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Transcript Exhibit(s)

Docket #(s): G-01551A-07-0504

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Arizona Corporation Commission
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JUL - 1 2008
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EXHIBIT
RUCO-1
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

SURREBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 27, 2008

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SURREBUTTAL EXHIBIT A

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. No. Mr. William Rigsby previously filed direct rate design testimony in this docket. I have adopted his direct testimony and will support both that testimony as well as the surrebuttal testimony I provide here.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony I will respond to the positions and arguments set forth by the various Arizona Water witnesses in their rebuttal testimony regarding rate design. I will show that certain arguments are without merit and demonstrate why such arguments should be rejected. I will reaffirm RUCO's positions on rate design.

Q. What rate design issues will you discuss in your surrebuttal testimony?

A. I will address the following rate design issues:

* Revenue Decoupling Adjustment Provision
* Weather Normalization Adjustment Provision
* Company Proposed "Allocated" Rate Design

REVENUE DECOUPLING ADJUSTMENT PROVISION (RDAP)

Q. Please discuss the Company's rebuttal comments concerning RUCO's recommendation to deny the proposed RDAP.

A. The Company rejects RUCO's recommendation to deny the RDAP and claims that RUCO's reasons for advocating rejection of the RDAP are not "a sound basis for rejecting it".

Q. What specifically does the Company consider "unsound" in RUCO's arguments?

A. The Company considers RUCO's regulatory lag, single-issue ratemaking, true-up, and conservation arguments to be "unsound".

Q. Do you agree with this characterization of RUCO's recommendation to deny the RDAP?

A. No. This characterization appears to merely reflect the Company's opinion, since SWG's rebuttal testimony presents no compelling evidence of the "unsoundness" of RUCO's position.

Q. Please discuss the Company's arguments concerning regulatory lag.

A. The Company first off agrees that declining average consumption is only problematic because of regulatory lag. However, the Company's agreement ends there. Rather than recognize that regulatory lag is a two way street from which the Company also benefits (i.e. accumulated

depreciation, expired amortization, retirements, economies of scale, cost savings etc.) and that any attempt to mitigate the regulatory lag associated with declining average consumption and ignore the above mentioned regulatory lags that accrue to the shareholder the Company attempts to turn this into a conservation issue.

Q. Please explain.

A. The Company claims that the loss of revenue that results from declining average consumption coupled with regulatory lag creates an incentive for the utility to promote increased sales, which is counter productive to the conservation goals of the public and the Commission.

Q. Does this logic have merit?

A. No. First, there is absolutely no evidence to support this argument. In fact, all evidence contradicts this argument. By the Company's own acknowledgement, average consumption continues to decline, which clearly demonstrates that regulatory lag has had no effect on conservation. Second, in the same breath that the Company pleads economic harm from regulatory lag it also acknowledges that regulatory lag is "an incentive for the utility to prevent cost increases and even to achieve cost decreases, because the utility retains the financial benefit of any cost saving it achieves between rate cases, and it also retains the

financial benefit of any cost increases it avoids."[1] This testimony supports RUCO's position that unfair and biased rates will result when extraordinary ratemaking schemes such as the RDAP are adopted.

Q. Please respond to the Company's rebuttal arguments regarding RUCO's objection to the RDAP being single-issue ratemaking?

A. The Company agrees in its rebuttal testimony that single issue ratemaking is biased yet then takes the stance that the "general objection to single issue ratemaking vanishes when a regulatory commission considers and then adopts an automatic adjustment clause in a general rate case, providing rate adjustments for changes in specific cost elements identified in advances of the changes in those elements. The RDAP fits this latter situation."[2]

Q. Is this true?

A. No. First, the proposed RDAP is not an automatic adjustment clause that provides for rate adjustments for changes in specific costs. In fact the RDAP, as proposed has nothing to do with specific cost increases or decreases. The RDAP would merely adjust the billing determinants used in assigning rates. Further, the RDAP would only adjust billing determinants for therms lost to conservation and ignore any gains in billing

[1] Rebuttal testimony of Ralph E. Miller, page 20, lines 5 through 8.
[2] Rebuttal testimony of Ralph E. Miller, page 19, lines 1 through 14.

determinants due to growth. In this respect it truly is biased and a perfect example of single issue ratemaking at its worst.

Q. Please discuss the Company's rebuttal comments concerning RUCO's position that the regulatory process already provides true-up of any changes in billing determinants are via rate cases.

A. The Company argues that RUCO is incorrect that billing determinants are trued-up during the rate case process.

Q. Why does the Company believe that RUCO is incorrect in this position?

A. The Company argues because there is no retroactive reimbursement for its perceived underrecoveries related to decreases in average consumption that there is no true-up.

Q. Do you agree?

A. No. Every time the Company files a rate case the bill determinants used in prior years to set rates are restated to the current bill determinants. Given the prohibition of retroactive ratemaking the Company is neither reimbursed for underrecoveries nor is it required to refund any overrecoveries. Nonetheless, the billing determinants used in the prior case to set rates are trued-up to the existing billing determinants, so that the new rates are based on the current level of billing determinants. RUCO made this point to simply demonstrate that the declines in average

consumption over the last 20 years are not detrimentally affecting the Company since the declines are trued-up in each subsequent rate case.

Q. Please discuss the Company's rebuttal comments regarding the RDAP and conservation.

A. The Company argues that, contrary to RUCO's ascertain that the RDAP requires customers to pay for gas they didn't use and therefore is counterproductive to conservation, the RDAP does in fact deliver a conservation message because customers do avoid the pure gas commodity charge under the RDAP, albeit not the gas margin on therms not used.

Q. Please respond.

A. The Company is correct than conservation will save the customer the pure commodity charge for gas under the RDAP, however it still would require the customer to pay the margin on any therms not used (i.e. conserved). Thus, the price message as it relates to incenting conservation is diluted so that the customer will not see as compelling of a conservation price message under the proposed RDAP as they otherwise would absent the RDAP.

...

Q. Do any of the Company's rebuttal arguments regarding the proposed RDAP change RUCO's recommendations?

A. No. None of the Company's rebuttal arguments are compelling, let alone are even new arguments that have not already been presented in prior cases and forums. Further, to-date the AAC has rejected these arguments as well as all of the decoupling proposals that have been offered. RUCO believes the ACC has reached the appropriate conclusion in rejecting the previous decoupling proposals and recommends that it do so here again.

WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

Q. Please discuss the Company's rebuttal comments concerning RUCO recommendation to reject the proposed WDAP.

A. The Company does not agree with RUCO's recommendation to reject the WNAP, arguing that on a year-to-year basis fluctuations in weather have historically caused under and over recoveries of SWG's authorized revenue requirement. SWG believes that such fluctuations in weather warrant a WNAP that would guarantee the Company revenue requirement recovery regardless of weather.

...

Q. What rebuttal arguments does the Company present in its support for the proposed WNAP?

A. The Company makes three arguments in its rebuttal testimony. First, it argues that the WNAP does not require customers to pay for gas they do not use. Second, that the WNAP does not inappropriately shift risks from shareholders to ratepayers and third, that the primary cause for the Company's underrecoveries is not weather.

Q. Please address the first of these arguments.

A. The first argument that the WNAP dose not require customers to pay for gas they do not use is the same argument I addressed regarding the RDAP. To reiterate, when weather is warmer than normal the customer will save the pure commodity charge for gas under the WNAP, however the customer still would be required to pay the margin on any therms not used.

Q. Please address the second argument.

A. The Company argues that because the WNAP works in favor of the shareholder when weather is warmer than normal and it favors of ratepayers when weather is colder than normal it therefore does not shift the weather risk to ratepayers.

Q. Do you agree with this argument?

A. No. Both the RDAP and the WNAP would result in ratepayers bearing certain operational risks that currently are borne by shareholders. The cost of equity determined by the parties compensates for risk, and thus adoption of the WNAP or RDAP would warrant a reduction in the cost of equity to reflect the reduction in risk that these mechanisms would create.

Q. Has the Company proposed such an adjustment to the cost of equity?

A. No. The Company has proposed the same cost of equity with or without the RDAP and WNAP. In SWG's last case it proposed a lower cost of equity if a decoupling mechanism were adopted, in recognition of the decreased risk. The Company, in instant case fails to recognize or adjust for the decreased risks inherent in the RDAP and the WNAP.

Q. Please discuss the Company's third rebuttal argument.

A. The Company argues that over a ten year period, 1998 through 2007 the net effect of variations in weather was an increase in average use per customer as opposed to RUCO's position that the primary contributor of SWG's underrecoveries was weather related.

...

Q. How does this information serve to strengthen the Company case supporting the need for the WNAP?

A. It does not. As discussed in RUCO's direct testimony, the Company's rate case revenues are adjusted to annualize for a ten-year weather normalization. The Company now admits that this ten-year normalization has not only recovered the necessary weather related average use per customer, but has exceeded that amount. This information simply confirms that there is no justification for a WNAP since the ten-year weather normalization mechanism is already ensuring cost recovery due to variations in weather related consumption.

COMPANY PROPOSED ALLOCATED RATE DESIGN

Q. Please address the Company's proposed Allocated/Volumetric rate design[3].

A. The Company has proposed a somewhat unusual rate design, which SWG claims will alleviate some of its perceived declining consumption problems. SWG's proposed allocated rate design is characterized by a higher than normal non-gas commodity charge in the first tier and a $0.00 non-gas commodity charge in the second tier. The gas charge in the Company proposed allocated rate design is lower in the first tier than the actual estimated base cost of gas and higher in the second tier than the

[3] The Company proposed rate design is called an "allocated" rate design in its direct testimony and a "volumetric" rate design in its rebuttal testimony. Both terms refer to the same rate design. In my testimony I refer to the Company's proposed rate design using the "allocated" terminology.

actual estimated cost of gas. The Company proposed allocated rate design compares with a more traditional type rate design as follows:

	Traditional	"Allocated"
Fixed Monthly Charge	$12.80	$12.80
Non-gas Commodity		
All Usage	.55376	
First 35 Therms		.88069
Second 35 Therms		.00000
PGA Base		
All Therms	.93689	
First 35 Therms		.60996
Second 35 Therms		1.49065

The Company argues that the allocated rate design is fair to customers because the allocated rate design has a commodity cost of $1.49065 in both the first and second tiers (.60996 + .88069 = 1.49065) and so does the traditional rate design (.55376 + .93689 = 1.49065).

Q. Do you agree?

A. No. The impact of the allocated rate design is not revenue neutral to the customer when compared to a traditional rate design. The Company proposed allocated rate design has the effect of shifting a portion of the non-gas costs of large users to small users. I have prepared Surrebuttal Exhibit (A), which compares a residential customer's bill under a typical rate design to the Company-proposed allocated rate design. Under the allocated rate design small users (less than 55 therms consumption) will pay more than they would have under a traditional rate design. This is

demonstrated on lines 1 – 10 of Surrebuttal Exhibit A. Users over 55 therms will pay less than they would have under a traditional rate design. Thus, the Company's proposed rate design shifts costs from large users to small users. This phenomena benefits the Company because it guarantees recovery of non-gas costs via the low usage blocks and SWG is thus financially indifferent to loss of consumption from high usage customers. The proposed allocated rate design results in small users paying more than they otherwise would of and large users paying less than they otherwise would have. This is certainly a perverse result that sends an undesirable message to ratepayers.

Q. Does RUCO's proposed rate design result in a fairer distribution of costs than the Company-proposed allocated rate design?

A. Yes. First, RUCO's proposed rate design does not shift costs from large users to small users, as does the Company's just described allocated rate design. Second, RUCO's proposed rate design charges the same price for each therm, which sends a better conservation message to consumers than SWG's current rate design which features a declining commodity price structure, where higher users pay less per therm than low users. Third, RUCO's proposed rate design assigns a slightly greater percentage of costs to the fixed charge than does SWG's current rate design. In this manner RUCO has addressed some of the Company's declining consumption and inability to recover cost concerns by essentially

guaranteeing a greater fixed cost recovery. RUCO's rate design is fair to both the Company and ratepayer, as well as sends the correct conservation message.

Q. Doe this conclude your surrebuttal testimony?

A. Yes.

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
A TYPICAL RATE DESIGN VS. THE COMPANY-PROPOSED
"ALLOCATED" RATE DESIGN

SURREBUTTAL EXHIBIT A

LINE NO.	CONSUMPTION	AVERAGE (NORMAL) RATE DESIGN	COMPANY PROPOSED "ALLOCATED" RATE DESIGN
	20 THERMS		
1	MONTHLY MINIMUM	$12.80	12.80
2	BASE COMMODITY	11.08	17.61
3	PGA	18.74	12.20
4	PGA ADJUSTOR	0.00	6.54
5	TOTAL	42.61	49.15
	40 THERMS		
6	MONTHLY MINIMUM	$12.80	12.80
7	BASE COMMODITY	22.15	30.82
8	PGA	37.48	28.80
9	PGA ADJUSTOR	0.00	8.67
10	TOTAL	72.43	81.10
	55 THERMS		
11	MONTHLY MINIMUM	$12.80	12.80
12	BASE COMMODITY	30.46	30.82
13	PGA	51.53	51.16
14	PGA ADJUSTOR	0.00	0.37
15	TOTAL	94.79	95.15
	60 THERMS		
16	MONTHLY MINIMUM	$12.80	12.80
17	BASE COMMODITY	33.23	30.82
18	PGA	56.21	58.61
19	PGA ADJUSTOR	0.00	(2.40)
20	TOTAL	102.24	99.84
	80 THERMS		
21	MONTHLY MINIMUM	$12.80	12.80
22	BASE COMMODITY	44.30	30.82
23	PGA	74.95	88.43
24	PGA ADJUSTOR	0.00	(13.48)
25	TOTAL	132.05	118.58
	100 THERMS		
26	MONTHLY MINIMUM	$12.80	12.80
27	BASE COMMODITY	55.38	30.82
28	PGA	93.69	118.24
29	PGA ADJUSTOR	0.00	(24.55)
30	TOTAL	161.87	137.31
	120 THERMS		
31	MONTHLY MINIMUM	$12.80	12.80
32	BASE COMMODITY	66.45	30.82
33	PGA	112.43	148.05
34	PGA ADJUSTOR	0.00	(35.63)
35	TOTAL	191.68	156.05
	140 THERMS		
36	MONTHLY MINIMUM	$12.80	12.80
37	BASE COMMODITY	77.53	30.82
38	PGA	131.16	177.87
39	PGA ADJUSTOR	0.00	(46.70)
40	TOTAL	221.49	174.79

	AVERAGE RATES	"ALLOCATED" RATES
BASIC SERVICE CHRG.	12.8	12.80
BASE COMMODITY		
ALL USAGE	0.55376	
FIRST 35 THERMS		0.88069
SECOND 35 THERMS		0.00000
PGA		
ALL THERMS	0.93689	
FIRST 35 THERMS		0.60996
SECOND 35 THERMS		1.49065

EXHIBIT
RUCO-2
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

REVISED SURREBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 30, 2008

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SURREBUTTAL EXHIBIT A

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. No. Mr. William Rigsby previously filed direct rate design testimony in this docket. I have adopted his direct testimony and will support both that testimony as well as the surrebuttal testimony I provide here.

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A. I will address the following rate design issues:

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REVENUE DECOUPLING ADJUSTMENT PROVISION (RDAP)

Q. Please discuss the Company's rebuttal comments concerning RUCO's recommendation to deny the proposed RDAP.

A. The Company rejects RUCO's recommendation to deny the RDAP and claims that RUCO's reasons for advocating rejection of the RDAP are not "a sound basis for rejecting it".

Q. What specifically does the Company consider "unsound" in RUCO's arguments?

A. The Company considers RUCO's regulatory lag, single-issue ratemaking, true-up, and conservation arguments to be "unsound".

Q. Do you agree with this characterization of RUCO's recommendation to deny the RDAP?

A. No. This characterization appears to merely reflect the Company's opinion, since SWG's rebuttal testimony presents no compelling evidence of the "unsoundness" of RUCO's position.

Q. Please discuss the Company's arguments concerning regulatory lag.

A. The Company agrees that declining average consumption is only problematic because of regulatory lag. However, the Company's agreement ends there. Rather than recognize that regulatory lag is a two-way street from which the Company also benefits (i.e. accumulated

depreciation, expired amortization, retirements, economies of scale, cost savings etc.) and that any attempt to mitigate the regulatory lag associated with declining average consumption (and ignore the above-mentioned regulatory lags that accrue to the shareholder), the Company attempts to turn this into a conservation issue.

Q. Please explain.

A. The Company claims that the loss of revenue that results from declining average consumption coupled with regulatory lag creates an incentive for the utility to promote increased sales, which is counter productive to the conservation goals of the public and the Commission.

Q. Does this logic have merit?

A. No. First, there is absolutely no evidence to support this argument. In fact, all evidence contradicts this argument. By the Company's own acknowledgement, average consumption continues to decline, which clearly demonstrates that regulatory lag has had no effect on conservation. Second, in the same breath that the Company pleads economic harm from regulatory lag it also acknowledges that regulatory lag is "an incentive for the utility to prevent cost increases and even to achieve cost decreases, because the utility retains the financial benefit of any cost saving it achieves between rate cases, and it also retains the

financial benefit of any cost increases it avoids."[1] This testimony supports RUCO's position that unfair and biased rates will result when extraordinary ratemaking schemes such as the RDAP are adopted.

Q. Please respond to the Company's rebuttal arguments regarding RUCO's objection to the RDAP being single-issue ratemaking?

A. The Company agrees in its rebuttal testimony that single issue ratemaking is biased yet then takes the stance that the "general objection to single issue ratemaking vanishes when a regulatory commission considers and then adopts an automatic adjustment clause in a general rate case, providing rate adjustments for changes in specific cost elements identified in advances of the changes in those elements. The RDAP fits this latter situation."[2]

Q. Is this true?

A. No. First, the proposed RDAP is not an automatic adjustment clause that provides for rate adjustments for changes in specific costs. In fact, the RDAP as proposed has nothing to do with specific cost increases or decreases. The RDAP would merely adjust the billing determinants used in assigning rates. Further, the RDAP would only adjust billing determinants for therms lost to conservation and ignore any gains in billing

[1] Rebuttal testimony of Ralph E. Miller, page 20, lines 5 through 8.
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determinants due to growth. In this respect it truly is biased and a perfect example of single issue ratemaking at its worst.

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A. The Company argues that RUCO is incorrect that billing determinants are trued-up during the rate case process.

Q. Why does the Company believe that RUCO is incorrect in this position?

A. The Company argues that because there is no retroactive reimbursement for its perceived under-recoveries related to decreases in average consumption that there is no true-up.

Q. Do you agree?

A. No. Every time the Company files a rate case the bill determinants used in prior years to set rates are restated to the current bill determinants. Given the prohibition of retroactive ratemaking the Company is neither reimbursed for under-recoveries nor is it required to refund any over-recoveries. Nonetheless, the billing determinants used in the prior case to set rates are trued-up to the existing billing determinants, so that the new rates are based on the current level of billing determinants. RUCO made this point to simply demonstrate that the declines in average consumption

over the last 20 years are not detrimentally affecting the Company since the declines are trued-up in each subsequent rate case.

Q. Please discuss the Company's rebuttal comments regarding the RDAP and conservation.

A. The Company argues that, contrary to RUCO's assertion that the RDAP requires customers to pay for gas they didn't use and therefore is counterproductive to conservation, the RDAP does in fact deliver a conservation message because customers do avoid the pure gas commodity charge under the RDAP, albeit not the gas margin on therms not used.

Q. Please respond.

A. The Company is correct that conservation will save the customer the pure commodity charge for gas under the RDAP; however, it still would require the customer to pay the margin on any therms not used (i.e. conserved). Thus, the price message as it relates to incenting conservation is diluted so that the customer will not see as compelling of a conservation price message under the proposed RDAP as they otherwise would absent the RDAP.

...

Q. Do any of the Company's rebuttal arguments regarding the proposed RDAP change RUCO's recommendations?

A. No. None of the Company's rebuttal arguments are compelling, let alone new arguments that have not already been presented in prior cases and forums. Further, to-date, the AAC has rejected these arguments as well as all of the decoupling proposals that have been offered. The ACC has reached the appropriate conclusion in rejecting the previous decoupling proposals and RUCO recommends that it do so here again.

WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

Q. Please discuss the Company's rebuttal comments concerning RUCO recommendation to reject the proposed WNAP.

A. The Company does not agree with RUCO's recommendation to reject the WNAP, arguing that on a year-to-year basis fluctuations in weather have historically caused under and over recoveries of SWG's authorized revenue requirement. SWG believes that such fluctuations in weather warrant a WNAP that would guarantee the Company revenue requirement recovery regardless of weather.

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Q. What rebuttal arguments does the Company present in its support for the proposed WNAP?

A. The Company makes three arguments in its rebuttal testimony. First, it argues that the WNAP does not require customers to pay for gas they do not use. Second, that the WNAP does not inappropriately shift risks from shareholders to ratepayers and third, that the primary cause for the Company's under-recoveries is not weather.

Q. Please address the first of these arguments.

A. The Company's first argument that the WNAP does not require customers to pay for gas they do not use is the same argument I addressed regarding the RDAP. To reiterate, when weather is warmer than normal the customer will save the pure commodity charge for gas under the WNAP; however, the customer still would be required to pay the margin on any therms not used.

Q. Please address the second argument.

A. The Company argues that because the WNAP works in favor of the shareholder when weather is warmer than normal and it favors ratepayers when weather is colder than normal it therefore does not shift the weather risk to ratepayers.

Q. Do you agree with this argument?

A. No. Both the RDAP and the WNAP would result in ratepayers bearing certain operational risks that currently are borne by shareholders. The cost of equity determined by the parties compensates for risk, and thus adoption of the WNAP or RDAP would warrant a reduction in the cost of equity to reflect the reduction in risk that these mechanisms would create.

Q. Has the Company proposed such an adjustment to the cost of equity?

A. No. The Company has proposed the same cost of equity with or without the RDAP and WNAP. In SWG's last case it proposed a lower cost of equity if a decoupling mechanism were adopted, in recognition of the decreased risk. The Company, in the instant case fails to recognize or adjust for the decreased risks inherent in the RDAP and the WNAP.

Q. Please discuss the Company's third rebuttal argument.

A. The Company argues that over a ten year period, 1998 through 2007 the net effect of variations in weather was an increase in average use per customer as opposed to RUCO's position that the primary contributor of SWG's under-recoveries was weather related.

...

Q. How does this information serve to strengthen the Company's case supporting the need for the WNAP?

A. It does not. As discussed in RUCO's direct testimony, the Company's rate case revenues are adjusted to annualize for a ten-year weather normalization. The Company now admits that this ten-year normalization has not only recovered the necessary weather related average use per customer, but has exceeded that amount. This information simply confirms that there is no justification for a WNAP since the ten-year weather normalization mechanism is already ensuring cost recovery due to variations in weather related consumption.

COMPANY PROPOSED ALLOCATED RATE DESIGN

Q. Please address the Company's proposed Allocated/Volumetric rate design[3].

A. The Company has proposed a somewhat unusual rate design, which SWG claims will alleviate some of its perceived declining consumption problems. SWG's proposed allocated rate design is characterized by a higher than normal non-gas commodity charge in the first tier and a $0.00 non-gas commodity charge in the second tier. The gas charge in the Company proposed allocated rate design is lower in the first tier than the actual estimated base cost of gas and higher in the second tier than the

[3] The Company proposed rate design is called an "allocated" rate design in its direct testimony and a "volumetric" rate design in its rebuttal testimony. Both terms refer to the same rate design. In my testimony I refer to the Company's proposed rate design using the "allocated" terminology.

actual estimated cost of gas. The Company proposed allocated rate design compares with a more traditional type rate design as follows:

	Traditional	"Allocated"
Fixed Monthly Charge	$12.80	$12.80
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The Company argues that the allocated rate design is fair to customers because the allocated rate design has a commodity cost of $1.49065 in both the first and second tiers (.60996 + .88069 = 1.49065) and so does the traditional rate design (.55376 + .93689 = 1.49065).

Q. Do you agree?

A. No. The impact of the allocated rate design is not revenue neutral to the customer when compared to a traditional rate design. The Company proposed allocated rate design has the effect of shifting a portion of the non-gas costs of large users to small users. I have prepared Surrebuttal Exhibit (A), which compares a residential customer's bill under a typical rate design to the Company-proposed allocated rate design. Under the allocated rate design small users (less than 55 therms consumption) will pay more than they would have under a traditional rate design. This is

demonstrated on lines 1 – 10 of Surrebuttal Exhibit A. Users over 55 therms will pay less than they would have under a traditional rate design. Thus, the Company's proposed rate design shifts costs from large users to small users. This phenomena benefits the Company because it guarantees recovery of non-gas costs via the low usage blocks and SWG is thus financially indifferent to loss of consumption from high usage customers. The proposed allocated rate design results in small users paying more than they otherwise would have and large users paying less than they otherwise would have. This is certainly a perverse result that sends an undesirable message to ratepayers.

Q. Does RUCO's proposed rate design result in a fairer distribution of costs than the Company-proposed allocated rate design?

A. Yes. First, RUCO's proposed rate design does not shift costs from large users to small users, as does the Company's allocated rate design described immediately above. Second, RUCO's proposed rate design charges the same price for each therm, which sends a better conservation message to consumers than SWG's current rate design which features a declining commodity price structure, where higher users pay less per therm than low users. Third, RUCO's proposed rate design assigns a slightly greater percentage of costs to the fixed charge than does SWG's current rate design. In this manner RUCO has addressed some of the Company's declining consumption and inability to recover cost concerns

by essentially guaranteeing a greater fixed cost recovery. RUCO's rate design is fair to both the Company and ratepayer, as well as sends the correct conservation message.

Q. Doe this conclude your surrebuttal testimony?

A. Yes.

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
A TYPICAL RATE DESIGN VS. THE COMPANY-PROPOSED
"ALLOCATED" RATE DESIGN

SURREBUTTAL EXHIBIT A

LINE NO.	CONSUMPTION	AVERAGE (NORMAL) RATE DESIGN	COMPANY PROPOSED "ALLOCATED" RATE DESIGN
	20 THERMS		
1	MONTHLY MINIMUM	$12.80	12.80
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3	PGA	18.74	12.20
4	PGA ADJUSTOR	0.00	6.54
5	TOTAL	42.61	49.15
	40 THERMS		
6	MONTHLY MINIMUM	$12.80	12.80
7	BASE COMMODITY	22.15	30.82
8	PGA	37.48	28.80
9	PGA ADJUSTOR	0.00	8.67
10	TOTAL	72.43	81.10
	55 THERMS		
11	MONTHLY MINIMUM	$12.80	12.80
12	BASE COMMODITY	30.46	30.82
13	PGA	51.53	51.16
14	PGA ADJUSTOR	0.00	0.37
15	TOTAL	94.79	95.15
	60 THERMS		
16	MONTHLY MINIMUM	$12.80	12.80
17	BASE COMMODITY	33.23	30.82
18	PGA	56.21	58.61
19	PGA ADJUSTOR	0.00	(2.40)
20	TOTAL	102.24	99.84
	80 THERMS		
21	MONTHLY MINIMUM	$12.80	12.80
22	BASE COMMODITY	44.30	30.82
23	PGA	74.95	88.43
24	PGA ADJUSTOR	0.00	(13.48)
25	TOTAL	132.05	118.58
	100 THERMS		
26	MONTHLY MINIMUM	$12.80	12.80
27	BASE COMMODITY	55.38	30.82
28	PGA	93.69	118.24
29	PGA ADJUSTOR	0.00	(24.55)
30	TOTAL	161.87	137.31
	120 THERMS		
31	MONTHLY MINIMUM	$12.80	12.80
32	BASE COMMODITY	66.45	30.82
33	PGA	112.43	148.05
34	PGA ADJUSTOR	0.00	(35.63)
35	TOTAL	191.68	156.05
	140 THERMS		
36	MONTHLY MINIMUM	$12.80	12.80
37	BASE COMMODITY	77.53	30.82
38	PGA	131.16	177.87
39	PGA ADJUSTOR	0.00	(46.70)
40	TOTAL	221.49	174.79

	AVERAGE RATES	"ALLOCATED" RATES
BASIC SERVICE CHRG.	12.8	12.80
BASE COMMODITY		
ALL USAGE	0.55376	
FIRST 35 THERMS		0.88069
SECOND 35 THERMS		0.00000
PGA		
ALL THERMS	0.93689	
FIRST 35 THERMS		0.60996
SECOND 35 THERMS		1.49065

EXHIBIT
RUCO-3
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

March 28, 2008

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INTRODUCTION

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

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Southwest Gas Corporation's ("Company" or "SWG") application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for gas service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended April 30, 2007.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the Company's overall revenue requirement and rate design. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of seven sets of data requests, the review and analysis of Company responses to Commission Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to SWG.

The Commission in Decision No. 68487, dated February 23, 2006, approved the Company's present rates and charges for utility service. The test year used in that proceeding was the 12-month period ending August 31, 2004.

Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income and revenue requirements. RUCO's witness William A. Rigsby will provide an analysis of the cost of capital as presented on Schedule RLM-19. RUCO's witness Marylee Diaz Cortez will address rate design in her testimony to be filed April 11, 2008. I will sponsor the rate design exhibits that will be filed with the testimony of Ms. Diaz Cortez.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-19.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and revenue requirements addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

Fair Value Rate Base – This adjustment states the fair value rate base by giving equal weighting (50/50 split) to RUCO's adjusted original cost rate base and RUCO's calculation of the reconstruction cost new depreciated rate base.

Construction Completed Not Classified - This adjustment includes the value of retired plant associated with the completed construction not classified recommended for rate base treatment.

Annualized Intangible Assets - This adjustment removes those assets, which will be fully amortized shortly after the end of the test year and includes those intangible assets that entered service shortly after the end of the test year.

Retired Plant Associated With the Sale of the "TEP Bypass" - This adjustment includes the value of retired plant associated with Tucson Electric Power Company's cancellation of gas transportation service through the "TEP Bypass", SWG's corresponding normalization of test-

year revenue and the Company's acknowledgement of the upcoming sale of these assets.

Accumulated Deferred Income Taxes Associated With Incentive Compensation and the Supplemental Executive Retirement Plan - This is a companion adjustment to recognize the deferred tax implications on RUCO's operating income adjustments to the Company's incentive compensation program and the supplemental executive retirement plan discussed below.

Allowance For Working Capital – This adjustment is the difference in the level of expense recommendations calculated by the Company and RUCO.

Operating Income

Labor and Labor Loading Annualization Expense – This adjustment reduces test-year operating expenses to reflect RUCO's recommended level of annualized payroll and payroll taxes.

Injuries and Damages Expense – This adjustment reflects RUCO's determination of an average annual level of expense.

Paiute Allocation Annualization Expense – This is a conforming adjustment corresponding to the Company's acknowledgment of omissions in the original filing expenses.

Depreciation and Amortization Annualization Expense - This adjustment reflects depreciation and amortization expenses calculated on RUCO's recommended gross plant in service.

Property Tax Expense - This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Unnecessary and/or Inappropriate Expenses – RUCO expanded the scope of the Company's proposed adjustment to miscellaneous expense adjustments and removed inappropriate expenditures not necessary in the provisioning of gas service.

Management Incentive Program - This adjustment reflects RUCO's determination to split the cost on a 50/50 basis for expenses associated with employee incentive compensation.

Supplemental Executive Retirement Plan – This adjustment reflects RUCO's determination to remove the cost of the supplemental executive retirement plan.

Employee Recognition - This adjustment reflects RUCO's determination to remove the costs of gifts and awards associated with employee recognition.

Uncollectible Expense – This adjustment reduces test-year operating expenses to reflect RUCO's recommended level of normalized uncollectible expense.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

Rate Design

Q. Please explain your contribution to RUCO's recommended rate designs.

A. I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). After reviewing the Company's workpapers, I accepted SWG's bill determinants adjusted for weather normalization and customer annualization. I will be filing Schedule RLM-18 on April 11, 2008 as part of RUCO's rate design recommendations. An in-depth discussion of RUCO's proposed rate design will be contained in the testimony of RUCO witness Marylee Diaz Cortez, also to be filed on April 11, 2008.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, RUCO is recommending that the increase in the Company's revenue requirement not exceed:

SWG	RUCO	DIFFERENCE
$50,219,828	$31,296,285	($18,923,543)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

SWG	RUCO	DIFFERENCE
12.58 %	7.84 %	-4.74 %

RUCO's recommended increase in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base ("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

SWG	RUCO	DIFFERENCE
$1,469,135,558	$1,463,643,611	($5,491,947)

The detail supporting RUCO's recommended rate base is presented on Schedules RLM-2, RLM-3, RLM-4, RLM-5 and RLM-6.

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

SWG	RUCO	DIFFERENCE
$103,457,659	$96,226,345	($7,231,314)

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

RATE BASE

Fair Value Rate Base

Q. Please explain the basis for your determination of the fair value rate base ("FVRB").

A. RUCO's determination of the FVRB consists of three elements. First, as shown on RLM-2, the value of the OCRB was restated to reflect RUCO's adjustment to the various rate base determinants. Second, as shown on

RLM-3, the value of the RCND was computed. Third, as shown of RLM-1, the FVRB was computed on an equal weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of adjustments to the OCRB. As shown on RLM-4, RUCO made three adjustments to the OCRB, each of which is discussed in detail below.

Q. Please elaborate on the second element of RUCO's FVRB determination.

A. The second element is the computation of the RCND. RUCO's RCND was computed by multiplying RUCO's OCRB by the percentage difference between the Company's OCRB and its RCND as filed.

Q. Please elaborate on the third element of RUCO's FVRB determination.

A. The third element is the computation of the FVRB. RUCO computed the FVRB by calculating a 50/50 split between RUCO's OCRB and its RCND.

This adjustment to fair value rate base decreased the test-year rate base by $5,491,947.

Rate Base Adjustment No. 1 – Completed Construction Not Classified

Q. Please explain your adjustment to completed construction not classified ("CCNC").

A. In response to RUCO data request 2.1, the Company acknowledged there were corresponding plant retirements associated with the CCNC identified in its Adjustment No. 17.

Therefore, my adjustment recognizes these plant retirements, because it is necessary to match the test-year plant additions not classified with the test-year retirements not classified.

Thus the adjustment reduces the gross plant in service by the value of the retirements ($66,377); however, the adjustment also reduces the accumulated depreciation by an equal amount, which offsets any effect on the rate base.

As shown on Schedule RLM-4 page 1, columns (D) and (E) and supporting Schedule RLM-5, my adjustment decreases the adjusted rate base by $0. However, this adjustment has an effect on the test-year depreciation expense, which is discussed later in my testimony on operating income.

Rate Base Adjustment No. 2 – Annualized Intangible Assets

Q. Please explain the Company's proposed adjustment to annualize its test-year intangible plant balances.

A. The Company's adjustment reflects construction expenditures made before the end of the test year. However, the actual recording of this construction activity into the plant accounts was made after the end of the test year due to delays in entering the required information into the Company's computer system.

Q. Do you agree with this adjustment?

A. No, not entirely. In response to Staff data requests 6.59 and 11.4, the Company acknowledged it had over-estimated costs of certain intangible plant additions in its original filing. My adjustment decreases the Company's proposed estimates of intangible plant additions with the actual plant additions.

These additional plant assets were system allocable miscellaneous intangible items primarily related to computer software. RUCO accepts the Company's recommendation to assign a three-year service life on these intangible plant assets, which will be discussed later in my testimony regarding operating income.

Thus the adjustment consists of determining the difference between the estimated and actual costs, and adjusting SWG's rate base to reflect the actual intangible plant additions.

As shown on Schedule RLM-4 page 2, column (E) and supporting Schedule RLM-10, page 3, column (B), my adjustment decreases the adjusted rate base by $79,231.

Rate Base Adjustment No. 3 – Retired Plant Associated With the Sale of the "TEP Bypass"

Q. Please explain your adjustment to retire plant associated with Tucson Electric Power Company's ("TEP") cancellation of gas service provided through the "TEP bypass".

