STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-12-07 APPLICATION OF THE SOUTHERN CONNECTICUT GAS COMPANY FOR A RATE INCREASE

July 17, 2009

By the following Commissioners:

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DECISION

The Department uses the most recent cost of gas to set the rate year cost of gas. Comparing the average cost of gas from the original filing of $11.50 Mcf to the updated cost of gas of $9.098 Mcf, ratepayers will save approximately $2.40 per Mcf. The reduction in the cost of gas reduces the carrying cost of gas associated with storage gas. Also, due to SFA, the Department increases total pro forma gas costs by $2,186,834.

I. DECOUPLING / SSC TRUE-UP

1. Decoupling

Decoupling refers to severing (decoupling) the link between a company's recovery of the distribution revenues approved by the Department in a rate application and the unpredictable volume of gas sales actually experienced following the implementation of new rates. If actual sales volumes exceed forecasted sales used to design rates, then actual revenues will exceed Department approved revenues, to the financial benefit of the company. Conversely, a shortfall in sales equates to a shortfall in revenues received by a company. Fundamentally, this misalignment of actually billed versus Department allowed revenues exists for all utilities that recover short-term fixed costs through any volumetric rate design. Volumetric rates continue to be used extensively to design Connecticut utility rates. The legislature addressed this issue in § 107 of PA 07-242 (Act) by requiring the Department to decouple gas and electric distribution revenues from sales volumes through one or more of the following strategies.

1. A mechanism that adjusts actual distribution revenues to allowed revenues.
2. Rate design changes that increase fixed distribution charges.
3. A sales adjustment clause, rate design changes that increase the amount of revenue recovered through fixed distribution charges, or both.

The Department is also required to consider the impact of decoupling on a company's ROE and make necessary adjustments thereto.

In the instant case, the Company proposed three decoupling strategies that fully decouple the Company's sales volume from its revenues.

1. A revenue true-up mechanism.
2. Increases in fixed customer charges.
3. Continuation of recently approved declining block volumetric rate structures.

Therrien, Simpson PFT, p. 7.

The revenue true-up mechanism is discussed here. Customer charges and rate structures are addressed in Section II.K. Rate Design.

The Company considers its decoupling proposal as "quid pro quo" ratemaking treatment that would allow it to enhance its commitment to conservation programs without hurting itself financially. Therrien and Simpson PFT, p. 10. The Company would increase expenditures for the programs referenced in the Joint 2009 Natural Gas

Conservation Program and monitor emerging high efficiency gas equipment for inclusion in such programs. Response to Interrogatory GA-294. Decoupling would also result in less frequent rate increase proceedings, saving time and expense for all parties. Therrien and Simpson PFT, p. 9. Current rate-making procedures no longer work because UPC has declined precipitously during recent history. Therrien and Simpson PFT, p. 8. Consequently, revenues obtained from new and existing customers during periods of declining UPC would not be sufficient to cover normal activities and afford the Company a reasonable opportunity to earn a fair rate of return. The Company's decoupling proposal would mimic current rate-setting procedures under a more stable UPC environment. Therrien and Simpson PFT, p. 14. Finally, the Company does not believe that any form of decoupling reduces business or financial risk for which equity investors require compensation. Consequently, no adjustment to ROE is required. Makholm PFT, p. 52.

The Company proposed modifying the existing CAM[3] to accommodate its usage-oriented decoupling true-up mechanism. Post-rate case actual monthly UPC would be trued-up to the monthly normalized UPC approved in the latest rate application. Each month's trued-up UPC would be multiplied by (1) the actual number of customers that month and (2) the volumetric rate[4] for the rate class in question. Interest, calculated at the Company's overall cost of money, would be added and the total trued-up revenue (debit or credit) would be booked. Annually, the accumulated net true-up for each rate class would be included in next year's CAM. The annual CAM would also include a deferral factor to recover prior year collection differences.[5] This new, expanded CAM (ECAM) would apply to all firm rate classes except Rate LGS, which the Company argues reflects too divergent a range in customer size to generate a meaningful class-average UPC. Rate LGS customers would continue under the existing CAM. Therrien and Heintz PFT, pp. 29 and 30.

The Company further explained that the proposed ECAM could result in a monthly credit adjustment to one rate class while another class experiences a debit adjustment. The proposed ECAM adjusts for all changes in sales while the added revenue from new customers is retained by the Company. Response to Interrogatory GA-310. Southern argues that new customer revenues must accrue to the Company as compensation for the costs of adding customers and to avoid creating a financial disincentive to adding customers. Response to Interrogatory GA-175.

OCC's position is that the Department should not approve the full decoupling proposed. But if a decoupling mechanism is approved, it should be an administratively simpler revenue decoupling model. Any decoupling reduces the net economic welfare of customers by shifting business risks from the utility and capital market to customers. Briden PFT, pp. 20 and 22. In turn, the reduced business risk should be rewarded by

3 The current CAM recovers Department approved Company conservation expenditures from customers by means of a standalone, Company-wide volumetric charge added to customer bills. It also employs an annual deferral mechanism to true-up collections.

4 June through September sales will be multiplied by the first block distribution rate. The second block rate will be used during the remaining months.

5 Being a volumetric rate, the CAM will over or under collect its target amount whenever actual sales deviate from assumed sales used to derive the annual CAM charge.

the capital markets in the form of a lower cost of capital, which translates into a lower revenue requirement. Further, customer revenue savings flowing from a lower ROE cannot adequately compensate customers for their assumption of risk under decoupling. The risk shifting effects of decoupling through rate design or a true-up mechanism are identical. Briden PFT, pp. 13-15. Finally, significant increases in rate design fixed cost recovery have already been made and that decoupling is not an effective means to promote conservation. Briden PFT, pp. 17-21.

AG believes that the Company's proposed full decoupling plan should be rejected in its entirety. The plan unfairly and improperly shifts the business risk of sales from the Company to customers. The risk should lie with the Company, whose ROE provides a cushion against fluctuations in sales. Brief, p. 16. AG argues that decoupling actually creates a disincentive for customers to pursue conservation and load management programs by denying the full bill reduction benefits of their conservational efforts. If the Department does approve decoupling, it should be a simple revenue tracker with a substantial reduction in ROE of at least 100 basis points. Further, a deadband, wherein 100% of the first 100 basis points of overearnings are returned to customers with a 50/50 sharing thereafter, should be implemented and on a trial-only basis. Brief, pp. 17 and 18.

ENE supports full decoupling and believes the Company should receive the full benefit of adding new customers. But unlike the Company's proposal, ENE prefers a revenue per customer (RPC) decoupling mechanism for all firm rate classes. According to ENE, a RPC approach would eliminate the need to choose a distribution block rate to calculate the revenue effect of a change in UPC. Also, basing the revenue-oriented decoupling true-up on a per customer basis would automatically credit the Company with new customer revenues. ENE believes that Rate LGS should be included in the Company's RPC as well. Leaving Rate LGS outside the true-up is not consistent with the language or intent of the Act. Brief, pp. 1-4.

The Department agrees with OCC and AG. The Company's full decoupling proposal compensates the Company for any type of reduction in consumption, such as warmer weather, customer loss, a deteriorating economy as well as permanent and price-induced conservation. The very large risk of revenue instability is shifted from the Company to the customer. Theoretically decoupling would benefit customers by providing bill credits during colder than normal periods, but the Company's firsthand empirical experience with the WNA belies this potential. On average, customers were at risk for $2.9 million during the WNA years for weather only fluctuations. Add to this a continuing loss in UPC as predicted by the Company plus the uncertainty of a faltering economy and customers, conservatively, are at risk for $4 to $6 million of annual revenue shortfall.

It will require at least a 100 basis point reduction in ROE (approximately a $4 million reduction in revenue) to provide customers with commensurate risk compensation. While decoupling can be expected, *a priori,* to reduce the frequency of rate applications and associated expense, the Company has not proffered any stay-out proposal. The enlarged conservation expenditures that the Company points to as the decoupling quid pro quo, will be paid for by ratepayers, who will also experience upward pressure on rates as UPC declines further. The Company's full decoupling proposal guarantees a revenue stream while providing the Company the freedom to file a rate application at will. Based on the aforementioned, the Company's full decoupling proposal is denied.

