lists several considerations that guide this decision.

The Division, the Committee, and AARP et al. all oppose the Company's proposed modifications to the BSF. These parties recommend no change to the meter categories and fees, rather, the new rate schedules should retain the current meter categories and fees. The Division reasons it is more appropriate to consider changes to the current BSF structure in the context of a general rate case when the permanent status of the CET is determined. In today's environment where conservation and energy efficiency are major public policy concerns, it may make more sense, given the CET, to put the onus on individual customers to conserve and become more energy efficient by increasing the DNG volumetric rate while reducing or completely eliminating the monthly customer charge. The Division also suggests that with the new schedules adopted for non-GS customers, it is better policy to keep BSF unchanged in order to isolate and understand the impact of the Company's proposed rate schedule consolidation.

The Committee maintains a higher BSF dampens price signals, is inconsistent with the demand-side management ("DSM") and CET proceedings, and includes costs that are not justified as part of the customer charge. AARP et al. argues increasing the BSF is inappropriate because the CET, applicable to the current GS-1 schedule which provides the bulk of the Company's revenues, already provides revenue stability to the Company.[14] The Committee also maintains it is inappropriate to increase the fixed charges while reducing the volumetric charges at a time when rate design should be promoting conservation of energy. AARP et al. observes that the Company's proposal increases the fixed charges to a level wherein it is necessary to reduce the amount of revenue collected from the energy charges by over $4 million.

We concur with the recommendation of the Division, the Committee, and AARP et al., who emphasize the importance at this time of energy efficiency and conservation in rate design. These are among the principal reasons the Commission encouraged the Company to undertake DSM programs and approved the CET pilot program. We note the Company's proposed new BSF structure and rates would collect from the residential GS-1 customers approximately twice the change in test year revenues. We also note, with respect to the Company's proposed new meter category for multi-family dwelling, i.e., individually-metered residential apartments, there

[14] Current GS-1 and GSS schedules comprise 94 percent of test year revenues.

may be other structures with a similar lower investment in mains and service lines. Given the concerns of the parties and the stage of the CET pilot, we find no reasonable basis for approving the Company's BSF increase in this case. Further, we find it reasonable to address changes in the meter categories and associated BSFs in the broader context of our decision regarding the future restructuring of the GS-1 schedule.

C. ADMINISTRATIVE CHARGES

The Company proposes to decrease the administrative fees associated with transportation services, including municipal transportation. The current primary administration fee for transportation schedules excluding municipal transportation is $6,800 annually, or $566.67 per month. The current primary administrative fee for municipal transportation is $8,000 annually, $667.67 per month. The Company proposes to reduce both of these fees to $4,500 annually, or $375 per month. The current secondary administration fee for transportation schedules excluding municipal transportation is $2,550 annually, or $212.50 per month. The current secondary administrative fee for municipal transportation is $3,000 annually, or $250.00 per month. The Company proposes to reduce both of these fees to $2,250 annually, or $187.50 per month.

The Company maintains some customers prefer higher up-front charges and lower usage rates while others would like to enjoy the benefits of transportation but the high fixed charge can present a barrier. The Company explains its proposed transportation administration charge covers both the incremental costs of new transportation customers and a share of the fixed costs caused by all transportation customers. The Company indicates the only significant change from past studies is the reduction of costs associated with the Company's industrial customer service representatives. These costs were reduced by 50 percent to reflect the reality that these employees would continue to have some responsibility for working with industrial customers in the absence of transportation. The Division supports the proposed reduction in fees indicating that all current transportation customers will benefit from the reduction in fees and some of the larger sales customers may also benefit if the costs of the administrative charges have kept them from moving to the transportation schedules.

We accept the Company's testimony regarding the cost basis for these administrative charges. As no party opposes this proposal and we are generally in favor of removing barriers to customers desiring transportation service we approve this change to administrative charges with the exception of the FT-2C contract noted below.

D. UTAH GAS TRANSPORTATION CONTRACT

The FT-2C is a special contract that came to the Company with the purchase of the Utah Gas system in 2001. In its electronic model the Company shows no change to the volumetric rates of the FT-2C contract. It did, however, reflect the Company's proposed BSF and administrative charges in the revenues collected from this customer. No party provides testimony on this contract. In direct testimony the Company testifies the contract rates will remain the same until the terms of the contract expire,[15] and at hearing, the Company testifies

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[15] QGC Exhibit 7.0, page 6, line 159-160.

these rates cannot change.[16] These testimonies contradict the Company's treatment of fixed charges for this contract in its electronic model.

Since the volumetric rates are fixed by the terms of the contract, and given our decisions to maintain the current BSFs and to reduce administrative charges, the net effect would be a decrease in revenues collected from this customer. We herein rely on the written and oral testimonies and find no change to the current rates of this contract shall be made in this case.

E. NATURAL GAS VEHICLES

In response to a Commission request, the Company, at hearing, provides an exhibit labeled "Questar Gas Proposed NGV Rates."[17] In this exhibit the Company presents a comparison of the NGV DNG rate reflecting both 50 percent and 100 percent of cost of service, both with and without Company-supplied gas (i.e., Wexpro gas). As reflected by our decision on NGV rates, the NGV rate in Appendix A of this document reflects the Company-calculated DNG rate at 50 percent cost of service for prices through June 30, 2009.

F. TRANSPORTATION BYPASS/FT-1 RATE SCHEDULE

Given its proposed BSFs, the Company prices the transportation bypass schedule, FT-1, by applying a uniform percentage increase to the block rates in order to achieve the FT-1 revenue target. Based on our previous decision on BSFs and revenue spread, we also obtain the revenue target by applying a uniform percentage increase to the block rates.

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[16] Transcript of Hearing Proceeding dated October 14, 2008, page 45, lines 1-4.

[17] Exhibit accepted into the record as Commission Exhibit One.

G. MUNICIPAL TRANSPORTATION

Given the Company-proposed BSFs, the Company prices MT by increasing the single block rate. Based on our previous decision on BSFs, administrative charges and revenue spread, we also obtain the revenue target by increasing the single block rate.