A. In the testimony of Company witness Mr. Cattanach, he states SWG annualized the test-year bills and volumes to reflect TEP's cancellation of gas service pursuant to the "TEP bypass". Moreover, in response to RUCO data request 7.2, the Company acknowledged there was an upcoming sale of the meters and pipes that service TEP planned for March 31, 2008 to transfer ownership to TEP. Because SWG annualized the end of test-year revenues based on end of test-year customer levels; it is also appropriate to annualize rate base items, such as plant in service and accumulated depreciation to reflect this adjusted customer level.

Therefore, my adjustment recognizes the plant that will be retired as a result of the "TEP bypass". This adjustment is necessary to match the test-year plant balances with the test-year customer level.

Thus, this adjustment reduces the gross plant in service by the value of the retirements ($210,619); however, the adjustment also reduces the accumulated depreciation by an equal amount, which offsets any effect on the rate base.

As shown on Schedule RLM-4 page 1, columns (G) and (H), my adjustment decreases the adjusted rate base by $0. This adjustment however has an effect on the test-year depreciation expense, which is discussed later in my testimony on operating income.

<u>Rate Base Adjustment No. 4 – Accumulated Deferred Income Taxes Associated With Management Incentive Program and the Supplemental Executive Retirement Plan</u>

Q. Please explain your adjustment to accumulated deferred income tax ("ADIT").

A. In response to Staff data request 11.11, the Company identified the ADIT associated with the management incentive program ("MIP") and the supplemental executive retirement plan ("SERP").

Q. Have you removed the entire ADIT balance related to MIP and SERP from rate base?

A. No. Since these two expenses have only been excluded from rates since SWG's last rate case, I have only removed the ADIT that has accrued since rates last went into effect through the end of the current test year. In this manner I have properly matched the MIP and SERP expense disallowances with the applicable ADIT accruals.

Furthermore, as shown on Schedule RLM-4, page 3, I have limited my ADIT adjustment related to MIP to 50 percent, since this was the portion of MIP expenses that was disallowed in SWG's prior rate order.

This is a companion adjustment to the MIP and SERP adjustments discussed below.

As shown on Schedule RLM-2, column (B), line 8, and supporting Schedule RLM-4, page 3, my adjustment decreases the adjusted rate base by $880,989.

<u>Rate Base Adjustment No. 5 – Allowance For Working Capital</u>

Q. What level of working capital is the Company requesting?

A. The Company is requesting a total working capital allowance of $5,681,932. This is comprised of cash working capital of ($10,379,937), materials and supplies of $12,389,898, and prepayments of $3,671,971.

Q. What is the basis of the Company's cash working capital request?

A. The Company's cash working capital request is based on the results of a lead/lag study.

Q. Please explain cash working capital and how a lead/lag study is used to measure cash working capital.

A. Cash working capital is the amount of cash needed by the Company to pay for goods and services in advance of the receipt of the associated revenues. The most accurate way to determine the necessary cash working capital requirement is through a lead/lag study. A lead/lag study measures the time between when service is rendered to customers and when the associated cash revenues are collected from customers (revenue lead/lag). The lead/lag study also measures the time between when goods and services are consumed in the production of utility service and when the utility makes payment for those goods and services (expense lead/lag). If the average lag in the receipt of revenues exceeds the average lag in payment of expenses, the utility has a positive cash working capital requirement. If the lead/lag study reveals that the average lag in the receipt of revenues is less than the average lag in the payment of expenses, the utility has a negative cash working capital requirement. In the first situation, stockholders must provide cash working capital to span the timing difference. In the latter situation, customers are supplying the cash working capital necessary to pay expenses through their earlier

payment of utility bills. The first situation requires an addition to rate base, the latter situation requires a rate base reduction.

Q. Does the Company's cash working capital calculation reflect an accurate and appropriate level of cash working capital?

A. No. The Company has made several errors in its calculation of cash working capital.

Q. Please discuss these errors.

A. The Company-proposed interest lag of 84.65 days is incorrect because it fails to include the interest expense related to its tax-deductible preferred stock and fails to include the interest expense related to its customer deposits. I have corrected both of these errors and recomputed an interest expense lag of 83.80 days.

Q. Did you review the Company's other calculations of revenue and expense lags?

A. Yes.

Q. Do you agree with all of the revenue and expense lags calculated by the Company?

A. No. In addition to the interest lag, I believe the 7.5-day expense lag calculated by the Company for Other O&M Expenses is understated.

Q. How did the Company calculate the Other O&M Expense lag?

A. The Company examined each test-year expense voucher that exceeded $10,000 and for each of these vouchers computed the lead/lag days between the service period and the date of payment. The resultant 7.5-day lag is the average of each of the individual test-year O&M expense lags.

Q. Why do you believe the Other O&M Expenses lag is understated?

A. In response to a data request, the Company provided samples of the vouchers it had included in its calculation of the Other O&M Expense lag. My examination of these vouchers revealed that a number of the vouchers included in the Other O&M Expense lag calculation were misclassified as expenses, when in fact these expenditures were Prepayments.

The inclusion of these prepayments as expenses in the lead/lag calculation has the effect of understating the true expense lag.

Q. What types of expenditures had the Company misclassified as expenses?

A. A number of large expenditures that the Company included in O&M expense were payments for annual maintenance contracts, annual rental payments, and extended warranties.

Under Generally Accepted Accounting Principles companies are required to record expenditures that provide future benefit as Prepayments and to amortize the expenditures over the period in which they provide benefit.

Q. What adjustment have you made?

A. I have removed those vouchers that represent Prepayments from the Company's calculation of the Other O&M Expense lag. I also removed two invoices for unnecessary expenses ($17,200 as a sponsor for a golf tournament and $19,548 for an advertisement in "Restauranteur of Arizona").

Q. Have you made any other adjustments to the Other O&M Expense lag?

A. Yes. In response to RUCO data request 6.1, the Company indicated that it had made some errors in the compilation of the lag days for three invoices. As shown on Schedule RLM-6, page 4, column (B), I have corrected those errors.

Removal of the vouchers and correcting the lag days results in an adjusted Other O&M Expense lag of 17.72 days.

Q. Are any other corrections and/or adjustments necessary to the Company's lead/lag calculations?

A. Yes. As shown on Schedule RLM-6, page 2, column (B), I have adjusted the expense levels included in the lead/lag study to reflect RUCO's proposed level of expenses. This adjustment is necessary to synchronize the lead/lag study with RUCO's pro-forma operating expenses.

Q. Did you review the other components the Company included in its working capital request?

A. Yes. I reviewed the Materials and Supplies and Prepayment balances the Company included in its working capital request.

Q. Are any adjustments necessary to these components?

A. Yes. The 13-month average Prepayment balance should be adjusted. As just discussed above, the Company had misclassified several test-year expenditures as O&M expenses, when in fact these expenditures were Prepayments. I have removed these expenditures from the O&M expenses included in the lead/lag study and I made a corresponding adjustment to include these amounts in the test year Prepayments balance (except for the two invoices deemed unnecessary - $17,200 as a sponsor for a golf tournament and $19,548 for an advertisement in "Restauranteur of Arizona").

As shown on Schedule RLM-6, page 5, I have transferred these expenditures into the applicable month of the Prepayments account. I have also reflected the effect on the Prepayment balance in each ensuing month of the amortization of the prepayment.

This adjustment increases the 13-month average Prepayment balance by $4,013,462.

Q. Please summarize your adjustment to working capital?

A. RUCO recommends that the Company's cash working capital request be adjusted to correct certain errors the Company made in its lead/lag study, to reclassify certain test-year expenditures from O&M expense to Prepayments, remove unnecessary expenditures and to synchronize with RUCO's operating expense adjustments.

As shown on Schedule RLM-6, page 1, a decrease in the Company's working capital request of $4,507,854 is necessary.

OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. As shown on Schedule RLM-8, pages 1 through 2, columns (B) through (Q), I analyzed the Company's sixteen adjustments to its historical test-year operating income and made several adjustments to the operating income as filed by the Company. My review, analysis and adjustments are explained below.

SWG Operating Income Adjustment No. 1 – Labor and Labor Loading Annualization Expense

Q. Please explain your adjustment to labor and labor loading expenses.

A. RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. Therefore, I disallowed the Company's proposed wage increases to be effective in June 2008.

Q. Please explain your computation associated with your adjustment.

A. After an analysis of the Company's workpapers, I accepted SWG's values and methodology utilized to annualize the labor and labor loading, which included annualization of the test-year payroll plus a 3 percent post test-year payroll increase. However, to adhere to the Historical Test-Year

principle I made one adjustment to the Company's formula. I adjusted the Company's proposed wage increase to be effective in June 2008 to zero; no other adjustments to the Company's calculation of the annualization of the labor and labor loading expense were made.

Q. Why is RUCO disallowing the June 2008 wage increase?

A. The inclusion of the June 2008 wage increase has the effect of triple-counting the increases in the salary and wage accounts - once for annualization of the test-year salaries, a second time for the post test-year 2007 three percent increase, and a third time for the 2008 increase. The Company's annualization adjustment to reflect estimated levels that will be in effect in June 2008 creates a mismatch between rate base, revenues and expenses at the end of the test year. If the Commission were to authorize rate recovery of the June 2008 payroll increases, the Company would be creating biased rates by picking and choosing which rate base, expense and revenue items it will reflect on an actual, projected or annualized basis. The Company's logic that the June 2008 wage increases should be allowed because they will be known and measurable prior to the hearing in this proceeding could be extended to all other operating income elements, since the Company will have recorded data through May 2008 by the time the hearing commences; yet SWG did not request post test year treatment of any other rate base, expense, or revenue items.

Q. Please explain the rationale of RUCO's recommendation to include the within grade movement and general wage increase effective May 2007 and June 2007 respectively, in the context of RUCO's strict adherence to the Historical Test-Year principle.

A. RUCO carefully analyzed the timeliness of the labor cost increases effective May 2007 and June 2007. Since the increases occurred within days of the end of the test year, RUCO will accept as reasonable the allowance of such annual adjustments for ratemaking treatment. This is reasonable because these annual increases do not accurately coincide with the staggered test year used in this case. Had SWG choose a test year ending two months later these wage increases would have automatically been included in operating expenses.

As shown on Schedule RLM-8, column (B) and supporting Schedule RLM-9, my adjustment decreases adjusted test-year expenses by $2,613,490.

Operating Income Adjustment No. 2 – Injury and Damages Expenses

Q. Please explain your adjustment to injury and damages expenses.

A. This is a conforming adjustment corresponding to the Company's responses to RUCO Data Request 2.5 and Staff Data Request 1.53, which recognized a failure to acknowledge $283,664 in expenses in the Company's original filing.

Therefore, as shown on Schedule RLM-8, column (C), this adjustment increased test-year expenses by $283,664.

Operating Income Adjustment No. 3 – Pauite Allocation Annualization Expense

Q. Please explain your adjustment to the Pauite allocation expense.

A. This is a conforming adjustment corresponding to the Company's responses to RUCO Data Request 2.5 and Staff Data Request 1.85, which acknowledged a failure to remove an aggregate $17,702 in expenses in the Company's original filing.

Therefore, as shown on Schedule RLM-8, column (D), this adjustment decreased test-year expenses by $17,702.

Operating Income Adjustment No. 4 – Depreciation and Amortization Annualization Expense

Q. Please explain your adjustment to depreciation and amortization expenses.

A. The adjustment is primarily attributable to RUCO's rate base adjustments. RUCO agrees with the set of depreciation rates that SWG is proposing to implement on a going-forward basis and to amortize the intangible plant included in the annualization adjustment over a three-year period.

As shown on Schedule RLM-8, column (E) and supporting Schedule RLM-10, pages 1 through 3, my adjustment decreases adjusted test-year expenses by $58,204.

Operating Income Adjustment No. 5 – Property Tax Expense

Q. Do you agree with SWG's methodology for computing gas utility property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes. The difference in the amount I calculated versus the Company is solely a result of our respective levels of recommended net plant in service.

As shown on Schedule RLM-8, column (F) and supporting Schedule RLM-11, RUCO and the Company, at the time of this filing, are in agreement on the level of test-year net plant in service; therefore, the adjustment increases adjusted test-year expenses by $0.

Operating Income Adjustment No. 6 – Disallowance of Inappropriate and/or Unnecessary Expenses

Q. Please explain your analysis of the various operating expense accounts that result in your removal of inappropriate or unnecessary costs for the provisioning of gas service.

A. After review of all the journal entries in various FERC accounts and the Company's response to RUCO Data Request 5.1, I determined there were numerous expenditures that were questionable, inappropriate, extravagant and/or unnecessary.

Therefore, as summarized on Schedule RLM-12, I have made an adjustment to remove test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service. The back-up documentation denoting each individual expense removed is recorded in Revised Exhibit A: FERC Account Code 880, pages 1 to 18, FERC Account 921, pages 1 to 14, FERC Account 923, page 1, and FERC Account 930, page 1.

RUCO provided SWG with a copy of the original Exhibit A in a data request to the Company. SWG concurred with RUCO in certain transactions and withdrew its request for recovery. The Company also

responded with comments as to the appropriateness and necessity of each expense. After analyzing the Company's response, RUCO removed $312,932 from the $517,302 test-year expenses submitted on the original Exhibit A.

However, of the questionable invoices originally submitted by RUCO on Exhibit A there still remain expenditures that are questionable, inappropriate, extravagant and/or unnecessary and that the Company deems as appropriate charges for recovery from customers in rates. Such "appropriate charges" include:

1. Massages for $2,160;
2. Gift certificates to theaters, restaurants and shopping malls for $18,230;
3. Water, ice, coffee, beverages and refreshments for Company offices for $66,422;
4. Breakfast, lunch and dinners for meetings for $71,358;
5. Management off-site meetings at the Crowne Plaza Hotel, J W Marriott Starr Pass Resort and Spa, Orange Tree Golf Resort for $8,835; and
6. One Board of Directors' Meeting at the Southern Highlands Golf Course (Company adjusted) for $5,365. (SWG agreed to remove $3,107.51 itemized as beverages).

As shown on Schedule RLM-8, column (G) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $204,370.

Operating Income Adjustment No. 7 – Management Incentive Program

Q. Please provide an explanation for RUCO's adjustment to the management incentive program ("MIP") expenses.

A. After reviewing the Commission's position on MIP expense as authorized in the recent UNS Gas rate case (Decision No. 70011, dated November 27, 2007); RUCO recommends a 50/50 sharing as a reasonable balancing of the interests between ratepayers and shareholders. The MIP is comprised of elements that relate to the Company's financial performance and cost containment goals, matters that primarily benefit shareholders; plus elements based on meeting customer service goals, which offers opportunity for the Company's customers to benefit from improved performance.

Therefore, I split the MIP expense level on a 50/50 basis.

As shown on Schedule RLM-8, column (H) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $1,905,048.

1 Operating Income Adjustment No. 8 – Supplemental Executive Retirement
2 Plan
3 Q. Please explain the basis for the adjustment you made to Supplemental
4 Executive Retirement Plan ("SERP") expenses.
5 A. The SERP is a retirement plan that is provided to a small select group of
6 high-ranking officers of the Company. The high-ranking officers who are
7 covered under the SERP receive these benefits in addition to the regular
8 retirement plan.
9
10 Q. Should ratepayers be required to pay the cost of supplemental benefits for
11 the high-ranking officers of the Company?
12 A. No. The cost of supplemental benefits for high-ranking officers is not a
13 necessary cost of providing electric service. These individuals are already
14 fairly compensated for their work and are provided with a wide array of
15 benefits including a medical plan, dental plan, life insurance, long term
16 disability, paid absence time, and a retirement plan. If the Company feels
17 it is necessary to provide additional perks to a select group of employees it
18 should do so at its own expense.
19
20 Q. In recent ACC Decisions did the Commissioners determine whether SERP
21 expenses were recoverable?
22 A. Yes. Recently, the Commission agreed with RUCO that SERP expenses
23 should not be the burden of ratepayers. In Southwest Gas' latest rate

case, (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses. In Arizona Public Service's most recent rate case, (Decision No. 69663, dated June 28, 2007), the Commission voted to disallow SERP. Moreover, the Commission voted to disallow SERP in the UNS Gas rate case (Decision No. 70011, dated November 27,2007). There is no reason to depart from this precedent; therefore, RUCO recommends the removal of the test-year cost of the SERP from operating expenses.

As shown on Schedule RLM-8, column (I) and supporting Schedule RLM-14, this adjustment decreased test-year expenses by $1,940,914.

Operating Income Adjustment No. 9 – Employee Recognition

Q. Please explain the basis for your adjustment to operating expenses for the removal of costs associated with employee recognition.

A. As previously explained in Operating Expense Adjustment No. 6, RUCO believes it is inappropriate to burden ratepayers with expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service.

Therefore, in the Company's responses to RUCO data request 2.4 and Staff Data Request 1.42, SWG acknowledged $54,174 was recorded in the test-year general ledger for employee recognition, this amount included expenses for such things as gift certificates to theaters, restaurants and shopping malls, etc.. The Company's response also states that no portion of the $54,174 has been removed in any other adjustment.

As shown on Schedule RLM-8, column (J), this adjustment decreased test-year expenses by $54,174.

Operating Income Adjustment No. 10 – Uncollectible Expense

Q. Please explain the basis for your adjustment to operating expenses for the decrease in the uncollectible expense.

A. Through discovery I reviewed and analyzed three years of expenses recorded in FERC account 904 – uncollectible accounts from 2004 through 2006.

My analysis indicated this expense was sufficiently volatile to recommend a test year adjustment to acknowledge the wide variation in annual costs and to provide recovery of a normalized level of uncollectibles.

My adjustment to the test year uncollectible expense in the instant case consisted of two elements. First, I calculated the annual three-year average of the ratio of the yearly uncollectible expense to that year's revenue for 2004 through 2006. Second, I multiplied this computed average ratio by RUCO's adjusted test-year revenue.

As shown on Schedule RLM-8, column (K) and supporting Schedule RLM-15, this adjustment decreased test-year expenses by $752,652.

Operating Income Adjustment No. 11 – Gain On The Sale Of Property

Q. Please explain your adjustment to operating expenses for the equity realized from the Company's sale of property.

A. In its response to Staff data request 9.1, the Company acknowledged it is appropriate to share the gain on the disposition of assets with the ratepayers on a 50/50 basis. Therefore, my adjustment reflects a 50 percent share of the net proceeds realized from the sale of land and structures identified through discovery.

Historically, the Commission has determined similar adjustments should be amortized over a multi-year period; so to be consistent with the Commission's decision and other adjustments in this case, the gain has been amortized over a three-year period.

As shown on Schedule RLM-8, column (L) and supporting Schedule RLM-16, this adjustment decreased test-year expenses by $69,699.

Operating Income Adjustment No. 12 – Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule RLM-8, column (Q) and supporting Schedule RLM-17, this adjustment increased test-year expenses by $3,118,244.

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

Q. Please explain your contribution to RUCO's recommended rate designs.

A. I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). I am in agreement with the bill determinants normalized by the Company. My recommended bill determinants are an integral part of the rate design presented on Schedule RLM-19, pages 1 through 4, to be filed on April 11, 2008.

Ms. Marylee Diaz Cortez will discuss RUCO's proposed rate design and structure in her testimony.

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that my recommended rate design will produce the recommended required revenue as illustrated, is presented also on Schedule RLM-19.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes, as shown on RLM-18, this adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 62 basis points from 9.45 to 8.83 percent to reflect current market conditions. This adjustment is fully explained in the testimony of RUCO witness William A. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX 1

Qualifications of Rodney Lane Moore

EDUCATION: Athabasca University
Bachelor's Degree in Business Administration - 1993

EXPERIENCE: Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona 85007
May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.
Rio Verde Utilities, Inc	WS-02156A-00-0321
Black Mountain Gas Company	G-03703A-01-0283
Green Valley Water Company	W-02025A-01-0559
New River Utility Company	W-01737A-01-0662

Utility Company	Docket No.
Dragoon Water Company	W-01917A-01-0851
Roosevelt Lake Resort, Inc.	W-01958A-02-0283
Southwest Gas Company	G-01551A-02-0425
Arizona-American Water Company	W-01303A-02-0867 et al.
Rio Rico Utilities, Inc.	WS-02676A-03-0434
Qwest Corporation	T-01051B-03-0454
Chaparral City Water Company	W-02113A-04-0616
Southwest Gas Company	G-01551A-04-0876
Arizona-American Water Company	W-01303A-05-0405
Far West Water and Sewer Company	WS-03478A-05-0801
Gold Canyon Sewer Company	SW-02519A-06-0015
Arizona-American Water Company	WS-01303A-06-0403
UNS Gas, Inc.	G-04204A-06-0463 et al.
UNS Electric, Inc.	E-04204A-06-0783
Tucson Electric Power Company	E-01933A-07-0402

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

TABLE OF CONTENTS TO RUCO SCHEDULES

LINE NO.	SCH. NO.	PAGE NO.	TITLE
1	RLM-1	1 & 2	REVENUE REQUIREMENT
2	RLM-2	1	RATE BASE - ORIGINAL COST
3	RLM-3	1	RATE BASE - RECONSTRUCTED COST NEW DEPRECIATED
4	RLM-4	1 & 2	SUMMARY OF TEST-YEAR PLANT ADJUSTMENTS
5	RLM-5	1 & 2	RATE BASE ADJUSTMENT NO. 1 - COMPLETED CONSTRUCTION NOT CLASSIFIED
6	TESTIMONY, RLM		RATE BASE ADJUSTMENT NO. 2 - MISCELLANEOUS INTANGIBLE PLANT
7	TESTIMONY, RLM		RATE BASE ADJUSTMENT NO. 3 - RETIRED TEP BYPASS PLANT
8	RLM-4	3	RATE BASE ADJUSTMENT NO. 4 - ADIT ASSOCIATED WITH MIP AND SERP
9	RLM-6	1 TO 5	RATE BASE ADJUSTMENT NO. 5 - CALCULATION OF WORKING CAPITAL
10	RLM-7	1	OPERATING INCOME
11	RLM-8	1 & 2	SUMMARY OF OPERATING INCOME ADJUSTMENTS
12	RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 1 - LABOR ANNUALIZATION
13	TESTIMONY, RLM		OPERATING INCOME ADJUSTMENT NO. 2 - INJURIES AND DAMAGES EXPENSES
14	TESTIMONY, RLM		OPERATING INCOME ADJUSTMENT NO. 3 - PAIUTE ALLOCATION ANNUALIZATION
15	RLM-10	1 & 2	OPERATING INCOME ADJUSTMENT NO. 4 - ANNUALIZED DEPRECIATION AND AMORTIZATION EXPENSE
16	RLM-11	1	OPERATING INCOME ADJUSTMENT NO. 5 - PROPERTY TAX
17	RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 6 - UNNECESSARY/INAPPROPRIATE EXPENSES
18	RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 7 - MANAGEMENT INCENTIVE PROGRAM
19	RLM-14	1	OPERATING INCOME ADJUSTMENT NO. 8 - SUPPLEMENTAL EMPLOYEE RETIREMENT PLAN
20	TESTIMONY, RLM		OPERATING INCOME ADJUSTMENT NO. 9 - EMPLOYEE RECOGNITION
21	RLM-15	1	OPERATING INCOME ADJUSTMENT NO. 10 - UNCOLLECTIBLE EXPENSE
22	RLM-16	1	OPERATING INCOME ADJUSTMENT NO. 11 - GAIN ON SALE OF PROPERTY
23	RLM-17	1	INCOME TAX CALCULATION
24	RLM-18	1	COST OF CAPITAL
25	RLM-19	1 TO 4	RATE DESIGN AND PROOF OF RECOMMENDED REVENUE (FILED SEPERATELY)

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	$ 1,089,321,967	$ 1,837,965,254	$ 1,463,643,611
2	Adjusted Operating Income (Loss)	$ 73,180,098	$ 73,180,098	$ 73,180,098	$ 77,394,464	$ 77,394,464	$ 77,394,464
3	Current Rate Of Return (Line 2 / Line 1)	6.68%	3.97%	4.98%	7.10%	4.21%	5.29%
4	Required Operating Income (Line 5 X Line 1)	$ 103,457,659	$ 103,457,659	$ 103,457,659	$ 96,226,345	$ 96,226,345	$ 96,226,345
5	Required Rate Of Return	9.45%	5.61%	7.04%	8.83%	5.24%	6.57%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 30,277,561	$ 30,277,561	$ 30,277,561	$ 18,831,882	$ 18,831,882	$ 18,831,882
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 2)	1.6586	1.6586	1.6586	1.6619	1.6619	1.6619
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 50,219,828	$ 50,219,828	$ 50,219,828	$ 31,296,285	$ 31,296,285	$ 31,296,285
9	Adjusted Test Year Revenue	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)	$ 449,454,506	$ 449,454,506	$ 449,454,506	$ 430,530,964	$ 430,530,964	$ 430,530,964
11	Required Percentage Increase In Revenue (Line 8 / Line 9)	12.58%	12.58%	12.58%	7.84%	7.84%	7.84%
12	Rate Of Return On Common Equity	11.25%	11.25%	11.25%	9.88%	9.88%	9.88%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Columns (D) Thru (F): Schedules RLM-2, RLM-5, RLM-6 And RLM-18

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		1.0000
2	Less: Uncollectibles	Adjusted 3-Yr Average Uncollectible Expense (See RLM-15)	0.0022
3	Subtotal	Line 1 - Line 2	0.9978
4	Less: Combined Federal And State Tax Rate	Line 14	39.60%
5	Subtotal	Line 3 - Line 4	0.6017
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6619**
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		1.0000
8	Arizona State Income Tax Rate		0.0697
9	Federal Taxable Income	Line 7 - Line 8	0.9303
10	Applicable Federal Income Tax Rate	Tax Table	35.17%
11	Effective Federal Income Tax Rate	Line 9 X Line 10	0.3272
12	Subtotal	Line 8 + Line 11	0.3969
13	Revenue Less Uncollectibles	Line 3	0.9978
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	39.60%

Southwest Gas Corporation
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Test Year Ended April 30, 2007

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO OCRB ADJUSTMENTS	REF.	(C) RUCO ADJUSTED AS OCRB
1	Gas Plant In Service	$ 2,053,847,890	$ (356,233)	(1)	$ 2,053,491,657
	Less:				
2	Accumulated Depreciation And Amortization	752,275,563	(276,996)	(1)	751,998,567
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 1,301,572,327	$ (79,237)		$ 1,301,493,090
	Additions:				
4	Allowance For Working Capital (RLM-6, Page 1)	$ 5,681,932	$ (4,507,854)	(2)	$ 1,174,078
5	Total Additions (Line 4)	$ 5,681,932	$ (4,507,854)		$ 1,174,078
	Deductions:				
6	Customer Advances In Aid Of Construction	$ (37,910,017)	$ -		$ (37,910,017)
7	Customer Deposits	(31,921,898)	-		(31,921,898)
8	Deferred Income Taxes	(142,632,297)	(880,989)	(3)	(143,513,286)
9	Total Deductions (Sum Of Lines 6, 7 & 8)	$ (212,464,212)	$ (880,989)		$ (213,345,201)
10	TOTAL ORIGINAL COST RATE BASE (Sum Of Lines 3, 5 & 9)	$ 1,094,790,047	$ (5,468,080)		$ 1,089,321,967

References:
- Column (A): Company Schedule B-1
- Column (B): References:
  - (1) Schedule RLM-4, Page 1
  - (2) Schedule RLM-6, Page 1
  - (3) Schedule RLM-3, Page 3
- Column (C): Column (A) + Column (B)

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

RATE BASE - RECONSTRUCTED COST NEW DEPRECIATED

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS RCND	(B) RUCO RCND ADJUSTMENTS	(C) RUCO ADJUSTED AS RCND
1	Gas Plant In Service	$ 3,224,193,614	$ (559,226)	$ 3,223,634,388
	Less:			
2	Accumulated Depreciation And Amortization	1,173,930,265	(432,254)	1,173,498,011
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 2,050,263,349	$ (126,972)	$ 2,050,136,377
	Additions:			
4	Allowance For Working Capital	$ 5,681,932	$ (4,507,854)	$ 1,174,078
5	Total Additions (Line 4)	$ 5,681,932	$ (4,507,854)	$ 1,174,078
	Deductions:			
6	Customer Advances In Aid Of Construction	$ (37,910,017)	$ -	$ (37,910,017)
7	Customer Deposits	(31,921,898)	-	(31,921,898)
8	Deferred Income Taxes	(142,632,297)	(880,989)	(143,513,286)
9	Total Deductions (Sum Lines 6, 7 & 8)	$ (212,464,212)	$ (880,989)	$ (213,345,201)
10	TOTAL RCND RATE BASE	$ 1,843,481,069	$ (5,515,815)	$ 1,837,965,254

References:
Column (A): Company Schedule B-1
Column (B): Column (C) - Column (A)
Column (C): OCRB (RLM-2, Column (C)) X Same Ratio As The Company's RCND Is To Its OCRB (144.84%)

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 1
"DIRECT" TEST-YEAR PLANT SCHEDULES
YEAR ENDED APRIL 30, 2007

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) DEP RATE	(B) COMPANY TEST YEAR AS FILED TOTAL PLANT VALUE	(C) ACCUMULATED DEPRECIATION	(D) ADJUSTMENT NO. 1 RETIREMENTS CCNC PLANT	(E) ACC. DEP.	(F) ADJ. NO. 2 SYS. ALLOC. ONLY	(G) ADJUSTMENT NO. 3 RETIREMENTS "TEP BYPASS" PLANT	(H) ACC.DEP	(I) RUCO AS ADJUSTED TOTAL PLANT VALUE	(J) ACCUMULATED DEPRECIATION	(K) NET PLANT VALUE
		Intangible Plant:											
1	301.0	Organization	Amor'd	$ 42,653	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,653	$ -	$ 42,653
2	302.0	Franchises & Consents	Amor'd	1,877,392	663,783	-	-	-	-	-	1,877,392	663,783	1,213,609
3	303.0	Miscellaneous Intangible	Amor'd	1,957,665	1,950,332	-	-	-	-	-	1,957,665	1,950,332	7,333
4		Total Intangible Plant		$ 3,877,710	$ 2,614,115	$ -	$ -	$ -	$ -	$ -	$ 3,877,710	$ 2,614,115	$ 1,263,595
		Distribution Plant:											
5	374.1	Land & Land Rights	N/A	$ 1,084,811	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,084,811	$ -	$ 1,084,811
6	374.2	Rights Of Way	2.17%	1,064,064	324,955	-	-	-	-	-	1,064,064	324,955	739,109
7	375.0	Structures	0.39%	110,557	64,023	-	-	-	-	-	110,557	64,023	46,534
8	376.0	Mains	3.82%	984,805,304	355,501,160	(22,897)	(22,897)	-	(28,526)	(28,526)	984,753,881	355,449,737	629,304,144
9	378.0	Measuring & Regulating Station	4.12%	32,754,093	3,128,320	(41,047)	(41,047)	-	-	-	32,713,046	3,087,273	29,625,773
10	380.0	Services	5.30%	605,265,994	284,242,868	(1,288)	(1,288)	-	-	-	605,264,706	284,241,580	321,023,126
11	381.0	Meters	1.98%	226,663,229	30,494,483	-	-	-	-	-	226,663,229	30,494,483	196,168,746
12	385.0	Industrial Measuring & Reg. Station	4.31%	7,567,081	3,321,866	(1,145)	(1,145)	-	(182,093)	(182,093)	7,383,843	3,138,628	4,245,215
13	387.0	Other Equipment	5.26%	462,730	560,209	-	-	-	-	-	462,730	560,209	(97,479)
14		Total Distribution Plant		$ 1,859,777,863	$ 677,637,884	$ (66,377)	$ (66,377)	$ -	$ (210,619)	$ (210,619)	$ 1,859,500,867	$ 677,360,888	$ 1,182,139,979
		General Plant:											
15	389.0	Land & Land Rights	N/A	$ 8,418,416	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,418,416	$ -	$ 8,418,416
16	390.1	Structures	1.84%	26,092,410	7,802,105	-	-	-	-	-	26,092,410	7,802,105	18,290,305
17	390.2	Structures - Leasehold Improv'ts	Amor'd	986,219	717,875	-	-	-	-	-	986,219	717,875	268,344
18	391.0	Office Furniture And Equipment	2.73%	5,655,651	920,003	-	-	-	-	-	5,655,651	920,003	4,735,648
19	391.1	Computer Equipment	14.87%	8,563,368	(861,384)	-	-	-	-	-	8,563,368	(861,384)	9,424,752
20	392.1	Transportation Equipment	7.65%	31,153,543	3,183,715	-	-	-	-	-	31,153,543	3,183,715	27,969,828
21	393.0	Stores Equipment	2.08%	542,520	26,553	-	-	-	-	-	542,520	26,553	515,967
22	394.0	Tools, Shop And Garage Equip.	2.17%	5,225,024	(3,434,620)	-	-	-	-	-	5,225,024	(3,434,620)	8,659,644
23	395.0	Laboratory Equipment	3.93%	279,065	(272,649)	-	-	-	-	-	279,065	(272,649)	551,714
24	396.0	Power Operated Equipment	3.88%	4,309,295	892,513	-	-	-	-	-	4,309,295	892,513	3,416,782
25	397.0	Communication Equipment	8.88%	2,658,259	2,623,207	-	-	-	-	-	2,658,259	2,623,207	35,052
26	397.2	Telemetering Equipment	6.19%	789,376	229,416	-	-	-	-	-	789,376	229,416	559,960
27	398.0	Miscellaneous Equipment	4.53%	892,348	18,215	-	-	-	-	-	892,348	18,215	874,133
28		Total General Plant		$ 95,565,494	$ 11,844,949	$ -	$ -	$ -	$ -	$ -	$ 95,565,494	$ 11,844,949	$ 83,720,545
				$ 1	$ (1)						$ 1	$ (1)	$ 2
29		TOTAL DIRECT PLANT		$ 1,959,221,068	$ 692,096,947	$ (66,377)	$ (66,377)	$ -	$ (210,619)	$ (210,619)	$ 1,958,944,072	$ 691,819,951	$ 1,267,124,121
30		Allocated Plant (See RLM-4, Page 2, Line 31)		94,626,822	60,178,616	-	-	(79,237)	-	-	94,547,585	60,178,616	34,368,969
31		TOTAL PLANT		$ 2,053,847,890	$ 752,275,563	$ (66,377)	$ (66,377)	$ (79,237)	$ (210,619)	$ (210,619)	$ 2,053,491,657	$ 751,998,567	$ 1,301,493,090
32		Direct Plant As Per Company		$ 1,959,221,068	$ 692,096,947	$ -	$ -	$ -	$ -	$ -	$ 1,959,221,068	$ 692,096,947	1,267,124,121
		Common Plant As Per Company		94,626,822	60,178,616	-	-	-	-	-	94,626,822	60,178,616	34,448,206
33		Difference		$ -	$ -	$ (66,377)	$ (66,377)	$ (79,237)	$ (210,619)	$ (210,619)	$ (356,233)	$ (276,996)	$ (79,237)

References:

Columns (A) (B) (C): Company Workpapers
Column (D): Retirements Assoicated With CCNC (See RLM-5)
Column (E): Accumulated Depreciation Assoicated CCNC (See Testimony, RLM)
Columns (F): System Allocable Adjustment Only (See RLM-4, Page 2)
Column (G): Retirements Assoicated With The Sale Of The TEP Bypass (See Testimony, RLM)
Column (H): Accumulated Depreciation Assoicated With The Sale Of The TEP Bypass (See Testimony, RLM)
Column (I): Sum Of Cols. (B), (D) & (G)
Column (J): Sum Of Cols. (C), (E) & (H)
Column (K): Column (I) - Column (J)

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 2
"SYSTEM ALLOCABLE" TEST-YEAR PLANT SCHEDULES
YEAR ENDED APRIL 30, 2007