The Department chooses to satisfy the Act by means of rate design. Since the adoption of the COSS standard in 2000, the Department aggressively supported increases in fixed distribution rate designs, including the adoption of 100% cost-based customer and demand charges. In the instant case, customer and demand charges are being increased by the Department even as the overall level of proposed revenue is reduced. Earlier approved declining block rate structures are continued and the proposed volumetric Sales Services Charge (SSC) and Transportation Services Charge (TSC) are being converted to demand charges. Also, the Company's existing CAM, which compensates the Company for sales reductions from Company sponsored conservation programs, will continue going forward. Existing, time-tested rate-setting principles afford Connecticut gas utilities ample opportunity to provide safe and efficient service while offering a reasonable opportunity to earn a fair rate of return on investment. The Department notes that the Company has filed only two rate applications since 1999, including the instant case. The existing process has worked well for the Company.

2. SSC True-up

The Company proposed the establishment of a supplemental supply cost reconciliation mechanism (SSCRM). The Company defined SSCRM as consisting of three main items affected by the cost of gas: (1) commodity-related uncollectible expense; (2) gas inventory carrying charges; and (3) gas working capital. The proposed reconciliation mechanism or true-up would update the fixed revenue requirement established for each item in the instant rate case to reflect future actual expenses through a line-item bill adjustment mechanism similar to the existing CAM. The detailed mechanics of the true-up procedure were initially agreed to by Connecticut's three gas utilities in the Cost Allocation Decision. Marks, Rudiak, Therrien PFT, pp. 38 and 39.

The Department addressed this issue in the Cost Allocation Decision and declined to implement a SSC true-up. The Department sees nothing new that warrants a change in its earlier position. Therefore, the Company's proposed SSCRM true-up is denied.

J. Cost of Service Study

In general, a cost of service study (COSS) is a mathematical business model that systematically assigns cost responsibility among customer classes for the assets and expenses incurred by a local distribution company (LDC) to serve customers. Since the COSS culminates in summarizing customer, energy, demand and total costs by customer class, it is an invaluable tool for documenting equity and establishing revenue requirements and tariff charges by customer class.

In developing its COSS, the Company followed extensive cost allocation and apportionment rules established in the Decision dated August 9, 2000 in Docket No. 99-03-28, DPUC Review of Natural Gas Companies Cost of Service Study

Methodologies and in the Cost Allocation Decision. All revenue and expense data used in the COSS replicates the same data used in the Company's proposed accounting and financial exhibits. Supporting workpapers represent test year data drawn from Company books and records. Therrien, Heintz PFT, p. 12. The Company's revised COSS included modest adjustments for minor discrepancies that came to light during hearings. Response to Interrogatory GA-2, Supplement No. 2.

OCC was concerned with the mechanics of the COSS and the reliance on COSS results as it influences rate design. OCC cautioned the Department not to become overly reliant on COSS results, which may prove questionable in a contracting economy. They also recommended that uncollectible expense be allocated among rate classes volumetrically. Brief, pp. 182 and 183.

While the Department finds that the Company complied correctly with the vast majority of COSS allocation rules, several issues are discussed below for clarity. The question of allocating cost responsibility for uncollectible expense has been raised many times before. In each case, the Department has reaffirmed the existing allocation methodology, and hereby does so again. The logic and mechanics of the Company's revised COSS as filed in the response to Interrogatory GA-2, Supplement No. 2, is approved, except where noted below.

1. FT Working Capital

The Company incorrectly calculated FT working capital in its original COSS filing. Working capital on purchased gas demand costs was allocated between FT and sales customers on the basis of each group's relative merchant-based peak day demand. Of the total gas demand working capital of $7,152,399, $1,344,096 or 18.65% was assigned to FT and $5,818,304 or 81.35% to sales. These incorrectly assigned amounts were then allocated correctly among customer classes based on each classes merchant-based peak day demand. Response to Interrogatory GA-283.

The Department wants to ensure that the LDCs calculate demand cost working capital in accordance with the directives established in the Cost Allocation Decision. The main difference is the way in which cost responsibility is initially split between FT and sales customers. The Cost Allocation Decision stated that FT's shifted demand costs minus capacity release is the basis for assigning demand working capital to FT customers. These two values are found in the Company's latest shifted cost calculation filed in accordance with Order No. 2 of the Cost Allocation Decision. In the instant case, FT's demand cost working capital is defined as follows:

Shifted Demand Costs	$8,790,257
Minus Capacity Release	897,246
Equals FT Basis	7,893,011
FT Basis Average Day	21,625
Proposed Lead/Lag Days	52.37
FT Demand Working Capital	$1,132,501

Response to Interrogatory GA-283.

This approach assigns the same total working capital amount of $7,152,399 slightly differently: 1,132,501 or 15.83% is assigned to FT, while $6,019,898 or 84.17% is assigned to sales. While the dollar impact is minimal, the Company is directed to adopt this approach in its supplemental and future COSS filings.

2. Equal Merchant, Distribution Rate of Returns

The Company's initial COSS development of the SSC and TSC set the return earned on all merchant assets for all firm rate classes equal to the proposed system-average ROR. The Company adjusted its cost assignment methodology such that all merchant and distribution rate base items contribute the same ROR as the rate class in question. Since the resultant change in SSC or TSC revenue was negated by an offsetting change in overall distribution revenues, proposed class-level RORs did not change. Response to Interrogatory GA-303.

The Department believes that earning the same class-level ROR from all assets within a class, whether a merchant or distribution component, enhances customer equity by insuring all customers are assigned costs in accordance with similar asset utilization. The Company is directed to file its compliance COSS using equal merchant and distribution RORs within each rate class. The Department intends that the Company file its initial COSS and SSC/TSC rate proposal in future rate applications using equal merchant and distribution RORs as ordered here.

3. 100% COSS Demand Charge

The Company's initial filing of demand charges was technically confusing. The derivation of class specific distribution demand costs were calculated correctly within the COSS. However, summary costs were divided by demand billing units when calculating class-specific demand charges used in revenue proof exhibits. Schedule E-6, COSS, Exhibit 5; Schedule E-3.5.

The Department believes that demand charges should be derived using the demand units that constitute the demand allocator used within the COSS, which typically is different than pro forma demand billing units. This COSS-derived demand rate would then be applied to billing units to calculate demand charge revenues. This approach carries COSS derived demand charges forward to revenue exhibits without alteration, save possible GET, making the statement "100% COSS rates" technically accurate. The Department intends for the Company to use this convention in its supplemental and future COSS filings as well as in the revenue proof Exhibit VI worksheet, which provides the 100% cost-based rates.

K. Rate Design

1. Methodology

Southern proposed to assign a firm pro forma revenue requirement to firm rate classes using the COSS as a guide. Its objective is to collect rates in a fashion that more closely mirrors the way its costs are incurred as well as moving the ROR from each rate class closer to the system-average ROR. This action reduces subsidies between rate classes as well as within a particular rate class and provides more accurate price signals to customers concerning the cost of gas distribution service. The Company stated that it seeks to build upon the rate design approved in the Rate Design Decision. However, due to consideration of rate continuity and customer rate impacts, the Company is not proposing to completely move each class ROR equal to the system-average ROR or to implement pure COSS-based rates. Therrien and Heintz PFT, pp. 3 and 4.

Southern's distribution costs are mostly fixed and the short-run costs of providing distribution service are largely unaffected by changes in delivery volumes and/or peak demand. The Company believes these fixed costs should be recovered through rates that produce relatively constant revenues, such as the monthly customer charge, demand charge, and in the head block delivery charge. Accordingly, Southern proposed to recover a larger portion of its fixed distribution costs from increased customer charges for all rate classes and increased demand charges from the applicable rate classes in an attempt to better align its revenue recovery with its cost to serve its customers. Id. The proposed volumetric charges are the result of a combination of COSS considerations, movement towards more equalized rates of return among the rate classes, and bill impact considerations. Therrien and Heintz PFT, p. 19. Southern's proposed head and tail block breakpoints remain unchanged from those approved in the Rate Design Decision. A review of bill frequencies supports the continued use of these breakpoints. Id.