H. FIRM SALES SERVICE

We have previously determined BSFs will remain unchanged. Therefore herein we address the volumetric revenues necessary to achieve the spread of revenue targeted for the FS schedule. The current FS rate structure consists of three volumetric blocks. These blocks are: 0 to 175 decatherms, greater than 175 to 875 decatherms, and greater than 875 decatherms. The Company proposes to increase these blocks to: 0 to 200 decatherms, greater than 200 to 2,000 decatherms, and greater than 2,000 decatherms. No party opposes the Company's proposed changes to the FS schedule block structure and therefore we accept them.

For winter rates, the Company proposes that the rate for the second block be 80 percent of the rate of the first block, and the rate for the third block be 90 percent of the rate of the second block. The Company also proposes a uniform winter-summer differential based upon its peak demand cost of the FS schedule. For each block the summer rate is simply the winter rate less the winter-summer differential.

The Division, using the Company's proposed blocks for the FS schedule and current rates for the old blocks in the F-1 schedule, proposes a uniform increase of 19.77 percent for all blocks with the exception of the winter third block which it increases by 33.46 percent. This combination allows the Division to achieve its target 10 percent increase for the FS schedule.

This approach maintains the winter-summer differential for the first and second blocks and increases the winter-summer differential for the third block.

Since we have accepted the Company's proposed FS block structure which results in a large increase in the top-end of the second block (i.e., from 875 decatherms to 2,000 decatherms) and in the start of the third block (i.e., from greater than 875 decatherms to greater than 2,000 decatherms), the rate relations based on current blocks used by the Division are less meaningful going forward. Therefore we accept the Company's proposal, with the exception of the winter-summer differential which we next address.

The Company is proposing a uniform winter-summer differential for all blocks based on the cost of peak demand for this schedule identified in the Company's cost-of-service study. This approximately quadruples the winter-summer differential. The effect of the Company's proposal is to put the revenue change primarily in the winter rates. Given the limitations of the cost-of-service study noted above and the magnitude of the proposed change, we decline to adopt the Company's proposal to increase the winter-summer differential at this time. We find the relative winter-summer differential in current rates reasonable and these relative proportions shall be maintained in calculating the new rates in this case.

Based upon our decisions on revenue spread, BSFs, block relations, and the relative winter-summer differentials in the blocks, we need only calculate the FS winter rate for the first block.

I. F-4 RATE SCHEDULE

The F-4 schedule is available to customers whose load factor is 80 percent or greater and whose usage does not exceed 10,000 decatherms in any one day during the winter season. As discussed above, we do not eliminate this schedule until the next DNG rate case. The current F-4 schedule consists of two blocks, 0 to 10,000 decatherms, and all over 10,000 decatherms and we retain these blocks. We obtain the revenue target by applying a uniform percentage increase to the block rates.

J. INTERRUPTIBLE SALES SERVICE

We have previously decided in this Order to eliminate the IS-4 rate schedule currently available to commercial and industrial customers in the new service extension areas. The five customers currently taking service under this schedule will be moved to the I-4 schedule, which is now renamed IS.

Currently I-4 and IS-4 consist of the same three blocks. These blocks are: 0 to 875 decatherms, greater than 875 to 122,500 decatherms, and greater than 122,500 decatherms. For the IS schedule the Company proposes new blocks. These blocks are: 0 to 2,000 decatherms, greater than 2,000 to 20,000 decatherms, and greater than 20,000 decatherms. For the ISE schedule, the Company proposes maintaining the current first block, changing the second block, and sets the third block equal to the same block as the IS schedule. These blocks are: 0 to 875 decatherms, greater than 875 to 20,000 decatherms, and greater than 20,000 decatherms. The Division proposes no blocks for its interruptible sales schedule.

With respect to volumetric rates for the IS schedule, the Company proposes the rate for the second block be 92 percent of the rate for the first block and the rate for the third block be 92 percent of the second block. For the ISE schedule, the Company proposes the rate for the first block be increased by the overall system average revenue increase and the rates for the second and third blocks be equal to the rates of the second and third blocks of the IS schedule. The Division proposes a flat volumetric rate for all usage for the combined IS and ISE schedules.

The Company's proposal emphasizes equity among customers whereas that of the Division emphasizes efficiency and conservation. In this case, the Company testifies the structure of the old blocks was undertaken many years ago and no longer reflects the current characteristics of customers. We are persuaded there is a sufficient variety of characteristics among the customers within this schedule to warrant the Company's proposed declining block structure of rates in this case. In the future, in order to assess the tradeoff between the equity and efficiency objectives, we require further information regarding the characteristics of the customers in this class.

Based upon our decision to eliminate the IS-4/ISE schedule and our decisions on revenue spread, BSFs, and block relations, we need only calculate the rate for the first block of the IS rate.

K. FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICES

The Company proposes to combine the firm (FT-2) and interruptible (IT) transportation service schedules, into a single, new Transportation Service (TS) schedule while maintaining a separate schedule for transportation customers in the new service extension areas. The difference between the rates for firm and interruptible customers under this new schedule results from the recovery of peak-demand costs through the use of a contract demand rate. The Division supports the Company's proposal regarding the combination of firm and interruptible transportation services into one schedule.

We have previously decided in this Order to eliminate the IT-S rate schedule currently available to transportation customers in the new service extension areas. There is currently only one customer on this schedule. This customer will now be moved to the new TS schedule. In addition, as previously discussed, the Company also proposes to eliminate the sales schedule F-4 and move those billing units to the TS schedule. Since we do not eliminate this schedule until the next DNG rate case we remove the F-4 billing units from the Company's TS billing units and price the F-4 schedule separately, as indicated below.

The Company proposes four blocks for the TS schedule which are: 0 to 20,000 decatherms, greater than 20,000 to 100,000 decatherms, greater than 100,000 to 500,000 decatherms, and greater than 500,000 decatherms. The Division proposes no blocks for its transportation schedule.