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) DEP RATE	(B) COMPANY TEST YEAR AS FILED TOTAL PLANT VALUE	(C) COMPANY TEST YEAR AS FILED ACCUMULATED DEPRECIATION	(D) ADJ. NO. 1 DIRECT ADJM'T ONLY	(E) ADJ. NO. 2 INTANGIBLES RLM-10, PG 3,	(F) RUCO AS ADJUSTED TOTAL PLANT VALUE	(G) RUCO AS ADJUSTED ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible Plant:								
1	301.0	Organization	0.00%	$ 61,816	$ -	$ -	$ -	$ 61,816	$ -	$ 61,816
2	302.0	Franchises & Consents	Amor'd	-	-	-	-	-	-	-
3	303.0	Miscellaneous Intangible	Amor'd	113,344,261	80,931,738	-	(139,748)	113,204,513	80,931,738	32,272,775
4		Total Intangible Plant		$ 113,406,077	$ 80,931,738	$ -	$ (139,748)	$ 113,266,329	$ 80,931,738	$ 32,334,591
		Distribution Plant:								
5	374.1	Land & Land Rights	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	374.2	Rights Of Way	N/A	-	-	-	-	-	-	-
7	375.0	Structures	N/A	-	-	-	-	-	-	-
8	376.0	Mains	N/A	-	-	-	-	-	-	-
9	378.0	Measuring & Regulating Station	N/A	-	-	-	-	-	-	-
10	380.0	Services	N/A	-	-	-	-	-	-	-
11	381.0	Meters	N/A	-	-	-	-	-	-	-
12	385.0	Indiustrial Measuring & Reg. Station	N/A	-	-	-	-	-	-	-
13	387.0	Other Equipment	N/A	-	-	-	-	-	-	-
14		Total Distribution Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -
		General Plant:								
15	389.0	Land & Land Rights	0.00%	$ 391,307	$ -	$ -	$ -	$ 391,307	$ -	$ 391,307
16	390.1	Structures	2.50%	13,961,544	3,733,837	-	-	13,961,544	3,733,837	10,227,707
17	390.2	Structures - Leasehold Improv'ts	Amor'd	4,232,644	3,118,764	-	-	4,232,644	3,118,764	1,113,880
18	391.0	Office Furniture And Equipment	8.16%	9,441,847	1,264,958	-	-	9,441,847	1,264,958	8,176,889
19	391.1	Computer Equipment	16.15%	14,791,422	12,836,794	-	-	14,791,422	12,836,794	1,954,628
20	392.1	Trans. Equip. - Light Vehicles	7.20%	3,495,826	646,045	-	-	3,495,826	646,045	2,849,781
21	393.0	Trans. Equip. - Heavy Vehicles	7.20%	86,303	(37,694)	-	-	86,303	(37,694)	123,997
22	394.0	Stores Equipment	16.03%	24,106	5,299	-	-	24,106	5,299	18,807
23	395.0	Tools, Shop And Garage Equip.	11.16%	232,096	(24,943)	-	-	232,096	(24,943)	257,039
24	396.0	Laboratory Equipment	4.77%	281,078	75,601	-	-	281,078	75,601	205,477
25	397.0	Communication Equipment	8.51%	5,376,875	3,611,659	-	-	5,376,875	3,611,659	1,765,216
26	397.2	Telemetering Equipment	40.23%	286,958	27,661	-	-	286,958	27,661	259,297
27	398.0	Miscellaneous Equipment	11.09%	882,254	(54,592)	-	-	882,254	(54,592)	936,846
28		Total General Plant		$ 53,484,260	$ 25,203,389	$ -	$ -	$ 53,484,260	$ 25,203,389	$ 28,280,871
29		TOTAL ALLOCABLE PLANT		$ 166,890,337	$ 106,135,127	$ -	$ (139,748)	$ 166,750,589	$ 106,135,127	$ 60,615,462
30		Allocation Factor		56.70%	56.70%	56.70%	56.70%	56.70%	56.70%	56.70%
				1	(1)			1	(1)	
31		TOTAL ALLOCATE PLANT		$ 94,626,822	$ 60,178,616	$ -	$ (79,237)	$ 94,547,585	$ 60,178,616	$ 34,368,967

References:

Columns (A) (B) (C): Company Workpapers
Column (D): Direct Plant Adjustment Only (See RLM-4, Page1)
Columns (E): Company Response To Staff Data Request 11.4 (See RLM-10, Page 3, Column (B))

Column (F): Sum Of Cols. (B) & (D)
Column (G): Sum Of Cols. (C) & (D)
Column (H): Column (F) - Column (G)

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 4
ACCUMULATED DEFERRED INCOME TAX (ADIT) ASSOCIATED WITH MIP AND SERP

LINE NO	DESCRIPTION	(A) ADIT ASSOCIATED WITH MIP ACCT 20701371	(B) ADIT ASSOCIATED WITH MIP ACCT 24201371	(C) ADIT ASSOCIATED WITH SERP ACCT 24201387	REFERENCE
	Deferred Income Tax Asset (Liability)				
1	April 30, 2007	$ 406,289	$ 1,775,833	$ 7,804,183	Co. Response To Staff DR 11-11
2	April 30, 2006	631,459	497,556	7,449,748	Co. Response To Staff DR 11-11
3	Test-Year ADIT	$ 225,170	$ (1,278,277)	$ (354,435)	Sum Lines 1 And 2
4	Total ADIT Assoicated With MIP		$ (1,053,107)		Sum Columns (A) & (B), Line 3
5	RUCO Adjustment To Split MIP 50% - Ratepayers & Shareholders		50.00%		See RLM Testimony & RLM-13
6	RUCO Adjusted MIP		$ (526,554)		Line 4 X Line 5
7	RUCO Adjusted SERP			$ (354,435)	Line 3, Column (C)
8	Total Adjustment To Test-Year ADIT			$ (880,989)	Sum Line 6 And 7
9	RUCO Adjustment (See RLM-2, Column (B), Line 8)			$ (880,989)	Line 8

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EXPLANATION OF SWG TEST-YEAR RATE BASE ADJUSTMENT NO. 1 - CONT'D
COMPLETED CONSTRUCTION NOT CLASSIFIED

LINE NO.	ACCT. NO.	DESCRIPTION	(A) CONST. WK ORDER	(B) RETIRE'T WK ORDER	(C) IN-SER. DATE	(D) ACTUAL CONST. COST	(E) ACTUAL RETIRE'T COST
		ARIZONA DIRECT					
		Intangible Plant					
1	303	Miscellaneous Intangible				$ -	$ -
2		Total Intangible				$ -	$ -
		Distribution					
3	374	Land and Land Rights				$ 733,126	$ -
		Mains					
4	376	Franchise Replacements				$ 527,574	$ -
5	376	Regular Replacement				190,569	-
6	376	Pressure Reinforcement				121,747	-
7	376	Cathodic Protection				171,752	-
8	376	High Pressure Dist.				518,422	-
9		Total Acct 376				$ 1,530,064	$ (22,897)
10	378	Regulator Station				$ 325,675	$ (41,047)
11	380	Services				-	(1,288)
12	385	Regulator Station-Lrg				117,130	(1,145)
13		Total Distribution Plant				$ 2,705,995	$ (66,377)
		General					
14	390.1	Structures and Improve.				$ 27,443	$ -
15	391	Office Furniture & Equip.				215,492	-
16	392	Transportation Equip.				27,184	-
17	391.1	Computer Equipment				-	-
18		Total General Plant				$ 270,120	$ -
19		SUBTOTAL ARIZONA DIRECT CCNC PLANT				$ 2,976,115	$ (66,377)
		SYSTEM ALLOCATE PLANT					
		Intangible Plant					
20	303	Miscellaneous Intangible				$ 1,696,000	$ -
21		Total Intangible				$ 1,696,000	$ -
		General					
22	390.1	Structures and Improve.				$ 265,254	$ -
23	391	Office Furniture & Equip.				28,258	-
24	392	Transportation Equip.				-	-
25	391.1	Computer Equipment				432,587	-
26		Total General Plant				$ 726,099	$ -
27		SUBTOTAL SYSTEM ALLOCATE CCNC PLANT				$ 2,422,099	$ -
28		Allocation Factor (Arizona 4-Factor)				56.70%	56.70%
29		SUBTOTAL AMOUNT ALLOCATED TO ARIZONA CCNC PLANT				$ 1,373,330	$ -
30		TOTAL CCNC PLANT				$ 4,349,445	$ (66,377)
31		RUCO RECOMMENDED TOTAL CCNC PLANT				$ 4,349,445	$ (66,377)
32		Company As Filed				4,349,445	-
33		RUCO ADJUSTMENT TO ARIZONA DIRECT CCNC				$ -	$ (66,377)

Reference
Columns (A) (B): Company Response To RUCO Date Request No. 1.17 And 2.1

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5
SUMMARY OF THE ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	
1	Cash Working Capital Per SWG	SWG SCH. B-5, Page 1	$	(10,379,937)
2	Cash Working Capital Per RUCO	RLM-6, Page 2, Line 14		(15,229,282)
3	Adjustment	Line 2 - Line 1	$	(4,849,345)
4	Materials And Supplies Per SWG	SWG SCH. B-5, Page 1	$	12,389,898
5	Materials And Supplies Per RUCO	SWG SCH. B-5, Page 1		12,389,898
6	Adjustment	Line 5 - Line 4	$	-
7	Prepayments Per SWG	SWG SCH. B-5, Page 1	$	3,671,971
8	Prepayments Per RUCO	RLM-6, Page 5, Line 15		4,013,462
9	Adjustment	Line 8 - Line 7	$	341,491
10	Total Adjustment	Sum Lines 3, 6, & 9	$	(4,507,854)

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EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
1	Cost Of Gas	$ 540,064,385	$ -	$ 540,064,385	42.30	$ 22,842,405,297
2	Labor Cost	117,038,570	(6,513,626)	110,524,944	12.33	1,363,305,727
3	Provision For Uncollectible Accts	2,977,729	(752,652)	2,225,077	120.00	267,009,303
4	Other O & M	54,826,860	(8,127)	54,818,733	17.72	971,137,425
	Total O & M Expenses	$ 714,907,544	$ (7,274,405)	$ 707,633,139	35.96	$ 25,443,857,753
5	Interest	$ 48,035,008	1,675,397	$ 49,710,405	82.73	$ 4,112,541,775
6	Taxes Other Than Income Taxes	33,124,880	-	33,124,880	185.34	6,139,365,177
7	Income Taxes	21,699,571	9,975,295	31,674,866	37.00	1,171,970,019
8	Revenue Taxes	97,747,450	3,201,610	100,949,060	51.75	5,224,113,855
9	Total Operating Expenses	$ 915,514,453	$ 4,376,287	$ 923,092,350	45.60	$ 42,091,848,579
10	Revenue Lag				39.53	Co. Workpapers
11					(6.07)	Line 10 - Line 9
12	Number Of Days In Test Period	365	Test Year			
13	Average Daily Operating Expenses	$ 2,508,259	Col. (A) Line 9 / Line 12			
14	Net Difference Rev - Exp Lag	(6.07)	Col. (D) Line 11			
15	Cash Working Capital	$ (15,229,282)	Col. (A), Line 13 X Line 14			

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL
CALCULATION OF PREFERRED EQUITY LAG

LINE NO.	MID-POINT OF SERVICE PERIOD	(A) PAYMENT DATE	(B) PERCENT PAYMENT	(C) (LEAD)/LAG DAYS	(D) DOLLARS DAYS
1	7/1/2006	3/31/2006	25.00%	(92)	(23.00)
2	7/1/2006	6/30/2006	25.00%	(1)	(0.25)
3	7/1/2006	9/30/2006	25.00%	91	22.75
4	7/1/2006	12/31/2006	25.00%	183	45.75
5	Totals		100.00%		45.25
6	Preferred Equity Lag			45.25	

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL
CALCULATION OF OTHER O & M LAG

LINE NO.	MONTH	(A) COST	(B) LAG DAYS	(C) DOLLAR DAYS
1	May 2006	$ 2,596,715	0.22	$ 566,253
2	June	2,611,117	35.16	91,799,499
3	July	2,546,481	18.55	47,227,421
4	August	2,460,510	36.74	90,404,740
5	September	2,021,521	35.60	71,973,470
6	October	3,018,228	52.99	159,935,937
7	November	2,733,777	45.29	123,820,351
8	December	3,394,550	(6.46)	(21,943,520)
9	January 2007	5,019,712	(2.82)	(14,168,034)
10	February	5,258,382	9.77	51,397,591
11	March	4,466,924	29.44	131,524,579
12	April	2,608,462	(17.75)	(46,306,652)
13	Total	$ 38,736,380	17.72	$ 686,231,635

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL
CALCULATION OF ADJUSTED PREPAYMENTS

LINE NO.	MONTH	(A) BALANCE	(B) DEBITS	(C) CREDITS	(D) ADJUSTED BALANCE
1	April 2006	$ 5,367,019	$ -	$ -	$ 5,367,019
2	May	4,571,452	18,221	-	4,589,673
3	June	3,756,402	-	1,518	3,773,104
4	July	5,219,958	22,000	1,518	5,257,142
5	August	9,299,535	195,806	3,352	9,529,173
6	September	8,623,454	15,186	19,669	8,848,609
7	October	7,836,438	66,720	20,934	8,107,379
8	November	6,430,014	128,656	26,494	6,803,117
9	December	9,144,710	163,132	37,216	9,643,729
10	January 2007	8,343,687	112,506	50,810	8,904,402
11	February	7,723,320	126,085	60,186	8,349,935
12	March	6,044,664	76,149	70,693	6,676,735
13	April	5,600,962	13,396	77,038	6,169,390
14	Total	$ 87,961,615			$ 92,019,406
15	13 Month Average	$ 6,766,278		56.70%	$ 4,013,462

References:
Column (A): Company Schedule B-5, Page 4
Column (B): Company Schedule B-5, Workpaper Sheets 30 - 59
Column (C): Column (B) Prior Months Accurals / 12 Months
Column (D): Column (D) Prior Month + Column (B) Current Month - Column (C) Current Month + Column (A) Current Month - Column (A) Prior Month

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OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
1	Revenues	$ 399,234,678	$ -	$ 399,234,678	$ 31,296,285	$ 430,530,964
2	Gas Cost	-	-	-	-	-
3	TOTAL MARGIN	$ 399,234,678	$ -	$ 399,234,678	$ 31,296,285	$ 430,530,964
	EXPENSES:					
4	Other Gas Supply	$ 701,601	$ (25,254)	$ 676,347	$ -	$ 676,347
5	Distribution	89,528,455	(2,467,490)	87,060,965	-	87,060,965
6	Customer Accounts	38,730,909	(1,811,510)	36,919,399	-	36,919,399
7	Customer Information	1,126,796	(20,117)	1,106,679	-	1,106,679
8	Sales	-	-	-	-	-
	Administrative & General					
9	Direct	4,009,539	(290,519)	3,719,020	-	3,719,020
10	System Allocable	52,937,155	(2,659,515)	50,277,640	-	50,277,640
	Depreciation & Amortization					
11	Direct	80,956,247	(11,621)	80,944,625	-	80,944,625
12	System Allocable	6,646,938	(46,583)	6,600,356	-	6,600,356
13	Regulatory Amortizations	284,528	-	284,528	-	284,528
14	Other Taxes	33,124,880	-	33,124,880	-	33,124,880
15	Interest On Cust. Deposits	1,915,314	-	1,915,314	-	1,915,314
16	Income Taxes	16,092,218	3,118,244	19,210,462	12,464,404	31,674,866
17	TOTAL EXPENSES	$ 326,054,578	$ (4,214,365)	$ 321,840,214	$ 12,464,404	$ 334,304,618
		$ (2)				
18	NET INCOME (LOSS)	$ 73,180,098		$ 77,394,464		$ 96,226,345

References:
- Column (A): Company Schedule C-1
- Column (B): Testimony, RLM And Schedule RLM-8
- Column (C): Column (A) + Column (B)
- Column (D): Testimony, RLM And Schedule RLM-1, Pages 1 & 2
- Column (E): Column (C) + Column (D)

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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 LABOR AND LABOR LOAD SCH. RLM-9	(C) ADJ. NO. 2 INJURIES AND DAMAGES TSTM'Y-RLM	(D) ADJ. NO. 3 PAIUTE ANNUALZ'N TSTM'Y-RLM	(E) ADJ. NO. 4 ANNUALIZED DEP/AMORT SCH. RLM-10	(F) ADJ. NO. 5 ANNUALIZED PROP'TY TAX SCH. RLM-11	(G) ADJ. NO. 6 UNNECESS EXPENSES SCH. RLM-12	(H) ADJ. NO. 7 MIP SCH. RLM-13	(I) ADJ. NO. 8 SERP SCH. RLM-14
1	Revenues	$ 399,234,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ 399,234,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EXPENSES:									
4	Other Gas Supply	$ 701,601	$ (15,070)	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,184)
5	Distribution	89,528,455	(1,364,268)	-	-	-	-	(110,809)	-	(949,044)
6	Customer Accounts	38,730,909	(619,707)	-	-	-	-	-	-	(428,347)
7	Customer Information	1,126,796	(11,910)	-	-	-	-	-	-	(8,206)
8	Sales	-	-	-	-	-	-	-	-	-
	Administrative & General		-	-	-	-	-	-	-	-
9	Direct	4,009,539	(21,716)	-	-	-	-	-	(145,002)	(54,102)
10	System Allocable	52,937,155	(580,819)	283,644	(17,702)	-	-	(93,561)	(1,760,046)	(491,031)
	Depreciation & Amortization		-	-	-	-	-	-	-	-
11	Direct	80,956,247	-	-	-	(11,621)	-	-	-	-
12	System Allocable	6,646,938	-	-	-	(46,583)	-	-	-	-
13	Regulatory Amortizations	284,528	-	-	-	-	-	-	-	-
14	Other Taxes	33,124,880	-	-	-	-	-	-	-	-
15	Interest On Cust. Deposits	1,915,314	-	-	-	-	-	-	-	-
16	Income Taxes	16,092,218	-	-	-	-	-	-	-	-
17	TOTAL EXPENSES	$ 326,054,579	$ (2,613,490)	$ 283,644	$ (17,702)	$ (58,204)	$ -	$ (204,370)	$ (1,905,048)	$ (1,940,914)
18	NET INCOME (LOSS)	$ 73,180,099								

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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(J) ADJ. NO. 9 EMPLOYEE RECOGNITION TSTM'Y-RLM	(K) ADJ. NO. 10 UNCOLL'TIBLE EXPENSE SCH. RLM-15	(L) ADJ. NO. 11 GAIN ON SALE - PROPERTY SCH. RLM-16	(M) INTENT'LY LEFT BLANK	(N) INTENT'LY LEFT BLANK	(O) INTENT'LY LEFT BLANK	(P) INTENT'LY LEFT BLANK	(Q) ADJ. NO. 12 INCOME TAX SCH. RLM-17	(R) RUCO AS ADJUSTED
1	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 399,234,678
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 399,234,678
	EXPENSES:									
4	Other Gas Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 676,347
5	Distribution	(43,370)	-	-	-	-	-	-	-	87,060,965
6	Customer Accounts	(10,804)	(752,652)	-	-	-	-	-	-	36,919,399
7	Customer Information	-	-	-	-	-	-	-	-	1,106,679
8	Sales	-	-	-	-	-	-	-	-	-
									-	-
	Administrative & General	-	-	-	-	-	-	-	-	-
9	Direct	-	-	(69,699)	-	-	-	-	-	3,719,020
10	System Allocable	-	-	-	-	-	-	-	-	50,277,640
					-	-	-	-	-	-
	Depreciation & Amortization	-	-	-	-	-	-	-	-	-
11	Direct	-	-	-	-	-	-	-	-	80,944,625
12	System Allocable	-	-	-	-	-	-	-	-	6,600,356
13	Regulatory Amortizations	-	-	-	-	-	-	-	-	284,528
					-	-	-	-	-	-
14	Other Taxes	-	-	-	-	-	-	-	-	33,124,880
15	Interest On Cust. Deposits	-	-	-	-	-	-	-	-	1,915,314
16	Income Taxes	-	-	-	-	-	-	-	3,118,244	19,210,462
17	TOTAL EXPENSES	$ (54,174)	$ (752,652)	$ (69,699)	$ -	$ -	$ -	$ -	$ 3,118,244	$ 321,840,214
18	NET INCOME (LOSS)									$ 77,394,464

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
LABOR AND LABOR LOADING ADJUSTMENT

LINE NO.	DESCRIPTION	(A) COMPANY LABOR & LABOR LOADING ADJUSTMENT	(B) RUCO LABOR & LABOR LOADING AS ADJUSTED	(C) RUCO LABOR & LABOR LOADING ADJUSTMENT
1	Other Gas Supply	$ 16,522	$ 1,452	$ (15,070)
2	Distribution	1,539,648	175,380	(1,364,268)
3	Customer Accounts	694,914	75,208	(619,707)
4	Customer Information	13,313	1,402	(11,910)
5	Sales	-	-	-
	Administrative & General			
6	Direct	24,518	2,803	(21,716)
7	System Allocable	578,837	(1,982)	(580,819)
8	TOTAL	$ 2,867,752	$ 254,262	$ (2,613,490)
9	RUCO ADJUSTMENT TO LABOR AND LABOR LOADING (See RLM-7, Page 1, Col (B))			$ (2,613,490)

References:
Column (A): Company WP's C-2, Column (d)
Column (B): See RUCO WP's Labor & Loading Adj. # 1 (Deficiency / C-2 Adjustments / Column (d))
Column (C): Column (B) - Column (A)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4
DIRECT PLANT TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.		(A) TOTAL PLANT VALUE	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible Plant:			
1	301	Organization	$ 42,653	Amortized	$ -
2	302	Franchises & Consents	1,877,392	Amortized	61,015
3	303	Miscellaneous Intangible	1,957,665	Amortized	12,594
4		Total Intangible Plant	$ 3,877,710		$ 73,609
		Distribution Plant:			
5	374.1	Land & Land Rights	$ 1,084,811	NA	$ -
6	374.2	Rights Of Way	1,064,064	2.17%	23,051
7	375	Structures	110,557	0.39%	431
8	376	Mains	984,753,881	3.82%	37,617,598
9	378	Measuring & Regulating Station	32,713,046	4.12%	1,347,777
10	380	Services	605,264,706	5.30%	32,079,029
11	381	Meters	226,663,229	1.98%	4,487,932
12	385	Industrial Measuring & Regulating Station	7,383,843	4.31%	318,244
13	387	Other Equipment	462,730	5.26%	24,340
14		Total Distribution Plant	$ 1,859,500,867		$ 75,898,402
		General Plant:			
15	389	Land & Land Rights	$ 8,418,416	NA	$ -
16	390.1	Structures	26,092,410	1.84%	480,100
17	390.2	Structures - Leasehold Improvments	986,219	Amortized	53,321
18	391	Office Furniture And Equipment	5,655,651	2.73%	154,399
19	391.1	Computer Equipment	8,563,368	14.87%	1,273,373
20	392.1	Transportation Equipment	31,153,543	7.65%	2,383,246
21	393	Stores Equipment	542,520	2.08%	11,284
22	394	Tools, Shop And Garage Equipment	5,225,024	2.17%	113,383
23	395	Laboratory Equipment	279,065	3.93%	10,967
24	396	Power Operated Equipment	4,309,295	3.88%	167,201
25	397	Communication Equipment	2,658,259	8.88%	236,053
26	397.2	Telemetering Equipment	789,376	6.19%	48,862
27	398	Miscellaneous Equipment	892,348	4.53%	40,423
28		Total General Plant	$ 95,565,494		$ 4,972,614
29		Total Direct Plant, Depreciation And Amortization	$ 1,958,944,071		$ 80,817,695
30		Total Amortization - Limited Term Gas Plant			126,930
31		Total Depreciation and Amortization			$ 80,944,625
32		Company As Filed	1,959,221,067		80,956,247
33		Difference	(276,996)		$ (11,621)
34	RUCO ADJUSTMENT TO TEST YEAR DIRECT DEPRECIATION EXPENSE (See RLM-8, Page 1, Column (E))				$ (11,621)

References:
Column (A): RLM-4, Page 1, Column (M)
Column (B): Company Workpapers
Column (C): Column (A) X Column (B)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4 - CONT'D
SYSTEM ALLOCABLE PLANT TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.		(A) TOTAL PLANT VALUE	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible Plant:			
1	301.0	Organization	$ 61,816	0.00%	$ -
2	302.0	Franchises & Consents	-	Amortized	-
3	303.0	Miscellaneous Intangible	113,204,513	Amortized	# 7,058,485
4		Total Intangible Plant	$ 113,266,329		$ 7,058,485
		Distribution Plant:			
5	374.1	Land & Land Rights	$ -	0.00%	$ -
6	374.2	Rights Of Way	-	0.00%	-
7	375.0	Structures	-	0.00%	-
8	376.0	Mains	-	0.00%	-
9	378.0	Measuring & Regulating Station	-	0.00%	-
10	380.0	Services	-	0.00%	-
11	381.0	Meters	-	0.00%	-
12	385.0	Industrial Measuring & Regulating Station	-	0.00%	-
13	387.0	Other Equipment	-	0.00%	-
14		Total Distribution Plant	$ -		$ -
		General Plant:			
15	389.0	Land & Land Rights	$ 391,307	0.00%	$ -
16	390.1	Structures	13,961,544	2.50%	348,983
17	390.2	Structures - Leasehold Improvments	4,232,644	Amortized	184,348
18	391.0	Office Furniture And Equipment	9,441,847	8.16%	770,455
19	391.1	Computer Equipment	14,791,422	16.15%	2,388,755
20	392.1	Transportation Equipment	3,495,826	7.20%	251,699
21	393.0	Stores Equipment	86,303	7.20%	6,214
22	394.0	Tools, Shop And Garage Equipment	24,106	16.03%	3,864
23	395.0	Laboratory Equipment	232,096	11.16%	25,902
24	396.0	Power Operated Equipment	281,078	4.77%	13,407
25	397.0	Communication Equipment	5,376,875	8.51%	457,594
26	397.2	Telemetering Equipment	286,958	40.23%	115,443
27	398.0	Miscellaneous Equipment	882,254	11.09%	97,845
28		Total General Plant	$ 53,484,260		$ 4,664,510
29		Total System Allocable Plant, Depreciation And Amortization	$ 166,750,589		$ 4,480,162
30		Total Amortization - Limited Term Gas Plant (See RLM-10, Page 3 For Clarification)			7,160,677
31		Total Depreciation and Amortization			$ 11,640,839
32		Company As Filed	$ 166,890,337		$ 11,722,995
33		Difference	$ (139,748)		$ (82,156)
34		Allocation Factor	56.70%		56.70%
35		TOTALS	$ (79,237)		$ (46,583)
36		RUCO ADJUSTMENT TO TEST YEAR SYSTEM ALLOCATED DEPRECIATION (See RLM-8, Page 1, Column (E))			$ (46,583)

References:
Column (A): RLM-4, Page 2, Column (M)
Column (B): Company Workpapers
Column (C): Column (A) X Column (B) Plus Further Clarification RLM-10, Page 3

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4 - CONT'D
ANNUALIZATION SYSTEM ALLOCABLE PLANT DEPRECIATION AND AMORTIZATION

LINE NO.	DESCRIPTION	(A) ESTIMATED CWIP INTANGIBLES	(B) ADJMT TO INTANGIBLES	(C) ACTUAL PIS INTANGIBLES	(D) ANNUALIZED PROVISION	(E) REFERENCE
	Projects in CWIP Which Closed Before 12/31/07 (Per Co. Response To STF 11.4)					
1	Autocad Map 3D 2007	$ 180,000	$ (51,871)	$ 128,129	$ 42,710	
2	Pi Data Access	24,000	1,900	25,900	8,633	
3	Receivables Software	105,000	(28,916)	76,084	25,361	
4	Load Balancer	38,000	(219)	37,781	12,594	
5	MacKinney VS/Cobol License	10,500	(10,500)	-	-	
6	Citrix Presentation License	83,000	(372)	82,628	27,543	
7	San Lefthand Network Expan	15,500	(11)	15,489	5,163	
8	EMRS/LMR Software Module	430,000	(430,000)	-	-	
9	EMRS Software	350,000	(350,000)	-	-	
10	Oracle UPK Licenses	250,000	(60,602)	189,398	63,133	
11	Oracle PUI Licenses	210,000	(37,600)	172,400	57,467	
	Revised List Of Projects in CWIP Which Closed Before 12/31/07 (Per Co. Supplement Response To STF 6.49)					
12	Comm Vault Licenses	-	10,419	10,419	3,473	
13	ACD Reporting License	-	20,678	20,678	6,893	
14	Powerbroker License	-	10,926	10,926	3,642	
15	Tivoli Workload Scheduler	-	110,638	110,638	36,879	
16	Powerbroker License	-	11,960	11,960	3,987	
17	Trident OS/EM Licenses	-	55,300	55,300	18,433	
18	MAPX GIS Software	-	35,030	35,030	11,677	
19	Oracle Internet Licenses	-	49,177	49,177	16,392	
20	HP Licenses	-	54,728	54,728	18,243	
21	Ops Mgr Server Licenses	-	61,285	61,285	20,428	
22	WMS Test Project	-	301,580	301,580	100,527	
23	TOTALS	$ 1,696,000	$ (246,470)	$ 1,449,530	$ 483,177	Sum Of Lines 1 Thru 22
24	RUCO System Allocable Adjustment		$ (246,470)			Line 23, Column (B)
25	Arizona 4-Factor		56.70%			Co. W/P Dep-Amort Adjmt
26	RUCO Allocated Arizona Rate Base Adjustment		$ (139,748)			Line 24 X Line 25
27	RUCO RB Adjmt No. 2 (See RLM-4, Pg 2, Col (E))		$ (139,748)			Line 26
28	RUCO Adjusted Amort. CWIP Transferred To PIS				$ 483,177	Line 23, Column (D)
29	Recorded Amort. Intangible Plant				6,493,152	Co. W/P Dep-Amort Adjmt
30	Recorded Amort. Leasehold Improvements				184,348	Co. W/P Dep-Amort Adjmt
31	RUCO Adjusted Dep/Amort Expense				$ 7,160,677	Sum Of Lines 28 Thru 30
32	Recorded Dep/Amort Expense				7,560,997	Co. W/P Dep-Amort Adjmt
33	RUCO Adjusted Total System Allocable Amortization				(400,320)	Line 31 - Line 32
34	Recorded Total System Alocable Depreciation				186,182	Co. W/P Dep-Amort Adjmt
35	RUCO Adjusted Total System Allocable Dep/Amort				(214,138)	Line 33 + Line 34
36	Arizona 4-Factor				56.70%	Co. W/P Dep-Amort Adjmt
37	RUCO Adjusted System Allocated Dep/Amort				(121,416)	Line 35 X Line 36
38	Company Adjusted System Allocated Dep/Amort				(74,834)	Co. Adjmt No. 14
39	Difference In Adjusted System Allocated Dep/Amort				(46,582)	Line 37 - Line 38
40	RUCO Adjustment (See RLM-8, Pages 1 & 2, Column (M))				(46,582)	Line 39

References:

Column (A): Company Workpapers "Dep-Amort Adjustment"
Column (B): Column (C) - Column (A)
Column (C): Company Response To Staff Data Request 11.4 And Response To Staff Dr 6.49
Column (D): Column (C) Amortized Over Three Years

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 5
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service		$ 1,267,124,121
	ADD:		
2	Materials And Supplies (RLM-6, Page 1, Line 5)	$ 12,389,898	
3	Total (Line 2)		$ 12,389,898
	SUBTRACT:		
4	Original Cost New Balance Of Transportation Equipment (Company Workpapers)	$ 27,969,828	
5	Land Rights (Company Workpapers)	$ 1,823,920	
6	Total (Line 2)		$ (29,793,748)
7	COMPANY'S FULL CASH VALUE (Sum Of Lines 1, 3, & 6)		$ 1,249,720,271
	Calculation Of The Company's Tax Liability:		
	MULTIPLY: Company Full Cash Value By Valuation Assessment Ratio And Then By Property Tax Rates:		
8	Assessment Ratio (Per House Bill 2779)	23.0%	
9	Assessed Value (Line 7 X Line 8)	$ 287,435,662	
	Property Tax Rates:		
10	Primary Tax Rate (2004 Tax Notice - Co.'s Data Response - "Property Tax")	11.52%	
11	Secondary Tax Rate (2004 Tax Notice - Co.'s Data Response - "Property Tax")	0.00%	
12	Estimated Tax Rate Liability (Line 10 + Line 11)	11.52%	
13	COMPANY'S TAX LIABILITY - Based On Full Cash Value (Line 12 X Line 13)		$ 33,112,588
14	Test Year Adjusted Property Tax Expense Per Company's Filing (Co. Sch. C-2, Adj No. 15))	$ 33,112,588	
15	Increase (Decrease) In Property Tax Expense (Line 13 - Line 14)	$ -	
16	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (See RLM-8, Page 1, Column (F))		$ -

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS ADJUSTMENTS

LINE NO	DESCRIPTION	(A) ALLOCABLE TOTAL	(B) RUCO ADJUSTMENTS ALLOC'N FACTOR	(C) ARIZONA TOTAL	(D) RUCO AS ADJUSTED
	Arizona Direct Accounts				
1	880 - Other Expenses	(110,809)	100.00%	(110,809)	
2	Sub Total Arizona Direct Accounts	$ (110,809)			$ (110,809)
	System Allocable Accounts To Arizona				
3	921 - Office Supplies And Expenses	$ (148,689)	56.70%	$ (84,306)	
4	930 - Miscellaneous General Expenses	(16,322)	56.70%	(9,254)	
5	Sub Total Administrative And General Expenses	$ (165,010)		$ (93,561)	
6	Sub Total System Allocable Accounts To Arizona	$ (165,010)			$ (93,561)
7	TOTAL				(204,370)
8	RUCO ADJUSTMENT TO MISCELLANEOUS ADJUSTMENTS (See RLM-8, Page 1, Column (G))				$ (204,370)

References:
Column (A): Workpapers Exhibit A (880) Pages 1 To 18, (921) Pages 1 To 14, (923) Page 1, And (930) Page 1
Column (B): Company Workpapers
Column (C): Column (A) X Column (B)
Column (D): Sums Of Column (C)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
MANAGEMENT INCENTIVE PROGRAM

LINE NO	DESCRIPTION	(A) ALLOCABLE TOTAL	(B) ALLOC'N FACTOR	(C) ARIZONA TOTAL	(D) RUCO AS ADJUSTED
	Arizona Direct Accounts				
1	Exempt Special Incentive	-	100.00%	-	
2	Service Planning Quality Incentive Award	290,004	100.00%	290,004	
3	Sub Total Arizona Direct Accounts	$ 290,004		$ 290,004	
4	Allocation Factor At A 50/50 Split			-50.00%	
					$ (145,002)
	System Allocable Accounts To Arizona				
5	Management Incdentive Plan	$ 5,919,502	56.70%	$ 3,356,358	
6	Exempt Special Incentive	151,250	56.70%	85,759	
7	Service Planning Quality Incentive Award	137,522	56.70%	77,975	
8	Sub Total Administrative And General Expenses	$ 6,208,274		$ 3,520,091	
9	Allocation Factor At A 50/50 Split			-50.00%	
10	Sub Total System Allocable Accounts To Arizona	$ 6,208,274			$ (1,760,046)
11	TOTAL				(1,905,048)
12	RUCO ADJUSTMENT TO MISCELLANEOUS ADJUSTMENTS (See RLM-8, Page 1, Column (H))				$ (1,905,048)

References:

Column (A): Company Response To Staff Data Request 1.78
Column (B): Company Workpapers
Column (C): Column (A) X Column (B)
Column (D): Sums Of Column (C)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
SUPPLEMENTAL EMPLOYEE RETIREMENT PLAN

LINE NO	DESCRIPTION	(A) COMPANY AS FILED	(B)	(C)	(D) RUCO ADJUSTMENT
	ALLOCATIONS:	WP C-2, Adj #3, Sh 8, L 11			Distributed Total RUCO DR 14-1.a
1	Arizona	$ 1,395,781			$ (1,395,781)
2	Corporate Direct	54,102			(54,102)
3	Other Jurisdictions	1,041,113			-
4	System Allocable	866,016			(866,016)
5	Total (Sum Of Lines 1, 2, 3 & 4)	$ 3,357,012			$ (2,694,668)