OCC requested that the Department take into consideration the overall business and economic environment, which limits the ability of consumers to pay ever increasing rates. First, OCC cautions that the results of the COSS may be questionable in a contracting economy. Second, the recent volatility of natural gas prices requires extreme caution in evaluating the reasonableness of the bill impacts from Southern's proposed rates. Third, with the extreme changes in rate design implemented on November 1, 2008 pursuant to the Rate Design Decision, there is no need to go to extremes in this case. According to OCC, if there was ever a case that called for the application of the rate design doctrine of rate stability, it is this case. As such, OCC recommends that the drop from the head to the tail block delivery charges be no more than 30%. Further, revenues should be allocated in such a way that all customers in all rate classes be treated evenly with regard to any increases/decreases. Brief, pp. 182 and 183.

In general, the Department has many of the same rate design goals as the Company. Proper revenue allocation between rate classes and increased fixed cost recovery help to minimize existing inter-class as well as intra-class subsidization. The Department has historically used rate design as a means to better provide revenue stability to the Company. This is especially evident in the more recent rate design Decisions issued in the last eight years. For example, the Department approved a $4.75 increase in the Customer Charge for Rate RSH, from $8.25 to $13.00, an increase of approximately 58%. See, Rate Design Decision. Despite the overall revenue requirement decrease approved herein, the Department continues to increase fixed charges across all rate classes, which satisfies decoupling of sales from revenue as required by Public Act 07-242 § 107.

Nonetheless, the Department agrees with OCC that rate stability is critical in this case. It is essential to consider customer impact, both in terms of individual rate components and most importantly as function of the total bill. First, many customers have experienced two substantial rate amendments since January 2006. As a result of the Amended Settlement Agreement approved in the Decision dated December 28, 2005 in Docket No. 05-03-17PH01, Application of The Southern Connecticut Gas Company for a Rate Increase – Revenue Requirements (2005 Decision), Southern's volumetric delivery charges were increased across-the-board on January 1, 2006. Once the rate design was finalized by the Rate Design Decision, the Department approved substantial increases to most fixed charges and allowed the Company to implement a declining block rate structure. Given the timing of the instant case, the Department is concerned about rate stability because less than one year has passed since the Company's most recent rates went into effect. The Department will address its concerns with various aspects of Southern's rate design proposal for each rate class individually rather than using a rule of thumb approach.

The Department finds that certain adjustments to the Company's revenue requirements in the instant case will require significant changes to the proposed class revenue allocations and proposed charges. Therefore, Southern will be directed to file a final rate design plan (Rate Design Plan) to the Department reflecting the revenue requirement level approved in the instant Decision. The Rate Design Plan shall include a COSS, revenue proof exhibits and a bill impact analysis. The Department will provide guidelines below for allocating rate class revenue and the basis for determining certain charges including customer and/or demand charges. To generate the approved revenue, an adjustment to the volumetric delivery charges may be necessary. The Department agrees with the Company that the current block breakpoints remain reasonable. In adjusting delivery charges for rate classes with dual blocks, Southern will allocate any adjustments in such a way as to reduce the differential between the head block delivery charge and the tail block delivery charge, depending on whether an increase or a decrease to the delivery charge is required. The Department used this allocation method in the past and found it to be fair and not unduly burdensome to either high or low use customers. To the extent there are any unintended adverse bill impacts resulting from the general rate design directives given by the Department, proposed modifications in the Rate Design Plan may be considered.

2. Revenue Allocation

Proposed revenues were allocated by the Company among rate classes based on a balance among several guidelines and criteria that relate to the design of utility rates. The criteria considered by the Company in determining revenue allocations include: (a) COSS results; (b) class contribution to present revenue levels; (c) customer impacts; and (d) the competitive market and general economic environment. Therrien and Heintz PFT, pp. 13 and 14. In general, rate classes with RORs above the system average were assigned a lower percentage increase than classes with RORs that were below the system average. These adjustments reduce or eliminate interclass subsidies and provide charges to customers that more closely reflect their cost to serve. Present and proposed rate class revenues and associated RORs for Southern are presented in the following table.

Total Revenue Requirement

Rate Class	Present Revenue	Present ROR	Proposed Revenue	Proposed ROR
RSG	$15,082,475	0.63%	$17,316,690	3.36%
RSH	$222,022,229	5.98%	$245,094,141	10.27%
RMDS	$12,366,570	7.92%	$13,053,444	10.86%
SGS	$30,951,377	2.38%	$36,193,975	6.77%
GS	$25,342,684	4.97%	$28,406,279	10.21%
LGS	$44,692,233	21.39%	$44,568,053	23.75%
Other	($250,626)	-	($246,331)	-
Firm Revenue Requirement	$350,206,942	6.47%	$384,386,251	10.51%
Special Contracts	$16,504,404	-	$16,504,404	-
Non-firm revenues and other	$17,690,900	-	$17,690,900	-
Total	$384,402,246	6.15%	$418,581,555	10.09%

Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit I.

For both Residential Service General (Rate RSG) and Rate SGS classes, the present RORs are significantly below the system average. The proposed ROR for Rate RSH, General Service (Rate GS), and Rate RMDS are moderately above the system average. The class revenue proposal for Rate LGS is significantly above the system average ROR. Southern proposed to increase the revenue allocations for Rate RSG and Rate RSH by 14.81% and 10.39%, respectively. The largest increase of 16.94% in total revenues is proposed for Rate SGS as a result of the reassignment of larger use customers in that class to Rates GS and LGS. The revenue increase assigned to Rate LGS shows a slight decrease of 0.28%. Id.

Although the Company stated it seeks to build upon the approved rate design from the Rate Design Decision, the Department finds that the proposed rate design is counterproductive to the progress made in that proceeding where half of the firm rate classes were within 1% of the system average ROR. The Department also approved a rate class ROR of less than 19.50% for Rate LGS. Increasing the proposed class revenue for Rate LGS to 23.75% reintroduces much of the cross-subsidies that previously existed among firm rate classes. Therefore, the Department directs the Company to decrease the proposed revenue allocation for Rate LGS in the Rate Design Plan such that the rate class ROR will continue to move toward the system average ROR. The remaining firm rate classes should continue to move toward the system average ROR as well.

As the final revenue figure will need to be reallocated to each rate class, the Department does not have the appropriate COSS information to approve actual rate class revenue; but can approve or provide guidance with respect to the rate class ROR. The Department approves the proposed ROR of 3.36% for Rate RSG. Although the instant Decision results in an overall rate decrease, revenue responsibility for this rate class should not be reduced as, historically, it has been heavily subsidized. The proposed class ROR for Rate RSH will be lowered to no more than the system average ROR approved herein. For the remaining rate classes, the proposed system average should be reasonably similar to the approved class ROR's relationship to the system average ROR from the Rate Design Decision, to the extent that this does not result in rate shock for any of these particular classes. The Department is concerned about the recent rate impact of Rate SGS resulting from the migration of large customers from this class. Therefore, any changes to this class should be modest. The Company will be directed to resubmit its class revenue allocations for Department approval as part of its Rate Design Plan.

3. Supply Charge

The Company set the supply charges at full COSS levels for all firm sales classes. Supply Charges are for illustrative purposes only, as gas costs are now recovered solely through the PGA. Therrien and Heintz PFT, p. 21.

The Department agrees with setting full COSS supply rates for each rate class, since this allocation methodology is consistent with prescribed PGA procedures. Bill comparisons at proposed and final rates in the instant case will best replicate actual bills that are calculated using PGA supply rates.

4. SSC/TSC

The Company proposed a volumetric SSC and TSC for all firm customer classes. Schedule E-3.5. As a general principle, the Company stated that it would not be opposed to establishing SSC and TSC demand charges for rate classes with a transportation service option (Rates RMDS, SGS, GS and LGS) because they already have a distribution demand charge. Nonetheless, the Company is not advocating for demand charges at this time. Southern is concerned about the effect of bill impacts, particularly for smaller customers. Response to Interrogatory GA-385. The Company did agree to implement SSCs and TSCs that were either 100% demand or commodity. Tr. 4/13/09, pp. 625 and 626.