For pricing purposes, the Company proposes the rate for the second block be 75 percent of the rate for the first block, the rate for the third block be 80 percent of the second block, and the rate for the fourth block be 40 percent of the third block. The Division proposes a flat volumetric rate for all usage. It notes the demand charge was develop to cover the fixed costs previously recovered in volumetric rates and the block rates for the current IT schedule are essentially flat.

Like the IS schedule, the Company's proposal for this schedule emphasizes equity among customers whereas again the Division emphasizes efficiency and conservation. The Company argues the Division's proposed flat volumetric rate for this schedule is unreasonable in a rate class in which the differential from the smallest to the largest customer is significant. Absent any other testimony, we accept the Company's testimony that the variety of characteristics among the customers supports a declining block structure of rates in this case. Like the IS schedule, in the future, in order to assess the tradeoff between the equity and efficiency objectives, we require further information regarding the characteristics of the customers in this class.

The Division observes the current firm and interruptible transportation customers currently pay different BSFs for categories two, three, and four. Because 70 percent of TS customers will come from the current interruptible transportation schedule, the Division recommends the BSFs for the new TS schedule be those of the current interruptible transportation schedule. We accept the Division's proposal and we recognize the change in revenues received from BSFs in calculating the rates for the new TS schedule.

The Company proposes to distinguish firm from interruptible service in the TS schedule by means of a contract demand rate for firm transportation service. The Company calculates this rate by dividing the cost of peak demand obtained from the Company's cost-of-service study by the contract demand of firm transportation customers. The contract demand is also the amount used in the formation of the peak demand allocation factor for transportation services. The resulting contract demand rate calculated by the Company is $18.79 per decatherm and by the

Division is $18.86 per decatherm. The slight difference in these rates is due to the differences in the peak demand costs of the transportation services. Since we are accepting other elements of the Company's proposed TS schedule at this point and there is no other opposition to this proposal, we accept the Company's position in this case.

Based upon our decision to eliminate the IT-S schedule and our decisions on revenue spread, BSFs, administrative fees and block relations, we need only calculate the rate for the first block of the TS rate.

L. GENERAL SERVICE

As discussed above, we do not accept the positions of the Company, Division, Committee, and UAE regarding a split of the GS-1 schedule in this case. Rather we retain this schedule in its current form. Further we accept the Division's proposal to eliminate the GSS rates. Since we also have accepted the Division's proposal regarding EACs, the 82 customers of New Harmony will no longer be required to pay the extension area charge. We recognize this amount of revenue decrease previously approved in calculating rates for the GS-1 schedule necessary to meet the spread decision above.

In order to move the GSS customers to the existing GS-1 rate schedule we assume the following characteristics of the GSS customers are equivalent to those of the GS-1 customers: 1) the percent of residential and commercial customers; 2) the percent of residential and commercial customers paying BSFs; 3) the distribution of residential and commercial customers to BSF meter categories; and 4) the distribution of seasonal usage into blocks.

The Company proposes the same winter-summer differential for its proposed GSR and GSC schedules based upon the peak demand cost of these schedules in its cost-of-service study. The proposed differential is two to three times higher than what is in current rates. Based on its cost-of-service study, the Division proposes a smaller winter-summer differential for the GSR schedule and GSC schedules than does the Company.

The Committee recommends the relative winter-summer differentials should not be increased since the proposed differentials are too significant relative to their historic trends, and summer usage is beginning to increase considerably, a trend which is likely to continue, as more electric generation is fired by natural gas. The Committee maintains the differentials as proposed by the Company and the Division lack cost justification and are inconsistent with the Commission's policy direction over the past two years in the DSM and CET proceedings. AARP et al. recommends maintaining the existing absolute winter-summer differential.

Given the limitations of the cost-of-service study noted above and the magnitude of the proposed change, we decline to adopt the Company's proposal to increase the winter-summer differential at this time. We note one of the issues discussed by the cost allocation and rate design task force was winter-summer rate differentials. The report of this task force on this issue contains no information which is helpful to us in this case. While we do agree it is appropriate to measure cost responsibility using peak demand concepts, it may be a different matter to recover peak demand costs only during winter months. Peak demand costs are associated with facilities and equipment which have life-times of several decades. In the Company's cost-of-service study, peak demand costs represents approximately 9.5 percent of DNG costs. DNG costs, in turn, are approximately 25 percent of a typical residential customer's bill (for the FS schedule DNG costs are in the neighborhood of 7 percent of a customer's bill). Hence, peak demand costs account for less than 2.5 percent of a typical residential customer's bill. In addition, in the 191 pass-through account, the winter and summer costs of producing, purchasing, gathering, transporting and storing natural gas are averaged over all usage throughout the year. The price signal to the customer inherent in his bill reflects two notions: one is appropriate cost recovery, the other is an incentive for efficiency and conservation. In either case, it is inappropriate to focus only on DNG costs for a seasonal differential We are unwilling to modify the winter-summer differential in DNG rates without a consideration of an appropriate winter-summer differential in the context of all rate elements that comprise the customer's bill. We look forward to the parties informing us in the future as how best to achieve the objectives of appropriate cost recovery and incentives to efficiency and conservation considering we have redesigned the regulatory apparatus by approving the CET pilot as a means to encourage the Company to undertake DSM on behalf of the customers.

We find the relative winter-summer differential in current rates reasonable and these relative proportions shall be maintained in calculating the new rates in this case.

Based on our decisions on BSFs, the EAC for New Harmony, the elimination of the GSS schedule, winter-summer differential and revenue spread, we achieve the revenue target by applying a uniform percentage increase to the existing block rates, including the winter-summer differential.