FUNCTIONALIZATION:

		DISTRIBUTION PRECENTAGE See NOTE A	DISTRIBUTION Of Col (D), Line 1	ALLOCATION FACTOR	RUCO ADJUSTMENT RLM-8, Pg 2, Col (H)
6	Other Gas Supply	0.73%	$ (10,184)	100.00%	$ (10,184)
7	Distribution	67.99%	(949,044)	100.00%	(949,044)
8	Customer Accounts	30.69%	(428,347)	100.00%	(428,347)
9	Customer Information	0.59%	(8,206)	100.00%	(8,206)
10	SUBTOTAL Sum Of Lines 6 Thru 9)	100.00%	(1,395,781)		$ (1,395,781)
	Administrative & General		DISTRIBUTION Of Col (D), L 2 & L4		
11	Direct		(54,102)	100.00%	(54,102)
12	System Allocable		(866,016)	56.70%	(491,031)
13	TOTAL (Sum Of Lines 10, 12 & 13) (See RLM-8, Pg 2, Col (H))				$ (1,940,914)

NOTE A

To Determine The Distribution Ratio Of Arizona Direct SERP
By Allocating Expenses At The Same Percentage As Labor Loading In SWG's Adjustment No. 3

		SWG ADJ'MT NO.3 SWG SCH. C-2	DISTRIBUTION PRECENTAGE
	Operating Expenses		
14	Other Gas Supply	$ 16,522	0.73%
15	Distribution	1,539,648	67.99%
16	Customer Accounts	694,914	30.69%
17	Customer Information	13,313	0.59%
18	SUBTOTAL	$ 2,264,397	100.00%
	Administrative & General		
19	Direct	$ 24,518	
20	System Allocable	578,837	
21	SUBTOTAL	$ 603,355	
22	TOTAL	$ 2,867,752	

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OPERATING INCOME ADJUSTMENT NO. 10
NORMALIZATION OF THE UNCOLLECTIBLE EXPENSE

LINE NO.	DESCRIPTION	(A) UNCOLLECTIBLES COMPANY DATA RUCO D.R. 1.12	(B) OPERT'G REVENUES COMPANY DATA E-2 & 2004 A. R.	(C) RATIO OF UNCL'TIBLES TO REV COLUMN (A) / (B)	(D) RUCO ADJUSTMENT
1	2004 Year-End	1,355,278	$ 693,070,359	0.00196	
2	2005 Year-End	1,447,967	748,627,816	0.00193	
3	2006 Year-End	2,538,849	895,549,006	0.00283	
4	Three Year Ratio Total (Sum Of Lines 1 Thru 3)			0.00672	
5	RUCO Adjusted Ratio Uncollectible Expense To Revenue - 3-Yr Average (Ln 4 / 3 Yrs)			0.00224	
6	RUCO Adjusted TY Rev. (Sch. RLM-7, Col. (C), Ln 1 + Gas Costs Of $593,424,664)			$ 992,659,342	
7	RUCO Adjusted Uncollectible Expense (Ln 5 X Ln 6)			$ 2,225,077	
8	Company Recorded Uncollectible Expense (Per Co. W. P.'s)			$ 2,977,729	
9	Difference (Ln 7 - Ln 8)				$ (752,652)
10	RUCO Adjustment (Line 9) (See RLM-8, Pages 1 & 2, Column (K))				$ (752,652)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 11
GAIN ON SALE OF PROPERTY

LINE NO	DESCRIPTION	(A) RUCO AS ADJUSTED
1	Gain On Sale Of Property (Per Co. Response To Staff Data Request 1.96)	$ 418,196
2	Sharing Percentage Between Ratepayers And Shareholders	50.00%
3	Ratepayers Portion Of The Gain (Line 1 X Line 2)	$ 209,098
4	Amortization Period	3 Years
5	Decrease In Test-Year Operating Expenses (Line 3 / Line 4)	$ (69,699)
6	RUCO Adjustment (Line 5) (See RLM-8, Pages 1 & 2, Column (L)	$ (69,699)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-6, Column (C), Line 18 + Line 16	$ 96,604,926
	LESS:		
2	Arizona State Tax	Line 11	(3,401,069)
3	Interest Expense	Note (A) Line 21	(47,795,091)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 45,408,766
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 10	35.17%
6	Federal Income Tax Expense	Line 4 X line 5	$ 15,972,492
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 96,604,926
	LESS:		
8	Interest Expense	Note (A) Line 21	(47,795,091)
9	State Taxable Income	Line 7 + Line 8	$ 48,809,835
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 3,401,069
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 15,972,492
13	State Income Tax Expense	Line 11	3,401,069
14	South Georgia Amortization	Company Schedule C-1, Sheet 17, Column (C), Line 8 + Line 18	365,253
15	Investment Tax Credit	Company Schedule C-1, Sheet 17, Column (C), Line 19	(528,352)
16	Total Income Tax Expense Per RUCO	Sum Of Lines 12, 13, 14 & 15	$ 19,210,462
17	Total Income Tax Expense Per Company Filing (Schedule C-1)		16,092,218
18	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Page 2, Column (Q))	Line 16 - Line 17	$ 3,118,244

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Schedule RLM-2, Column (C), Line 10)	$ 1,089,321,967
20	Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2)	4.39%
21	Interest Expense (Line 19 X Line 20)	$ 47,795,091

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST
1	Long-term Debt	51.00%	7.96%	4.06%
2	Preferred Stock	4.00%	8.20%	0.33%
3	Common Equity	45.00%	9.88%	4.45%
4	TOTAL CAPITAL	100.00%		
5	WEIGHTED COST OF CAPITAL			8.83%

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) X Column (B)
Column (C) Line 5: Sum Of Column (C) Lines 1 Thru 3

EXHIBIT
RUCO-4
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

DIRECT
RATE DESIGN TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

April 11, 2008

TABLE OF CONTENTS

INTRODUCTION 1

RATE DESIGN 2

PROOF OF RECOMMENDED REVENUE 3

TYPICAL BILL ANALYSIS 3

INTRODUCTION

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

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on March 28, 2008.

Q. What is the purpose of your additional direct testimony?

A. My additional direct testimony will address RUCO's rate design and prove that this rate design will produce RUCO's recommended revenue. Also I have included an analysis of a typical residential bill.

To support RUCO's position in this additional direct testimony, I have prepared Schedules numbered RLM-19 and RLM-20.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. As shown on Schedule RLM-19, I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). After reviewing the Company's workpapers, I accepted SWG's bill determinants as adjusted for weather normalization and customer annualization. An in-depth discussion of RUCO's proposed rate design is contained in the testimony of RUCO witness, William Rigsby. In summary, for residential customers, RUCO proposes a monthly basic service charge of $11.50 and a commodity charge of $0.08803 for all therms consumed.

Q. Please explain elements of the rate design.

A. Schedule RLM-19 illustrates the elements of RUCO's rate design proposed by Mr. Rigsby in his testimony, which are:

1. Provides a positive move to mitigate the Company's risk of not recovering its authorized revenue requirement by placing more cost recovery into basic customer charge;
2. Is consistent with the Company's Cost of Service Study parameters;
3. Eliminates the two-tier volumetric rates to send appropriate price signals regarding gas conservation; and

4. Resets the beginning PGA to zero, by shifting all existing gas costs to base rates.

PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that RUCO's recommended rate design will produce the recommended required revenue as illustrated, is presented on Schedule RLM-19.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for residential customers with various levels of usage is presented on Schedule RLM-20.

Q. Please provide an excerpt of RUCO's rate structure that illustrates RUCO's rate design goals as set forth in the testimony of Mr. Rigsby that captures these fundamental changes in SWG's current rate design.

A. Schedule RLM-20 provides an extensive breakdown of the effects of RUCO's proposed rates on the G-5 Residential Customer. Below is a chart gleaned from Schedule RLM-19 comparing SWG's proposed rates to RUCO's proposed annual rates:

1 SWG Proposed Rates and Charges

2 Basic Monthly Service Charge $12.80

3 Non-Weather Sensitive Use – Charge Per Therm

Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.88069	$0.60996	$1.49065

6 Weather Sensitive Use – Charge Per Therm

Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.00	$1.49065	$1.49065

9

10 RUCO Proposed Rates and Charges

11 Basic Monthly Service Charge $11.50

12 All Consumption – Charge Per Therm

Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.880298	$0.60996	$1.49026

15

16 Q. Does this conclude your direct testimony?

17 A. Yes, it does.

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	Single-Family Residential Gas Service	G-5									
	Summer (May - October)										
1	Basic Service Charge per Month		5,107,859		$ 11.50		$ 58,737,949		$ 58,737,949		$ 58,737,949
	Commodity Charge per Therm										
2	First 15 Therms			48,048,640		$ 0.88030		$ 42,297,115	42,297,115	$ 29,307,749	71,604,864
3	Over 15 Therms			16,007,105		0.00000		0	0	23,860,990	23,860,990
	Winter (November - April)										
4	Basic Service Charge per Month		5,190,171		$ 11.50		$ 59,684,499		$ 59,684,499		$ 59,684,499
	Commodity Charge per Therm										
5	First 35 Therms			133,956,357		$ 0.88030		117,921,493	117,921,493	81,708,020	199,629,513
6	Over 35 Therms			91,044,013		0.00000		0	0	135,714,758	135,714,758
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 118,422,448	$ 160,218,608	$ 278,641,056	$ 270,591,517	$ 549,232,573
8	Ratio Of Fixed To Variable Revenues						42.50%	57.50%			
	Low Income Single-Family Residential Gas Svc	G-10									
	Summer (May - October)										
9	Basic Service Charge		153,923		$ 7.25		$ 1,115,942		$ 1,115,942		$ 1,115,942
	Commodity Charge per Therm										
	Summer (May - October)										
10	First 15 Therms			1,499,731		$ 0.88030		$ 1,320,210	1,320,210	$ 735,693	2,055,903
11	Over 15 Therms			343,792		0.00000		0	0	471,422	471,422
	Winter (November - April)										
12	Basic Service Charge per Month		156,983		$ 7.25		$ 1,138,127		$ 1,138,127		$ 1,138,127
	Commodity Charge per Therm										
13	First 35 Therms			4,229,842		$ 0.88030		3,723,520	3,723,520	2,074,949	5,798,469
14	Next 115 Therms			2,532,839		0.00000		0	0	3,473,130	3,473,130
15	Over 150 Therms			52,769		0.00000		0	0	72,359	72,359
16	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,254,069	$ 5,043,730	$ 7,297,799	$ 6,827,553	$ 14,125,352
17	Ratio Of Fixed To Variable Revenues						30.89%	69.11%			
	Special Residential Gas Service for Air Conditioning	G-15									
	Summer (May - October)										
18	Basic Service Charge per Month		648		$ 11.50		$ 7,452		$ 7,452		$ 7,452
	Commodity Charge per Therm										
19	First 15 Therms			7,899		$ 0.88030		$ 6,953	6,953	$ 4,744	11,697
20	Over 15 Therms			65,327		0.00000		0	0	96,765	96,765
	Winter (November - April)										
21	Basic Service Charge per Month		648		$ 11.50		$ 7,452		$ 7,452		$ 7,452
	Commodity Charge per Therm										
22	First 35 Therms			19,309		$ 0.88030		16,998	16,998	11,596	28,594
23	Over 35 Therms			48,985		$ -		0	0	72,559	72,559
24	Total Special Residential Gas Service		1,296	141,520			$ 14,904	$ 23,951	$ 38,855	$ 185,664	$ 224,519
25	Ratio Of Fixed To Variable Revenues						38.36%	61.64%			

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	Multi-Family Residential Gas Service	G-6									
	Summer (May - October)										
26	Basic Service Charge per Month		182,409		$ 9.00		$ 1,641,681		$ 1,641,681		$ 1,641,681
	Commodity Charge per Therm										
27	First 7 Therms			1,044,432		$ 0.88030		$ 919,411	919,411	$ 637,062	1,556,473
28	Over 7 Therms			950,005		$ 0.00000		0	0	1,416,125	1,416,125
	Winter (November - April)										
29	Basic Service Charge per Month		188,153		$ 9.00		$ 1,693,377		$ 1,693,377		$ 1,693,377
	Commodity Charge per Therm										
30	First 18 Therms			2,633,090		$ 0.88030		2,317,904	2,317,904	1,606,080	3,923,984
31	Over 18 Therms			1,880,532		$ -		0	0	2,803,214	2,803,214
32	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,335,058	$ 3,237,315	$ 6,572,373	$ 6,462,481	$ 13,034,854
33	Ratio Of Fixed To Variable Revenues						50.74%	49.26%			
	Low Income Multi-Family Residential Gas Svc	G-11									
	Summer (May - October)										
34	Basic Service Charge per Month		13,560		$ 7.25		$ 98,310		$ 98,310		$ 98,310
	Commodity Charge per Therm										
35	First 7 Therms			79,822		$ 0.88030		$ 70,267	70,267	$ 39,157	109,424
36	Over 7 Therms			78,071		$ 0.00000		-	0	107,054	107,054
	Winter (November - April)										
37	Basic Service Charge per Month		13,828		$ 7.25		$ 100,253		$ 100,253		$ 100,253
	Commodity Charge per Therm										
38	First 18 Therms			207,982		$ 0.88030		183,086	183,086	102,026	285,112
39	Next 132 Therms			186,423		$ -		0	0	255,630	255,630
40	Over 150 Therms			345		$ -		0	0	473	473
41	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 198,563	$ 253,353	$ 451,916	$ 504,340	$ 956,256
42	Ratio Of Fixed To Variable Revenues						43.94%	56.06%			
43	Total Residential Gas Service		11,008,182	304,917,309			124,225,042	168,776,957	293,001,999	284,571,555	577,573,554
	Ratio Of Fixed To Variable Revenues						42.40%	57.60%			
	Master Metered Mobile Home Park Gas Service	G-20									
44	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080		$ 118,080
	Commodity Charge per Therm All Usage										
45	All Usage			2,223,993		$ 0.39476		$ 877,950	877,950	$ 2,083,637	2,961,587
46	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 877,950	$ 996,030	$ 2,083,637	$ 3,079,667
							11.86%	88.14%			
	General Gas Service - Small	G-25(S)									
47	Basic Service Charge Per Month		201,805		$ 25.00		$ 5,045,125		$ 5,045,125		$ 5,045,125
	Commodity Charge per Therm All Usage										
48	Transportation Customers			10,138		$ 0.68117	-	$ 6,906	6,906	$ 8,288	15,194
49	Sales Customers			5,010,616		$ 0.68117		3,413,068	3,413,068	4,647,246	8,060,314
50	Total Small General Gas Service		201,805	5,020,754			$ 5,045,125	$ 3,419,974	$ 8,465,099	$ 4,655,534	$ 13,120,633
51	Ratio Of Fixed To Variable Revenues						59.60%	40.40%			

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	General Gas Service - Medium	G-25(M)									
52	Basic Service Charge		193,790		$ 41.59		$ 8,060,078		$ 8,060,078		$ 8,060,078
	Commodity Charge per Therm All Usage										
53	Transportation Customers			172,365		$ 0.39190		$ 67,550	67,550	$ 140,905.00	208,455
54	Sales Customers			45,357,904		$ 0.39190		17,775,765	17,775,765	42,068,549	59,844,314
55	Total Medium General Gas Service		193,790	45,530,269			$ 8,060,078	$ 17,843,315	$ 25,903,393	$ 42,209,454	$ 68,112,847
56	Ratio Of Fixed To Variable Revenues						31.12%	68.88%			
	General Gas Service - Large	G-25(L)									
57	Basic Service Charge		85,510		$ 152.98		$ 13,081,438		$ 13,081,438		$ 13,081,438
	Commodity Charge per Therm All Usage										
58	Transportation Customers			3,556,829		$ 0.27578		$ 980,894	980,894	$ 2,907,637.00	3,888,531
59	Sales Customers			145,666,025		$ 0.27578		40,171,430	40,171,430	135,102,325	175,273,755
60	Total Large General Gas Service		85,510	149,222,854			$ 13,081,438	$ 41,152,324	$ 54,233,762	$ 138,009,962	$ 192,243,724
61	Ratio Of Fixed To Variable Revenues						24.12%	75.88%			
	General Gas Service - Transportation Eligible	G-25(TE)									
62	Basic Service Charge		2,222		$ 908.33		$ 2,018,303		$ 2,018,303		$ 2,018,303
63	Demand Charge per Month			12,803,712	0.061328			$ 9,422,748	9,422,748		9,422,748
	Commodity Charge per Therm All Usage										
64	Transportation Customers			32,517,415		$ 0.09468		$ 3,078,630	3,078,630	$ 26,582,336	29,660,966
65	Sales Customers			67,008,985		$ 0.09468		6,344,166	6,344,166	62,149,493	68,493,659
66	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,018,303	$ 18,845,544	$ 20,863,847	$ 88,731,829	$ 109,595,676
67	Ratio Of Fixed To Variable Revenues						9.67%	90.33%			
68	Total General Gas Service		483,327	299,300,277			28,204,944	81,261,157	109,466,101	273,606,779	383,072,880
69	Ratio Of Fixed To Variable Revenues						25.77%	74.23%			
	Air Conditioning Gas Service	G-40									
	Basic Service Charge										
70	With Other Service - No BSC		60		$ 0.00		$ -		$ -		$ -
71	General Service - Small		198		25.00		4,950		4,950		4,950
72	General Service - Medium		0		41.59		-		-		-
73	General Service - Large		48		152.98		7,343		7,343		7,343
74	Essential Agricultural		12		908.33		10,900		10,900		10,900
	Commodity Charge per Therm All Usage										
75	Transportation Customers			373,987		$ 0.09076		$ 33,944	33,944	$ 305,727	339,671
76	Sales Customers			744,265		$ 0.09076		67,552	67,552	690,291	757,843
77	Total Air Conditioning Gas Service		318	1,118,252			23,193	101,496	124,689	996,018	1,120,707
78	Ratio Of Fixed To Variable Revenues						18.60%	81.40%			
	Street Lighting Gas Service	G-45									
	Commodity Charge per Therm of Rated Capacity										
79	All Usage		324	102,289		$ 0.66833		$ 68,363	$ 68,363	$ 94,871	$ 163,234
80	Total Street Lighting Gas Service		324	102,289			$ -	$ 68,363	$ 68,363	$ 94,871	$ 163,234
81	Ratio Of Fixed To Variable Revenues						0.00%	100.00%			

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	Gas Service for Compression on Customer's Premises	G-55									
	Basic Service Charge										
82	Small		252		$ 25.00		$ 6,300		$ 6,300		$ 6,300
83	Large		288		239.03		68,842		68,842		68,842
84	Residential		1,272		11.50		14,627		14,627		14,627
	Commodity Charge per Therm All Usage										
85	Transportation Customers			0		$ 0.16793		$ -	$ -	$ -	$ -
	Sales Customers										
86	Small			177,495		$ 0.16793		29,807	29,807	164,623	194,430
87	Large			2,060,152		$ 0.16793		345,960	345,960	1,910,750	2,256,710
88	Residential			77,361		$ 0.16793		12,991	12,991	71,751	84,742
89	Total CNG Gas Service		1,812	2,315,008			89,769	388,758	478,527	2,147,124	2,625,651
90	Ratio Of Fixed To Variable Revenues						18.76%	81.24%			
	Electric Generation Gas Service	G-60									
	Basic Service Charge										
91	General Service - Small		36		$ 25.00		$ 900		$ 900		$ 900
92	General Service - Medium		36		41.59		1,497		1,497		1,497
93	General Service - Large		84		152.98		12,850		12,850		12,850
94	General Service - Transportation Eligible		84		-		0		0		0
95	Essential Agricultural		12		114.74		1,377		1,377		1,377
	Commodity Charge per Therm All Usage										
96	Transportation Customers			0		$ 0.11820		$ -	$ -	$ -	$ -
97	Sales Customers			21,521,946		$ 0.11820		2,544,000	2,544,000	19,961,174	22,505,174
98	Total Electric Generation Gas Service		252	21,521,946			16,624	2,544,000	2,560,624	19,961,174	22,521,798
99	Ratio Of Fixed To Variable Revenues						0.65%	99.35%			
	Essential Agriculture User Gas Service	G-75									
100	Basic Service Charge		1,216		$ 114.74		$ 139,519		$ 139,519		$ 139,519
	Commodity Charge per Therm All Usage										
101	Transportation Customers			6,217,976		$ 0.22311		$ 1,387,316	1,387,316	$ 5,083,071.00	6,470,387
102	Sales Customers			7,214,684		$ 0.22311		1,609,695	1,609,695	6,691,475	8,301,170
103	Total Essential Agricultural Gas Service		1,216	13,432,660			139,519	2,997,011	3,136,530	11,774,546	14,911,076
104	Ratio Of Fixed To Variable Revenues						4.45%	95.55%			
	Natural Gas Engine Gas Service	G-80									
	Basic Service Charge										
105	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ -		$ -		$ -
106	Peak Season (April - September)		2,589		119.52		309,429		309,429		309,429
	Commodity Charge per Therm All Usage										
107	Transportation Customers			0		$ 0.17924		$ -	$ -	$ -	$ -
108	Sales Customers			13,070,981		$ 0.17924		2,342,801	2,342,801	9,591,355	11,934,156
109	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 309,429	$ 2,342,801	$ 2,652,230	$ 9,591,355	$ 12,243,585
110	Ratio Of Fixed To Variable Revenues						11.67%	88.33%			
111	Total Tariff Sales		11,502,504	658,002,715			$ 153,126,600	$ 259,358,493	$ 412,485,093	$ 604,827,059	$ 1,017,312,152
112	Optional Gas Service	G-30	84	49,447,344			120,540	3,135,458	3,255,998	40,422,215	43,678,213
113	Special Contract Service	B-1	244	35,660,859			449,274	2,078,755	2,528,029		2,528,029
114	Other Operating Revenues						12,261,805		12,261,805		12,261,805
115	Total		11,502,832	743,110,918			$ 165,958,219	$ 264,572,707	$ 430,530,926	$ 645,249,274	$ 1,075,780,200
116	Ratio Of Fixed To Variable Revenues						38.55%	61.45%			
117	Total Revenue Requirement								430,530,964	645,249,274	1,075,780,237
118	Over/(Under)								$ (37)	$ -	$ (37)

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

SINGLE - FAMILY RESIDENTIAL TYPICAL BILL ANALYSIS
COMPARISON OF PRESENT MONTHLY CHARGES TO COMPANY PROPOSED AND RUCO PROPOSED

LINE NO.	DESCRIPTION	(A) USAGE THERMS	(B) TOTAL MONTHLY COST PRESENT RATES	(C) TOTAL MONTHLY COST COMPANY PROPOSED	(D) TOTAL MONTHLY COST RUCO PROPOSED	(E) RUCO INCREASE OVER PRESENT CHANGE	(F) PERCENTAGE
	Single-Family Residential Gas Service						
	Summer (May - October)						
1	50% Average Summer Usage per Month	6	$ 18.97	$ 22.15	$ 20.84	$ 1.87	9.86%
2	75% Average Summer Usage per Month	9	$ 23.61	$ 26.82	$ 25.52	$ 1.91	8.07%
3	**100% Average Monthly Summer Use**	**13**	**$ 28.25**	**$ 31.49**	**$ 30.19**	**$ 1.94**	**6.88%**
4	125% Average Summer Usage per Month	16	$ 32.86	$ 36.17	$ 34.86	$ 2.01	6.10%
5	150% Average Summer Usage per Month	19	$ 37.36	$ 40.84	$ 39.53	$ 2.17	5.81%
	Winter (November - April)						
6	50%Average Winter Usage per Month	22	$ 41.76	$ 45.11	$ 43.80	$ 2.05	4.90%
7	75%Average Winter Usage per Month	33	$ 57.78	$ 61.27	$ 59.95	$ 2.17	3.75%
8	**100% Average Monthly Winter Use**	**43**	**$ 73.47**	**$ 77.42**	**$ 76.10**	**$ 2.63**	**3.59%**
9	125% Average Winter Usage per Month	54	$ 89.05	$ 93.58	$ 92.26	$ 3.20	3.60%
10	150% Average Winter Usage per Month	65	$ 104.64	$ 109.73	$ 108.41	$ 3.77	3.60%

RATE SCHEDULES

	DESCRIPTION	BASIC SERVICE CHARGE	NON-GAS COSTS	GAS COST	TOTAL GAS COST
	PRESENT RATES				
	Single-Family Residential Gas Service				
	Summer (May - October)				
11	Basic Service Charge per Month	$ 9.70			
	Commodity Charge per Therm				
12	First 15 Therms		$ 0.54200	$ 0.93689	$ 1.47889
13	Over 15 Therms		$ 0.50100	$ 0.93689	$ 1.43789
	Winter (November - April)				
14	Basic Service Charge per Month	$ 9.70			
	Commodity Charge per Therm				
15	First 35 Therms		$ 0.54200	$ 0.93689	$ 1.47889
16	Over 35 Therms		$ 0.50100	$ 0.93689	$ 1.43789
	COMPANY PROPOSED RATES				
	Single-Family Residential Gas Service				
	All Year Around And All Usage				
17	Basic Service Charge per Month	$ 12.80			
18	Non- Weather Sensitive Use - Commodity Charge per Therm		$ 0.88069	$ 0.60996	$ 1.49065
19	Weather Sensitive Use - Commodity Charge per Therm		$ -	$ 1.49065	$ 1.49065
	RUCO PROPOSED RATES				
	Single-Family Residential Gas Service				
	All Year Around And All Usage				
20	Basic Service Charge per Month	$ 11.50			
21	Commodity Charge per Therm		$ 0.880298	$ 0.60996	$ 1.49026

EXHIBIT
RUCO-5
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

REVISED

DIRECT
RATE DESIGN TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

April 18, 2008

1 **TABLE OF CONTENTS**

2 INTRODUCTION 1

3 RATE DESIGN 2

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5 TYPICAL BILL ANALYSIS 3

INTRODUCTION

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

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on March 28, 2008.

Q. What is the purpose of your additional direct testimony?

A. My additional direct testimony will address RUCO's rate design and prove that this rate design will produce RUCO's recommended revenue. Also I have included an analysis of a typical residential bill.

To support RUCO's position in this additional direct testimony, I have prepared Schedules numbered RLM-19 and RLM-20.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. As shown on Schedule RLM-19, I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). After reviewing the Company's workpapers, I accepted SWG's bill determinants as adjusted for weather normalization and customer annualization. An in-depth discussion of RUCO's proposed rate design is contained in the testimony of RUCO witness, William Rigsby. In summary, for residential customers, RUCO proposes a monthly basic service charge of $11.50 and a commodity charge of $0.055352 for all therms consumed.

Q. Please explain elements of the rate design.

A. Schedule RLM-19 illustrates the elements of RUCO's rate design proposed by Mr. Rigsby in his testimony, which are:

1. Provides a positive move to mitigate the Company's risk of not recovering its authorized revenue requirement by placing more cost recovery into basic customer charge;
2. Is consistent with the Company's Cost of Service Study parameters;
3. Eliminates the two-tier volumetric rates to send appropriate price signals regarding gas conservation; and

4. Resets the beginning PGA to zero, by shifting all existing gas costs to base rates.

PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that RUCO's recommended rate design will produce the recommended required revenue as illustrated, is presented on Schedule RLM-19.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for residential customers with various levels of usage is presented on Schedule RLM-20.

Q. Please provide an excerpt of RUCO's rate structure that illustrates RUCO's rate design goals as set forth in the testimony of Mr. Rigsby that captures these fundamental changes in SWG's current rate design.

A. Schedule RLM-20 provides an extensive breakdown of the effects of RUCO's proposed rates on the G-5 Residential Customer. Below is a chart gleaned from Schedule RLM-19 comparing SWG's proposed rates to RUCO's proposed annual rates:

1 SWG Proposed Rates and Charges

2 Basic Monthly Service Charge $12.80

3 Non-Weather Sensitive Use –Charge Per Therm

Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.88069	$0.60996	$1.49065

6 Weather Sensitive Use –Charge Per Therm

Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.00	$1.49065	$1.49065

9

10 RUCO Proposed Rates and Charges

11 Basic Monthly Service Charge $11.50

12 All Consumption –Charge Per Therm

Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.55352	$0.93689	$1.49041

15

16 Q. Does this conclude your direct testimony?

17 A. Yes, it does.

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	Single-Family Residential Gas Service	G-5									
	Summer (May - October)										
1	Basic Service Charge per Month		5,107,859		$ 11.50		$ 58,737,949		$ 58,737,949		$ 58,737,949
	Commodity Charge per Therm										
2	First 15 Therms			48,048,640		$ 0.55352		$ 26,595,746	26,595,746	$ 45,016,291	71,612,037
3	Over 15 Therms			16,007,105		0.55352		8,860,207	8,860,207	14,996,896	23,857,103
	Winter (November - April)										
4	Basic Service Charge per Month		5,190,171		$ 11.50		$ 59,684,499		$ 59,684,499		$ 59,684,499
	Commodity Charge per Therm										
5	First 35 Therms			133,956,357		$ 0.55352		74,147,140	74,147,140	125,502,371	199,649,511
6	Over 35 Therms			91,044,013		0.55352		50,394,422	50,394,422	85,298,225	135,692,647
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 118,422,448	$ 159,997,515	$ 278,419,963	$ 270,813,783	$ 549,233,746
8	Ratio Of Fixed To Variable Revenues						42.53%	57.47%			
	Low Income Single-Family Residential Gas Svc	G-10									
	Summer (May - October)										
9	Basic Service Charge		153,923		$ 7.25		$ 1,115,942		$ 1,115,942		$ 1,115,942
	Commodity Charge per Therm										
	Summer (May - October)										
10	First 15 Therms			1,499,731		$ 0.55352		$ 830,127	830,127	$ 1,226,000	2,056,127
11	Over 15 Therms			343,792		0.55352		190,295	190,295	281,043	471,338
	Winter (November - April)										
12	Basic Service Charge per Month		156,983		$ 7.25		$ 1,138,127		$ 1,138,127		$ 1,138,127
	Commodity Charge per Therm										
13	First 35 Therms			4,229,842		$ 0.55352		2,341,290	2,341,290	3,457,811	5,799,101
14	Next 115 Therms			2,532,839		0.55352		1,401,970	1,401,970	2,070,545	3,472,515
15	Over 150 Therms			52,769		0.55352		29,208	29,208	43,137	72,345
16	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,254,069	$ 4,792,890	$ 7,046,959	$ 7,078,536	$ 14,125,495
17	Ratio Of Fixed To Variable Revenues						31.99%	68.01%			
	Special Residential Gas Service for Air Conditioning	G-15									
	Summer (May - October)										
18	Basic Service Charge per Month		648		$ 11.50		$ 7,452		$ 7,452		$ 7,452
	Commodity Charge per Therm										
19	First 15 Therms			7,899		$ 0.55352		$ 4,372	4,372	$ 7,326	11,698
20	Over 15 Therms			65,327		0.55352		36,160	36,160	60,589	96,749
	Winter (November - April)										
21	Basic Service Charge per Month		648		$ 11.50		$ 7,452		$ 7,452		$ 7,452
	Commodity Charge per Therm										
22	First 35 Therms			19,309		$ 0.55352		10,688	10,688	17,909	28,597
23	Over 35 Therms			48,985		0.55352		27,114	27,114	45,433	72,547
24	Total Special Residential Gas Service		1,296	141,520			$ 14,904	$ 78,334	$ 93,238	$ 131,257	$ 224,495
25	Ratio Of Fixed To Variable Revenues						15.98%	84.02%			

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	Multi-Family Residential Gas Service	G-6									
	Summer (May - October)										
26	Basic Service Charge per Month		182,409		$ 9.00		$ 1,641,681		$ 1,641,681		$ 1,641,681
	Commodity Charge per Therm										
27	First 7 Therms			1,044,432		$ 0.55352		$ 578,111	578,111	$ 978,518	1,556,629
28	Over 7 Therms			950,005		0.55352		525,844	525,844	890,050	1,415,894
	Winter (November - April)										
29	Basic Service Charge per Month		188,153		$ 9.00		$ 1,693,377		$ 1,693,377		$ 1,693,377
	Commodity Charge per Therm										
30	First 18 Therms			2,633,090		$ 0.55352		1,457,461	1,457,461	2,466,916	3,924,377
31	Over 18 Therms			1,880,532		0.55352		1,040,906	1,040,906	1,761,851	2,802,757
32	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,335,058	$ 3,602,322	$ 6,937,380	$ 6,097,335	$ 13,034,715
33	Ratio Of Fixed To Variable Revenues						48.07%	51.93%			
	Low Income Multi-Family Residential Gas Svc	G-11									
	Summer (May - October)										
34	Basic Service Charge per Month		13,560		$ 7.25		$ 98,310		$ 98,310		$ 98,310
	Commodity Charge per Therm										
35	First 7 Therms			79,822		$ 0.55352		$ 44,183	44,183	$ 65,253	109,436
36	Over 7 Therms			78,071		0.55352		43,214	43,214	63,822	107,036
	Winter (November - April)										
37	Basic Service Charge per Month		13,828		$ 7.25		$ 100,253		$ 100,253		$ 100,253
	Commodity Charge per Therm										
38	First 18 Therms			207,982		$ 0.55352		115,122	115,122	170,021	285,143
39	Next 132 Therms			186,423		0.55352		103,188	103,188	152,397	255,585
40	Over 150 Therms			345		0.55352		191	191	282	473
41	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 198,563	$ 305,898	$ 504,461	$ 451,775	$ 956,236
42	Ratio Of Fixed To Variable Revenues						39.36%	60.64%			
		0.553517147									
43	Total Residential Gas Service		11,008,182	304,917,309			124,225,042	168,776,959	293,002,001	284,572,686	577,574,687
	Ratio Of Fixed To Variable Revenues						42.40%	57.60%			
	Master Metered Mobile Home Park Gas Service	G-20									
44	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080		$ 118,080
	Commodity Charge per Therm All Usage										
45	All Usage			2,223,993		$ 0.39476		$ 877,950	877,950	$ 2,083,637	2,961,587
46	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 877,950	$ 996,030	$ 2,083,637	$ 3,079,667
							11.86%	88.14%			
	General Gas Service - Small	G-25(S)									
47	Basic Service Charge Per Month		201,805		$ 25.00		$ 5,045,125		$ 5,045,125		$ 5,045,125
	Commodity Charge per Therm All Usage										
48	Transportation Customers			10,138		$ 0.68117	-	$ 6,906	6,906	$ 8,288	15,194
49	Sales Customers			5,010,616		$ 0.68117		3,413,068	3,413,068	4,647,246	8,060,314
50	Total Small General Gas Service		201,805	5,020,754			$ 5,045,125	$ 3,419,974	$ 8,465,099	$ 4,655,534	$ 13,120,633
51	Ratio Of Fixed To Variable Revenues						59.60%	40.40%			