The Department believes that equal SSC and TSC demand charges should be implemented for each of the three C&I rate classes. The analysis done in response to Interrogatory GA-385, which gave the Company concern over bill impacts and potential customer shift, is not representative of the situation that exists under final rates in the instant case. First, this interrogatory assumes Company proposed costs and ROR. Second, the analysis reflects the proposed full cost assignment of SSC and TSC costs among rate classes. In contrast, the instant Decision reflects a noticeably different set of costs, ROR and SSC-TSC COSS assignment among rate classes. The Company is directed to allocate SSC and TSC costs among C&I rate classes using the appropriate demand and commodity allocators to arrive at the correct revenue requirement for each rate class. All assets within a class will provide the same ROR as the rate class in question. The total class revenue requirement for both SSC and TSC will then be divided by the combined sales and FT peak demand to arrive at an equal SSC and TSC demand charge for each rate class. Rate RMDS will employ a separate volumetric SSC and TSC, while Rates RSG and RSH will employ volumetric SSC only. The Department believes that the introduction of a demand-based SSC and TSC satisfies the decoupling pursuant to Public Act 07-242 §107, while stabilizing gross margin recovery for the Company.

5. Residential Service Rates

Southern proposed to move toward more cost-based rates by increasing customer charges for all of its firm rate classes and adjust the demand charge for Rate RMDS. Therrien and Heintz PFT, p. 15. The proposed 100% COSS based customer and demand unit rates are as follows:

Rate	Customer	Demand
RSG	$49.11	-
RSH	$50.40	-
RMDS	$179.80	$1.3020

Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit VI.

The Company stated that the current customer charges for the residential rate classes collect less than one-third of the actual customer costs. Customer costs not collected through a customer charge but rather through a volumetric distribution charge send improper price signals and erode based delivery revenue as a result of declining NUPC and changes in weather. Therrien and Heintz PFT, p. 7.

a. Residential General

Based on the proposed revenue of $17,316,690, Southern proposed the following charges for Rate RSG: (a) a monthly Customer Charge of $19.75, an increase of $4.75 over the current charge of $15.00; (b) a single block Delivery Charge of $1.1500 per ccf, a slight increase over the current charge of $1.0928 per ccf; (c) a Supply Charge of $0.8317 per ccf; and (d) a SSC of $0.0144 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

In the Rate Design Decision, the Department approved a class ROR of approximately 3.0% for Rate RSG. As stated above, the Department approves maintaining the Company's proposed class average ROR of 3.36% for Rate RSG. This slight increase in class ROR moves the rate class closer to the system average ROR while limiting the bill impact associated with increased revenue responsibility for the rate class. Given the recent increases in revenue allocation and fixed charges for the Rate RSG class, the Department finds the proposed Customer Charge of $19.75 far too aggressive. The Department approves a Customer Charge of $17.00, a more modest increase of $2.00 over Southern's present Customer Charge of $15.00. This Customer Charge represents approximately 35% of the unit cost of $49.11 derived by the COSS. Further, the approved Customer Charge increases the Company's fixed cost recovery by approximately $591,044 (295,522 bills x $2.00). The Department believes that such an increase is necessary to recover fixed costs from low volume customers. The proposed Delivery Charge of $1.1500 per ccf will be adjusted to recover the allowed revenue for the Rate RSG class. The SSC shall be calculated in accordance with Section II.K.4. SSC/TSC, above.

b. Residential Heating

For Rate RSH, Southern proposed a monthly Customer Charge of $18.50, an increase of $5.50 over the current Customer Charge of $13.00. The proposed head block Delivery Charge was set at $1.0595 per ccf in the attempt to collect the remaining customer related charges not recovered through the monthly Customer Charge. Bill considerations also factored into Southern's proposed head block Delivery Charge. The proposed tail block Delivery Charge was set at $0.3995, a sufficient level to collect the remaining revenue requirement for the customer class not collected in the Customer Charge and/or head block Delivery Charge. Southern set the Supply Charge at $0.9868 per ccf and the SSC at $0.0783 per ccf. Southern's proposals for Rate RSH results in an annual revenue recovery of $245,094,141, an increase of 10.39% over present revenues. Response to Interrogatory GA-2 Supplement 1, Exhibits I and V.

The Department believes that Southern's proposed Rate RSH Customer Charge of $18.50 is excessive and would compromise rate stability for its largest class of customers. The proposed charge would result in an increase of $10.25 over less than a one-year period. Prior to the Rate Design Decision, the approved Customer Charge was $8.25. Because it had not been increased in many years, the Department allowed Southern to increase it by $4.75, or approximately 58%. Given the large increase in the Rate RSH Customer Charge approved in the Rate Design Decision, the Department believes a charge of $14.00 is more reasonable. The approved Customer Charge represents approximately 28% of the unit cost of $50.40 derived by the COSS. Further, it increases the Company's fixed cost recovery by approximately $1,595,928 (1,595,928 bills x $1.00). The Company will adjust its Delivery Charges to collect the remaining revenue allocation for Rate RGS class for Department approval in the Rate Design Plan. The SSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

c. Residential Multi–Dwelling

Southern's proposal for Rate RMDS results in an annual revenue recovery of $13,053,444. Southern proposed the following charges for Rate RMDS: (a) a monthly Customer Charge of $45.00, an increase of $10.00 over the current charge of $35.00; (b) Demand Charge of $0.4000 per ccf of demand, an increase of $0.3000 over the current $0.1000 Demand Charge; (c) declining block Delivery Charge head block of $0.3577 per ccf, and $0.1280 for tail block; (d) a Supply Charge of $0.9176 per ccf; (e) a SSC of $0.0844 per ccf; and (f) a TSC of $0.0802 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

The Department approves Southern's proposed Customer Charge of $45.00. The approved Customer Charge represents approximately 25% of the unit cost of $179.80 derived by the COSS. A slightly more modest Demand Charge of $0.3000 is approved at this time as this charge only had been implemented for this class within the last year. Once the customers in this class have had more experience with Demand Charges to understand the extensive cost savings available from peak day conservation, the charge for this class can be moved closer to full cost. The approved Customer Charge and Demand Charge increase the Company's fixed cost recovery by approximately $392,226 [(12,352 bills x $10.00) + (1,343,532 ccf of demand x $0.20)]. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

The Company also proposed to deploy DDM devices for all Rate RMDS customers. These customers historically have not been required to have DDMs for two reasons. First, until recently, Rate RMDS customers were not subject to a Demand Charge. Second, multi-dwelling properties were often subject to vandalism. The new technology, wireless DDMS, require only a small attachment to the existing meter and no phone line connection. Therefore the risk of vandalism is significantly lower. Further, daily usage information would now be available to these customers to assist with peak day management. This provides another conservation opportunity to a wider group of customers. The Company estimates that it will have approximately 1,029 Rate RMDS customers during the rate year. The proposed monthly DDM charge of $6.91 is pure cost based and grossed up for Residential GRT. The Company-proposed pro forma revenues of $85,352 related to DDMs for Rate RMDS. Therrien and Heintz PFT, p. 20; Response to Interrogatory GA-2, Supplement 1, Attachment 1, Exhibit V

The Company discussed the pros and cons of its proposal to require DDMs for all Rate RMDS customers with the alternative of using the current 500 Mcf annual throughput standard used for C&I customers. Out of 948 total Rate RMDS customers, the Company identified 607 Rate RMDS customers, or approximately 64%, that used more than 500 Mcf on an annual basis during the test year. The Company stated that one of the drawbacks to having the DDM requirement only for customers that use more than 500 Mcf annually is the loss of daily consumption data for this group and the corresponding reduction in accuracy when setting their maximum daily quantity (MDQ) value. Another drawback is the additional administrative costs that would be required to create and maintain a Rate RMDS sub-group. The Company would need to identify the customers that would be exempt from the DDM requirement, monitor their exemption status at some regular frequency, and code them differently than other Rate RMDS customers for billing purposes. Additionally it would potentially require the addition and removal of DDM devices as customers exceed or fall below the 500 Mcf threshold. The positive result of the alternative is that it removes the expense of the DDM devices from the bills of the smallest customers in this rate class. Response to Interrogatory GA-309.