M. CONSERVATION ENABLING TARIFF

All parties note that an additional increase in the GS-1 schedule is necessary to recover the Company's projected $11.2 million test period imbalance in the CET. As of the end of October 2008, 10 months into the test period, the balance in the CET account as reported by the Company is $938,970. Although no party addresses this forecasting error, we decline to increase GS-1 rates to recover the Company's projected imbalance of $11.2 million in this DNG rate case. Any end-of-year imbalance in the CET will be dealt with in a subsequent CET proceeding.

As a consequence of this decision it may be necessary to change the percentage increase in the allowed DNG revenue per customer per month from that authorized in Phase I of this proceeding.

The Company recommends two changes to the CET allowed revenue per customer. First, the Company proposes to divide the allowed revenue per customer into residential and commercial components, matching its proposed split of the GS-1 schedule into residential and commercial schedules. Second, the Company proposes a monthly shape for the allowed revenues per customer based on an average of the last three years. Since we have declined to accept the Company's proposed GS-1 split and for the purposes of ensuring consistent data to evaluate the effectiveness of the CET pilot program, we decline to accept these changes.

One of the difficulties in this case has been the Company's revenue forecasts. In Phase I of this proceeding, the Company provided a forecast of test year revenue based on the CET allowed revenue per customer, wherein only a forecast of the number of customers is needed. However, for the cost of service and pricing in Phase II of this proceeding, the Company provided revenues based on a forecast usage at tariff rates. The purpose of a rate case is to establish new tariff rates sufficient to enable the Company to recover the difference in revenue requirement and what the Company is collecting from customers at current tariff rates – not the difference in revenue requirement and what the Company is allowed to collect under the CET. We require in the Company's next rate case that its forecast of revenues in the revenue requirement phase of the proceeding be based not on the CET allowed revenues per customer and a forecast of the number of customers, but instead on a forecast of usage and the tariff rates.

V. MISCELLANEOUS POLICY AND TARIFF-RELATED ISSUES

A. INTRODUCTION

The Company, the Division, UAE and AARP et al. provide testimony on issues relating to service charges, the line extension policy, tariff restrictions, gas balancing charges, tariff component breakout, rate-change proposal filings, formation of a low-income task force, and tariff liability wording which we discuss herein.

B. SECURITY DEPOSIT

The Company proposes two changes to the residential security deposit requirements contained in Section 8.03 of its Utah Natural Gas Tariff ("Tariff"). First, for applicants with no payment history or applicants with less than twelve months of satisfactory payment history (i.e., consecutive, timely payments), the Company proposes the Section 8.03 specify that the Company may require a security deposit equal to the highest monthly charge at the premises over the last 12 months. The Company's current Tariff does not address these types of applicants. Second, for residential customers with poor credit[18] the Company proposes the Tariff specify that the Company may require a security deposit equal to two times the highest monthly charge at the premises over the last twelve months. The Company's current Tariff limits the security deposit for residential customers with poor credit to one times the highest monthly charge at the premise over the last 12 months.

The Company maintains these changes will help reduce bad debt expense and provides data indicating the proposed increase in the average deposit for poor credit customers would be closer to the average amount of a poor credit write-off. The Company claims the amount of security deposit it is allowed to collect is arbitrary and inadequate in direct relation to the potential risk of losses from new and poor credit customers and that approving the proposed changes takes an important step in the direction of more fully mitigating these potential risks. The Company contends the proposed Tariff language will ensure that all new customers will be treated the same and all customers with poor credit will be treated the same. The Company reduced its revenue requirement by $179,000 to reflect these changes.

The Division supports the Company's proposed change with respect to applicants however it recommends the amount of security deposit for customers with poor credit history remain at the current level. The Division maintains the majority of people who find themselves in a poor credit circumstance are already struggling with strained financial resources. In light of current natural gas costs, the Division contends it seems unreasonable to impose an even greater

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[18] In this proceeding the Company proposes to change the definition of poor credit from "a customer whose service has been terminated for non pay, or who has a history of delinquency with the Company" to "a customer whose service has been terminated for non payment, or who is delinquent or has a history of delinquency with the Company."

financial burden on these customers by requiring an increase in security deposit that is greater than expected. In addition, the Division suggests it seems discriminatory to require a security deposit of the highest monthly bill for applicants with no credit history versus two times the highest monthly bill for customers with poor credit history as some of the applicants may very well be in the same circumstances as existing customers who may be required to pay double the amount for a security deposit.

AARP et al. recommends the Commission reject the Company's proposed changes to its security deposit requirements. AARP et al. maintains customers encompassed by the Company's definition of having poor credit are overwhelmingly likely to be low-income households and Questar's proposal would increase the number of customers obligated to provide a security deposit, both for new and existing customers. AARP et al. points out the current average security deposit is $140 and that the amount of security deposit would vary according to total natural gas costs, i.e., in years of high gas prices the security deposit would be even higher. AARP et al. contends these increased amounts have a profound effect on the low-income customers as not only do they pay larger security deposits but these customers are more likely to face service shut-offs and the attendant costs of reconnection, interest on past-due accounts, collection fees and all of the other costs associated with payment difficulties. In effect, while low-income customers use less gas than other customers, they pay much more due to the structure of these additional charges. AARP et al. suggests that bad debt in the form of arrearages and write-offs is more closely related to the amount of the bills received than anything else and that as long as a customer can pay at least the equivalent of commodity costs there is a benefit to having that customer on the system. AARP et al. argues the policy of imposing additional security deposit costs on low-income customers increases the likelihood of payment problems and will lead to even higher uncollectible amounts. Additionally, the loss of those customers who would remain on the system were it not for the additional security deposit is a loss in the contribution toward fixed costs that must be made up by other customers.

While we cannot ascertain the economic tipping point for any individual natural gas customer, AARP et al. explains how, once that tipping point is reached, financial obligations for natural gas service can quickly escalate not only for low-income customers, but also for any customer who should happen to fall behind in his or her bill for a couple of months.[19] We observe that the Company's current and proposed security deposit requirements can result in dramatic variability because of the relationship of the security deposit to natural gas prices, weather, and usage by either the customer or the previous customer of the residence. These dependencies can result in abnormally high security deposit requirements in one year and substantially lower security deposit requirements the next. In addition, as proposed by the Company, an applicant with less than twelve months of satisfactory payment history in the past is treated differently from a residential customer who has been delinquent. We acknowledge the Company's attention to bad debt expense. At this time, however, we concur with AARP et al. and decline to make any changes to the security deposit requirements. We encourage additional input on this issue as provided by the Low Income Task Force mentioned below.