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

Schedule RLM-19
Pages 1 to 4 of 4

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	General Gas Service - Medium	G-25(M)									
52	Basic Service Charge		193,790		$ 41.59		$ 8,060,078		$ 8,060,078		$ 8,060,078
	Commodity Charge per Therm All Usage										
53	Transportation Customers			172,365		$ 0.39190		$ 67,550	67,550	$ 140,905.00	208,455
54	Sales Customers			45,357,904		$ 0.39190		17,775,765	17,775,765	42,068,549	59,844,314
55	Total Medium General Gas Service		193,790	45,530,269			$ 8,060,078	$ 17,843,315	$ 25,903,393	$ 42,209,454	$ 68,112,847
56	Ratio Of Fixed To Variable Revenues						31.12%	68.88%			
	General Gas Service - Large	G-25(L)									
57	Basic Service Charge		85,510		$ 152.98		$ 13,081,438		$ 13,081,438		$ 13,081,438
	Commodity Charge per Therm All Usage										
58	Transportation Customers			3,556,829		$ 0.27578		$ 980,894	980,894	$ 2,907,637.00	3,888,531
59	Sales Customers			145,666,025		$ 0.27578		40,171,430	40,171,430	135,102,325	175,273,755
60	Total Large General Gas Service		85,510	149,222,854			$ 13,081,438	$ 41,152,324	$ 54,233,762	$ 138,009,962	$ 192,243,724
61	Ratio Of Fixed To Variable Revenues						24.12%	75.88%			
	General Gas Service - Transportation Eligible	G-25(TE)									
62	Basic Service Charge		2,222		$ 908.33		$ 2,018,303		$ 2,018,303		$ 2,018,303
63	Demand Charge per Month			12,803,712	0.061328			$ 9,422,748	9,422,748		9,422,748
	Commodity Charge per Therm All Usage										
64	Transportation Customers			32,517,415		$ 0.09468		$ 3,078,630	3,078,630	$ 26,582,336	29,660,966
65	Sales Customers			67,008,985		$ 0.09468		6,344,166	6,344,166	62,149,493	68,493,659
66	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,018,303	$ 18,845,544	$ 20,863,847	$ 88,731,829	$ 109,595,676
67	Ratio Of Fixed To Variable Revenues						9.67%	90.33%			
68	Total General Gas Service		483,327	299,300,277			28,204,944	81,261,157	109,466,101	273,606,779	383,072,880
69	Ratio Of Fixed To Variable Revenues						25.77%	74.23%			
	Air Conditioning Gas Service	G-40									
	Basic Service Charge										
70	With Other Service - No BSC		60		$ 0.00		$ -		$ -		$ -
71	General Service - Small		198		25.00		4,950		4,950		4,950
72	General Service - Medium		0		41.59		-		-		-
73	General Service - Large		48		152.98		7,343		7,343		7,343
74	Essential Agricultural		12		908.33		10,900		10,900		10,900
	Commodity Charge per Therm All Usage										
75	Transportation Customers			373,987		$ 0.09076		$ 33,944	33,944	$ 305,727	339,671
76	Sales Customers			744,265		$ 0.09076		67,552	67,552	690,291	757,843
77	Total Air Conditioning Gas Service		318	1,118,252			23,193	101,496	124,689	996,018	1,120,707
78	Ratio Of Fixed To Variable Revenues						18.60%	81.40%			
	Street Lighting Gas Service	G-45									
	Commodity Charge per Therm of Rated Capacity										
79	All Usage		324	102,289		$ 0.66833		$ 68,363	$ 68,363	$ 94,871	$ 163,234
80	Total Street Lighting Gas Service		324	102,289			$ -	$ 68,363	$ 68,363	$ 94,871	$ 163,234
81	Ratio Of Fixed To Variable Revenues						0.00%	100.00%			

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) REVENUE AT PROPOSED RATES GAS COST	(J) TOTAL REVENUE
	Gas Service for Compression on Customer's Premises	G-55									
	Basic Service Charge										
82	Small		252		$ 25.00		$ 6,300		$ 6,300		$ 6,300
83	Large		288		239.03		68,842		68,842		68,842
84	Residential		1,272		11.50		14,627		14,627		14,627
	Commodity Charge per Therm All Usage										
85	Transportation Customers			0		$ 0.16793		$ -	$ -	$ -	$ -
	Sales Customers										
86	Small			177,495		$ 0.16793		29,807	29,807	164,623	194,430
87	Large			2,060,152		$ 0.16793		345,960	345,960	1,910,750	2,256,710
88	Residential			77,361		$ 0.16793		12,991	12,991	71,751	84,742
89	Total CNG Gas Service		1,812	2,315,008			89,769	388,758	478,527	2,147,124	2,625,651
90	Ratio Of Fixed To Variable Revenues						18.76%	81.24%			
	Electric Generation Gas Service	G-60									
	Basic Service Charge										
91	General Service - Small		36		$ 25.00		$ 900		$ 900		$ 900
92	General Service - Medium		36		41.59		1,497		1,497		1,497
93	General Service - Large		84		152.98		12,850		12,850		12,850
94	General Service - Transportation Eligible		84		-		0		0		0
95	Essential Agricultural		12		114.74		1,377		1,377		1,377
	Commodity Charge per Therm All Usage										
96	Transportation Customers			0		$ 0.11820		$ -	$ -	$ -	$ -
97	Sales Customers			21,521,946		$ 0.11820		2,544,000	2,544,000	19,961,174	22,505,174
98	Total Electric Generation Gas Service		252	21,521,946			16,624	2,544,000	2,560,624	19,961,174	22,521,798
99	Ratio Of Fixed To Variable Revenues						0.65%	99.35%			
	Essential Agriculture User Gas Service	G-75									
100	Basic Service Charge		1,216		$ 114.74		$ 139,519		$ 139,519		$ 139,519
	Commodity Charge per Therm All Usage										
101	Transportation Customers			6,217,976		$ 0.22311		$ 1,387,316	1,387,316	$ 5,083,071.00	6,470,387
102	Sales Customers			7,214,684		$ 0.22311		1,609,695	1,609,695	6,691,475	8,301,170
103	Total Essential Agricultural Gas Service		1,216	13,432,660			139,519	2,997,011	3,136,530	11,774,546	14,911,076
104	Ratio Of Fixed To Variable Revenues						4.45%	95.55%			
	Natural Gas Engine Gas Service	G-80									
	Basic Service Charge										
105	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ -		$ -		$ -
106	Peak Season (April - September)		2,589		119.52		309,429		309,429		309,429
	Commodity Charge per Therm All Usage										
107	Transportation Customers			0		$ 0.17924		$ -	$ -	$ -	$ -
108	Sales Customers			13,070,981		$ 0.17924		2,342,801	2,342,801	9,591,355	11,934,156
109	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 309,429	$ 2,342,801	$ 2,652,230	$ 9,591,355	$ 12,243,585
110	Ratio Of Fixed To Variable Revenues						11.67%	88.33%			
111	Total Tariff Sales		11,502,504	658,002,715			$ 153,126,600	$ 259,358,495	$ 412,485,095	$ 604,828,190	$ 1,017,313,285
112	Optional Gas Service	G-30	84	49,447,344			120,540	3,135,458	3,255,998	40,422,215	43,678,213
113	Special Contract Service	B-1	244	35,660,859			449,274	2,078,755	2,528,029		2,528,029
114	Other Operating Revenues						12,261,805		12,261,805		12,261,805
115	Total		11,502,832	743,110,918			$ 165,958,219	$ 264,572,709	$ 430,530,928	$ 645,250,405	$ 1,075,781,333
116	Ratio Of Fixed To Variable Revenues						38.55%	61.45%			
117	Total Revenue Requirement								430,530,964	645,249,274	1,075,780,237
118	Over/(Under)								$ (35)	$ 1,131	$ 1,096

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

SINGLE - FAMILY RESIDENTIAL TYPICAL BILL ANALYSIS
COMPARISON OF PRESENT MONTHLY CHARGES TO COMPANY PROPOSED AND RUCO PROPOSED

LINE NO.	DESCRIPTION	(A) USAGE THERMS	(B) TOTAL MONTHLY COST PRESENT RATES	(C) TOTAL MONTHLY COST COMPANY PROPOSED	(D) TOTAL MONTHLY COST RUCO PROPOSED	(E) RUCO INCREASE OVER PRESENT CHANGE	(F) RUCO INCREASE OVER PRESENT PERCENTAGE
	Single-Family Residential Gas Service						
	Summer (May - October)						
1	50% Average Summer Usage per Month	6	$ 18.97	$ 22.15	$ 20.84	$ 1.87	9.87%
2	75% Average Summer Usage per Month	9	$ 23.61	$ 26.82	$ 25.52	$ 1.91	8.08%
3	**100% Average Monthly Summer Use**	**13**	**$ 28.25**	**$ 31.49**	**$ 30.19**	**$ 1.94**	**6.88%**
4	125% Average Summer Usage per Month	16	$ 32.86	$ 36.17	$ 34.86	$ 2.01	6.11%
5	150% Average Summer Usage per Month	19	$ 37.36	$ 40.84	$ 39.54	$ 2.17	5.81%
	Winter (November - April)						
6	50%Average Winter Usage per Month	22	$ 41.76	$ 45.11	$ 43.81	$ 2.05	4.91%
7	75%Average Winter Usage per Month	33	$ 57.78	$ 61.27	$ 59.96	$ 2.17	3.76%
8	**100% Average Monthly Winter Use**	**43**	**$ 73.47**	**$ 77.42**	**$ 76.11**	**$ 2.64**	**3.59%**
9	125% Average Winter Usage per Month	54	$ 89.05	$ 93.58	$ 92.26	$ 3.21	3.61%
10	150% Average Winter Usage per Month	65	$ 104.64	$ 109.73	$ 108.42	$ 3.78	3.61%

RATE SCHEDULES

	DESCRIPTION	BASIC SERVICE CHARGE	NON-GAS COSTS	GAS COST	TOTAL GAS COST
	PRESENT RATES				
	Single-Family Residential Gas Service				
	Summer (May - October)				
11	Basic Service Charge per Month	$ 9.70			
	Commodity Charge per Therm				
12	First 15 Therms		$ 0.54200	$ 0.93689	$ 1.47889
13	Over 15 Therms		$ 0.50100	$ 0.93689	$ 1.43789
	Winter (November - April)				
14	Basic Service Charge per Month	$ 9.70			
	Commodity Charge per Therm				
15	First 35 Therms		$ 0.54200	$ 0.93689	$ 1.47889
16	Over 35 Therms		$ 0.50100	$ 0.93689	$ 1.43789
	COMPANY PROPOSED RATES				
	Single-Family Residential Gas Service				
	All Year Around And All Usage				
17	Basic Service Charge per Month	$ 12.80			
18	Non- Weather Sensitive Use - Commodity Charge per Therm		$ 0.88069	$ 0.60996	$ 1.49065
19	Weather Sensitive Use - Commodity Charge per Therm		$ -	$ 1.49065	$ 1.49065
	RUCO PROPOSED RATES				
	Single-Family Residential Gas Service				
	All Year Around And All Usage				
20	Basic Service Charge per Month	$ 11.50			
21	Commodity Charge per Therm		$ 0.553517	$ 0.93689	$ 1.49041

EXHIBIT
RUCO-6
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

SURREBUTTAL TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 27, 2008

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INTRODUCTION

Q. Please state your name for the record.

A. My name is Rodney Lane Moore.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on March 28, 2008 and additional direct testimony regarding rate design on April 11, 2008.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments pertaining to adjustments I sponsored in my direct testimony.

SUMMARY OF ADJUSTMENTS

Q. What areas will you address in your surrebuttal testimony?

A. My surrebuttal testimony will address the following RUCO proposed adjustments:

Rate Base:

Adjustment No. 4 – Accumulated Deferred Income Taxes Associated With the Management Incentive Plan and the Supplemental Executive Retirement Plan;

Adjustment No. 5 – Allowance For Working Capital.

Operating Income:

Adjustment No. 1 – Annualized Labor and Labor Loading;

Adjustment No. 6 – Unnecessary Miscellaneous Expenses;

Adjustment No. 7 – Incentive Compensation;
Adjustment No. 8 – Supplemental executive Retirement Plan;
Adjustment No. 9 – Employee Recognition;
Adjustment No. 10 – Uncollectible Expense;
Adjustment No. 12 – Yuma Manors Pipe Replacement Expenses; and
Adjustment No. 13 – Income Tax Calculation.

To support the adjustments in my surrebuttal testimony, I have revised specific direct testimony Schedules and prepared Surrebuttal Schedules numbered SURR RLM-1, SURR RLM-2, SURR RLM-6, SURR RLM-7, SURR RLM-8, and SURR RLM-17 through SURR RLM-20, which are filed concurrently in my surrebuttal testimony.

These Schedules quantify the adjustments recommended in RUCO's surrebuttal testimonies and consist of revisions to:

1. Accumulated Deferred Income Tax ("ADIT") associated with Management Incentive Plan ("'MIP") and the Supplemental Executive Retirement Plan ("'SERP") accept the Company's adjustment;
2. Lead/Lag Study used to calculate the Allowance For Working Capital to accept the Company's adjustment;
3. Unnecessary Miscellaneous Expenses to remove double counted expenditures;
4. Uncollectible Expenses to accept the Company's adjustment;
5. Yuma Manors Pipe Replacement Expenses as a conforming adjustment to the Company's Revised Rebuttal position;

6. Income Tax Expense to reflect changes in the operating expenses associated with the surrebuttal adjustments; and
7. Rate Design, Proof of Recommended Revenue and Typical Bill Analysis to reflect changes in the operating expenses associated with the surrebuttal adjustments.

RATE BASE

RUCO Rate Base Adjustment No. 4 – ADIT Associated With MIP and SERP

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the test-year ADIT?

A. Yes. The Company's ADIT was recorded in an account that is not a component of SWG's rate base.

Therefore, as shown on Surrebuttal Schedule SURR RLM-2, RUCO adjusted the ADIT to reflect the Company's level of ADIT as filed.

RUCO Rate Base Adjustment No. 5 – Allowance For Working Capital

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the allowance for working capital?

A. Yes. The Company accepted two adjustments RUCO made to the lead-lag study. First, the Company agrees with RUCO that the interest expense on the preferred stock should be included in the lead/lag study, albeit at 79.50 days as opposed to 82.73 days and disagreed with the

inclusion of interest on customer deposits. As shown on Surrebuttal Schedule SURR RLM-6, page 2, RUCO removed $1,915,314 of interest on customer deposits, adjusted the interest expense lag from 82.73 days to 79.50 days to include the impact of preferred securities. Second, the Company agreed with RUCO's adjustment to include the lag associated with revenue taxes. However, the Company has calculated a revenue tax lag of 45.24 days versus the 51.75 days recommended by RUCO. The Company's 45.24 days is based on the premise that the revenue taxes payable monthly are paid on the same date as associated revenue is received (see Company Rebuttal Exhibit RAM-3). However, through discovery the Company provided information to the contrary and inherently there is approximately an additional lag of 14 days between the payment of the monthly revenue-based taxes and the date the revenue is received. This 14-day lag computes to an overall revenue tax lag of 57.51 days versus the Company's rebuttal filing of 45.24 days. I have also made this adjustment on Schedule SURR RLM-6, page 2.

OPERATING INCOME

Operating Income Adjustment No. 1 – Annualized Labor and Labor Loading

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to annualize the labor and labor loading expenses?

A. No. As stated in my direct testimony, the inclusion of the June 2008 wage increase has the effect of triple-counting the increases in the salary and wage accounts - once for annualization of the test-year salaries, a second time for the post test-year 2007 three percent increase, and a third time for the 2008 increase. The Company's annualization adjustment to reflect estimated levels that will be in effect in June 2008 creates a mismatch between rate base, revenues and expenses at the end of the test year. If the Commission were to authorize rate recovery of the June 2008 payroll increases, the Company would be creating biased rates by picking and choosing which rate base, expense and revenue items it will reflect on an actual, projected or annualized basis. RUCO has allowed the test-year annualization as well as the post test-year 2007 wage increase, which is consistent with previous RUCO filings when the wage increase falls within a few months outside of the test year, but believes that a third proforma increase in 2008 is unwarranted.

Operating Income Adjustment No. 6 – Unnecessary Miscellaneous Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment of unnecessary miscellaneous expense?

A. Yes, the Company has provided information indicating RUCO's adjustment double counted certain expenditures related to employee recognition gift certificates.

Therefore, as shown on Schedule SURR RLM-8, column (G), I revised the unnecessary miscellaneous expense adjustment to recognize the double count, which increased test-year operating expenses by $19,160.

However, as for the remainder of the adjustment, RUCO and the Company have a philosophical difference as to the appropriateness of certain expenditures. RUCO does not believe that gift certificates, office refreshments, meals during meetings and extravagant off-site meetings are necessary in the provisioning of natural gas service to its customers.

Operating Income Adjustment No. 7 – Incentive Compensation

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment on incentive compensation?

A. No, for the reasons outlined in my direct testimony. Consistent with the Commission's Decisions on incentive compensation expense as set forth

in Decision No. 70011, dated November 27, 2007 (the recent UNS Gas rate case); and the Decision (No. unavailable at filing) in the very recent UNS Electric rate case, RUCO recommends a 50/50 sharing of the incentive compensation expense.

A 50/50 sharing represents a reasonable balancing of the interests between ratepayers and shareholders. The incentive program is comprised of elements that relate to the Company's financial performance and cost containment goals, matters that primarily benefit shareholders; plus elements based on meeting customer service goals, which offers an opportunity for the Company's customers to benefit from improved performance.

Operating Income Adjustment No. 8 – SERP

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the SERP?

A. No, RUCO's position is unchanged – the ratepayers should not be responsible for paying the cost of supplemental benefits to a small select group of high-ranking officers of the Company.

However, RUCO does allow the full costs of the Company's stock option compensation to be included in test-year expenses.

It seems disingenuous in the present climate of spiraling utility costs to request that the ratepayers be burdened with the cost of this elite retirement plan for an exclusive group of employees who are already receiving lucrative salaries and benefits.

As stated in my direct testimony, the Commission agreed with RUCO that SERP expenses should not be the burden of ratepayers. In Southwest Gas' last rate case (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses. In Arizona Public Service's most recent rate case, (Decision No. 69663, dated June 28, 2007), the Commission voted to disallow SERP. The Commission voted to disallow SERP in the UNS Gas rate case (Decision No. 70011, dated November 27,2007). Moreover, the Decision (No. unavailable at filing) in the very recent UNS Electric rate case also disallows SERP. I see no reason to depart from this precedent; therefore, RUCO recommends the removal of the test-year cost of the SERP from operating expenses.

RUCO has made no surrebuttal adjustment to the SERP as filed in direct testimony.

Operating Income Adjustment No. 9 – Employee Recognition

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to employee recognition expenses?

A. No. RUCO does not deny the importance for SWG to have proactive programs and policies on safety, productivity and cost containment. Where RUCO differs, is the necessity to burden ratepayers with the expense incurred by the Company in offering additional compensation to its employees to perform work functions, some of which are county mandated, that should be considered a condition of employment.

Operating Income Adjustment No. 10 – Uncollectible Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to test-year uncollectible expenses?

A. Yes, the Company's rebuttal testimony, workpapers and 2008 data illustrate that annual uncollectible expenses are trending upwards as a percentage of annual revenues.

RUCO will accept the Company's adjustment as filed. Therefore, as shown on Schedule SURR RLM-8, Column (K), I removed the adjustment.

Operating Income Adjustment No. 12 – Yuma Manors Pipe Replacement Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its operating income adjustments?

A. Yes. RUCO is making a conforming adjustment to include the test-year reduction in operating expenses proposed by the Company. SWG identified costs related to the replacement of steel pipe to the Manors subdivision in Yuma that SWG considered to be over and above those that it would have experienced had the replacement took place over a more routine time period.

RUCO accepts the expenses identified by the Company in its response to Commission Staff's data request 13.21 as those costs that are over and above what would have been experienced had the replacement been done in a more routine manner. The adjustment reduces gross plant by $320,779 for capitalized overtime and shift premium. The adjustment also reduces property tax expense by $8,499 and $15,175 in depreciation expense related to the $320,779 plant reduction.

Therefore, as shown on Schedules SURR RLM-2, Column (B), line 1 and SURR RLM-8, Column (M), this adjustment decreased test-year rate base by $320,779 and operating expenses by $23,674.

Operating Income Adjustment No. 13 – Income Tax Expense

Q. What adjustments have you made to the test-year Income Tax Expense account?

A. As shown on Schedule SURR RLM-17, I recalculated total test-year income taxes to reflect calculations based on my surrebuttal adjusted test-year revenue and expenses.

As shown on Schedule SURR RLM-8, column (Q), this adjustment increases the Company's adjusted test-year expenses by $2,825,460. This is an income tax decrease of $292,784 from the $3,118,244 increase recommended in my direct testimony.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. As shown on Schedule SURR RLM-19, I maintained the same set of bill determinants (i.e. test-year customer bill counts and therms consumed) as recommended in my direct testimony. After reviewing the Company's rebuttal testimony, I did not accept SWG's revised bill determinants as adjusted for declines in average weather normalized consumption through March 2008. The Company's proposed rebuttal post test-year bill count adjustment will result in mismatches in test-year elements. Furthermore, biased rates will result if the Commission were to recognize post test-year declines in consumption due to conservation; yet ignore post test-year

increases in consumption due to customer growth. An in-depth discussion of RUCO's proposed rate design is contained in the surrebuttal testimony of RUCO witness, Ms Diaz Cortez. In summary, for residential customers, RUCO proposes a monthly basic service charge of $11.52 and a commodity charge of $0.55455 for all therms consumed.

PROOF OF RECOMMENDED REVENUE

Q. Have you revised your additional direct testimony Schedule to present proof of your revised surrebuttal recommended revenue?

A. Yes, I have. Proof that RUCO's direct testimony recommended rate designs would produce the revised surrebuttal recommended required revenue as illustrated, is presented on Schedule SURR RLM-19.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for G-5 residential customers with various levels of usage is presented on Schedule SURR RLM-20.

Q. Please provide an excerpt of RUCO's rate structure that illustrates RUCO's rate design goals as set forth in the testimony of Ms. Diaz Cortez that captures these fundamental changes in SWG's current rate design.

A. Schedule SURR RLM-20 provides an extensive breakdown of the effects of RUCO's proposed rates on the G-5 Residential Customer.

Below is a chart gleaned from Schedule SURR RLM-19 comparing SWG's proposed rates to RUCO's proposed annual rates:

<u>SWG Proposed Rates and Charges</u>		
Basic Monthly Service Charge		$12.80
Non-Weather Sensitive Use –Charge Per Therm		
Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.88069	$0.60996	$1.49065
Weather Sensitive Use –Charge Per Therm		
Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.00	$1.49065	$1.49065

<u>RUCO Proposed Rates and Charges</u>		
Basic Monthly Service Charge		$11.52
All Consumption –Charge Per Therm		
Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.55455	$0.93689	$1.49144

COST OF CAPITAL

Q. Is RUCO revising its adjustments to the Company proposed cost of capital?

A. No. RUCO is not revising the adjustment to the weighted cost of capital. This position is fully explained in the surrebuttal testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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SURREBUTTAL
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5	SURR RLM-8	1 & 2	SUMMARY OF OPERATING INCOME ADJUSTMENTS
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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	$ 1,089,082,745	$ 1,837,726,032	$ 1,463,404,389
2	Adjusted Operating Income (Loss)	$ 73,180,098	$ 73,180,098	$ 73,180,098	$ 76,939,110	$ 76,939,110	$ 76,939,110
3	Current Rate Of Return (Line 2 / Line 1)	6.68%	3.97%	4.98%	7.06%	4.19%	5.26%
4	Required Operating Income (Line 5 X Line 1)	$ 103,457,659	$ 103,457,659	$ 103,457,659	$ 96,205,213	$ 96,205,213	$ 96,205,213
5	Required Rate Of Return	9.45%	5.61%	7.04%	8.83%	5.24%	6.57%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 30,277,561	$ 30,277,561	$ 30,277,561	$ 19,266,103	$ 19,266,103	$ 19,266,103
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 2)	1.6586	1.6586	1.6586	1.6634	1.6634	1.6634
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 50,219,828	$ 50,219,828	$ 50,219,828	$ 32,046,846	$ 32,046,846	$ 32,046,846
9	Adjusted Test Year Revenue	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)	$ 449,454,506	$ 449,454,506	$ 449,454,506	$ 431,281,524	$ 431,281,524	$ 431,281,524
11	Required Percentage Increase In Revenue (Line 8 / Line 9)	12.58%	12.58%	12.58%	8.03%	8.03%	8.03%
12	Rate Of Return On Common Equity	11.25%	11.25%	11.25%	9.88%	9.88%	9.88%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Columns (D) Thru (F): Schedules SURR RLM-2, RLM-5, SURR RLM-6 And SURR RLM-18

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SURREBUTTAL
RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO OCRB ADJUSTMENTS	REF.	(C) RUCO ADJUSTED AS OCRB
1	Gas Plant In Service	$ 2,053,847,890	$ (677,012)	(1) & (4)	$ 2,053,491,657
	Less:				
2	Accumulated Depreciation And Amortization	752,275,563	(276,996)	(1)	751,998,567
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 1,301,572,327	$ (400,016)		$ 1,301,493,090
	Additions:				
4	Allowance For Working Capital (SURR RLM-6, Page 1)	$ 5,681,932	$ (5,628,064)	(2)	$ 53,868
5	Total Additions (Line 4)	$ 5,681,932	$ (5,628,064)		$ 53,868
	Deductions:				
6	Customer Advances In Aid Of Construction	$ (37,910,017)	$ -		$ (37,910,017)
7	Customer Deposits	(31,921,898)	-		(31,921,898)
8	Deferred Income Taxes	(142,632,297)	-	(3)	(142,632,297)
9	Total Deductions (Sum Of Lines 6, 7 & 8)	$ (212,464,212)	$ -		$ (212,464,212)
10	TOTAL ORIGINAL COST RATE BASE (Sum Of Lines 3, 5 & 9	$ 1,094,790,047	$ (6,028,081)		$ 1,089,082,745

References:
Column (A): Company Schedule B-1
Column (B): References:
(1) Schedule RLM-4, Page 1 (Adjustment is -$356,233)
(2) Schedule SURR RLM-6, Page 1
(3) Schedule RLM-3, Page 3
(4) See Surrebuttal Testimony - Adjustment No. 12 - Yuma Manors (Adjustment is -$320,779)
Column (C): Column (A) + Column (B)

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SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5
SUMMARY OF THE ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	
1	Cash Working Capital Per SWG	SWG SCH. B-5, Page 1	$	(10,379,937)
2	Cash Working Capital Per RUCO	SURR RLM-6, Page 2, Line 14		(16,349,492)
3	Adjustment	Line 2 - Line 1	$	(5,969,555)
4	Materials And Supplies Per SWG	SWG SCH. B-5, Page 1	$	12,389,898
5	Materials And Supplies Per RUCO	SWG SCH. B-5, Page 1		12,389,898
6	Adjustment	Line 5 - Line 4	$	-
7	Prepayments Per SWG	SWG SCH. B-5, Page 1	$	3,671,971
8	Prepayments Per RUCO	SURR RLM-6, Page 5, Line 15		4,013,462
9	Adjustment	Line 8 - Line 7	$	341,491
10	Total Adjustment	Sum Lines 3, 6, & 9	$	(5,628,064)

SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
1	Cost Of Gas	$ 540,064,385	$ -	$ 540,064,385	42.30	$ 22,842,405,297
2	Labor Cost	117,038,570	(6,513,626)	110,524,944	12.33	1,363,305,727
3	Provision For Uncollectible Accts	2,977,729	-	2,977,729	120.00	357,327,523
4	Other O & M	54,826,860	11,033	54,837,893	17.72	971,476,853
	Total O & M Expenses	$ 714,907,544	$ (6,502,593)	$ 708,404,951	36.05	$ 25,534,515,400
5	Interest	$ 48,035,008	(250,413)	$ 47,784,595	79.50	$ 3,798,875,265
6	Taxes Other Than Income Taxes	33,124,880	-	33,124,880	185.34	6,139,365,177
7	Income Taxes	21,699,571	9,998,850	31,698,421	37.00	1,172,841,556
8	Revenue Taxes	97,747,450	3,278,392	101,025,842	57.51	5,809,996,195
9	Total Operating Expenses	$ 915,514,453	$ 3,245,844	$ 922,038,689	46.05	$ 42,455,593,594
10	Revenue Lag				39.53	Co. Workpapers
11					(6.52)	Line 10 - Line 9
12	Number Of Days In Test Period	365	Test Year			
13	Average Daily Operating Expenses	$ 2,508,259	Col. (A) Line 9 / Line 12			
14	Net Difference Rev - Exp Lag	(6.52)	Col. (D) Line 11			
15	Cash Working Capital	$ (16,349,492)	Col. (A), Line 13 X Line 14			

SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - CALCULATION OF PREFERRED EQUITY LAG

LINE NO.	MID-POINT OF SERVICE PERIOD	(A) PAYMENT DATE	(B) PERCENT PAYMENT	(C) (LEAD)/LAG DAYS	(D) DOLLARS DAYS
1	7/1/2006	3/31/2006	25.00%	(92)	(23.00)
2	7/1/2006	6/30/2006	25.00%	(1)	(0.25)
3	7/1/2006	9/30/2006	25.00%	91	22.75
4	7/1/2006	12/31/2006	25.00%	183	45.75
5	Totals		100.00%		45.25
6	Preferred Equity Lag			45.25	

SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - CALCULATION OF OTHER O & M LAG

LINE NO.	MONTH	(A) COST	(B) LAG DAYS	(C) DOLLAR DAYS
1	May 2006	$ 2,596,715	0.22	$ 566,253
2	June	2,611,117	35.16	91,799,499
3	July	2,546,481	18.55	47,227,421
4	August	2,460,510	36.74	90,404,740
5	September	2,021,521	35.60	71,973,470
6	October	3,018,228	52.99	159,935,937
7	November	2,733,777	45.29	123,820,351
8	December	3,394,550	(6.46)	(21,943,520)
9	January 2007	5,019,712	(2.82)	(14,168,034)
10	February	5,258,382	9.77	51,397,591
11	March	4,466,924	29.44	131,524,579
12	April	2,608,462	(17.75)	(46,306,652)
13	Total	$ 38,736,380	17.72	$ 686,231,635

SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - CALCULATION OF ADJUSTED PREPAYMENTS

LINE NO.	MONTH	(A) BALANCE	(B) DEBITS	(C) CREDITS	(D) ADJUSTED BALANCE
1	April 2006	$ 5,367,019	$ -	$ -	$ 5,367,019
2	May	4,571,452	18,221	-	4,589,673
3	June	3,756,402	-	1,518	3,773,104
4	July	5,219,958	22,000	1,518	5,257,142
5	August	9,299,535	195,806	3,352	9,529,173
6	September	8,623,454	15,186	19,669	8,848,609
7	October	7,836,438	66,720	20,934	8,107,379
8	November	6,430,014	128,656	26,494	6,803,117
9	December	9,144,710	163,132	37,216	9,643,729
10	January 2007	8,343,687	112,506	50,810	8,904,402
11	February	7,723,320	126,085	60,186	8,349,935
12	March	6,044,664	76,149	70,693	6,676,735
13	April	5,600,962	13,396	77,038	6,169,390
14	Total	$ 87,961,615			$ 92,019,406
15	13 Month Average	$ 6,766,278		56.70%	$ 4,013,462

References:
Column (A): Company Schedule B-5, Page 4
Column (B): Company Schedule B-5, Workpaper Sheets 30 - 59
Column (C): Column (B) Prior Months Accurals / 12 Months
Column (D): Column (D) Prior Month + Column (B) Current Month - Column (C) Current Month + Column (A) Current Month - Column (A) Prior Month

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SURREBUTTAL
OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
1	Revenues	$ 399,234,678	$ -	$ 399,234,678	$ 32,046,846	$ 431,281,524
2	Gas Cost	-	-	-	-	-
3	TOTAL MARGIN	$ 399,234,678	$ -	$ 399,234,678	$ 32,046,846	$ 431,281,524
	EXPENSES:					
4	Other Gas Supply	$ 701,601	$ (25,254)	$ 676,347	$ -	$ 676,347
5	Distribution	89,528,455	(2,448,330)	87,080,125	-	87,080,125
6	Customer Accounts	38,730,909	(1,058,858)	37,672,051	-	37,672,051
7	Customer Information	1,126,796	(20,117)	1,106,679	-	1,106,679
8	Sales	-	-	-	-	-
	Administrative & General					
9	Direct	4,009,539	(290,519)	3,719,020	-	3,719,020
10	System Allocable	52,937,155	(2,659,515)	50,277,640	-	50,277,640
	Depreciation & Amortization					
11	Direct	80,956,247	(26,796)	80,929,450	-	80,929,450
12	System Allocable	6,646,938	(46,583)	6,600,356	-	6,600,356
13	Regulatory Amortizations	284,528	-	284,528	-	284,528
14	Other Taxes	33,124,880	(8,499)	33,116,381	-	33,116,381
15	Interest On Cust. Deposits	1,915,314	-	1,915,314	-	1,915,314
16	Income Taxes	16,092,218	2,825,460	18,917,678	12,780,743	31,698,421
17	TOTAL EXPENSES	$ 326,054,578	$ (3,759,011)	$ 322,295,568	$ 12,780,743	$ 335,076,311
		$ (2)				
18	NET INCOME (LOSS)	$ 73,180,098		$ 76,939,110		$ 96,205,213

References:
- Column (A): Company Schedule C-1
- Column (B): Testimony, RLM And Schedule SURR RLM-8
- Column (C): Column (A) + Column (B)
- Column (D): Testimony, RLM And Schedule SURR RLM-1, RLM-1, Page 2
- Column (E): Column (C) + Column (D)

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 LABOR AND LABOR LOAD SCH. RLM-9	(C) ADJ. NO. 2 INJURIES AND DAMAGES TSTM'Y-RLM	(D) ADJ. NO. 3 PAIUTE ANNUALZ'N TSTM'Y-RLM	(E) ADJ. NO. 4 ANNUALIZED DEP/AMORT SCH. RLM-10	(F) ADJ. NO. 5 ANNUALIZED PROP'TY TAX SCH. RLM-11	(G) ADJ. NO. 6 UNNECESS EXPENSES SURR-TSTM'Y	(H) ADJ. NO. 7 MIP SCH. RLM-13	(I) ADJ. NO. 8 SERP SCH. RLM-14
1	Revenues	$ 399,234,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ 399,234,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EXPENSES:									
4	Other Gas Supply	$ 701,601	$ (15,070)	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,184)
5	Distribution	89,528,455	(1,364,268)	-	-	-	-	(91,649)	-	(949,044)
6	Customer Accounts	38,730,909	(619,707)	-	-	-	-	-	-	(428,347)
7	Customer Information	1,126,796	(11,910)	-	-	-	-	-	-	(8,206)
8	Sales	-	-	-	-	-	-	-	-	-
	Administrative & General		-	-	-	-	-	-	-	-
9	Direct	4,009,539	(21,716)	-	-	-	-	-	(145,002)	(54,102)
10	System Allocable	52,937,155	(580,819)	283,644	(17,702)	-	-	(93,561)	(1,760,046)	(491,031)
	Depreciation & Amortization		-	-	-	-	-	-	-	-
11	Direct	80,956,247	-	-	-	(11,621)	-	-	-	-
12	System Allocable	6,646,938	-	-	-	(46,583)	-	-	-	-
13	Regulatory Amortizations	284,528	-	-	-	-	-	-	-	-
14	Other Taxes	33,124,880	-	-	-	-	-	-	-	-
15	Interest On Cust. Deposits	1,915,314	-	-	-	-	-	-	-	-
16	Income Taxes	16,092,218	-	-	-	-	-	-	-	-
17	TOTAL EXPENSES	$ 326,054,579	$ (2,613,490)	$ 283,644	$ (17,702)	$ (58,204)	$ -	$ (185,210)	$ (1,905,048)	$ (1,940,914)
18	NET INCOME (LOSS)	$ 73,180,099								