The Department extends to Rate RMDS its long standing DDM requirement for C&I customers with annual consumption greater than 500 Mcf. Customers above the annual threshold would benefit from daily consumption data as they have a greater ability to modify daily usage than those customers with lower annual consumption. For smaller customers, the possible cost savings from modifying peak day usage are much less than the costs associated with paying a monthly DDM charge. As with Rate SGS customers, the algorithm used by Southern to determine the peak day usage for these customers is sufficient. Other than coding these customers differently for billing purposes, the Department sees no material change in how the Company handles these customers administratively. The Department notes that prior to the elimination of C&I customer rate choice, Southern previously maintained a sub-group of Rate SGS customers that were not required to have DDMs.

As stated previously the Company identified that approximately 64% of its Rate RMDS customers used more than 500 Mcf on an annual basis during the test year. To calculate the pro forma adjustment, the Department applied the same factor to total pro forma customers to determine the approximate number of customers subject to a DDM requirement. Based on the Company's pro forma estimate of 1,029 Rate RMDS customers during the rate year, approximately 669 (1,029 x 0.65) of these customers can reasonably be expected to have a DDM requirement. The Department approves pro forma revenue in the amount of $55,473 (669 x 12 x $6.91) related to the Rate RMDS DDM requirement during the rate year. This represents a decrease of $29,879 from the Company proposed revenues of $85,352.

6. Commercial and Industrial Services

The Company proposed further increases to its C&I Customer Charges to move closer to cost–based rates. Southern's proposal sets the Rate LGS Customer Charge equal to the COSS unit rate. The Company also stated that its proposed Demand Charges are set at full COSS unit rates for both Rates GS and LGS. Therrien and Heintz PFT, p. 15. The proposed 100% COSS based customer and demand unit rates are as follows:

Rate	Customer	Demand
SGS	$97.73	$1.4948
GS	$190.71	$1.3345
LGS	$258.07	$1.3410

Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit VI.

The Department notes that the Demand Charge for Rates GS and the Customer Charge and Demand Charge for Rate LGS were set by the Company at less than the proposed 100% COSS-based rates. As discussed in Section II.K.4. SSC/TSC, the Department modified the Company's approach in favor of carrying the COSS derived demand charges forward to revenue exhibits without alteration, save gross receipts tax (GRT), making the statement "100% COSS rates" technically accurate.

a. Small General Service

Southern's proposal for Rate SGS results in an annual revenue recovery of $36,193,975. Southern proposed the following charges for Rate SGS: (a) a monthly Customer Charge of $45.00, which is a $15.00 increase over its current charge of $30.00; (b) a Demand Charge of $0.4000, an increase of $0.1000 over the current charge of $0.3000; (c) declining block Delivery Charges of $0.7295 per ccf up to the first 100 ccf of usage, and $0.2950 for each ccf thereafter; (d) a Supply Charge of $1.0740 per ccf; (e) a SSC of $0.0498 per ccf; and (f) a TSC of $0.0771 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

The Department remains concerned about the negative rate impact that resulted from the direct assignment of high volume C&I customers out of Rate SGS as previously approved in the Rate Design Decision. As a result, the Department believes that a $15.00 increase for the Customer Charge for Rate SGS is far too aggressive, and believes one third of the proposed increase is more appropriate at this time. The

Department approves a Customer Charge of $35.00 for Rate SGS, which is just over 35% of the unit rate of $97.73 derived by the COSS. The proposed Demand Charge increase is modest, and therefore approved without modification. The approved Customer Charge and Demand Charge increases the Company's fixed cost recovery by approximately $1,031,257 [(174,476 bills x $5.00) + (1,588,766 ccf of demand x $0.10)]. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the Rate SGS class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

b. General Service

Southern's proposal for Rate GS results in an annual revenue recovery of $28,406,279. Southern proposed the following charges for Rate GS: (a) a monthly Customer Charge of $75.00, which is an increase of $15.00 over its current charge of $60.00; (b) a Demand Charge of $1.3345, a slight increase from its current Demand Charge of $1.1790; (c) declining block Delivery Charges of $0.2950 per ccf up to the first 300 ccf of usage, and $0.0995 for each ccf thereafter; (d) a Supply Charge of $0.9340 per ccf; (e) a SSC of $0.0682 per ccf; and (f) a TSC of $0.0784 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

The proposed Rate GS Customer Charge of $75.00 is reasonable, and therefore approved. The approved Customer Charge represents approximately 40% of the unit cost of $190.71 derived by the COSS. The approved charge increases the Company's fixed cost recovery by approximately $483,345 (32,223 bills x $15.00). The Demand Charge shall be 100% cost-based as determined by the COSS submitted in support of the Rate Design Plan. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the Rate GS class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

c. Large General Service

Southern's proposal for Rate LGS results in an annual revenue recovery of $44,568,053. Southern proposed the following charges for Rate LGS: (a) a monthly Customer Charge of $251.00, which is an increase of $58.00 from its current charge of $193.00; (b) a Demand Charge of $1.3410, an increase from its current charge of $1.1875; (c) declining block Delivery Charges of $0.1395 per ccf up to the first 5,000 ccf of usage, and $0.0385 for each ccf thereafter; (d) a Supply Charge of $0.7568 per ccf; (e) a SSC of $0.1377 per ccf; and (f) a TSC of $0.0826 per ccf. Response to Interrogatory GA-2, Supplement 1, Attachment 1, Exhibit V.

Southern's proposed class revenue for Rate LGS and resulting ROR of 23.75% remains significantly higher than the proposed system average ROR of 10.09%. It is the highest ROR of all the rate classes. Response to Interrogatory GA-2, Supplement 1, Attachment 1, Exhibit I. As previously discussed, the Department believes it is appropriate to reduce the proposed revenue allocation dramatically to reduce subsidization by this class. As it did in the Rate Design Decision, the Department approves a 100% cost-based Customer Charge and Demand Charge as determined by the COSS submitted in support of the Rate Design Plan. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the Rate LGS class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

7. Summary of Rate Design Changes

The Department believes the approved charges herein builds upon the rate design approved in the Rate Design Decision. Rate class revenue responsibility will be assigned in a fashion that reduces cross-subsidies between rate classes to the extent possible. Further, the Department approved increases in fixed charges for all rate classes that are not already at 100% cost based reduces intra-class subsidies and increases fixed cost recovery by the Company. Yet to be quantified, customer and/or demand charges for Rates GS and LGS that will be set by the Company's COSS with its Rate Design Plan. Initial customer and demand charges approved in the instant Decision increase the Company's fixed cost recovery by approximately $4.1 million. Actual fixed cost recovery will not be known until the Company submits its proposed Rate Design Plan. Increased fixed charges fulfill the requirements of Public Act 07-242 § 107 by decoupling sales from revenue. The introduction of demand SSC and TSC also decouples sales from revenue while stabilizing gross margin recovery for the Company.

8. Weather Normalization Adjustment

The WNA is a rate mechanism that adjusts the non-gas portion of customers' bills to offset the influence of weather on those bills. If weather is warmer than normal, the adjustment is upward (customers are charged a higher unit non-gas charge); if weather is colder than normal, the adjustment is downward (customers are charged a lower unit non-gas charge). To date, Southern has been the only Connecticut LDC to be allowed a WNA mechanism.

Southern's WNA was established by the Decision dated December 1, 1993 in Docket No. 93-03-09, Application of The Southern Connecticut Gas Company to Increase Its Rates and Charges, as a result of a settlement agreement among the Company, Prosecutorial Division of the Department (Prosecutorial) and OCC. The Department accepted this aspect of the settlement on the belief that the WNA mechanism "... provides both revenue protections for the Company and bill moderation for customers." Decision, p. 8.

In the first rate case proceeding following the establishment of the WNA, the Department reviewed the merits of the WNA and decided to allow its continuation by Decision dated January 28, 2000, in Docket No. 99-04-18PH02, DPUC Review of The Southern Connecticut Gas Company's Rates and Charges (2000 Decision). However, Southern's authorized ROE was reduced by 25 basis points, from 10.96% to 10.71%, to account for the earnings stability provided by that mechanism. During that proceeding, the evidence showed that Southern had benefited significantly from the WNA. For the five-year period (1994-1998) that the WNA had been in effect, the Company averaged an ROE of 12.64% with the WNA, an increase of 85 basis points versus an 11.79% ROE without a WNA. The Department viewed the ROE effect as "an accident of history" because the 5-year WNA period included two of the warmest years of that century. The Department was of the belief that the ROE would be reduced in future years when weather approached normal over the long term. The Department stated that "the revenue flows produced by the WNA should average out over the 30-year cycle, which is the basis for the determination of normal weather." 2000 Decision, pp. 69 and 70. The Department stated that it will continue to monitor the effects of the WNA on the Company and its ratepayers. 2000 Decision, p. 70.