[19]Section 9.06 of the Company's Tariff specifies that a bill for residential service is considered to be delinquent when not paid within 20 days of the date the bill is rendered.

C. AFTER HOURS RECONNECTION CHARGE

The Company proposes to add to Section 8.03 of its Tariff an after-hours reconnection fee for reconnection of service outside of the Company's normal business days or hours of operation. The Company maintains this change reflects the requirements of U.A.C. R746-200-6. Reconnection of Discontinued Service. The Company indicates that over the last five years it has only received occasional requests to perform after-hours reconnection and estimates that it will receive 15 to 20 requests annually for this service in Utah. The Company has included a $2,000 increase in revenue requirement adjustment for this new fee. While initially proposing an after hours reconnection fee of $100, in rebuttal testimony the Company accepts the Division's recommendation that the reconnection fee be set at $150, which is closer to the actual cost of providing the service. At hearing the Company explained that if a leak existed on the customer's side of the meter the Company would not disconnect the meter, they would only turn off the gas. The Company further explained that a licensed contractor could turn the gas back on at the meter as soon as the pipe was repaired. This circumstance would not require a disconnection or a reconnection as addressed in this rule.

The Division suggests the costs for after hours reconnection service should be closer to the estimated actual cost of $156 presented by the Company and therefore recommends a fee of $150 for after hours reconnection service. The Division also suggests additional language should be added to the tariff clarifying what hours constitute an after-hours connection and that the Company should explain whether there are any restrictions on how much notice customers must provide before a request for an after-hours reconnection fee is even considered. In rebuttal testimony, the Company proposed clarifying language changes.

AARP et al. recommends the Commission reject the imposition of an after-hours reconnection charge. AARP et al. maintains that the amount of the costs the fee will recover is simply too small. AARP et al.'s major concern is that imposition of this fee could result in a health and safety issue and if a modification to the Company's recommendation is to be made AARP et al. recommends the fee be waived if health and safety are at issue. At hearing AARP et al. recognized the distinction between turning the gas off and disconnection and with this information said it would need to study the matter further.

Our evaluation of this issue is two-fold. First, whether a separate fee for after hours reconnection should be imposed and if so, the appropriate charge for this service. Since Utah Administrative Code R746-200-6 requires public utilities to have personnel available 24 hours each day to reconnect utility service and the Company's Tariff provides options for avoiding termination of service during normal business hours, it is appropriate to implement an after hours reconnection fee for those parties who wait until the last minute to request reconnection of service. We observe that in addressing concerns regarding potential health and safety issues related to after hours reconnection, the Company explained the difference between turning off the gas to complete a repair, which can be done by a plumbing contractor, and disconnecting service, which must be done by a Company employee. To the extent there may be instances where after the imposition of an after hours reconnection fee might adversely effect the health and safety of an individual, we direct the Company to work with interested parties to identify such circumstances for which after hours reconnection fee would not apply, provide the appropriate training to its staff, and notify the Commission of the result of this work group by March 31, 2009.

With respect to the charge for after hours reconnection, the Company estimates the cost of this service to be $156.93 consisting of $34.14 for equipment and $122.79 for labor. In reviewing this proposed charge with respect to the other connection charges listed in the Section 8.03 Miscellaneous Charges, we observe that a full connection fee is $30 and a limited connection fee is $8. It is obvious that these fees do not include equipment charges. In our view a Questar field employee must have a vehicle and other equipment to perform his or her job regardless of the number of reconnections that he/she completes. Therefore it is inconsistent to include equipment charges in the proposed after hours reconnection fee while not including them in other fees. We conclude that an after hours fee of $100 as initially proposed by the Company is appropriate for this service.

D. LINE EXTENSION POLICY

The Committee recommends a decrease in the Company's construction allowances for residential mains, residential service lines, and commercial customers specified in Sections 9.02 and 9.03 of the Company's Tariff. These changes would result in an increase in a customer's contributions in aid of construction ("CIAC"). Specifically the Committee proposes a decrease in the construction allowance for residential mains from $645 to $560, for residential service lines from $364 to $150, and for commercial customers from $1,572 to $1,395. The Committee indicates that a line extension policy is designed to recover excess costs from new customers connecting to the system and that by charging new customers CIAC associated with the higher cost of a new connection relative to the embedded cost, the inter-generational inequity between old and new customers is minimized.

The Committee provides an analysis in Exhibit CCS-5.11 of the Company's main and service extension allowances and an analysis of the cost to serve new customers relative to embedded costs. We note, however, that the sources of the data used in this exhibit are undocumented as required by U.A.C. R746-100-10.F.2.c. The Committee proposes that when the cost to serve new customers is substantially more than the cost to service existing customers the discrepancy can be resolved by recalibrating the Company's main and service extension policies such that the amount of CIAC collected from new customers is closer to the difference between current costs and embedded costs.

The Company disagrees with the Committee's proposal on CIAC. The Company explains that CIAC was discussed and debated in great detail in Docket No. 02-057-02 and contends the Commission approved an extension policy that brought back into balance the relationship between new and existing customers consistent with what historically had been allowed. The Company suggests the Committee's desire to have new customers increase their CIAC for new facilities is in fact occurring naturally in that when the total cost to install the main, service line and meter increases, the allowance provided by the Company to new customers as a percentage of their total cost becomes smaller. The Company believes the only change that makes sense is to increase the construction allowances in order to preserve the same relationship or balance between what customers have historically paid for this service and what they are currently being asked to pay for this service. The Company is not recommending this change at this time but recommends the issue be reviewed in the next general rate case.