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(J) ADJ. NO. 9 EMPLOYEE RECOGNITION TSTM'Y-RLM	(K) ADJ. NO. 10 UNCOLL'TIBLE EXPENSE SURR-TSTM'Y	(L) ADJ. NO. 11 GAIN ON SALE - PROPERTY SCH. RLM-16	(M) ADJ. NO. 12 YUMA MANORS SURR-TSTM'Y	(N) INTENT'LY LEFT BLANK	(O) INTENT'LY LEFT BLANK	(P) INTENT'LY LEFT BLANK	(Q) ADJ. NO. 13 INCOME TAX SURR RLM-17	(R) RUCO AS ADJUSTED
1	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 399,234,678
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 399,234,678
	EXPENSES:									
4	Other Gas Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 676,347
5	Distribution	(43,370)	-	-	-	-	-	-	-	87,080,125
6	Customer Accounts	(10,804)	-	-	-	-	-	-	-	37,672,051
7	Customer Information	-	-	-	-	-	-	-	-	1,106,679
8	Sales	-	-	-	-	-	-	-	-	-
									-	-
	Administrative & General	-	-	-	-	-	-	-	-	-
9	Direct	-	-	(69,699)	-	-	-	-	-	3,719,020
10	System Allocable	-	-	-	-	-	-	-	-	50,277,640
					-	-	-	-	-	-
	Depreciation & Amortization	-	-	-	-	-	-	-	-	-
11	Direct	-	-	-	(15,175)	-	-	-	-	80,929,450
12	System Allocable	-	-	-	-	-	-	-	-	6,600,356
13	Regulatory Amortizations	-	-	-	-	-	-	-	-	284,528
					-	-	-	-	-	-
14	Other Taxes	-	-	-	(8,499)	-	-	-	-	33,116,381
15	Interest On Cust. Deposits	-	-	-	-	-	-	-	-	1,915,314
16	Income Taxes	-	-	-	-	-	-	-	2,825,460	18,917,678
17	TOTAL EXPENSES	$ (54,174)	$ -	$ (69,699)	$ (23,674)	$ -	$ -	$ -	$ 2,825,460	$ 322,295,568
18	NET INCOME (LOSS)									$ 76,939,110

SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule SURR RLM-7, Column (C), Line 18 + Line 16	$ 95,856,788
	LESS:		
2	Arizona State Tax	Line 11	(3,349,670)
3	Interest Expense	Note (A) Line 21	(47,784,595)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 44,722,523
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 10	35.17%
6	Federal Income Tax Expense	Line 4 X line 5	$ 15,731,106
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 95,856,788
	LESS:		
8	Interest Expense	Note (A) Line 21	(47,784,595)
9	State Taxable Income	Line 7 + Line 8	$ 48,072,193
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 3,349,670
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 15,731,106
13	State Income Tax Expense	Line 11	3,349,670
14	South Georgia Amortization	Company Schedule C-1, Sheet 17, Column (C), Line 8 + Line 18	365,253
15	Investment Tax Credit	Company Schedule C-1, Sheet 17, Column (C), Line 19	(528,352)
16	Total Income Tax Expense Per RUCO	Sum Of Lines 12, 13, 14 & 15	$ 18,917,678
17	Total Income Tax Expense Per Company Filing (Schedule C-1)		16,092,218
18	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See SURR RLM 7, Page 2, Column (Q))	Line 16 - Line 17	$ 2,825,460

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Schedule SURR RLM-2, Column (C), Line 10)	$ 1,089,082,745
20	Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2)	4.39%
21	Interest Expense (Line 19 X Line 20)	$ 47,784,595

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SURREBUTTAL
COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST
1	Long-term Debt	51.00%	7.96%	4.06%
2	Preferred Stock	4.00%	8.20%	0.33%
3	Common Equity	45.00%	9.88%	4.45%
4	TOTAL CAPITAL	100.00%		
5	WEIGHTED COST OF CAPITAL			8.83%

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) X Column (B)
Column (C) Line 5: Sum Of Column (C) Lines 1 Thru 3

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) GAS COST	(J) TOTAL REVENUE
	Single-Family Residential Gas Service	G-5									
	Summer (May - October)										
1	Basic Service Charge per Month		5,107,859		$ 11.52		$ 58,847,277		$ 58,847,277		$ 58,847,277
	Commodity Charge per Therm										
2	First 15 Therms			48,048,640		$ 0.55455		$ 26,645,248	26,645,248	$ 45,016,291	71,661,539
3	Over 15 Therms			16,007,105		0.55455		8,876,698	8,876,698	14,996,896	23,873,594
	Winter (November - April)										
4	Basic Service Charge per Month		5,190,171		$ 11.52		$ 59,795,587		$ 59,795,587		$ 59,795,587
	Commodity Charge per Therm										
5	First 35 Therms			133,956,357		$ 0.55455		74,285,147	74,285,147	125,502,371	199,787,518
6	Over 35 Therms			91,044,013		0.55455		50,488,219	50,488,219	85,298,225	135,786,444
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 118,642,864	$ 160,295,312	$ 278,938,176	$ 270,813,783	$ 549,751,959
8	Ratio Of Fixed To Variable Revenues						42.53%	57.47%	64.68%		
	Low Income Single-Family Residential Gas Svc	G-10									
	Summer (May - October)										
9	Basic Service Charge		153,923		$ 7.26		$ 1,118,019		$ 1,118,019		$ 1,118,019
	Commodity Charge per Therm										
	Summer (May - October)										
10	First 15 Therms			1,499,731		$ 0.55455		$ 831,672	831,672	$ 1,226,000	2,057,672
11	Over 15 Therms			343,792		0.55455		190,649	190,649	281,043	471,692
	Winter (November - April)										
12	Basic Service Charge per Month		156,983		$ 7.26		$ 1,140,245		$ 1,140,245		$ 1,140,245
	Commodity Charge per Therm										
13	First 35 Therms			4,229,842		$ 0.55455		2,345,648	2,345,648	3,457,811	5,803,459
14	Next 115 Therms			2,532,839		0.55455		1,404,579	1,404,579	2,070,545	3,475,124
15	Over 150 Therms			52,769		0.55455		29,263	29,263	43,137	72,400
16	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,258,264	$ 4,801,811	$ 7,060,075	$ 7,078,536	$ 14,138,611
17	Ratio Of Fixed To Variable Revenues						31.99%	68.01%	1.64%		
	Special Residential Gas Service for Air Conditioning	G-15									
	Summer (May - October)										
18	Basic Service Charge per Month		648		$ 11.52		$ 7,466		$ 7,466		$ 7,466
	Commodity Charge per Therm										
19	First 15 Therms			7,899		$ 0.55455		$ 4,380	4,380	$ 7,326	11,706
20	Over 15 Therms			65,327		0.55455		36,227	36,227	60,589	96,816
	Winter (November - April)										
21	Basic Service Charge per Month		648		$ 11.52		$ 7,466		$ 7,466		$ 7,466
	Commodity Charge per Therm										
22	First 35 Therms			19,309		$ 0.55455		10,708	10,708	17,909	28,617
23	Over 35 Therms			48,985		0.55455		27,165	27,165	45,433	72,598
24	Total Special Residential Gas Service		1,296	141,520			$ 14,932	$ 78,480	$ 93,412	$ 131,257	$ 224,669
25	Ratio Of Fixed To Variable Revenues						15.99%	84.01%	0.02%		

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LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) GAS COST	(J) TOTAL REVENUE
	Multi-Family Residential Gas Service										
26	Summer (May - October)										
27	Basic Service Charge per Month	G-6	182,409		$ 9.02		$ 1,644,737		$ 1,644,737		$ 1,644,737
28	Commodity Charge per Therm										
	First 7 Therms			1,044,432		$ 0.55455		$ 579,187		$ 978,518	
	Over 7 Therms			950,005		0.55455		526,823		890,050	
29	Winter (November - April)										
30	Basic Service Charge per Month		188,153		$ 9.02		$ 1,696,529		$ 1,696,529		$ 1,557,705
31	Commodity Charge per Therm										
	First 18 Therms			2,633,090		$ 0.55455		1,460,173		2,466,916	1,416,873
	Over 18 Therms			1,880,532		0.55455		1,042,844		1,761,851	
32	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,341,266	$ 3,609,027	$ 6,950,293	$ 6,097,335	$ 13,047,628
33	Ratio Of Fixed To Variable Revenues						48.07%	51.93%	1.61%		
	Low Income Multi-Family Residential Gas Svc										
34	Summer (May - October)										
35	Basic Service Charge per Month	G-11	13,560		$ 7.26		$ 98,493		$ 98,493		$ 98,493
36	Commodity Charge per Therm										
	First 7 Therms			79,822		$ 0.55455		44,265		65,253	
	Over 7 Therms			78,071		0.55455		43,294		63,822	
37	Winter (November - April)										
38	Basic Service Charge per Month		13,828		$ 7.26		$ 100,440		$ 100,440		$ 100,440
39	Commodity Charge per Therm										
	First 18 Therms			207,982		$ 0.55455		115,336		170,021	109,518
	Next 132 Therms			186,423		0.55455		103,380		152,397	107,116
	Over 150 Therms			345		0.55455		191		282	
40	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 198,933	$ 306,466	$ 505,399	$ 451,775	$ 957,174
41	Ratio Of Fixed To Variable Revenues						39.36%	60.64%	0.12%		
42	Total Residential Gas Service		11,008,182	304,917,309			124,456,259	169,091,096	293,547,355	284,572,686	578,120,041
43	Ratio Of Fixed To Variable Revenues						42.40%	57.60%	68.06%		
	Master Metered Mobile Home Park Gas Service										
44	Basic Service Charge per Month	0.554547384	1,968		$ 60.11		$ 118,300		$ 118,300		$ 118,300
45	Commodity Charge per Therm All Usage										
	All Usage			2,223,993		$ 0.39550		$ 879,584	$ 879,584	$ 2,083,637	
46	Total MMHP Gas Service	G-20	1,968	2,223,993			$ 118,300	$ 879,584	$ 997,884	$ 2,083,637	$ 2,963,221
47	General Gas Service - Small						11.86%	88.14%	0.23%		
48	Basic Service Charge Per Month		201,805		$ 25.05		$ 5,054,515		$ 5,054,515		$ 5,054,515
49	Commodity Charge per Therm All Usage										
	Transportation Customers			10,138		$ 0.68244		$ 6,919	$ 6,919	$ 8,288	
50	Sales Customers			5,010,616		$ 0.68244		$ 3,419,421	$ 3,419,421	$ 4,647,246	
51	Total Small General Gas Service		201,805	5,020,754			$ 5,054,515	$ 3,426,340	$ 8,480,855	$ 4,655,534	$ 13,136,389
	Ratio Of Fixed To Variable Revenues						59.60%	40.40%	1.97%		

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LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) GAS COST	(J) TOTAL REVENUE
	General Gas Service - Medium	G-25(M)									
52	Basic Service Charge		193,790		$ 41.67		$ 8,075,079		$ 8,075,079		$ 8,075,079
	Commodity Charge per Therm All Usage										
53	Transportation Customers			172,365		$ 0.39263		$ 67,676	67,676	$ 140,905.00	208,581
54	Sales Customers			45,357,904		$ 0.39263		17,808,850	17,808,850	42,068,549	59,877,399
55	Total Medium General Gas Service		193,790	45,530,269			$ 8,075,079	$ 17,876,526	$ 25,951,605	$ 42,209,454	$ 68,161,059
56	Ratio Of Fixed To Variable Revenues						31.12%	68.88%	6.02%		
	General Gas Service - Large	G-25(L)									
57	Basic Service Charge		85,510		$ 153.27		$ 13,105,786		$ 13,105,786		$ 13,105,786
	Commodity Charge per Therm All Usage										
58	Transportation Customers			3,556,829		$ 0.27629		$ 982,720	982,720	$ 2,907,637.00	3,890,357
59	Sales Customers			145,666,025		$ 0.27629		40,246,200	40,246,200	135,102,325	175,348,525
60	Total Large General Gas Service		85,510	149,222,854			$ 13,105,786	$ 41,228,920	$ 54,334,706	$ 138,009,962	$ 192,344,668
61	Ratio Of Fixed To Variable Revenues						24.12%	75.88%	12.60%		
	General Gas Service - Transportation Eligible	G-25(TE)									
62	Basic Service Charge		2,222		$ 910.02		$ 2,022,059		$ 2,022,059		$ 2,022,059
63	Demand Charge per Month			12,803,712	0.061331			$ 9,423,139	9,423,139		9,423,139
	Commodity Charge per Therm All Usage										
64	Transportation Customers			32,517,415		$ 0.09485		$ 3,084,360	3,084,360	$ 26,582,336	29,666,696
65	Sales Customers			67,008,985		$ 0.09485		6,355,974	6,355,974	62,149,493	68,505,467
66	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,022,059	$ 18,863,473	$ 20,885,532	$ 88,731,829	$ 109,617,361
67	Ratio Of Fixed To Variable Revenues						9.68%	90.32%	4.84%		
68	Total General Gas Service		483,327	299,300,277			28,257,439	81,395,259	109,652,698	273,606,779	383,259,477
69	Ratio Of Fixed To Variable Revenues						25.77%	74.23%	25.42%		
	Air Conditioning Gas Service	G-40									
	Basic Service Charge										
70	With Other Service - No BSC		60		$ 0.00		$ -		$ -		$ -
71	General Service - Small		198		25.05		4,959		4,959		4,959
72	General Service - Medium		0		41.67		-		-		-
73	General Service - Large		48		153.27		7,357		7,357		7,357
74	Essential Agricultural		12		910.02		10,920		10,920		10,920
	Commodity Charge per Therm All Usage										
75	Transportation Customers			373,987		$ 0.09093		$ 34,007	34,007	$ 305,727	339,734
76	Sales Customers			744,265		$ 0.09093		67,677	67,677	690,291	757,968
77	Total Air Conditioning Gas Service		318	1,118,252			23,236	101,684	124,920	996,018	1,120,938
78	Ratio Of Fixed To Variable Revenues						18.60%	81.40%	0.03%		
	Street Lighting Gas Service	G-45									
	Commodity Charge per Therm of Rated Capacity										
79	All Usage		324	102,289		$ 0.66957		$ 68,490	$ 68,490	$ 94,871	$ 163,361
80	Total Street Lighting Gas Service		324	102,289			$ -	$ 68,490	$ 68,490	$ 94,871	$ 163,361
81	Ratio Of Fixed To Variable Revenues						0.00%	100.00%	0.02%		

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	Gas Service for Compression on Customer's Premises	G-55									
	Basic Service Charge										
82	Small		252		$ 25.05		$ 6,312		$ 6,312		$ 6,312
83	Large		288		239.48		68,970		68,970		68,970
84	Residential		1,272		11.52		14,655		14,655		14,655
	Commodity Charge per Therm All Usage										
85	Transportation Customers			0		$ 0.16824		$ -	$ -	$ -	$ -
	Sales Customers										
86	Small			177,495		$ 0.16824		29,862	29,862	164,623	194,485
87	Large			2,060,152		$ 0.16824		346,604	346,604	1,910,750	2,257,354
88	Residential			77,361		$ 0.16824		13,015	13,015	71,751	84,766
89	Total CNG Gas Service		1,812	2,315,008			89,937	389,481	479,418	2,147,124	2,626,542
90	Ratio Of Fixed To Variable Revenues						18.76%	81.24%	0.11%		
	Electric Generation Gas Service	G-60									
	Basic Service Charge										
91	General Service - Small		36		$ 25.05		$ 902		$ 902		$ 902
92	General Service - Medium		36		41.67		1,500		1,500		1,500
93	General Service - Large		84		153.27		12,874		12,874		12,874
94	General Service - Transportation Eligible		84		-		0		0		0
95	Essential Agricultural		12		114.95		1,379		1,379		1,379
	Commodity Charge per Therm All Usage										
96	Transportation Customers			0		$ 0.11842		$ -	$ -	$ -	$ -
97	Sales Customers			21,521,946		$ 0.11842		2,548,736	2,548,736	19,961,174	22,509,910
98	Total Electric Generation Gas Service		252	21,521,946			16,655	2,548,736	2,565,391	19,961,174	22,526,565
99	Ratio Of Fixed To Variable Revenues						0.65%	99.35%	0.59%		
	Essential Agriculture User Gas Service	G-75									
100	Basic Service Charge		1,216		$ 114.95		$ 139,779		$ 139,779		$ 139,779
	Commodity Charge per Therm All Usage										
101	Transportation Customers			6,217,976		$ 0.22353		$ 1,389,898	1,389,898	$ 5,083,071.00	6,472,969
102	Sales Customers			7,214,684		$ 0.22353		1,612,692	1,612,692	6,691,475	8,304,167
103	Total Essential Agricultural Gas Service		1,216	13,432,660			139,779	3,002,590	3,142,369	11,774,546	14,916,915
104	Ratio Of Fixed To Variable Revenues						4.45%	95.55%	0.73%		
	Natural Gas Engine Gas Service	G-80									
	Basic Service Charge										
105	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ -		$ -		$ -
106	Peak Season (April - September)		2,589		119.74		310,005		310,005		310,005
	Commodity Charge per Therm All Usage										
107	Transportation Customers			0		$ 0.17957		$ -	$ -	$ -	$ -
108	Sales Customers			13,070,981		$ 0.17957		2,347,162	2,347,162	9,591,355	11,938,517
109	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 310,005	$ 2,347,162	$ 2,657,167	$ 9,591,355	$ 12,248,522
110	Ratio Of Fixed To Variable Revenues						11.67%	88.33%	0.62%		
111	Total Tariff Sales		11,502,504	658,002,715			$ 153,411,610	$ 259,824,082	$ 413,235,692	$ 604,828,190	$ 1,018,063,882
112	Optional Gas Service	G-30	84	49,447,344			120,540	3,135,458	3,255,998	40,422,215	43,678,213
113	Special Contract Service	B-1	244	35,660,859			449,274	2,078,755	2,528,029		2,528,029
114	Other Operating Revenues						12,261,805		12,261,805		12,261,805
115	Total		11,502,832	743,110,918			$ 166,243,229	$ 265,038,296	$ 431,281,525	$ 645,250,405	$ 1,076,531,930
116	Ratio Of Fixed To Variable Revenues						38.55%	61.45%	100.00%		
117	Total Revenue Requirement								431,281,524	645,249,274	1,076,530,798
118	Over/(Under)								$ 1	$ 1,131	$ 1,132

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Test Year Ended April 30, 2007

SURREBUTTAL
SINGLE - FAMILY RESIDENTIAL TYPICAL BILL ANALYSIS
COMPARISON OF PRESENT MONTHLY CHARGES TO COMPANY PROPOSED AND RUCO PROPOSED

LINE NO.	DESCRIPTION	(A) USAGE THERMS	(B) TOTAL MONTHLY COST PRESENT RATES	(C) TOTAL MONTHLY COST COMPANY PROPOSED	(D) TOTAL MONTHLY COST RUCO PROPOSED	(E) RUCO INCREASE OVER PRESENT CHANGE	(F) PERCENTAGE
	Single-Family Residential Gas Service						
	Summer (May - October)						
1	50% Average Summer Usage per Month	6	$ 18.97	$ 22.15	$ 20.87	$ 1.90	10.01%
2	75% Average Summer Usage per Month	9	$ 23.61	$ 26.82	$ 25.55	$ 1.94	8.21%
3	**100% Average Monthly Summer Use**	**13**	**$ 28.25**	**$ 31.49**	**$ 30.22**	**$ 1.98**	**7.00%**
4	125% Average Summer Usage per Month	16	$ 32.86	$ 36.17	$ 34.90	$ 2.05	6.23%
5	150% Average Summer Usage per Month	19	$ 37.36	$ 40.84	$ 39.58	$ 2.21	5.92%
	Winter (November - April)						
6	50%Average Winter Usage per Month	22	$ 41.76	$ 45.11	$ 43.85	$ 2.09	5.01%
7	75%Average Winter Usage per Month	33	$ 57.78	$ 61.27	$ 60.01	$ 2.23	3.86%
8	**100% Average Monthly Winter Use**	**43**	**$ 73.47**	**$ 77.42**	**$ 76.18**	**$ 2.71**	**3.68%**
9	125% Average Winter Usage per Month	54	$ 89.05	$ 93.58	$ 92.34	$ 3.29	3.69%
10	150% Average Winter Usage per Month	65	$ 104.64	$ 109.73	$ 108.50	$ 3.87	3.70%

RATE SCHEDULES

	DESCRIPTION	BASIC SERVICE CHARGE	NON-GAS COSTS	GAS COST	TOTAL GAS COST
	PRESENT RATES				
	Single-Family Residential Gas Service				
	Summer (May - October)				
11	Basic Service Charge per Month	$ 9.70			
	Commodity Charge per Therm				
12	First 15 Therms		$ 0.54200	$ 0.93689	$ 1.47889
13	Over 15 Therms		$ 0.50100	$ 0.93689	$ 1.43789
	Winter (November - April)				
14	Basic Service Charge per Month	$ 9.70			
	Commodity Charge per Therm				
15	First 35 Therms		$ 0.54200	$ 0.93689	$ 1.47889
16	Over 35 Therms		$ 0.50100	$ 0.93689	$ 1.43789
	COMPANY PROPOSED RATES				
	Single-Family Residential Gas Service				
	All Year Around And All Usage				
17	Basic Service Charge per Month	$ 12.80			
18	Non- Weather Sensitive Use - Commodity Charge per Therm		$ 0.88069	$ 0.60996	$ 1.49065
19	Weather Sensitive Use - Commodity Charge per Therm		$ -	$ 1.49065	$ 1.49065
	RUCO PROPOSED RATES				
	Single-Family Residential Gas Service				
	All Year Around And All Usage				
20	Basic Service Charge per Month	$ 11.52			
21	Commodity Charge per Therm		$ 0.554547	$ 0.93689	$ 1.49144

EXHIBIT
RUCO-7
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

March 28, 2008

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INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utility regulation in Arizona since 1994. During this period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

...

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Southwest Gas Corporation's ("SWG" or "Company") application for a permanent rate increase ("Application"). SWG filed the Application with the ACC on August 31, 2007. The Company has chosen the one-year operating period ended April 30, 2007 for the test year in this proceeding.

Q. Briefly describe SWG.

A. SWG is a local distribution company ("LDC") based in Las Vegas, NV, and is publicly-traded on the New York Stock Exchange ("NYSE"). The Company is the dominant provider of natural gas distribution services in the state of Arizona. SWG also provides natural gas in the states of California and Nevada. The Company's last rate increase was approved in Decision No. 68487, dated February 23, 2006. In that case, SWG was granted a rate of return of 8.40 percent with a cost of equity capital of 9.50 percent.

Q. Please explain your role in RUCO's analysis of SWG's Application.

A. I reviewed SWG's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity, cost of preferred

equity and my recommended cost of debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving SWG?

A. No. I testified on cost of capital issues for RUCO during SWG's prior rate case proceeding during 2005.

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. No. RUCO witnesses Marylee Diaz Cortez, CPA, RUCO's Chief of Accounting and Rates, and Rodney L. Moore will provide testimony on those issues.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into eight sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate that SWG is operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will explain my recommended cost of preferred equity. Sixth, I will compare my recommended capital structure with the Company-proposed capital structure. Seventh, I will explain my weighted cost of capital recommendation and eighth, I will comment on SWG's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

...

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of SWG, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.88 percent cost of equity capital. This 9.88 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending a 7.96 percent cost of debt. This is based on my review of the costs associated with SWG's various debt instruments.

Cost of Preferred Equity – I am recommending that the Commission adopt an 8.20 percent cost of preferred equity. This figure represents the effective cost of SWG's $100 million issue of trust originated preferred securities ("TOPrS").

Capital Structure – I am recommending that the Commission adopt the Company-proposed target capital structure of 51.0 percent debt, 4.0 percent preferred equity and 45.0 percent common equity.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and debt analyses, I am recommending an 8.83 percent cost of capital for SWG. This figure represents the weighted cost of my recommended costs of common equity, preferred equity and debt.

Q. Why do you believe that your recommended 8.83 percent cost of capital is an appropriate rate of return for SWG to earn on its invested capital?

A. The 8.83 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations

and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow* is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as SWG, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for SWG?

A. Based on the results of my DCF and CAPM analyses, which ranged from 9.20 percent to 10.83 percent, I am recommending a 9.88 percent cost of equity capital for SWG. My recommended 9.88 percent figure represents a mean average of the results of my DCF and CAPM analyses, which utilized a sample of publicly-traded natural gas local distribution companies ("LDC").

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate SWG's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the

stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine SWG's cost of equity capital. It is similar to one of the models used by the Company.

Q. In determining the rate of future dividend growth for SWG, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same

constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[1]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

[1] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[2] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[3] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends,

[2] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) / Year 1 Earnings/Sh] = [($1.04 - $1.00) / $1.00] = [$0.04 / $1.00] = 4.00%

[3] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

displayed in the last column, are 16.20 percent. If this rate were to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent / 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

...

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings

expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[4] Dr. Gordon identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:
- g = DCF expected growth rate,
- b = the earnings retention ratio,
- r = the return on common equity,
- s = the fraction of new common stock sold that accrues to a current shareholder, and

[4] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

v = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - \left(\frac{BV}{MP}\right)$

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M / B) + 1] / 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M / B) + 1] / 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In the prior SWG rate case[5], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for SWG was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a natural gas proxy group consisting of eight natural gas local distribution companies ("LDC").

Q. Why did you use this methodology as opposed to a direct analysis of SWG?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly-traded company. Although SWG is publicly-traded on the NYSE, SWG's Arizona operations are not. Because of this situation, I used the aforementioned proxy that includes eight publicly-traded natural gas providers that have similar risk

[5] Decision No. 68487, dated February 23, 2006 (Docket No. G-01551A-04-0876)

characteristics to SWG in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the natural gas LDC's included in your proxy for SWG?

A. Each of the natural gas LDC's used in the proxy are publicly-traded on a major stock exchange (all ten trade on the NYSE) and are followed by The Value Line Investment Survey ("Value Line"). Each of the eight LDC's are tracked in Value Line's Natural Gas Utility industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment A of my testimony contains Value Line's most recent evaluation of the natural gas proxy group that I used for my cost of common equity analysis.

Q. What companies are included your natural gas proxy?

A. The eight natural gas LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("ATG"), Atmos Energy Corp. ("ATO"), Laclede Group, Inc. ("LG"), Nicor, Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Piedmont Natural Gas Company ("PNY"), South Jersey Industries, Inc. ("SJI"), and WGL Holdings, Inc. ("WGL").

Q. Briefly describe the regions of the U.S. served by the eight natural gas LDC's that make up your sample proxy.

A. The eight LDC's listed above provide natural gas service to customers in the Middle Atlantic region (i.e. SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast and South Central portions of the U.S. (i.e. ATG which serves Virginia, southern Tennessee and the Atlanta, Georgia area and PNY which serves customers in North Carolina, South Carolina and Tennessee), the South, deep South and Midwest (i.e. ATO which serves customers in Kentucky, Mississippi, Louisiana, Texas, Colorado and Kansas, GAS which provides service to northern and western Illinois, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. NWN which serves Washington state and Oregon).

...

Q. Did the Company's witness also perform a similar analysis using the natural gas LDC's included in your proxy?

A. Yes. The Company's cost of capital witness, Mr. Frank Hanley, CRRA, used the same eight LDC's that I have included in my proxy.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2003 to 2007. Schedule WAR-5 also includes Value Line's projected 2008, 2009 and 2011-13 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the LDC's that make up my proxy.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AGL Resources, Inc., NYSE symbol ATG, as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (page 10) to multiply ATG's earned return on common equity by its earnings retention ratio for each year 2003 through 2007 to derive the utility's

annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the 2008 internal growth rate and projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, ATG's sustainable internal growth rates experienced an up and down pattern during the 5-year observation period. This resulted in a 5.84% average over the 2003 to 2007 time frame. Value Line's analysts are forecasting a steady pattern of growth through 2013 ranging from 5.00% in 2008 to 6.16% by the end of 2013. Value Line has made no changes to its prior 5-year earnings projection of 5.50% but has revised its projections for dividend growth and book value downward from 5.50% and 2.50% to 4.00% and 1.50% respectively. Based on these estimates I believe a 5.75% rate of growth is reasonable for ATG (Schedule WAR-6).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 illustrates that ATG's average share growth was 4.32% over the current 2003 – 2007 observation period. Value Line expects negative growth during the 2008 and 2009 operating periods. After remaining stagnant at 76.00 million shares for the aforementioned periods, outstanding shares are expected to increase to 80.00 million during the

2011-13 period. Taking this data into consideration, I am standing on my prior estimate of a 0.55 rate of growth for ATG. My final dividend growth rate estimate for ATG is 5.92 percent (5.75 percent internal + 0.17 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the LDC's in your sample?

A. Based on the DCF model, my average dividend growth rate estimate is 5.18 percent as displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my sustainable growth estimates with the five-year projections of both Zacks (Attachment B) and Value Line. My 5.18 percent estimate is 131 basis points higher than the average projected rate of growth published by Value Line (which is an average of projected EPS, DPS and BVPS), and 8 basis points higher than the 5.10 percent average of projected 5-year EPS of analyst consensus opinions published by Zacks Investment Research, Inc. ("Zacks"). My 5.18 percent estimate is also 44 basis points higher than the 4.74 percent average of Value Line's and Zacks' projected and historical figures on EPS, DPS and BVPS. This indicates that investors are expecting increased performance from LDC's in the future. Based on this comparison, I would still say my

5.18 percent estimate is a fair representation of the growth projections that are available to the investing public.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's March 14, 2008 Ratings and Reports natural gas utility industry update. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period January 28, 2008 to March 20, 2008.

Q. Why did you rely on an eight-week observation period for the closing stock prices as opposed to a spot price at a given point in time?

A. The eight-week average tends to smooth out random events that may influence a stocks price on any one particular trading day. For this reason I typically rely on an eight-week mean average of closing stock prices as opposed to a spot price.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the natural gas utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.73 percent for the LDC's included in my sample.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[6], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model[7]. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[8] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of

[6] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[7] Dr. Sharpe shared the 1990 Nobel Prize in Economics with Harry M. Markowitz of City University of New York, and the late Merton H. Miller of the University of Chicago.

[8] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where:

k	=	cost of capital of a given security,
r_f	=	risk-free rate of return,
$ß$	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average of the yields on a 91-day Treasury Bill ("T-Bill").[9] The yields can be viewed in Attachment C of my testimony. This six-week average resulted in a risk-free (r_f) rate of return of 1.65 percent.

[9] A six-week average was computed for the current rate using 91-day T-Bill yield quotes listed in Value Line's Selection and Opinion newsletter from February 22, 2008 to March 28, 2008.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. This is because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will generally reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index[11] from 1926 to 2006 as the proxy for the market rate of return (r_m). The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 8.75 percent (10.40% - 1.65% = 8.75%). The risk premium that results by using the arithmetic mean calculation for r_m is 10.65 percent (12.30% - 1.65% = 10.65%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in my proxy, were calculated by Value Line and were current as of March 14, 2008 for the natural gas LDC's that comprise my sample. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas

[11] The historical return information on the S&P 500 index was obtained from Morningstar's SBBI 2007 Yearbook (previously published by Ibbotson Associates).

are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the natural gas service providers included in my sample ranged from 0.80 to 1.00 with an average beta of 0.86.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 9.20 percent. My calculation using an arithmetic mean results in an average expected return of 10.83 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	9.73%
CAPM	9.20% – 10.83%

Based on these results, my best estimate of an appropriate range for a cost of common equity for SWG is 9.20 percent to 10.83 percent. My final recommendation for SWG is 9.88 percent.

Q How did you arrive at your recommended 9.88 percent cost of common equity?

A. My recommended 9.88 percent cost of common equity is the mean average of my DCF and CAPM results. The calculation can be seen on Page 4 of Schedule WAR-1.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.25 percent cost of equity capital proposed by the Company is 137 basis points higher than the 9.88 percent cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-

[12] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these

types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[13]"

...

[13] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[14] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[15]

...

[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[15] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[16]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[17]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

[16] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.
[17] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[18]

Q. What has been the state of the economy over the past year?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate

[18] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

unchanged at 5.25 percent.[19] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crises rooted in a deterioration of the market for U.S. subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[20] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [21] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

[19] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[20] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[21] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What recent actions have the Fed taken in regard to interest rates?

A. As of this writing, the Fed has continued to cut rates and announced a 75 basis point reduction in the federal funds rate on March 18, 2008. The Fed's decision to cut rates was based on its belief that, at this point in time, the slowing economy is a greater concern than the current rate of inflation (which the majority of FOMC members believe will moderate

during the present economic slowdown).[22] As a result of the Fed's rate cutting action, the federal funds rate now stands at 2.25 percent.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. Despite the increases (prior to June 2006) by the FOMC, interest rates and yields on U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 2.50 percent from 5.73 percent in 2000.

Q. What has been the trend in other leading interest rates over the last year?

A. As of March 28, 2008, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C). The prime rate has fallen from 8.25 percent a year ago to 5.25 percent. The benchmark federal funds rate, just discussed, has decreased from 5.25 percent, in March 2007, to a level of 2.25 percent (as a result of the March 18, rate cut discussed above). The yields on several maturities of U.S. Treasury instruments have also decreased over the past year. A previous trend,

[22] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

described by former Chairman Greenspan as a "conundrum"[23], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, appears to have ended and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 91-day T-bill rate, used in my CAPM analysis, has fallen from 5.03 percent, in March 2007, to 0.56 percent as of March 19, 2008. The 1-Year Treasury constant maturity rate also decreased from 4.94 percent over the past year to 1.40 percent. Again, for the most part, these current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

Q. What is the current outlook for interest rates, inflation, and the economy?

A. As a result of the FOMC's March 18, 2008 rate cutting action, the federal funds rate of 2.25 percent is already below The Wall Street Journal's February 2008 Economic Forecasting Survey's prediction that the rate would drop to 2.64 percent by December 2008. The change in the consumer price index, a key measure of inflation, is also expected to fall from the December 2007 level of 4.10 percent to 2.30 percent by December 2008.

[23] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

Value Line's analysts have been decidedly pessimistic in their outlook on the economy recently and had this to say in their Economic and Stock Market Commentary that appeared in the March 28, 2008 edition of Value Line's Selection and Opinion publication:

> **The evidence that we are in a recession continues to build.** Such indicators include declining nonfarm payrolls, sluggish manufacturing and nonmanufacturing data, a falloff in March retail sales, and additional softness in industrial production.
>
> **The economic problems, which began with the housing market, are spreading and could well spread further in the months to come.** Not only are housing's woes intensifying and weakness evolving in other key markets, but businesses are unlikely to increase their spending on plant and equipment given the slowdown on the consumer front. We also think nonresidential construction, which gave a boost to the economy in 2007, will ease this year due to the recent tightening in credit conditions. The spreading construction slump, in the meantime, is likely to increase the unemployment rolls still further.

Despite their less than favorable outlook on the economy, Value Line's analysts believe that the Federal Reserve is on the right track as also stated in the March 28, 2008 edition of Value Line's Selection and Opinion publication:

> **Effective action by the Federal Reserve should lessen the severity of an economic setback.** The Fed has not only been reducing interest rates aggressively, taking the federal funds rate (the overnight lending rate between banks) down from 5.25% to 2.25% since last September, but it has extended its lending program to provide liquidity to cash-strapped companies. We think other innovative moves to alleviate the strains caused by the tightening in the credit markets will be taken by the Fed in the weeks to come to lessen the severity of any economic downturn and to hopefully boost flagging investor confidence.

Q. How has the current economic environment of lower interest rates affected various regulated utility industries as a whole?

A. Value Line analyst Nils C. Van Liew took note of the environment of low interest rates that existed in the early part of 2007. In Value Line's Electric

Utility (East) Industry update dated March 2, 2007, Mr. Van Liew had this to say:

> **Low Interest Rates.** Several factors are, no doubt, driving the electric utilities' strong share-price performance. Perhaps most important is a benign interest-rate environment. Utilities frequently tap the credit markets to fund their operations. (Low interest rates mean they can cost effectively build new power plants and maintain existing ones.) "Cheap money" also tends to drive economic expansion, thereby increasing electricity demand. That said, interest rates should remain relatively low, though the likelihood that the Federal Reserve eases (monetary) policy is small, given persistent inflation concerns.