During Southern's subsequent rate case proceeding, the Department sought to review the merits of continuing the WNA. However, in the 2005 Decision the WNA was continued as part of a settlement agreement among Southern, OCC, Prosecutorial, as well as Select Energy, Inc., and Amerada Hess Corporation. 2005 Decision, p. 13.

In the instant case, Southern proposed to eliminate the WNA only in the event its proposed decoupling mechanism is approved. Therrien and Heintz PFT, p. 5. See, also Section II.I. Decoupling/SSC True-Up, above. Southern stated that theoretically, the WNA should serve as a volatility smoother for deviations from normal weather and be of equal benefit to the ratepayers and the Company. Administratively Noticed Docket No. 08-12-06, Tr. 3/24/09, p. 1418. Southern acknowledged, however, that to date the WNA had not equally benefited ratepayers and the Company. Id., p. 1420. Southern benefits significantly from the WNA, which is currently in its 16th year. During this time, Southern received a total of $43.6 million in net WNA revenue through March 2009. Ratepayers benefited in only three of those 15-plus years. Responses to Interrogatories GA-141 Supplement, Attachment; and GA-138 Supplement, Attachment. Further, the Company's ROE benefited significantly. The table below shows the Company's ROE with and without the WNA for each year the WNA was in effect.

Year	% ROE With WNA	% ROE Without WNA	Difference
1994	11.97%	12.05%	0.08%
1995	11.34%	9.79%	-1.55%
1996	12.38%	13.52%	1.14%
1997	12.35%	11.71%	-0.64%
1998	11.53%	8.19%	-3.34%
1999	12.46%	10.48%	-1.98%
2000	12.74%	12.28%	-0.46%
2001	15.05%	13.80%	-1.25%
2002	8.49%	6.40%	-2.09%
2003	10.44%	11.57%	1.13%
2004	10.84%	10.45%	-0.39%
2005	7.42%	7.05%	-0.37%
2006	7.04%	5.13%	-1.91%
2007	11.93%	10.98%	-0.95%
2008	11.27%	9.84%	-1.43%
Average	**11.15%**	**10.22%**	**-0.93%**

Response to Interrogatory GA-141, Attachment.

As indicated, the average ROE with the WNA was 11.15% versus 10.22% without a WNA, an increase of 93 basis points (11.15% - 10.22%).

Based on the WNA history, OCC believes that it is fatally flawed and overwhelmingly in favor of the Company and against ratepayers. Brief, p. 178. However, if OCC could be assured that the WNA would serve as a volatility smoother and equally provide benefits to ratepayers and the Company, then OCC would have no objection to its use and may even favor it. Id., p. 176.

The WNA has not performed as the Department had believed it would when its continuation was allowed in the 2000 Decision. To date, the WNA has been one-sided in favor of the Company. As stated earlier, the Department was of the belief that the ROE would be reduced in future years and that the revenue flows would average out over the 30-year normal weather period. The WNA is now half-way through the 30-year averaging period and neither has happened. The 85 basis point average bonus to the ROE has now increased to 93 basis points and the Company is nearly $44 million better off with the WNA than without. Further, what was deemed an "accident of history" by the Department in the 2000 Decision has actually continued on a trend of warmer than normal weather in 12 of the 15 years since the WNA was established. Unless the weather pattern turns colder than normal for the majority of the remaining years of the 30-year cycle, the revenue flows will have little or no opportunity to average-out, and the benefit between ratepayers and the Company will not equalize as expected. Because there is no guarantee that the current weather trend will reverse itself, the Department finds that continuing the WNA would not be in the public interest. Consequently, the Department hereby abolishes Southern's WNA. Effective with new rates, Southern is directed to cease applying the WNA to customer bills. The Department reserves for a future proceeding any determination regarding the historic operation and financial impact on the company and ratepayers of the WNA.

L. MAXIMUM DAILY QUANTITY

The MDQ measures a customer's peak day consumption and is used to allocate class specific Demand Charges to individual customers. In the Rate Design Decision, the Department concluded that Southern's tariffs were clear and unambiguous regarding the calculation of the MDQ. Further, it concluded that Southern was not calculating the MDQ accurately or in accordance with its tariffs. Rate Design Decision, p. 34.

The failure to calculate the MDQ accurately or in accordance with the Company's tariffs has ramifications for the instant rate case. When designing new rates, the Demand Charge listed on specific tariffs is multiplied by the aggregate billed MDQ to determine Demand Charge revenue. If billed MDQs are misstated in this calculation, then demand revenue is also misstated. The resultant error in demand revenue is then built into other tariff charges to collect the correct total revenue. When MDQs are billed incorrectly, all other customers are affected through their respective tariff components. Miscalculated MDQs result in an over or under collection of revenue by the Company. To gauge the scope of the problem identified in the Rate Design Decision, the Department ordered Southern to file a MDQ analysis in Order No. 20. Southern was directed to calculate the revenue it did not collect during the test year. Order No. 20

was not a complete list of all of the billing records issued during the test year. It did not include customer bills that were issued based on estimated reads. Tr. 4/21/09, pp. 2166-2185.

In the instant case, Southern included a proposed positive revenue adjustment of $102,020 for Demand Charges not collected. Using Southern's exhibits, the Department applied the average daily use test as described in the tariffs, which was in effect during the test year, customers would have seen higher bills. The excel spreadsheets included in the Order No. 20 submission included 220,000 separate lines of C&I billing records for the test year. Rudiak and Therrien PFT, p. 23.

Southern stated that the MDQ is based on a customer's peak day usage during the winter months and is used to determine the Demand Charge. A DDM is used to measure the peak day consumption. If the customer does not have a DDM in place, the highest average daily usage during the winter is used. In April, the Company performs an annual review of each customer's November through March consumption to determine the MDQ to be used for the May bill. This MDQ is held consistent for the next 12 months. Tr. 4/21/09, pp. 2166-2185. During the April review, the billing department downloads "all of the data" associated with each of the 17,000 C&I customers' billing data into one file. Then a rate analyst reviews and evaluates the consumption data, and checks for reasonableness and accuracy of the MDQs. Throughout the review, management typically checks the data using specific tests related to customer load factor and verifies whether the MDQ results are reasonable. At the end of the April review, management performs a comparison to the previous year's data to verify that the new MDQs are reasonable. Tr. 4/21/09, pp. 2166-2185.

Southern agreed that the Rates SGS, GS and LGS tariffs require all C&I customers to pay Demand Charges. Tr. 4/21/09, pp. 2166-2185. However, if a MDQ is not determined correctly, that customer will not pay a correct Demand Charge. The Company sent out 456 bills to Rates SGS (161), GS (195) and LGS (100) customers with a billed Demand Charge of one during the test year. Response to Interrogatory GA-390. The Company testified that it did not send out bills showing zero MDQs during the test year. Tr. 4/21/09, pp. 2166-2185.

A MDQ of one means that a customer used, at most, one unit of gas each day for the billing period. Though Rate SGS customers have no minimum annual usage requirement, the class average usage is 1,042 ccf. Assuming a constant load, an average Rate SGS customer would have at a minimum a 16 ccf MDQ. The corresponding minimum MDQ for Rate GS is 89 ccf and Rate LGS is 391. However a customer could reasonably be charged a MDQ and Demand Charge of one if that customer was a new account and did not have any previous consumption data for the November through March period. Further, a customer could be assigned a one MDQ if the April review demonstrated the preceding winter's consumption did not produce a MDQ greater then 1 ccf. If the MDQ is less then 1 ccf, the computer program will default to a one and leave the MDQ space on the bill blank. Consequently, the Demand Charge will also default to zero. Administrative Notice Docket No. 08-12-06, Tr. 3/24/09, pp. 1365-1369.