As in the 2002 rate case, CIAC is again a source of controversy as the Committee advocates a decrease in the CIAC allowance to minimize intergenerational inequities and the Company advocates a future increase in the CIAC allowance to ensure that new customers pay the same historic average percentage of construction costs. In Docket 02-057-02 we note that while the Company proposed a methodology for determining the CIAC allowance, the construction allowance issue was resolved in the settlement process as reflected in Stipulation 2 referenced earlier in this document. We concur with the Committee that the magnitude of the Company's construction allowances should be evaluated periodically, at least during every general rate case. In this proceeding, however, we find there is insufficient information to determine whether a change in the construction allowance is warranted. We agree with the Company that this issue should be reviewed in the next general rate case. We therefore direct the Company to prepare and file in its next general rate case an updated CIAC study through calendar year 2008, similar to that provided in Docket No. 02-057-02 Exhibit QGC 5.2, along with the Company's recommendation on proposed modifications to construction allowances.

E. LOW-INCOME TASK FORCE

AARP et al. recommends the Commission require Questar to meet with interested parties to develop a proposal to help low-income customers stay on Questar's system. The exact details of the proposal should be recommended by the parties in the next general rate case. AARP et al. maintains that both Questar and its customers are better off retaining those customers who can pay some of the costs of their service, so long as their payment exceeds the cost of the natural gas consumed.

In rebuttal testimony, Questar indicates its willingness to meet with parties to discuss low-income proposals that could be recommended in a future rate case or proceeding. As such, we direct Questar to convene a task force co-chaired by a representative of AARP et al. and including representatives from the Division and other interested parties, with the goal of identifying and evaluating ways to help low-income customers stay on Questar's system. The evaluation should include the effects of the proposed methods on other residential rate payers and the Conservation Enabling Tariff balancing account. The task force shall be convened by no later than February 1, 2009, and provide a report to the Commission on its research and conclusions preferably by the filing of Questar's next general rate case, if possible, but by no later than August 31, 2009.

F. RESTRICTIONS ON RIBBONING

As discussed earlier, we concur with the Company's proposal to eliminate ribboning between sales and transportation services schedules in the next DNG rate case. While we concur with the Company's proposal in concept, we find the Company's proposed wording in Section 8.01 misleading and unclear. For example, to implement this change the Company has added to its Tariff the sentence, "Customers will not be entitled to receive sales service and transportation service through one meter set." Yet the very next sentence states "Customers electing a combination of firm sales service, firm transportation service, interruptible sales service and/or interruptible transportation service may receive service under multiple rates through one meter."

The two sentences appear to be contradictory and as such we direct the Company to address this in the next DNG rate case when sales and transportation service ribboning is terminated.

G. GAS BALANCING CHARGES

The Company proposes two major changes to existing Tariff Section 5.11 dealing with transportation imbalances. First, the Company proposes to modify its language relating to the calculation of penalties applicable to daily balancing restrictions imposed by the Company. While no party has opposed this modification we recommend that the phrase "as defined in the glossary" be added after the words "monthly market index price and the gas daily market price" for clarity.

Second, the Company proposes changes to the treatment of monthly imbalances outside of the ± 5 percent tolerance window which have not been remedied within the fifteen day period after the close of the month. For positive imbalances, the Company proposes to change the terms to allow that the Company may purchase imbalances for the lesser of the transportation market index price or the commodity cost component of the Company GSR rate schedule, each less $1.00 per decatherm. Further, the transportation market index price and the GSR commodity price may, at the Company's discretion, be the price associated with either in the month the imbalance occurred, or in the month following the month in which the imbalance occurred.

Similarly, the Company is proposing that negative imbalances may be sold to customers for $1.00 per decatherm plus the greater of the transportation market index price or the GSR commodity cost component. In this case, the transportation market index price and the GSR commodity price may, also at the Company's discretion, be the price associated with either in the month the imbalance occurred, or either of the two months following the month in which the imbalance occurred. The Company's proposed Tariff modifications also specify that the transportation market index for deliveries made north of the Company's Indianola gate station is the Questar Pipeline index price, for deliveries at or downstream of Indianola is the Southern California Gas Company ("SoCal") index price, and for deliveries in Grand and San Juan Counties is the Northwest Pipeline-Rocky Mountains index price.

The Company maintains the current Tariff provisions do not always provide sufficient incentives for the transportation customers to stay within the imbalance tolerance window and in some circumstances, the current provisions provide incentives for customers to stay out of balance for a period of time. The Company explains the consequences of negative and positive imbalances and their potential impacts on the system and the Company's gas purchasing and gas management requirements. The Company argues the proposed cash-out provisions are specifically designed to prevent transportation customers from creating an imbalance situation to the detriment of the firm sales service customers. The Company testifies one Questar employee spends most of her time dealing with industrial customers and their imbalances.

UAE recommends the Commission reject both the Company's proposed changes to Section 5.11 which would provide the Company the option to cash out imbalances by selecting prices from multiple months and its proposal to apply SoCal index price for cashing out imbalances at or downstream of Indianola. UAE agrees with the Company it is important to encourage transportation customers to stay within the imbalance tolerance window but maintains the current tariff terms already provide a sufficient incentive for minimizing imbalances through the existing pricing penalties. The Company, in UAE's opinion, has not provided any evidence that additional penalties are needed or that the proposed pricing discretion it is seeking will improve the status quo in a just and reasonable manner. UAE contends that while the current Tariff prescribes specific economic penalties for customers who maintain an imbalance outside the tolerance band fifteen days after the close of the month, Questar is attempting to introduce a "shopping list" of pricing options that will allow the Company to exact an even stiffer penalty by selecting more adverse prices from subsequent months at the Company's sole discretion. UAE argues that adopting this provision will create an invitation for the Company to apply its discretion selectively, without a countervailing public benefit to justify departure from the current tariff's prescriptive terms

UAE also argues the use of the So-Cal index for cashing out imbalances for customers whose gas is delivered into the distribution system at or downstream of Indianola would enable the Company to purchase positive imbalances from affected customers at the Company's own commodity costs less a dollar and sell negative imbalances at the much higher So-Cal index plus one dollar. UAE maintains that transportation customers in southern Utah typically purchase their gas supplies in the Rocky Mountain markets and argues Questar's penalty is excessive and unduly punitive for these customers. UAE recommends that either the Questar Pipeline index price or the Northwest Pipeline (Rocky Mountain) index price should be used for this purpose.