While Mr. Van Liew's views appeared in Value Line's Electric Utility Industry update, I believe his comments hold true for all regulated utilities including the natural gas distribution segment. Given the fact that interest rates are even lower now than they were at the time of Mr. Van Liew's writing, and utility bond rates are currently lower than their 2007 averages (Schedule WAR 8), I believe that his views are still valid. In fact, my opinions are supported by Gabe Moreen, an analyst for Merrill Lynch, who had this to say in his February 21, 2008 report[24] on SWG:

> **Falling interest rates bode well for utilities** The Fed's recent interest rate cuts buoyed our natural gas utility index stocks, which had underperformed during recent credit market turmoil. The liquidity squeeze elevated concerns over higher capital costs for this capital-intensive industry, but credit market concerns do not fundamentally threaten the sector, in our view. Most gas utilities in our index have investment grade credit and, were the cost of debt to rise, could recover higher capital costs via rate cases. The interest rate cut also boosted gas utility stocks as 10-year Treasury prices rose and yields fell. 10-year Treasury yields provide a common benchmark for utility valuation; like Treasury bills, utility stocks typically offer steady income and are often valued by yield differential above Treasury bills. The dividend yield-Treasury yield differential has recently shrunk to 85 [basis points], just shy of the long-term average 86 [basis point] differential. Treasury yields are relatively low at 3.9%, and we expect this low differential to help sustain gas utility stocks at their high valuations in the near term. For

[24] Provided in the Company's response to ACC Staff data request STF-2-8 dated March 6, 2008.

> Merrill Lynch's current interest rate outlook, please see The Market Economist. 15 February 2008.

Q. How does the average dividend yield of your sample LDC stocks compare to the average dividend yield for all of the LDC stocks followed by Value Line?

A. As can be seen in Schedule WAR-3, my sample LDC's have an average dividend yield of 4.55 percent which falls between Value Line's 3.60 percent 2006 average dividend yield for the natural gas industry and their 2011-13 projection of 4.60 percent (Attachment A).

Q. How has the slowdown in housing construction impacted SWG?

A. It would appear the housing slowdown discussed above is actually having a positive effect on SWG. This was reflected in several security analysts' reports that the Company provided in response to ACC Staff data request STF-2-8. Analysts for North American Equity Research, a subsidiary of J.P. Morgan Chase, had this to say:

> **Slowing Customer Growth; Reduced Equity Issuance Need**
> Southwest Gas highlighted a decline in its customer growth rate to below 3% in 2007, a decline attributable to problems in the housing market. Specifically, unoccupied homes and associated inactive meters accounted for a significant portion of the year-over-year decline. The large inventory of existing homes is expected to place downward pressure on new construction. As such, for the next two years the company anticipates growth in the range of 1.5-3% until the housing market returns to more normal levels. A more normalized growth rate reduces capital expenditures, mitigates cost creep associated with serving the growing demand and thereby should reduce the impact of regulatory lag caused in part by rate making in AZ which utilizes a historical test-year. On a related issue, we note that Southwest Gas has placed meters in approximately 20,000-30,000 homes that are currently vacant. The company highlighted that once these houses are occupied and gas meters turned on, Southwest Gas will begin bringing on new customers at no cost. As the capital for these meters are already

> included in the company's AZ rate case, these new customer additions would be incremental to earnings. Along with the decline in the company's customer growth forecast, Southwest Gas has revised its 2008-2010 capital expenditure forecast as disclosed in the 2007 10K. SWX forecasts capex of $850 million with $70-80 million equity financed. That is a reduction from the prior three-year outlook of $880 million and $100-125 million of equity financing. The reduction in their equity financing needs equates to about 2.8% of outstanding shares and is a positive development for shareholders.

Analysts at Citigroup Global Markets, Inc. had this to say:

> **What's Wrong? -** We believe the housing downturn in AZ, NV and CA has led some to believe that SWX will be negatively impacted by lower customer growth (6% previously down to 3% on the high-end). We think differently. First, we had always assumed that customer growth would trend back to normal levels. Second, during times of high customer growth, SWX struggled to earn its cost of capital because of historical test years in its rate cases (EVA negative). We estimate a one to two year lull in housing growth will enable SWX to push ROR above its costs of capital creating positive EVA.

Based on the above analysts' outlooks, it is reasonable to say that the slowdown in the housing sector is actually having a positive effect on SWG, given the fact that the Company will not have to devote higher levels of internally generated funds on capital expenditures, thus providing SWG with the opportunity to build on its existing equity position and possibly increase dividends.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.88 percent cost of equity capital that you have estimated is reasonable for SWG?

A. I believe that my recommended 9.88 percent cost of equity will provide SWG with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are low by historical

standards), the current lull in growth in new housing construction, and the Fed's ability to keep inflation in check are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of equity analysis, which is an average of the results of both the DCF and CAPM models, has produced such a return.

COST OF DEBT

Q. Have you reviewed SWG's testimony on the Company-proposed cost of debt?

A. Yes. I have reviewed the testimony provided by SWG witness Theodore K. Wood who presents the Company's capital structure, cost of debt and cost of preferred equity proposals.

Q. Briefly explain how SWG calculated the Company-proposed cost of debt.

A. The Company-proposed cost of debt is the weighted cost of the SWG's fixed rate and variable rate debt instruments excluding industrial development revenue bonds ("IDRB") that were issued to finance specific assets located in Clark County, Nevada and the City of Big Bear, California.

Q. Have you adopted the Company-proposed cost of debt?

A. Yes. The weighted cost of the Company's debt was also used in RUCO witness Rodney L. Moore's synchronized interest calculation which produced the interest deduction reflected in RUCO's recommended level of income tax expense.

COST OF PREFERRED EQUITY

Q. Have you reviewed SWG's testimony on the Company-proposed cost of preferred equity?

A. Yes. SWG witness Wood presented testimony on the Company-proposed 8.20 percent embedded cost of preferred equity, which reflects the effective cost of the Company's $100 million in trust originated preferred securities ("TOPrS").

Q. Have you accepted the Company-proposed 8.20 percent cost of preferred equity?

A. Yes I have.

Q. Is the weighted cost of SWG's preferred equity also reflected in RUCO's recommended level of income tax expense?

A. Yes it is. Ordinarily this type of regulatory accounting treatment would not be considered for the dividends of preferred equity instruments. However, as explained on pages 34 and 35 of SWG witness Theodore K. Wood, the

dividends of the TOPrS are tax-deductible as a result of the trust structure used by the Company to issue the securities. Given the tax-deductible nature of the dividends, it is only logical that their weighted cost be included in the synchronized interest calculation that produces an appropriate interest expense deduction that is used to compute a final recommended level of income tax expense.

CAPITAL STRUCTURE

Q. Have you reviewed SWG's testimony regarding the Company's proposed capital structure?

A. Yes.

Q. What was SWG's actual capital structure during the test year?

A. According to the direct testimony of SWG witness Wood (pages 10 and 11), the Company's actual capital structure during the test year was comprised of 52.70 percent debt, 4.40 percent preferred equity, and 42.90 percent common equity.

...

Q. How does the Company's actual capital structure compare to the average capital structure of the eight LDC's in your cost of equity capital proxy group?

A. As can be seen in Schedule WAR-9, the average capital structure of the eight LDC's included in my sample was comprised of 45.90 percent debt, 0.20 percent preferred equity, and 53.90 percent common equity. My analysis shows that the equity positions of the LDC's in my sample have increased slightly since SWG's cost of capital consultant, Mr. Hanley, conducted his analysis (as seen on page 11 of Mr. Wood's direct testimony).

Q. Is SWG's capital structure in line with industry averages?

A. No. As I explained above, SWG's actual capital structure is heavier in debt and preferred equity than the natural gas utilities included in my sample (Schedule WAR-9). Thus, the cost of equity derived in my DCF analysis is applicable to companies that are not as leveraged and, theoretically speaking not as risky than a utility with a level of debt similar to SWG's. In the case of a publicly-traded company, such as those included in my proxy, a company with SWG's level of debt would be perceived as having a higher level of financial risk and would therefore also have a higher expected return on common equity.

...

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a target capital structure comprised of 51.00 percent debt, 4.00 percent preferred equity, and 45.00 percent common equity.

Q. What capital structure are you recommending for SWG?

A. I am recommending the same capital structure being proposed by SWG.

Q. Have you made an adjustment to your cost of equity estimate based on the perception of higher financial risk that you explained earlier?

A. No, I have not. The target (i.e. hypothetical) capital structure that I am recommending will provide SWG with additional operating income and cash flows that will offset any perceived financial risk.

Q. Please explain.

A. The higher level of equity in my recommended capital structure will provide the Company with a higher overall weighted cost of equity (i.e. 8.83 percent as opposed to 8.80 percent) and will likewise provide SWG with a higher level of operating income. The higher level of equity in the target capital structure also results in a lower weighted cost of debt which in turn produces a lower synchronized interest deduction. This has the overall effect of providing SWG with a higher level of income tax expense. This higher level of income tax expense results in additional cash flow to

SWG because the Company's actual income tax liability will be lower (as a result of the higher actual interest expense deduction that the Company is entitled to). For these reasons I have made the decision not to make any adjustment to my recommended cost of equity which was based on the results of my DCF and CAPM analyses. In summary, I believe that my recommended target capital structure will provide SWG with a return on invested capital that will compensate the Company's shareholders for any perceived financial risk that they may face.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted cost of capital of 9.45 percent. This composite figure is the result of a weighted average of SWG's proposed 7.96 percent cost of debt, 8.20 percent cost of preferred equity, and 11.25 percent cost of equity capital. The Company-proposed 9.45 percent weighted cost of capital is 62 basis points higher than the 8.83 percent weighted cost of capital that I am recommending.

COMMENTS ON SOUTHWEST GAS CORPORATION'S COST OF EQUITY CAPITAL TESTIMONY

Q. Please describe SWG's cost of equity capital testimony.

A. As noted earlier in my testimony, SWG's cost of capital testimony was prepared by the Company's cost of equity consultant Mr. Frank J. Hanley, CRRA. Mr. Hanley's testimony presents the results of his cost of common equity analysis, which used the DCF, CAPM, risk premium, and comparable earnings methodologies. Mr. Hanley believes that the Company is entitled to an 11.25 percent cost of common equity based on the results of his cost of capital analysis.

Q. Please compare the way you conducted your DCF analysis with the way that Mr. Hanley conducted his.

A. Mr. Hanley conducted a DCF analysis using a similar single-stage constant growth model as I did. As I explained earlier in my testimony, Mr. Hanley also conducted his analysis using a proxy group comprised of the same eight natural gas utilities that were included in my sample. In addition to the aforementioned proxy group, Mr. Hanley also treated SWG as a stand-alone company in his analysis.

...

Q. How did Mr. Hanley determine the dividend yield component in his DCF model?

A. For the P_0 portion of the DCF formula, Mr. Hanley averaged spot prices that occurred on June 25, 2007 with average high and low prices that occurred during the months of May 2007 and April 2007 to arrive at initial average dividend yields of 3.94 percent, 3.67 percent, and 3.67 percent respectively for his proxy group of eight LDC's. After obtaining his initial dividend yields, he averages the results to arrive at an unadjusted average dividend yield of 3.76 percent. Mr. Hanley then adds a dividend growth component, which averages 0.08 percent for his sample LDC's, to arrive at a final adjusted average dividend yield of 3.84 percent. His final adjusted dividend yield is 71 basis points lower than the average 4.55 percent dividend yield that I obtained using an average of closing stock prices during a more recent 8-week period (Schedule WAR-3).

Q. How did Mr. Hanley obtain his final growth (i.e. g) estimate in his DCF analysis?

A. Mr. Hanley averaged the long-term (i.e. 2010-12) June 15, 2007 earnings per share projections of Value Line analysts and the June 23, 2007 five-year earnings per share projections of Thompson FN/First Call analysts to arrive at an average DCF growth rate of 4.51 percent for his proxy group of eight LDC's. His final average DCF growth estimate result of 4.51

percent is 67 basis points lower than my growth rate estimate of 5.18 percent.

Q. What is the average DCF result for the average dividend yields and growth estimates that were obtained by Mr. Hanley?

A. Mr. Hanley's final average DCF cost of equity estimate, using the inputs that I have just described, is 8.35 percent or 138 basis points lower than my DCF estimate of 9.73 percent. Mr. Hanley's final DCF estimate of 9.92 percent is 19 basis points higher than my final DCF estimate of 9.73 percent.

Q. How did Mr. Hanley obtain his final DCF cost of equity estimate of 9.92 percent when the average of his LDC sample produced an estimate of 8.35 percent?

A. To arrive at his final DCF cost estimates, Mr. Hanley ignored any results that were lower than 9.60 percent, which he states was the lowest rate awarded to a gas distribution utility during the twelve month period ended March 31, 2007. This methodology had the effect of eliminating the results of six of the eight LDC's in his proxy group.

...

Q. Do you agree with Mr. Hanley's method which eliminates any results under 9.60 percent?

A. No, I do not. Even though my final DCF estimate falls above the 9.60 percent threshold established by Mr. Hanley I still don't agree with his methodology. By setting his 9.60 percent threshold, Mr. Hanley is in effect refusing to consider the fact that the market has priced the returns of LDC's at a lower level than what regulators have adopted and that the investment community is willing to accept lower rates of returns.

Q. Please compare the results of your CAPM analysis with the results of Mr. Hanley's CAPM analysis.

A. Mr. Hanley performed two CAPM analyses, one using the traditional CAPM model which I used (i.e. the Sharpe/Lintner version expressed as $k = r_f + [ß (r_m - r_f)]$) and a second using the empirical ("ECAPM") version of the model which assumes that the risk-free rate of return used in the traditional model is understated. Typically the ECAPM uses unadjusted betas that are lower than the adjusted Value Line betas that I used in my CAPM analysis (a point on which Mr. Hanley and I disagree).

Q. Why didn't you use the ECAPM version in your CAPM analysis?

A. I did not use this version mainly because the ECAPM has been given little to no weight by the ACC in prior Commission proceedings (most notably in

a number of Arizona-American Water Company filings where the model was employed by a Boston consulting firm known as the Brattle Group).

Q. What were the differences between your CAPM analysis and Mr. Hanley's CAPM analysis?

A. Mr. Hanley performed his analysis using the same proxy that he used in his DCF analyses and also treated SWG as a stand-alone entity. His CAPM analysis produced an average expected return, or k, of 10.35 percent for his group of eight LDC's. As in his DCF analysis, Mr. Hanley simply rejected any results lower than 9.60 percent. Thus, his final CAPM estimate of 10.49 percent is higher than the aforementioned average of all eight of the LDC's used in both of our samples. His final CAPM estimate of 10.49 percent is 129 basis points higher than my 9.20 percent CAPM analysis result using a geometric mean, and 34 basis points lower than my 10.83 percent CAPM analysis result using an arithmetic mean. His stand-alone result for SWG is 10.17 percent. Mr. Hanley's ECAPM analysis produced an average expected return of 10.51 percent for his group of eight LDC's (the results for all eight of his sample companies exceeded his 9.60 percent threshold). His final ECAPM estimate of 10.51 percent results is 131 basis points higher than my 9.20 percent CAPM analysis result using a geometric mean, and 31 basis points lower than my 10.83 percent CAPM analysis result using an arithmetic mean. His ECAPM result for SWG as a stand-alone entity is 10.38 percent.

Q. What beta coefficient (ß) did you use in your CAPM model and what beta coefficient did Mr. Hanley's use in his CAPM analysis?

A. I used a beta coefficient of 0.86, which is an average of Value Line's adjusted betas for the eight LDC's included in my proxy. Mr. Hanley used an average beta coefficient of 0.88 for his group of eight LDC's. The lower average beta used in my analysis reflects the fact that the betas for several of the LDC's used in our samples have fallen (indicating lower risk) since Mr. Hanley conducted his analysis. Technically, Mr. Hanley's ECAPM model overstates the expected return because of his use of an adjusted beta in a model that contains an upward adjustment for the risk-free rate of return.

Q. Please compare the risk free rate of return (r_f) proxies used in both your and Mr. Hanley CAPM analyses.

A. As I explained earlier in my testimony (page 25), I used a six-week average on a 91-day T-Bill rate. This resulted in a risk-free rate of return of 1.65 percent. Mr. Hanley on the other hand, used an average of economist's projections, reported in Blue Chip Financial Forecasts dated July 1, 2007, on the yields of 30-year U.S. Treasury Notes for the six quarters ending with the final calendar quarter of 2008. This resulted in a higher risk-free rate of return of 5.33 percent. The difference between the two average yields is 368 basis points.

Q. What is the difference between your market risk premium and the market risk premium used by Mr. Hanley?

A. Mr. Hanley derived his 5.69 percent market risk premium figure by averaging Value Line and Morningstar data. The 5.69 percent market risk premium used by Mr. Hanley is 306 basis points lower than my 8.75 percent market risk premium, using a geometric mean, and is 496 basis points lower than my 10.65 percent market risk premium, using an arithmetic mean.

Q. Did you conduct a risk premium study or a comparable earnings analysis similar to the ones performed by Mr. Hanley?

A. No I did not. The risk premium methodology is basically an offshoot of the CAPM and the comparable earnings method, though used by most analysts to some degree, has been largely replaced by forward-looking methods such as DCF and CAPM.

Q. How does Mr. Hanley arrive at his 11.25 percent cost of common equity figure after presenting the results of his DCF, risk premium, CAPM and comparable earnings analyses?

A. Mr. Hanley arrived at his recommended 11.25 percent cost of common equity by weighing the results of all four of his models. This resulted in a cost rate of 11.00 percent for his proxy group of eight LDC's. After this he makes an upward adjustment of 31 basis points as a result of SWG's

credit ratings. His final 11.25 percent cost of common equity for SWG is conditioned on the Commission's adoption of the 45.00 percent level of equity, in the Company-proposed capital structure, and the Company's proposed tariff tools.

Q. Has Mr. Hanley given any consideration to the risk mitigation inherent in SWG's decoupling proposal in his cost of equity analysis?

A. No. Mr. Hanley's testimony concentrates on why his recommended 11.25 percent cost of common equity is appropriate for SWG given the various characteristics of the LDC's in his sample which includes their credit ratings and the fact that six of the eight have some form of decoupling or weather normalization in some of the jurisdictions they serve. However, Mr. Hanley's testimony does not address the fact that the implementation of a decoupling mechanism, which would essentially provide SWG with a guaranteed return on the Company's invested capital, does in itself merit a lower cost of common equity that reflects the elimination of the risk of not being able to earn an authorized rate of return.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Hanley constitute your acceptance of his positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on SWG?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase/ACRM
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase/ACRM

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase/ACRM
Tucson Electric Power Company	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase/ACRM
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0403	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power Company	E-01933A-07-0402	Rate Increase

ATTACHMENT A

The Natural Gas Utility Industry ranks in the bottom half of our industry spectrum for Timeliness. However, many firms are developing opportunities to bolster growth for the years ahead. Moreover, companies in this sector tend to be stable businesses that offer attractive dividend yields, which may add appeal to many issues, given the current lackluster economic environment. Still, limited near-term earnings prospects and a tough regulatory environment continue to weigh on firms here.

INDUSTRY TIMELINESS: 70 (of 97)

Economic Environment

The domestic economy appears to be moving closer to a possible recession. Investor sentiment has soured over the past year, as turmoil in the credit markets and a weak housing market have been a drag on the broader economy. The weakness ir the housing market has hurt companies in this industry, as customer growth has slowed for many Natural Gas Utilities. Oil prices have risen, which has helped offset some of this pressure, as natural gas has become an increasingly popular choice for consumers to meet their energy needs. Given the current turmoil in the world's financial markets, good quality businesses such as these may come increasingly into favor. These equities offer fairly predictable results, solid balance sheets, and above-average yields. Thus, conservative accounts may want to consider some of the stocks in this industry if they are trying to reduce risk in their portfolios.

Regulation

Rate cases are a key theme for the companies in this industry. These firms are regulated by state commissions that dictate the return on equity these companies can achieve. As a result, these utilities tend to register flat bottom-line results from year to year. Notably, numerous firms are in the process of applying for new rates or have cases pending. Therefore, when reading the following pages, investors should pay special attention to this factor as it will likely remain key for these firms going forward. This should be increasingly important if the tough real estate market continues to hinder demand for natural gas. When considering new cases, regulators try to strike a balance between consumer and shareholder interests. Given the recent challenges of this industry, the management of these firms are eagerly hoping for relief from these commissions in order to boost results.

Business Structure

Companies in this sector have sought various ways to drive profits. One such way has been developing or adding unregulated businesses to their operations. These ventures are not limited by state commissions and possess the potential to drive share-net beyond their typical levels. Currently, this strategy only makes up a small portion of this industry's results. However, it may become an increasingly important long-term opportunity. Another way firms have been trying to boost performance is by improving cost controls. Firms have also been looking to evolve their business model in an effort to create more sustainable growth. Companies have developed new ventures such as the ones mentioned above, while others have added bolt-on acquisitions to improve their position in this mature market. As a result, we believe that there will probably continue to be consolidation in this industry for the foreseeable future. All told, these strategies have been necessary for companies to continue to grow their business.

Weather

Weather is another factor that firms have to contend with in the Natural Gas Utility industry. Unseasonably warm or cold weather can create increased volatility. As a result, the predictable growth these firms enjoy can be disrupted. Some of these utilities hedge their risk through weather-adjusted rate mechanisms. This can minimize volatility if these weather abnormalities occur. Therefore, investors interested in firms with more stable performance should look for companies that use these strategies.

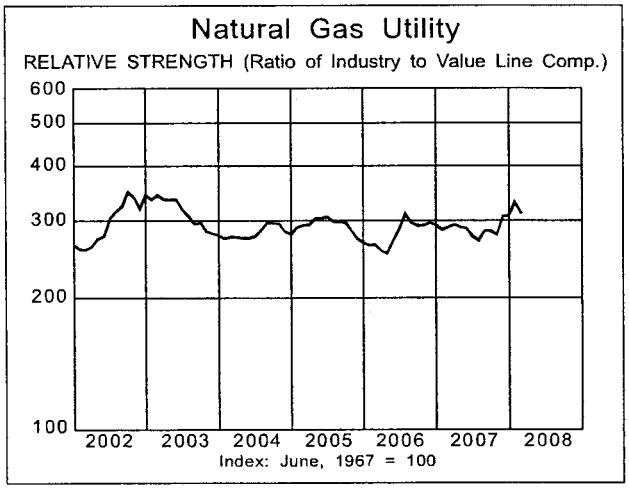
Investment Consideration

The majority of the stocks in this industry have subpar prospects over the 3- to 5-year pull. Additionally, the lion's share of the equities in this industry are ranked average or lower for Timeliness. Therefore, we believe performance-minded investors should look elsewhere. However, conservative income-oriented accounts may be attracted by these companies' above-average yields.

Richard Gallagher

Composite Statistics: Natural Gas Utility

2004	2005	2006	2007	2008	2009		11-13
33220	41399	41401	*44500*	*46500*	*49500*	Revenues ($mill)	*61500*
1517.2	1788.8	1823.0	*2050*	*2150*	*2350*	Net Profit ($mill)	*3000*
35.7%	35.8%	36.1%	*36.0%*	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
4.6%	4.3%	4.4%	*4.6%*	*4.6%*	*4.7%*	Net Profit Margin	*4.9%*
53.2%	50.7%	52.0%	*51.0%*	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
45.7%	48.3%	47.0%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*46.0%*
31268	33911	35357	*36750*	*38000*	*39750*	Total Capital ($mill)	*44000*
32053	35030	35944	*39000*	*41000*	*43000*	Net Plant ($mill)	*47500*
6.4%	6.9%	6.7%	*7.0%*	*7.0%*	*7.5%*	Return on Total Cap'l	*8.0%*
10.4%	10.7%	10.7%	*11.5%*	*11.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
10.5%	10.8%	11.0%	*11.5%*	*11.5%*	*12.0%*	Return on Com Equity	*12.5%*
4.0%	4.4%	4.6%	*5.2%*	*5.3%*	*5.5%*	Retained to Com Eq	*6.0%*
63%	59%	59%	*60%*	*60%*	*60%*	All Div'ds to Net Prof	*60%*
15.6	16.2	15.8		*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.82	.87	.90		*Value Line*		Relative P/E Ratio	*.85*
4.0%	3.6%	3.6%		*estimates*		Avg Ann'l Div'd Yield	*4.6%*
308%	331%	315%	*325%*	*325%*	*330%*	Fixed Charge Coverage	*330%*



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AGL RESOURCES NYSE-ATG

RECENT PRICE	35.54	P/E RATIO	12.4 (Trailing: 13.0 / Median: 14.0)	RELATIVE P/E RATIO	0.80	DIV'D YLD	4.7%	VALUE LINE

TIMELINESS **3** Raised 3/14/08

SAFETY **2** New 7/27/90

TECHNICAL **3** Raised 12/21/07

BETA .85 (1.00 = Market)

High:	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1					
Low:	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	34.4					

2011-13 PROJECTIONS

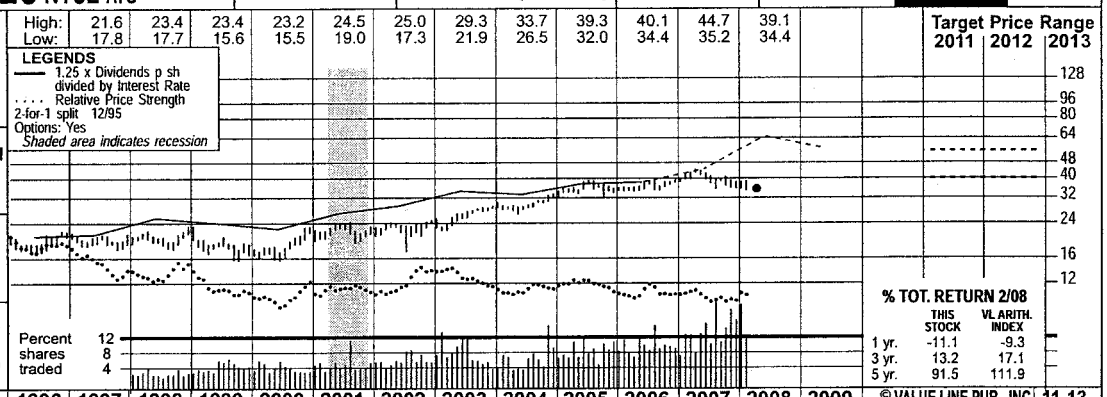
	Price	Gain	Ann'l Total Return
High	55	(+55%)	15%
Low	40	(+15%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	0	0	1	0	0	0	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	132	106	128
to Sell	101	112	99
Hld's(000)	50323	47302	47469



% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.1	-9.3
3 yr.	13.2	17.1
5 yr.	91.5	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
20.43	22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	*34.55*	*36.20*	Revenues per sh A	*41.25*
2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.77	*4.95*	*5.15*	"Cash Flow" per sh	*5.65*
1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	*2.80*	*2.90*	Earnings per sh A B	*3.20*
1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	*1.68*	*1.72*	Div'ds Decl'd per sh C■	*1.84*
2.74	2.4[illegible]	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	*3.50*	*3.60*	Cap'l Spending per sh	*3.65*
9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	*22.35*	*23.05*	Book Value per sh D	*22.50*
48.69	49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	*76.00*	*76.00*	Common Shs Outst'g E	*80.00*
15.5	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.77	*Value Line*		Relative P/E Ratio	*1.00*
5.9%	5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $2254.0 mill. **Due in 5 Yrs** $897.0 mill.
LT Debt $1674.0 mill. **LT Interest** $95.0 mill.

(Total interest coverage: 3.7x)
Leases, Uncapitalized Annual rentals $26.0 mill.

Pension Assets-12/07 $383.0 mill. **Oblig.** $427.0 mill.

Pfd Stock None
Common Stock 76,439,305 shs. as of 1/31/08

MARKET CAP: $2.7 billion (Mid Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	*2625*	*2750*	Revenues ($mill) A	*3300*
80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	210.5	*215*	*225*	Net Profit ($mill)	*260*
32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.4%	*8.2%*	*8.2%*	Net Profit Margin	*7.9%*
47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	*3400*	*3500*	Total Capital ($mill)	*3600*
1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	*3700*	*3800*	Net Plant ($mill)	*4150*
7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.5%	*7.5%*	*8.0%*	Return on Total Cap'l	*8.5%*
11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	*12.5%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	*12.5%*	*13.0%*	Return on Com Equity	*14.5%*
4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	*5.0%*	*5.5%*	Retained to Com Eq	*6.5%*
64%	101%	72%	65%	52%	53%	49%	52%	52%	58%	*59%*	*58%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	30.0	20.0	21.0
Other	2002.0	1802.0	1790.0
Current Assets	2032.0	1822.0	1811.0
Accts Payable	264.0	213.0	172.0
Debt Due	522.0	539.0	580.0
Other	1153.0	875.0	893.0
Current Liab.	1939.0	1627.0	1645.0
Fix. Chg. Cov.	442%	397%	391%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	3.5%	13.5%	*3.5%*
"Cash Flow"	5.5%	7.0%	*4.0%*
Earnings	7.0%	15.0%	*3.5%*
Dividends	2.5%	4.0%	*4.0%*
Book Value	6.5%	10.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	908	430	387	993	2718
2006	1044	436	434	707	2621
2007	973	467	369	685	2494
2008	*1000*	*475*	*400*	*750*	*2625*
2009	*1025*	*500*	*425*	*800*	*2750*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.46	.60	2.72
2007	1.29	.40	.17	.86	2.72
2008	*1.35*	*.35*	*.30*	*.80*	*2.80*
2009	*1.35*	*.40*	*.35*	*.80*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41	.41	.41	1.64
2008	.42				

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Also wholesales and retails propane. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Off./dir. own less than 1.0% of common; Barclays Global Investors, 5.0% (3/07 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources reported solid performance for the fourth quarter. Revenues declined slightly in the recent interim. However, the company enjoyed lower operating costs, and the bottom-line improved considerably. But share earnings for 2007 as a whole only matched the prior year's figure, owing to unfavorable comparisons in the first and third quarters. Operating earnings were lower at the company's Wholesale Services business, resulting from a significant decrease in commercial activity due to lower volatility in the natural gas market during the year. Performance was supported by solid earnings growth in the company's Distribution Operations, and a strong bottom-line advance in its Retail Energy Operations. The Distribution business benefited from modest customer growth and higher base rates at Chattanooga Gas. The Retail Energy line experienced higher average customer usage, a greater customer base, and increased late payment fees.

Earnings growth ought to resume in 2008. The company has initiated share-net guidance of $2.75 to $2.85 for the current year. Our estimate lies at the midpoint of this range. This assumes normal weather patterns and average volatility for gas prices in 2008. Earnings per share stand a good chance of advancing at about the same deliberate pace in 2009, as well.

The board of directors recently approved a modest dividend increase. The quarterly dividend will now increase to $0.42, beginning with the March payout. This represents slower growth than in the past few years, which makes sense, considering the company's flat earning comparison for 2007 and its lower cash balance in recent times. Nevertheless, this level of dividend growth will probably continue going forward.

These shares have improved a notch in Timeliness, and are now ranked 3 (Average). That said, this issue earns good marks for Safety and Price Stability, and we project steady earnings growth at AGL Resources over the pull to 2011-2013. Income-seeking investors may also find this stock attractive, considering its healthy dividend yield. Overall, these shares offer worthwhile total return potential for the coming years.

Michael Napoli, CPA *March 14, 2008*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07). Next earnings report due late April/early May.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2007: $420 million, $5.50/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

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ATMOS ENERGY CORP. NYSE-ATO

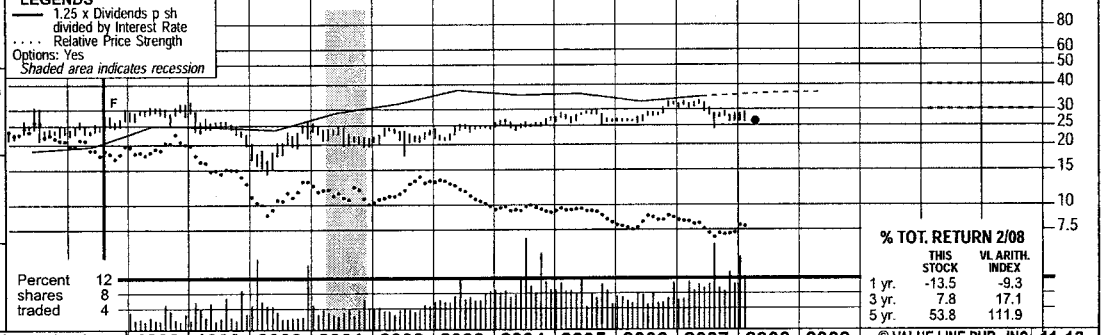
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
26.34	13.2	(Trailing: 14.5 Median: 16.0)	0.85	5.0%	VALUE LINE

TIMELINESS 3 Raised 1/25/08
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Lowered 3/7/08
BETA .85 (1.00 = Market)

High:	30.5	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3
Low:	22.1	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5	23.9	25.8

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	15%
Low	30	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	1	0	0	2	2
Options	0	1	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	3	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	115	100	113
to Sell	101	112	104
Hld's(000)	58169	56311	59007

Percent shares traded 12 8 4

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.5	-9.3
3 yr.	7.8	17.1
5 yr.	53.8	111.9

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
27.90	22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	66.03	*65.30*	*64.65*	Revenues per sh A	*76.50*
3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	*4.25*	*4.35*	"Cash Flow" per sh	*4.65*
1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	*2.00*	*2.10*	Earnings per sh A B	*2.45*
1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	*1.30*	*1.32*	Div'ds Decl'd per sh C■	*1.40*
4.44	3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	*4.85*	*5.00*	Cap'l Spending per sh	*6.20*
12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	*22.75*	*22.50*	Book Value per sh	*25.15*
30.40	31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.33	*94.00*	*99.00*	Common Shs Outst'g D	*115.00*
15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.80	1.88	1.23	.80	.83	.76	.84	.86	.73	.83	*Value Line*		Relative P/E Ratio	*.95*
3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*
848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	*6140*	*6400*	Revenues ($mill) A	*8800*
55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	*190*	*210*	Net Profit ($mill)	*280*
36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	*36.0%*	*36.0%*	Income Tax Rate	*38.0%*
6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	*3.1%*	*3.3%*	Net Profit Margin	*3.2%*
51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	*49.0%*	*48.0%*	Common Equity Ratio	*49.0%*
769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	*4360*	*4640*	Total Capital ($mill)	*5900*
917.9	965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	*4040*	*4250*	Net Plant ($mill)	*5450*
9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	*9.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	*9.0%*	*9.5%*	Return on Com Equity	*9.5%*
6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
58%	NMF	112%	79%	82%	70%	77%	73%	63%	65%	*64%*	*62%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $2330.8 mill. **Due in 5 Yrs** $920.0 mill.
LT Debt $2124.9 mill. **LT Interest** $125.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $16.9 mill.
Pfd Stock None
Pension Assets-9/07 $389.1 mill. **Oblig.** $335.6 mill.
Common Stock 89,957,651 shs. **as of 1/30/08**
MARKET CAP: $2.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/07
Cash Assets	75.8	60.7	51.9
Other	1041.7	1008.2	1468.1
Current Assets	1117.5	1068.9	1520.0
Accts Payable	345.1	355.3	739.8
Debt Due	385.6	154.4	205.9
Other	388.5	410.0	389.9
Current Liab.	1119.2	919.7	1335.6
Fix. Chg. Cov.	408%	405%	400%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	8.5%	19.0%	2.0%
"Cash Flow"	4.0%	5.5%	2.0%
Earnings	3.5%	7.5%	4.5%
Dividends	2.5%	1.5%	2.0%
Book Value	7.0%	9.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	2075.6	1218.2	1002.0	5898.4
2008	1657.5	*2135*	*1280*	*1067.5*	*6140*
2009	*1600*	*1600*	*1600*	*1600*	*6400*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	d.15	d.05	1.94
2008	.82	*1.30*	*d.07*	*d.05*	*2.00*
2009	*.90*	*1.30*	*d.06*	*d.04*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32	.32	.325	1.29
2008	.325				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2007 gas volumes: 297 MMcf. Breakdown: 56%, residential; 32%, commercial; 8%, industrial; and 4% other. 2007 depreciation rate 3.7%. Has around 4,470 employees. Officers and directors own approximately 1.8% of common stock (12/07 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy began fiscal 2008 (ends September 30th) on a sour note. That was attributable primarily to the nonregulated marketing segment, which experienced a drop in margins because of less volatility in natural gas prices. We look for this trend to continue, barring major storm activity.