Southern provided an exhibit that showed 362 bills were issued to Rate LGS customers during the test year with MDQs that were less then the minimum MDQ described above. Of these bills, 318 had MDQs of 1 ccf of which 23 were sent to one customer with multiple premises. The exhibit shows that 57 of the 362 bills were to accounts that did not have DDMs. The bills indicated that DDMs were installed on 305 (362 - 57) meters between 1999 and 2001. The exhibit also showed that 50 Rate LGS bills, each with a billed MDQ of 22 ccf, were sent to one customer with multiple premises with DDMs installed during 1999. Of these 50 bills to the same customer, 12 had a very large monthly consumption and 38 had zero monthly consumption. Response to Interrogatory GA-390. There was no explanation why an operating DDM would not record an accurate MDQ.

Southern's exhibit also showed that it issued 562 bills during the test year that were less than the minimum average for the Rate GS customer class. Of these 562 bills, 195 were issued with a MDQ of 1 ccf and 104 bills were issued with MDQs between 2 and 4 ccf. The exhibit shows that 91 bills had DDMs installed between 1999 and 2001, 33 bills had DDMs installed between 2003 and 2005 and the remaining 113 customers had DDMs installed between 2007 and 2008. The exhibit also showed that 322 bills were issued during the test year that did not have a DDM installed. Finally, the exhibit shows that Southern issued 161 bills to Rate SGS customers with a zero MDQ and a zero Demand Charge. Of these 161 bills issued, 22 had DDMs installed during 1999 and 2000. Response to Interrogatory GA-390. There was no explanation why an operating DDM would not record an accurate MDQ.

Southern provided its criteria to determine whether a customer should take service under Rates SGS, GS or LGS. Customers are placed on a specific rate based on the customer's actual or reasonably anticipated consumption. Southern listed the specific consumption requirements as part of the Company's tariffed Rates GS and LGS. Response to Interrogatory OCC-207. According to the Company, its policy is to apply the customer charge as of the date the meter is turned on and the gas flow is available for the customer. The MDQ and Demand Charge should be applied to all C&I customers' bills as of the date the meter is turned on and the Customer Charge is applied. Tr. 4/21/09, pp. 2166-2185.

There are three types of C&I customers where inexplicably low MDQ readings are problematic. First, existing customers who have received service for over one year. Second, transfer customers who become the occupant of existing premises where the service and meter are already connected to the distribution system. However, if the premises were vacant during the winter prior to the April review there would not be any historical consumption data for that premises and the billing program would default to a MDQ of 1 ccf. During the next annual review the customer's consumption during the winter would be included in the consumption data and used to calculate the MDQ for the subsequent 12 month period. Administrative Notice Docket No. 08-12-06, Tr. 3/24/09, pp. 1372 and 1380; Tr. 4/21/09, pp. 2166- 2185. Third, new customers who have never received service from the Company's distribution system. For these customers, Southern's sales and marketing department performs a Hurdle Rate analysis. This analysis includes estimated annual consumption and maximum hourly loads based on the customer's equipment, internal processes and hours of operation. The maximum hourly loads included in the Hurdle Rate analysis would be used by the engineering department to design the customer's service and would form the basis for the estimated MDQ until actual MDQ reads become available. Tr. 4/21/09, pp. 2166- 2185.

Southern testified that it used the data from Order No. 20 to calculate the revenue adjustments for the test year, pro forma, and rate year contained in the response to Interrogatory GA-390. That exhibit calculated a minimum class average MDQ by taking the minimum consumption included in the tariff for each of the relevant rate classes and dividing that number by 365 days. The exhibit then listed each of the C&I customers that did not meet this test. Then each of the MDQs, which were less than the minimum average, was replaced with the class average MDQ. This new MDQ was then multiplied by the appropriate rate for the class to equal the corresponding revenue adjustment. Southern's exhibit shows that 1,085 bills were issued that were less than the minimum MDQ as determined by the Department above. Of the bills issued with a MDQ of 1 ccf, 17.9% (195 / 1,085) were reasonably expected to Rate GS customers and 29.3% (318 / 1,085) Rate LGS customers. The exhibit also subdivided the respective rate classes into FT and sales categories. The exhibit estimates that the Company did not bill a total of $270,502 during the test year to C&I customers. Southern made adjustments in the pro forma revenues at present rates of $279,929 and at proposed rates of $318,529. Response to Interrogatory GA-390, pp. 21.

During the MDQ audit at its offices, the Department requested the Company submit more than 30 Hurdle Rate calculations to support their MDQ estimates. The Company submitted four. Response to Interrogatory GA-1 and ADRs 1-17. The Department calculated the total revenue that Southern should have billed during the test year using several methods. The most accurate method the Department could have used would be the sales and hourly loads for each customer included in the Hurdle Rate calculation. However, Southern testified that researching and providing the Hurdle Rate calculations for each customer with a zero or 1 ccf MDQ would have been an impossible task if it had Hurdle Rate calculations for these customers. If the Department were to use the Hurdle Rate calculations provided and extrapolate those to each customer class, the test year revenue adjustment would be between $429,000 and $1.38 million over the eight year period evidencing incorrect MDQ billings. The total revenue misallocation would be approximately $11 million. Interrogatory GA-392 required the Company to calculate a minimum class average MDQ based on the minimum consumption included in the tariff requirements for Rates GS and LGS and dividing that number by 365 days.

As a validity test, Southern compared those minimum class averages to each MDQ reported by the Company. The Company applied these to estimate the uncollected MDQ revenue during the test year to calculate its $270,502 test year revenue adjustment in the response to Interrogatory GA-390. This method seriously under-estimates the test year MDQ revenue adjustment because it assumes a highly improbable 100 load factor. Over the eight-year period evidencing incorrect MDQ billing, the total misallocation would be approximately $2.16 million.

The Department accepts the Company's test year revenue adjustment of $270,502 despite its methodological infirmities. The Department finds it improbable that the Company was unaware of the scope and size of the MDQ issue for so long. The Company was imprudent. Therefore, the Department reduces the Company's ROE by

10 basis points because of imprudence. In arriving at the imprudence penalty, the Department considered alternative options. The failure to bill and collect Demand Charges from the under billed customers also affects other customers; all else held equal, if revenues from the under billed customers are not included in rate case sales projections, the effect of understated sales is increased rates. To acknowledge the unfairness to other customers that results from uneven application by the Company of its tariffs, the Department considered requiring shareholders to contribute further to peak demand conservation programs. Additionally, the Department considered the possibility that higher rates to other customers also leads to higher uncollectible balances, and therefore contemplated a downward adjustment to uncollectible balances. The Department assumes that 10 basis points equals approximately $400,000.

Southern explained that its Hurdle Rate model, defined as a "SCG Capital Investment Decision Model," is a discounted cash flow analysis over a 34-year period that is used to calculate the annual cash flow for potential new customers. Southern performs a Hurdle Rate calculation for each potential customer that contacts the Company regarding possible connection to the distribution system. If a Hurdle Rate calculation results in a positive cash flow over the standard 10-year payback period, the customer does not pay a contribution-in-aid-of-construction (CIAC). The payment of a CIAC by a customer brings the Hurdle Rate calculation back to a positive value. The model calculates the revenues based on the currently approved tariffs. A customer's anticipated annual consumption must recover the capital investment necessary for them to be connected to the distribution system. The model also includes the impact of taxes and deferred taxes on the revenue for that customer. Response to Interrogatory GA-97.

The Company provided an excel spreadsheet for a hypothetical potential residential customer anticipated to take service under Tariff Code-1 1c. The example of the hypothetical customer's specific characteristics included: the annual base and heating annual consumption, service and meter costs, customer's peak day, full year gross margin, load factor, annual revenue and annual cash flow and the net margin for commission. The working excel spreadsheet showed the depreciation rates used in the Hurdle Rate model. The model indicated the following time periods over which certain items were depreciated: mains over 34 years, services 17 years and meters 23 years. Response to Interrogatory GA-97, Attachment 1.

The Company presented different depreciation rates in the Hurdle Rate model than in the Depreciation Study. Tr. 4/14/09, pp. 867-880. The Hurdle Rate model assumes that there is consistent revenue over the entire period of 34 years. The Company provided an example of a Hurdle Rate calculation for a hypothetical Southern residential heating customer on Rate 1C in North Branford. See, Response to Interrogatory GA-97, Attachment 1. The Company's Hurdle Rate model included a salesman's commission rate for residential rate classes of 45% and 15% for C&I rate classes. Southern Hurdle Rate model shows Net Margins for Commissions related to the specific residential customer used in the model was $406 and a corresponding first year gross margin of $894. The model shows that the internal rate of return (IRR) is based on a first year's revenue, which was reduced by revenues for the salesman's commissions. Response to Interrogatory GA-97.