We find that penalties and incentives must be both explicit and designed such that a specific behavior is achieved. In light of the fact that Section 5.11 of the Tariff has not changed in 10 years we find the Company's actions to modify this language appropriate as it attempts to clarify the applicable market index pricing. Based on the Company's testimony at hearing and the fact that one person dedicates most of her time dealing with industrial customers imbalances, we know imbalances do occur. The Company testifies that gas supplies delivered to the Company's WECCO tap will command prices that are consistently much higher than the Questar Pipeline Company or Northwest Pipeline Index hence the best surrogate price for gas delivered at WECCO off of the Kern River Pipeline is the SoCal Index. The Company explains that without being able to use the SoCal index as proposed, the Company will not always collect the necessary revenues via imbalance cashout charges to cover the costs associated with the corresponding imbalance. This situation results in the net costs being borne by the Company's firm sales service customers through the amortization of the 191 account.

While UAE argues that most of the transportation customers purchase Rockies gas and imbalances should be based on that price, in our view the penalty should not simply represent the transportation's customer cost for the gas, but the ultimate cost the Company incurs to the manage the imbalances within its system due to the actions of transportation customers. As the gas imbalance management process can be complex and the Company deals with these issues on a daily basis, we accept all of the Company's proposed changes to Section 5.11 with the exception that the Company change the references to GSR in the applicable section of the Tariff to GS-1, consistent with our decision to deny the Company's proposal to split the GS-1 class.

We also recognize UAE's concerns regarding the Company's discretion in applying this tariff provision. For instance, we observe that the Company has changed the wording in Section

5.11 from “. . . Any remaining imbalance will be treated in the following manner” to “ . . . Any remaining balance may be cashed out in the following manner.”. While “will” indicates a mandatory action, “may” indicates some level of discretion. In order to understand how the Company will apply this Tariff provision in a consistent manner we direct the Company to submit by February 15, 2009, a written explanation and procedures demonstrating how the Company ensures these changes will be applied uniformly and consistently to all transportation customers.

H. LIABILITY PROVISIONS IN TARIFF

The Committee recommends eliminating the language pertaining to liability and legal remedies in Section 7.02 of the Company’s Tariff. The current language of Section 7.02 addressing liability includes the following: “The customer will indemnify, save harmless, and defend the Company against all claims, demands, cost or expense for loss, damage or injury to persons or property in any manner directly or indirectly connected with or growing out of the serving or use of gas service by the customer, at or on the customer’s side of the point of delivery.” The Committee contends this provision greatly overstates the burden a customer should be expected to bear as it arguably assigns to the customer the risks inherent with use of a hazardous commodity, including the utility’s acts and omissions, negligent, reckless or otherwise. The Committee recommends the Commission eliminate this tariff language and that the Company should legally justify this language if it proposes it in the future.

The Company disagrees with the Committee’s proposal and indicates this wording has existed in the Tariff for over 30 years. The Company argues that the Tariff properly places that risk upon the person who bears the responsibility for ensuring the safety of natural gas appliances and equipment. The referenced portion of Section 7.02 ensures that customers are responsible for the facilities they own and maintain and as such the Company cannot be held responsible for equipment it does not own, has not installed, and does not have the right or obligation to maintain. The Committee counters that the language is overly broad and gives consumers responsibilities beyond what they can reasonably be expected to know and understand. In addition, the longtime existence of this language is not a reason to continue its existence. The Committee believes there are legal barriers to a regulated public utility conditioning service upon a customer agreeing to such onerous terms.

It is important to read Section 7.02 as a whole in considering Tariff changes to wording addressing liability. We agree with the Committee that the wording in the Tariff is overly broad when considering the Company's responsibilities relating to maintaining the integrity of its system and training of its employees. We therefore direct the Company to eliminate the words "save harmless, and defend" from paragraph two of Section 7.02. Further argument on this issue may be filed by parties in future proceedings.

I. BREAKOUT OF RATE COMPONENTS

The Division recommends the Company modify the way it presents the various rate elements in its Tariff. The Division proposes the Company present the various subcomponents of the DNG, supplier non-gas, and commodity components of the rates in its Tariff. The Company agrees with this recommendation. We concur with this recommendation and direct the Company in future Tariff sheets to provide a breakout of applicable subcomponents.

J. RATE CHANGE PROPOSAL FORMATTING

The Division recommends changes to the way the Company presents information in filings associated with rate adjustments. The Division proposes a specific format for presenting the rate changes. This format will provide summary documentation of the history of the rate changes in the filing so that parties are better able to track how rates are changing and in which dockets the rate changes are made. This format will also provide a complete record in the Company's filings of exactly how the new rates are derived and the impact those new rates will have on customers in relation to current rates. By incorporating these recommended changes into the Company's filings the application, review, and approval processes will be more straightforward. This allows parties to both analyze the processes as well as provide an historical tracking record of tariff changes. The Company agrees to implement this recommendation. We concur with this recommendation and direct the Company to implement such changes as agreed.

K. MISCELLANEOUS TARIFF ISSUES

1. Modifications to the Weather Normalization Adjustment

The Company proposes modifications to Section 2.07 of the Tariff dealing with the weather normalization adjustment ("WNA"). With this change the Company expands selection of weather zones used in the WNA calculation from three to eight and has provided the associated 30 year heating degree day average from January 1, 1977 through December 31, 2006 for each of the zones. The Division does not oppose these modifications. We concur with the Company's proposal. We note, however, the proposed wording regarding the weather zones is a bit vague in that the Tariff states ". . . In calculating the WNA degree days calculated from one of the Company's weather zones . . . will be used." The Tariff does not specify the weather zone applicable to each county. For the purposes of clarity and transparency, we direct the Company to specify in Section 2.07 the weather zone applicable to each county.