During the hearings, the Company was requested to provide a proposed revision to the Hurdle Rate model using the straight line method of depreciating the capital investments included in the model and not use accelerated depreciation for a residential heating customer. The Company did not provide a comparison of the accelerated depreciation versus the straight line depreciation. Late Filed Exhibit No. 115, Attachment 1 and 2. Since the Company did not provide a revised Hurdle Rate using the correct depreciation rates, the Department was unable to review and determine whether the current Hurdle Rate model is appropriate. The Company is directed to use only Department approved tariff terms and depreciation rates in its Hurdle Rate model.

The Department believes that its sampling of the Hurdle Rate model inputs does not comport with the Department's expected calculation of the CIAC. Therefore, the Department intends to audit the Company's Hurdle Rate model process.

M. NON-FIRM MARGIN SHARING

The LDCs generate profits in the form of a NFM during the year by making sales utilizing seasonal excess pipeline capacity through on- and off-system sales, capacity release activities and optimization savings recoverable from the gas supply alliances or similar arrangements approved by the Department. The Department approves an annual NFM threshold for Southern based on the margins it is reasonably expected to earn from non-firm sales. The NFM achieved up to the threshold flows 100% to firm customers. The NFM earned in excess of the threshold is shared between Southern's ratepayers and shareholders at percentages of 86% and 14%, respectively, pursuant to Section G.3 of the Amended Settlement Agreement in the Company's last rate case proceeding.

In the instant case, Southern proposed no change to the NFM sharing percentages above the annual NFM Threshold. The Company stated that the current NFM sharing percentages provide the Company with the necessary incentive to maximize margins. Marks, Rudiak and Therrien PFT, p. 43. The Company believes that the current NFM sharing is an appropriate incentive to go beyond ongoing customer service, such as formulating monthly flex prices, tariff administration, managing curtailments, and other customer service functions through aggressive and creative NFM program administration. This includes significant marketing key account representation and support, as well as special contract negotiations. The Company also recognizes its obligations to maximize margins as a general premise and regulatory requirement given its funding of full cost of service through firm rates. Response to Interrogatory GA-369.

There has been considerable discussion in the past about the level of effort on the Company's part and the proper level of incentive the Company should be given to maximize NFM. The Company stated that up to 30-40% of these sales are attained with little administrative effort. The remaining 60% or so requires varying degrees of effort to attain, but mainly depend on the competitiveness of natural gas to alternative fuels. The last 5-10% of sales, in which the Company goes out to find new customers or new loads, is where a considerable amount of effort may be made. Docket No. 04-05-11, DPUC Generic Review of the Southern Methodology of Allocating Gas Costs, Response to Interrogatory GA-47; Tr. 1/25/05, pp. 790 and 791. However, the single biggest factor that affects the amount of margin generated is the spread between natural gas and oil, of which the Company has little to no control over. Docket No. 04-05-11, Tr. 1/25/05, pp. 797 and 798. This spread primarily influences how much volume interruptible customers will consume as well as the level of margin per each unit consumed. To the extent that the Company can pursue opportunities to bring new or additional interruptible load on the system, it is largely a function of the competitiveness of natural gas to alternative fuels. Further, sales volumes can be lost due to poor economic conditions, over which the Company also has little control.

While it has been difficult, at best, to determine the optimal level of necessary incentive, the Department finds that the incentive structure in place for many years has been much more generous than necessary to accomplish the goal of maximizing NFMs. The Company retained on average approximately $1.19 million in NFM annually for the last five years. Response to Interrogatory GA-369, Attachment 1. These generous incentives are at the detriment of ratepayers who pay for the system making these sales possible. The Decision dated August 12, 2005 in Docket No. 04-05-11 stated, in relevant part:

> ...margins above the threshold margin target will be shared with the LDCs at a lower rate than the existing rate for margins earned in excess of the target margin. Since the elimination of a target included in base rates completely eliminates the downside risk for the LDC from any specific target, a reduction in reward is appropriate.

Decision, p. 14.

Despite the decrease in its sharing percentage that resulted from the Settlement Agreement in Southern's last rate case, the Department finds there has been no reduction in reward to the Company in return for the risk that was shifted to ratepayers. Conversely, Southern received approximately $1.8 million in 2007, or $467,989 more than it earned in 2005. Response to Interrogatory GA-369, Attachment 1.

Admittedly, the current NFM mechanism in place has some inherent flaws. If the NFM threshold is forecasted too high and the Company believes it is unattainable, the Company has little incentive to maximize NFM regardless of where the sharing percentages are set. Further, the methodology in place for forecasting the annual NFM threshold is not forward looking, but rather, based on historical information. The Department believes an alternate NFM mechanism that starts with the very first sale is far more appropriate. Although the level of incentive will vary from year to year, some level of incentive will be achievable by the Company each and every year, and the incentives will be directly related to the actual NFM attained.

The Department hereby eliminates the annual threshold in the NFM sharing mechanism in favor of a lower sharing percentage from the very first dollar of NFM earned, rather than from a historical estimate of the future. Because there is no longer any risk to the Company for any level of NFM earned and the level of NFM achieved is largely a function of market conditions outside of Southern's efforts, a sharing percentage of 1% under the new mechanism is much more reasonable. Had this mechanism been in place during 2007, the Company would have received $176,505

($17,650,552 x 1%) in shareholder incentives. Response to Interrogatory GA-396, Attachment 1. The Department believes that this is a much more reasonable incentive level. The new mechanism will provide some incentive level each and every year, more commensurate with the Company's activities, and less on market conditions.

Based on the above, the Department establishes a modified NFM mechanism in which Southern shall retain 1% of all NFM earned. The new NFM mechanism will go into effect on January 1, 2010 upon conclusion of the Company's current mechanism year, which is for calendar year 2009. As there will be no NFM threshold going forward, Southern will no longer need to file NFM testimony in a separate docketed proceeding as directed in the Interim Decision dated March 26, 2008 in Docket Nos. 07-04-01 and 07-10-01, DPUC Semi-Annual Investigation of the Purchased Gas Adjustment Clause Charges or Credits Filed by: Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company. Instead, the Company will file a report in the semi-annual PGA proceedings on the level of NFM earned monthly from each source of non-firm activity as well as the sharing levels between ratepayers and the Company's shareholders.

N. TARIFF CHANGES

1. Interruptible Service Commitment Period

Interruptible rates are established using value-of-service (VOS) pricing based on the alternate fuel source. Until recently, interruptible VOS prices were typically lower than firm rates. However, the extraordinary market conditions recently experienced in the energy markets have resulted in interruptible rates that were higher than firm service rates. The Company has two options under this scenario. It could charge below market VOS pricing to retain the customer on interruptible service. Or it could provide the customer with the applicable firm service, as well as educate the customer as to service obligations under firm and interruptible service and leave the decision to the customer. Since December 2007, Southern has had several interruptible customers switch to firm service to take advantage of the recent economically attractive rates. Therrien and Heintz PFT, p. 28.

Because the Company maintains supplier of last resort (SOLR) obligations for its firm rate classes, it takes on additional SOLR obligations when interruptible customers switch to firm service, even if only for one year. As a result of the interruptible to firm switches, the Company has taken on approximately 5,000 Mcf in additional peak day load in the last two years. Tr. 5/7/09, p. 2290. The Company notes that obtaining additional capacity in the constrained Northeast market is no easy task. Incremental supply, if available, is costly and requires very long contractual arrangements, perhaps ten to fifteen years. This creates a potential cost shifting of these capacity costs to firm customers in the event the customer switches back to interruptible service. Brief, p. 139.

To eliminate potential cost shifting and allow the Company to efficiently plan for supply, Southern proposes to modify its Manual Interruptible Service (Rate IS) tariff. This modification would require any customer switching to firm service to remain on the assigned firm rate for a minimum of three years. Therrien and Heintz PFT, p. 28. Rate