2. Budget Plan

The Company proposes modifications to Section 2.09 of the existing Tariff dealing with Budget Plan. The Company proposes to move Section 2.09 to a new Section 8.05, deletes wording regarding the design of the plan, and also changes the availability of the budget plan from "General Service customers" to "residential customers." This change was not specifically discussed by the Company in its testimony nor commented on by parties. We approve the Company's proposal to move Section 2.09 to Section 8.05. and delete wording on the plan design. However, as we have not approved the Company's proposed General Service residential/commercial split in this proceeding, we decline to approve the wording change limiting budget billing to residential customers at this time as the record contains no testimony regarding whether or not General Service commercial customers currently utilize the budget billing option.

3. Customer Obligations Regarding Company Rights-of-Way

The Company proposes to add a new Section 7.05 to the Tariff pertaining to customer obligations regarding rights-of-way and environmental issues. The proposed Section 7.05 clarifies the initial, as well as on-going, customer obligations to protect the Company's right-of-way from unacceptable encroachment or hazardous materials. The Company maintains these requirements have been the basis for the Company's right-of-way policies for many years and that the proposed Tariff modification will make the Company better able to enforce these requirements and to protect its pipelines and facilities. The Division recommends adoption of this change. We accept the Company's proposal and approve this Tariff modification.

4. Interruptible Purchase Volumes

The Company proposes a modification to Section 5.04 of the Tariff dealing with gas purchase arrangements during periods of interruption. With this change, the Company proposes to use the average of the three most recently confirmed gas-day nominations to calculate the required volumes available for purchase during an interruption. The current Tariff language uses the average of the confirmed gas deliveries over the most recently completed three days to calculate this volume. The Company maintains this change will allow it to use recent confirmed nomination data more relevant to the interruptions period to calculate the required volume of gas available for purchase during an interruption. The Division recommends adoption of this change. We accept the Company's proposal and approve this Tariff modification.

5. Complaint Procedures and Customer Service

The Committee recommends that Section 9.06 of the Company's Tariff applicable to Company/customer disputes be modified to include contact information for the Division and the Commission. The Company did not respond to this recommendation. We find that inclusion of contact information for the Division is helpful for customers and direct the Company to revise this Section 9.06 of the Tariff to include the Division's ten digit Salt Lake City complaint telephone number, toll free state-wide telephone number, and complaint procedure URL.

VI. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order the Company to:

1. Eliminate the GSS, IS-4, and IT-S rates and move these customers to the appropriate, non-expansion rate schedules;

2. Recalculate EAC payoff dates using a 6 percent interest rate;

3. Revise Tariff Section 9.02 to comport with the EAC decision contained herein, including payout dates no longer than the originally calculated payout date;

4. Eliminate the F-3 and T-1 rate schedules;

5. Rename and combine rate classes and schedules as discussed herein;

6. Eliminate the NGV Equipment Leasing program for new customers and make the appropriate tariff revisions;

7. Eliminate the F-4 rate schedule and modify Tariff Section 8.02 addressing restrictions on ribboning in the next DNG rate case as discussed herein;

8. Include all rate classes, schedules and contracts in the next cost-of-service study;

9. Reduce transportation service administrative charges as discussed herein;

10. File tariff sheets to effect the rate changes and Tariff decisions in this order including those relating to after-hours reconnection fees, gas balancing charges, liability, and other miscellaneous Tariff issues approved herein.

11. Form workgroups, modify filings and tariff sheets, and submit information and reports as discussed herein.

This Report and Order constitutes final agency action on Questar Gas Company's December 19, 2007, Application. Pursuant to Utah Code § 63-46b-12, an aggrieved party may file, within 30 days after the date of this Report and Order, a written request for rehearing or reconsideration by the Commission. Pursuant to Utah Code § 54-7-15, failure to file such a request precludes judicial review of the Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied. Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (Utah Code § 63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 22nd day of December, 2008.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#60171

APPENDIX A: COMMISSION PRICING DECISIONS

Basic Service Fees		no change
Administrative Charges		
Primary		$375.00
Secondary		$187.50
NGV Service		
Volumetric Rate, to June 30, 2009		$4.96031
Volumetric Rate, beginning July 1, 2009		$7.36392
FT-1 Firm Transportation		
1st block	0 - 10,000	$0.20353
2nd block	10,001 - 122,500	$0.18876
3rd block	122,501 - 600,000	$0.12551
4th block	over 600,000	$0.02773
MT Municipal Transportation		
Volumetric Rate		$0.64222
FS Firm Service		
Winter 1st block	0 - 200	$0.73516
Winter 2nd block	201 - 2,000	$0.58813
Winter 3rd block	over 2,000	$0.52932
Summer 1st block	0 - 200	$0.65741
Summer 2nd block	201 - 2,000	$0.51415
Summer 3rd block	over 2,000	$0.44676
F-4 Firm Sales		
1st block	0 - 10,000	$0.35463
2nd block	over 10,000	$0.34147
IS Interruptible Service		
1st block	0 - 2,000	$0.23461
2nd block	2,001 - 20,000	$0.21584
3rd block	over 20,000	$0.19857
TS Transportation Service		
1st block	0 - 20,000	$0.19940
2nd block	20,000 - 100,000	$0.14955
3rd block	100,001 - 500,000	$0.11964
4th block	over 500,000	$0.04786
Contract Demand		$18.79
GS-1 General Service		
Winter 1st block	0 - 45	$2.10193
Winter 2nd block	over 45	$0.87265
Summer 1st block	0 - 45	$1.77033
Summer 2nd block	over 45	$0.65719
Emergency Service		
Volumetric Rate		$1.75503