But one bright spot was the utility unit, thanks to higher rates in Texas, Louisiana, Tennessee, and Kentucky. It should also be mentioned that mechanisms reducing exposure to possible adverse weather patterns during the 2007-2008 winter heating season are in place for virtually all operations.

Nonetheless, we think share net will advance only 3%, to $2.00, this fiscal year. The bottom line stands to increase at a somewhat stronger 5% pace, to $2.10 a share, in fiscal 2009, assuming additional expansion in operating margins. Please note that our estimates exclude amounts from pending rate cases in Texas, where Atmos is seeking a $52 million increase in annual revenues, and Kansas (where a $5 million boost in annual revenues is being sought).

We envision steady, albeit unspectacular, earnings gains out to 2011-2013. With the utility unit currently serving customers across 12 states, Atmos does not depend on the business climate in any one region of the country. Moreover, the nonregulated segments, particularly pipelines, possess healthy overall prospects. Lastly, management will undoubtedly stick to its winning strategy of purchasing less-efficient utilities and shoring up their profitability via expense-reduction initiatives, rate relief, and aggressive marketing efforts. (Future business combinations are not factored into our presentation, however.) In the present configuration, annual share-net growth may be in the mid-single-digit range over the 3- to 5-year horizon.

The good-quality stock offers an attractive dividend, which is well covered by the company's earnings. Further moderate increases in the distribution seem plausible.

Risk-adjusted total return possibilities are decent, too. But the shares are ranked only 3 (Average) for Timeliness.

Frederick L. Harris, III *March 14, 2008*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢. Next egs. rpt. due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	80

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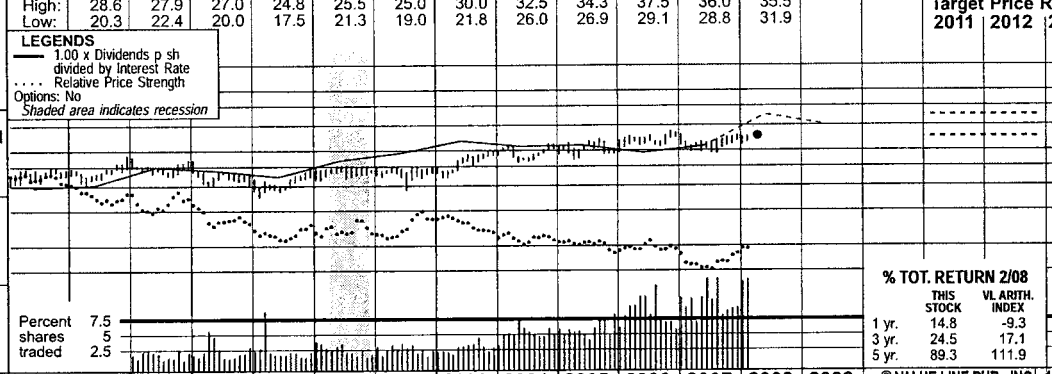
LACLEDE GROUP NYSE-LG

RECENT PRICE 35.50 | P/E RATIO 15.1 (Trailing: 14.8 Median: 15.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Raised 9/14/07
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 2/29/08
BETA .90 (1.00 = Market)

High:	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	35.5
Low:	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



Target Price Range 2011 | 2012 | 2013

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	10%
Low	35	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	1
Options	0	0	0	0	2	1	0	0	1
to Sell	0	0	0	0	2	1	0	0	1

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	67	57	64
to Sell	50	57	51
Hld's(000)	9261	9337	9951

Percent shares traded 7.5 5 2.5

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.8	-9.3
3 yr.	24.5	17.1
5 yr.	89.3	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	*92.75*	*91.55*	Revenues per sh	*107.85*
2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	*4.10*	*4.30*	"Cash Flow" per sh	*5.10*
1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	*2.35*	*2.35*	Earnings per sh A B	*2.70*
1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	*1.49*	*1.53*	Div'ds Decl'd per sh C■	*1.65*
2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	*2.85*	*2.95*	Cap'l Spending per sh	*3.70*
11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	*20.65*	*21.15*	Book Value per sh D	*24.95*
15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	*22.00*	*22.50*	Common Shs Outst'g E	*25.50*
15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	*Value Line*		Relative P/E Ratio	*1.00*
6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $650.1 mill. **Due in 5 Yrs** $275.0 mill.
LT Debt $355.5 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/07 $260.3 mill. **Oblig.** $293.3 mill.
Pfd Stock $.6 mill. **Pfd Div'd** $.04 mill.
Common Stock 21,788,966 shs. as of 1/31/08

MARKET CAP: $775 million (Small Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	*2040*	*2060*	Revenues ($mill) A	*2750*
27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	*51.5*	*53.0*	Net Profit ($mill)	*70.0*
35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	*33.5%*	*34.0%*	Income Tax Rate	*36.0%*
5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	*2.5%*	*2.6%*	Net Profit Margin	*2.5%*
40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*47.0%*
58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	*55.0%*	*55.0%*	Common Equity Ratio	*53.0%*
438.0	488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	*825*	*865*	Total Capital ($mill)	*1200*
490.6	519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	793.8	*820*	*850*	Net Plant ($mill)	*1150*
8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.0%*
10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	*11.5%*	*11.0%*	Return on Shr. Equity	*11.0%*
10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	*11.5%*	*11.0%*	Return on Com Equity	*11.0%*
1.8%	1.0%	2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
83%	89%	98%	83%	113%	74%	73%	72%	59%	63%	*64%*	*65%*	All Div'ds to Net Prof	*60%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/07
Cash Assets	50.8	52.7	66.9
Other	409.0	414.6	495.5
Current Assets	459.8	467.3	562.4
Accts Payable	103.3	106.8	128.6
Debt Due	207.5	251.6	294.6
Other	120.1	115.3	129.0
Current Liab.	430.9	473.7	552.2
Fix. Chg. Cov.	285%	282%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	11.5%	16.5%	*3.5%*
"Cash Flow"	1.5%	5.5%	*6.5%*
Earnings	3.0%	9.5%	*3.5%*
Dividends	1.0%	1.0%	*2.5%*
Book Value	3.0%	4.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	442.5	576.5	311.3	266.7	1597.0
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	457.9	323.3	2021.6
2008	541.4	*708*	*447*	*343.6*	*2040*
2009	*515*	*515*	*515*	*515*	*2060*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	.79	1.06	.29	d.24	1.90
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	.43	.03	2.31
2008	.97	*.97*	*.36*	*.05*	*2.35*
2009	*.96*	*1.01*	*.33*	*.05*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365	.365	.365	1.46
2008	.375				

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 632,000 customers. Purchased SM&P for approximately $43 million (1/02). Therms sold and transported in fiscal 2007: 1.12 mill. Revenue mix for regulated operations: residential, 60%; commercial and industrial, 24%; transportation, 1%; other, 15%. Has around 3,845 employees. Officers and directors own approximately 7.0% of common shares (1/08 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group began fiscal 2008 (which ends September 30th) on a decent note. That can be attributed largely to Laclede Energy Resources, which enjoyed higher per-unit gas sales prices and increased volumes (held back a bit by a rise in operating expenses). Furthermore, results for Laclede Gas, the core subsidiary, benefited from a general rate hike that became effective on August 1st of last year, that, among other things, provides greater earnings stability and recovery of its distribution costs. But partial offsets here included a decline in margins within the service area (reflecting an unusually late start to the winter heating season) and increased maintenance costs. At this juncture, we look for earnings per share to advance at a moderate rate, to $2.35, this fiscal year. The bottom line may be relatively flat in fiscal 2009, given the utility operation's limited growth prospects.

Management intends to sell SM&P Utility Resources, the unregulated unit specializing in locating and marking services for underground facilities, to Stripe Acquisition. A portion of the $85 million in proceeds (nearly double what Laclede paid for SM&P in 2002) would be used to bolster the balance sheet. We think SM&P was not central to present corporate strategy, as it accounted for just around 6% of fiscal 2007 share net. (Our presentation will exclude the divestiture when it is completed shortly, pending customary closing conditions.)

Unexciting results appear to be in store for the company over the next three to five years. The market in which the natural gas division operates has encountered sluggish customer growth for some time because it is in a mature phase. Too, we don't see any major acquisitions on the horizon. Consequently, annual share-net gains may be between 4% and 5% out to 2011-2013.

Total return potential is limited. That's because Laclede shares are currently trading within our 3- to 5-year Target Price Range, and we assume moderate hikes in the dividend (just increased 2.7%). What's more, the equity is ranked to perform only in line with the broader market averages.

Frederick L. Harris, III *March 14, 2008*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '07: $289.7 mill., $13.38/sh.
(E) In millions.
(F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

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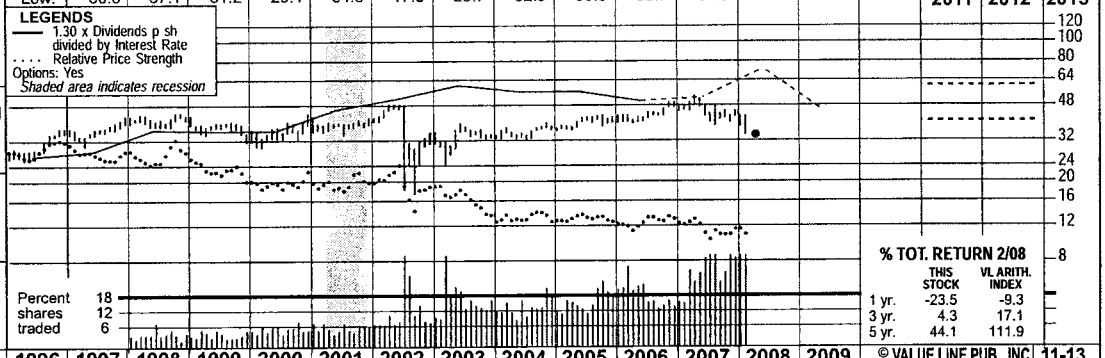
NICOR, INC. NYSE-GAS

RECENT PRICE **34.12** | P/E RATIO **13.7** (Trailing: 11.9 Median: 15.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **5.5%** | VALUE LINE

TIMELINESS 3 Raised 12/7/07
SAFETY 3 Lowered 6/17/05
TECHNICAL 3 Lowered 2/15/08
BETA 1.00 (1.00 = Market)

High:	42.9	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	53.7	42.7
Low:	30.0	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	37.8	33.6

Target Price Range 2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+75%)	19%
Low	40	(+15%)	9%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	1	1	0	0	0
Options	0	3	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	0	0	0	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	119	93	96
to Sell	111	123	111
Hld's(000)	37018	36014	32986

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-23.5	-9.3
3 yr.	4.3	17.1
5 yr.	44.1	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
28.90	31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	70.27	*74.45*	*77.80*	Revenues per sh	*80.45*
4.14	3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	*6.95*	*6.70*	*7.25*	"Cash Flow" per sh	*8.00*
1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	2.87	2.74	*2.25*	*2.60*	Earnings per sh A	*3.25*
1.18	1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.86	*1.86*	*1.90*	Div'ds Decl'd per sh B	*1.90*
3.12	2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	*4.45*	*4.55*	*4.65*	Cap'l Spending per sh	*4.65*
12.76	13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	19.43	*20.40*	*20.80*	*21.50*	Book Value per sh	*24.25*
55.77	53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.20	*45.00*	*45.00*	Common Shs Outst'g C	*46.00*
11.6	14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	15.0	16.3	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81	.86	*Value Line*		Relative P/E Ratio	*1.05*
5.3%	4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*
						1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	*3350*	*3500*	Revenues ($mill)	*3700*
						111.1	121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	135.2	*100*	*115*	Net Profit ($mill)	*150*
						34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	*30.0%*	*31.0%*	*31.5%*	Income Tax Rate	*33.0%*
						7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	*3.0%*	*3.3%*	Net Profit Margin	*4.0%*
						42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	*30.0%*	*27.0%*	*24.0%*	Long-Term Debt Ratio	*21.0%*
						57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	*70.0%*	*73.0%*	*76.0%*	Common Equity Ratio	*79.0%*
						1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	*1315*	*1285*	*1250*	Total Capital ($mill)	*1400*
						1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	*2850*	*3000*	*3050*	Net Plant ($mill)	*3400*
						9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	*11.0%*	*9.5%*	*11.0%*	Return on Total Cap'l	*12.0%*
						14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	*13.5%*	*11.0%*	*12.0%*	Return on Shr. Equity	*13.5%*
						14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	*13.5%*	*11.0%*	*12.0%*	Return on Com Equity	*13.5%*
						5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	*4.5%*	*2.0%*	*3.5%*	Retained to Com Eq	*5.5%*
						63%	60%	56%	58%	63%	88%	84%	81%	65%	*67%*	*82%*	*73%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $867.4 mill. **Due in 5 Yrs** $422.7 mill.
LT Debt $423.3 mill. **LT Interest** $32.0 mill.
(Total interest coverage: 4.6x)

Pension Assets-12/06 $478.7 mill. **Oblig.** $262.2 mill.

Pfd Stock $.6 mill. **Pfd Div'd** None

Common Stock 45,135,079 shares as of 10/26/07
MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	126.9	67.6	91.1
Other	1218.8	843.1	932.7
Current Assets	1345.7	910.7	1023.8
Accts Payable	658.2	564.5	662.7
Debt Due	636.0	350.0	444.0
Other	328.7	227.9	169.7
Current Liab.	1622.9	1142.4	1276.4
Fix. Chg. Cov.	367%	543%	544%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '11-'13
Revenues	7.5%	7.5%	2.5%
"Cash Flow"	3.5%	1.0%	3.5%
Earnings	1.5%	-3.0%	4.0%
Dividends	4.0%	2.5%	.5%
Book Value	3.0%	2.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1179.9	484.4	336.0	1357.5	3357.8
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	556.9	365.2	919.5	3176.3
2008	*1350*	*575*	*375*	*1050*	*3350*
2009	*1400*	*600*	*400*	*1100*	*3500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.98	.35	d.06	1.02	2.29
2006	.94	.41	.39	1.29	3.03
2007	.93	.40	.32	1.09	2.74
2008	*.82*	*.33*	*.25*	*.85*	*2.25*
2009	*.90*	*.35*	*.30*	*1.05*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.465	.465	.465	.465	1.86
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465	.465	.465	1.86
2008	.465				

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.2 million customers in northern and western Illinois. 2007 gas delivered: 468.3 Bcf, incl. 212.1 Bcf from transportation. 2007 gas sales (256.2 bcf): residential, 79%; commercial, 19%; industrial, 2%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,900 employees. Off./dir. own about 1.7% of common stock (3/07 proxy). Chairman and CEO: Russ Strobel. Inc.: Illinois Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor posted disappointing results in 2007. Earnings were down in all four quarters year over year, due to higher costs and a decline in utility earnings. Additionally, the gas distribution segment struggled, which also hurt profitability. However, the company managed to post an increase on the top line as a result of a solid performance in the shipping business.

Management revised its guidance for 2008. Indeed, Nicor now expects the bottom line to be between $2.20 and $2.40 a share. The new outlook is notably lower than our $2.90 earnings estimate from our last report. Upon news of the revised guidance, GAS shares declined slightly. In response, we have dropped our share-net estimate to $2.25 for 2008.

The company may seek rate relief. Management is evaluating the need for a filing with the Illinois Commerce Commission. The process usually takes about a year, and a positive ruling would help Nicor meet its allowed return. The company would also likely seek a rate mechanism that decouples gas revenues from gas sales, which would further help results. Until Nicor gains rate relief, these shares may not show any special strength.

We are introducing our 2009 estimates. The company should post earnings of roughly $2.60 a share on sales of about $3.5 billion. Management's focus on cost controls should help GAS rebound.

This stock offers an above-average dividend yield. Nicor offers a yield that is double the *Value Line* median despite not raising its payout in recent years. What's more, we believe the board will increase the distribution in the coming years once the regulatory environment improves.

This issue has below-average capital appreciation potential over the 3- to 5-year pull. However, if the company receives rate relief and continues to improve its cost controls, the long-term picture should improve. Moreover, Nicor's other energy-related ventures may also help drive growth over this time frame.

These shares are ranked to mirror the market in the year ahead. Despite the company's solid balance sheet and diversified business, this issue has limited appeal at this time.

Richard Gallagher *March 14, 2008*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due late April. (B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	75

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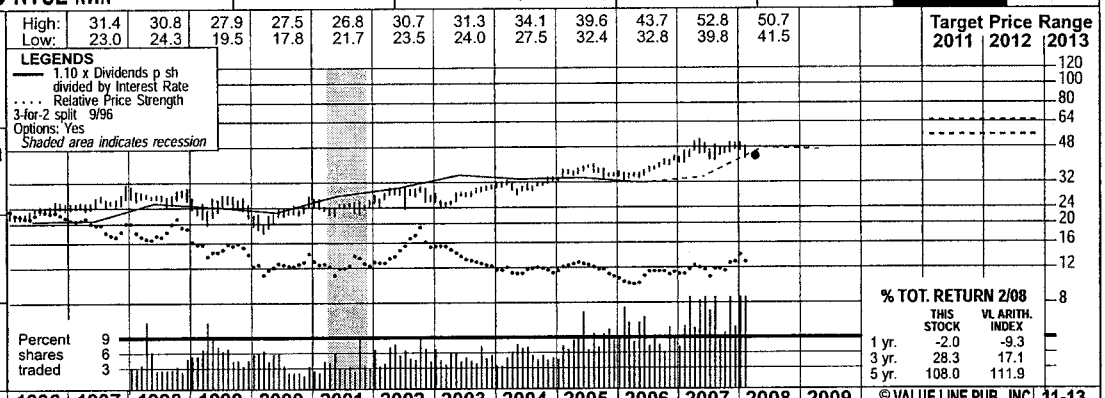
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **43.28** | P/E RATIO **17.2** (Trailing: 16.1 / Median: 16.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS 4 Lowered 2/22/08
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Lowered 2/29/08
BETA .80 (1.00 = Market)

High:	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	43.7	52.8	50.7
Low:	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8	39.8	41.5

Target Price Range
2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+50%)	14%
Low	55	(+25%)	10%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	1	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	4	0
to Sell	0	1	0	0	1	0	0	5	1

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	94	66	95
to Sell	65	88	60
Hld's(000)	16847	16048	16848

Percent shares traded 9 6 3

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-2.0	-9.3
3 yr.	28.3	17.1
5 yr.	108.0	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.12	*41.35*	*42.90*	Revenues per sh	*48.20*
3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	*5.40*	*5.70*	"Cash Flow" per sh	*6.60*
.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	*2.60*	*2.75*	Earnings per sh A	*3.35*
1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	*1.52*	*1.60*	Div'ds Decl'd per sh B■	*1.88*
3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	*4.60*	*6.80*	Cap'l Spending per sh	*4.50*
12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	21.97	22.52	*23.00*	*23.75*	Book Value per sh	*26.50*
19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.28	26.41	*26.00*	*26.00*	Common Shs Outst'g C	*28.00*
27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.88	*Value Line*		Relative P/E Ratio	*1.20*
5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*
						416.7	455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	*1075*	*1115*	Revenues ($mill)	*1350*
						27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	65.2	74.5	*68.0*	*71.5*	Net Profit ($mill)	*94.0*
						31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
						6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	*6.1%*	*6.4%*	Net Profit Margin	*6.9%*
						45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	*46.5%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
						50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	*53.5%*	*53.5%*	Common Equity Ratio	*53.0%*
						815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	*1150*	*1200*	Total Capital ($mill)	*1500*
						894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	*1550*	*1650*	Net Plant ($mill)	*2000*
						5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	*8.5%*	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
						6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
						6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
						NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
						118%	74%	70%	67%	79%	72%	69%	63%	59%	52%	*58%*	*56%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $660.1 mill. **Due in 5 Yrs** $179.7 mill.
LT Debt $512.0 mill. **LT Interest** $31.0 mill.

(Total interest coverage: 3.5x)

Pension Assets-12/06 $236 mill.
Oblig. $269 mill.
Pfd Stock None

Common Stock 26,407,000 shs.

MARKET CAP $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	7.1	5.8	6.1
Other	316.6	303.0	268.8
Current Assets	323.7	308.8	274.9
Accts Payable	135.3	113.6	119.7
Debt Due	134.7	129.6	148.1
Other	56.6	98.3	122.1
Current Liab.	326.6	341.5	389.9
Fx. Chg. Cov.	340%	349%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '11-'13
Revenues	6.5%	8.0%	*6.5%*
"Cash Flow"	2.0%	3.0%	*5.0%*
Earnings	2.0%	3.5%	*7.0%*
Dividends	1.0%	1.5%	*5.5%*
Book Value	4.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	308.7	153.7	106.7	341.4	910.5
2006	390.4	171.0	114.9	336.9	1013.2
2007	394.1	183.2	124.2	331.7	1033.2
2008	*405*	*190*	*125*	*355*	*1075*
2009	*415*	*200*	*130*	*370*	*1115*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1.44	.04	d.31	.94	2.11
2006	1.48	.07	d.35	1.15	2.35
2007	1.77	.10	d.22	1.11	2.76
2008	*1.60*	*.10*	*d.30*	*1.20*	*2.60*
2009	*1.70*	*.10*	*d.30*	*1.25*	*2.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355	.355	.355	.375	1.44
2008	.375				

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 652,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,100. Fidelity owns 14.9% of shares; Snyder Cap'l, 8.7%; off./dir., 2.0% (4/07 proxy). CEO: Mark S. Dodson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural benefited from unusually high gas cost savings in 2007. The company retains one-third of the difference between forecasted and actual gas costs in Oregon, passing on two-thirds to its customers. Last year, it earned a record $0.27 a share through skillful gas buying, mostly in the first and third quarters. While Northwest has usually made a small profit on gas purchasing, it has shared a loss on the activity about a quarter of the time. Ignoring the commodity profits and some other unusual items, NWN would have earned about $2.45 a share in 2007, a respectable but not extraordinary performance.

We look for a roughly 6% earnings gain, from normalized 2007 results, this year. Northwest's customer growth, at over 3% per year for many years, slowed to 2.4% in 2007. Customer growth will likely continue to ease in 2008 as the Portland area suffers a bit from the widespread housing problems but should remain above the national average. The company is increasing its marketing efforts directed at persuading people to switch to gas heat, and that should bear fruit this year. Operating costs, which rose just 1% on a normalized basis last year, will likely grow slower than revenues.

Another mild earnings gain is likely in 2009. By then, customer growth will probably be heading back toward the recent 3% average. Northwest will have completed its work reorganization program, including outsourcing some functions and centralizing others. And the company could start to benefit from enhanced automated meter-reading capacity.

Continued customer growth and two large projects should help boost earnings toward the end of our time horizon. Portland's high-density zoning has been expanded many times over the last 30 years, making it profitable to lay gas mains. An expansion to the southeast of the city should add substantially to customer growth over the next 10 years. And by 2011, NWN will probably invest around $300 million in a gas storage project in California and a new pipeline in Oregon.

These top-quality shares, though untimely, have worthwhile risk-adjusted total-return potential.

Sigourney B. Romaine *March 14, 2008*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06). Next earnings report due late April.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Dividend reinvestment plan available.
(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	80

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PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
24.98	16.7	(Trailing: 17.8 Median: 17.0)	1.08	4.0%	VALUE LINE

TIMELINESS **3** Raised 6/15/07

SAFETY **2** New 7/27/90

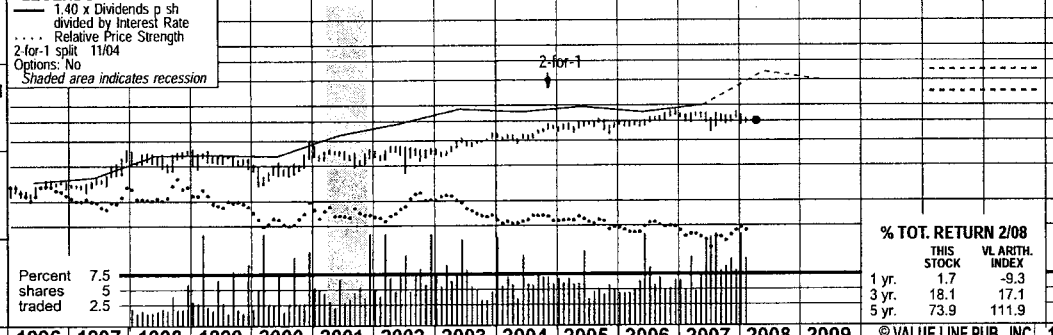
TECHNICAL **3** Lowered 3/7/08

BETA .85 (1.00 = Market)

High:	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	28.0	27.0
Low:	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	22.0	24.0

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/04
Options: No
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+80%)	19%
Low	35	(+40%)	12%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	84	78	85
to Sell	77	80	81
Hld's(000)	35264	35472	36470

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.7	-9.3
3 yr.	18.1	17.1
5 yr.	73.9	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
8.91	10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	*24.20*	*24.95*	Revenues per sh A	*27.55*
1.07	1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	*2.75*	*2.80*	"Cash Flow" per sh	*3.00*
.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	*1.50*	*1.55*	Earnings per sh B	*1.75*
.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	*1.04*	*1.08*	Div'ds Decl'd per sh C■	*1.20*
1.41	1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	*2.00*	*2.05*	Cap'l Spending per sh	*2.30*
5.13	5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	*12.45*	*12.85*	Book Value per sh D	*14.30*
51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	*73.00*	*72.75*	Common Shs Outst'g E	*72.00*
12.3	15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*22.0*
.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.98	*Value Line*		Relative P/E Ratio	*1.50*
5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*
						765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.6	1711.3	*1765*	*1815*	Revenues ($mill) A	*1985*
						60.3	58.2	64.0	65.5	62.2	74.4	95.2	101.3	97.2	104.4	*110*	*115*	Net Profit ($mill)	*125*
						39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	*6.2%*	*6.2%*	Net Profit Margin	*6.4%*
						44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	*48.1%*	*47.8%*	Long-Term Debt Ratio	*46.7%*
						55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	*51.9%*	*52.2%*	Common Equity Ratio	*53.3%*
						829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	*1750*	*1790*	Total Capital ($mill)	*1930*
						990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	*2200*	*2250*	Net Plant ($mill)	*2400*
						9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	*7.5%*	*8.0%*	Return on Total Cap'l	*8.0%*
						13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	*12.0%*	*12.0%*	Return on Shr. Equity	*12.5%*
						13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	*12.0%*	*12.0%*	Return on Com Equity	*12.5%*
						4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
						65%	72%	71%	75%	83%	74%	66%	68%	74%	70%	*69%*	*70%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 10/31/07
Total Debt $1019.9 mill. **Due in 5 Yrs** $150.0 mill.
LT Debt $824.9 mill. **LT Interest** $55.7 mill.
(LT interest earned: 4.0x; total interest coverage: 4.0x)

Pension Assets-10/07 $225.0 mill.
Oblig. $188.7 mill.

Pfd Stock None

Common Stock 73,233,664 shs.
as of 12/20/07
MARKET CAP: $1.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	10/31/07
Cash Assets	7.1	8.9	7.5
Other	497.8	467.1	427.8
Current Assets	504.9	476.0	435.3
Accts Payable	182.8	80.3	97.2
Debt Due	193.5	170.0	195.0
Other	152.3	150.1	132.3
Current Liab.	528.6	400.4	424.5
Fix. Chg. Cov.	271%	261%	225%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	8.0%	11.0%	*2.5%*
"Cash Flow"	5.5%	7.0%	*3.0%*
Earnings	5.0%	6.0%	*5.0%*
Dividends	5.0%	4.5%	*4.0%*
Book Value	6.0%	6.5%	*3.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2005	680.6	508.0	232.9	339.6	1761.1
2006	921.4	483.2	237.9	282.1	1924.7
2007	677.2	531.5	224.4	278.2	1711.3
2008	*685*	*540*	*240*	*300*	*1765*
2009	*697*	*553*	*250*	*315*	*1815*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2005	.93	.52	d.06	d.07	1.32
2006	.94	.57	d.16	d.08	1.27
2007	.94	.69	d.12	d.11	1.40
2008	*.95*	*.70*	*d.10*	*d.05*	*1.50*
2009	*1.00*	*.75*	*d.13*	*d.07*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.208	.215	.215	.215	.85
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007	.24	.25	.25	.25	.99
2009	.25				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 932,097 customers in North Carolina, South Carolina, and Tennessee. 2007 revenue mix: residential (54%), commercial (30%), industrial (14%), other (2%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 69.4% of revenues. '07 deprec. rate: 3.4%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,876 employees. Officers & directors own less than 1% of common stock (1/08 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas likely posted relatively unchanged earnings for the first quarter (ended January 31st). The company was scheduled to report earnings for its January interim after this report went to press. We have racheted down our top-line estimate for 2008, though, we look for some progress this year. During the first quarter, Piedmont's revenues likely advanced in the low single-digit range. The reduced expectations stem from slower growth in the residential construction market. Subsequently, in an effort to increase volumes, PNY has been working on converting users of other types of energy to natural gas. Meanwhile, the fourth quarter of 2007 experienced warmer-than-normal weather. But that interim is not subject to the weather normalization clause (WNC) for its Tennessee and South Carolina service areas. The WNC protects the bottom line against decreased usage. The adjustment should help during the January interim, though. Overall, we look for a nominal advance in share net for the first quarter.

The company ought to experience better volume comparisons as the year progresses. And its revenues ought to advance approximately 3% this year and next. Efforts to gain customers from the conversion markets should help this cause. Furthermore, the company intends to file a general rate case in North Carolina, its largest service area. Meanwhile, its non-utility business ought to pick up steam as the Hardy Storage joint venture (JV) contributes to both top and bottom lines for the whole of 2008. And, we expect solid performance to persist from its South Star Energy JV.

All told, we look for the bottom line to advance 7% and 3% for this year and next, respectively. This ought to stem from continued investments in its natural gas infrastructure. Further streamlining and consolidation of business processes and operations should help maintain margins, as well.

The equity offers a solid dividend yield and decent total return potential to 2011-2013. Meanwhile, these shares are ranked to perform in line with the broader market averages for the year ahead.

Bryan Fong *March 14, 2008*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early May.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2007: $23.9 million, 33¢/share.
(E) In millions, adjusted for stock split.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	80

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SOUTH JERSEY INDS. NYSE-SJI

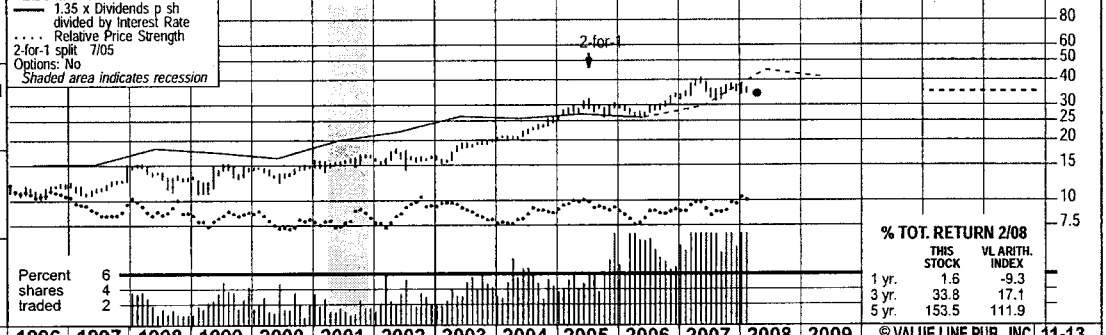
RECENT PRICE **34.23** | P/E RATIO **15.3** (Trailing: 17.5 Median: 14.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **3.2%** | VALUE LINE

TIMELINESS **4** Lowered 9/14/07
SAFETY **2** Lowered 1/4/91
TECHNICAL **2** Raised 3/14/08
BETA .80 (1.00 = Market)

High:	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	38.4	
Low:	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	33.6	

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 1.35 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+45%)	12%
Low	35	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	3	0	0	1	0	0	2	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	69	67	66
to Sell	64	58	59
Hld's(000)	16955	16787	16995

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.6	-9.3
3 yr.	33.8	17.1
5 yr.	153.5	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
16.67	17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.29	*34.35*	*36.05*	Revenues per sh	*39.05*
1.56	1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.03	*3.20*	*3.50*	"Cash Flow" per sh	*4.05*
.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	*2.25*	*2.45*	Earnings per sh A	*3.00*
.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	*1.10*	*1.16*	Div'ds Decl'd per sh B ■	*1.28*
1.69	1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.87	*2.15*	*2.45*	Cap'l Spending per sh	*3.15*
6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.24	*17.35*	*18.35*	Book Value per sh C	*20.30*
19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.62	*30.00*	*30.50*	Common Shs Outst'g D	*32.00*
13.2	15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.90	*Value Line*		Relative P/E Ratio	*.95*
6.6%	5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $476.3 mill. **Due in 5 Yrs** $156.1 mill.
LT Debt $357.9 mill. **LT Interest** $21.0 mill.
(Total interest coverage: 4.8x)

Pension Assets-12/07 $120.4 mill. **Oblig.** $133.0 mill.

Pfd Stock none

Common Stock 29,624,492 common shs. as of 2/23/08

MARKET CAP: $1.0 billion (Mid Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
450.2	392.5	515.9	837.3	505.1	696.8	819.1	921.0	931.4	956.4	*1030*	*1100*	Revenues ($mill)	*1250*
13.8	22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.9	*67.5*	*75.0*	Net Profit ($mill)	*95.0*
46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	*40.7%*	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	*6.6%*	*6.8%*	Net Profit Margin	*7.6%*
57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	*41.5%*	*40.5%*	Long-Term Debt Ratio	*41.0%*
33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	*58.5%*	*59.5%*	Common Equity Ratio	*59.0%*
401.1	405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	839.0	*890*	*945*	Total Capital ($mill)	*1100*
504.3	533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	*980*	*1015*	Net Plant ($mill)	*1200*
5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	*8.5%*	*9.0%*	*9.0%*	Return on Total Cap'l	*10.0%*
8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.9%	*13.0%*	*13.5%*	Return on Shr. Equity	*14.5%*
10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.9%	*13.0%*	*13.5%*	Return on Com Equity	*14.5%*
NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	*6.5%*	*7.0%*	Retained to Com Eq	*8.5%*
112%	72%	67%	76%	62%	57%	52%	50%	37%	48%	*49%*	*47%*	All Div'ds to Net Prof	*43%*

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	4.9	7.9	11.7
Other	352.6	363.8	316.6
Current Assets	357.5	371.7	328.3
Accts Payable	179.0	101.6	101.2
Debt Due	149.7	197.0	118.4
Other	74.4	124.2	108.7
Current Liab.	403.1	422.8	328.3
Fix. Chg. Cov.	486%	527%	476%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	6.5%	4.5%	3.5%
"Cash Flow"	6.5%	8.5%	*NMF*
Earnings	9.5%	12.0%	*NMF*
Dividends	2.0%	3.5%	5.5%
Book Value	6.0%	13.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	328.6	154.0	157.0	281.4	921.0
2006	372.6	153.8	154.7	250.3	931.4
2007	368.4	171.7	156.2	260.1	956.4
2008	*390*	*190*	*170*	*280*	*1030*
2009	*405*	*205*	*190*	*300*	*1100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.96	.27	.09	.39	1.71
2006	1.06	.20	.51	.69	2.46
2007	1.30	.21	d.05	.63	2.09
2008	*1.25*	*.25*	*.10*	*.65*	*2.25*
2009	*1.30*	*.30*	*.15*	*.70*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007	--	.245	.245	.515	1.01
2008					

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 335,663 customers in New Jersey's southern counties, which covers 2,500 square miles and includes Atlantic City. Gas revenue mix '07: residential, 46%; commercial, 23%; cogeneration and electric generation, 8%; industrial, 23%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 604 employees. Off./dir. cntrl. 1.2% of com. shares; Dimensional Fund Advisors, 8.3%; Barclays, 6.0% (3/07 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries reported a modest advance in revenues for 2007, although economic earnings increased roughly 14%. Utility South Jersey Gas benefited from continued growth in the customer base and lower interest costs. The company's nonutility operations also posted a solid performance. Readers are advised that our earnings-per-share figures are now based on economic earnings, a non-GAAP measure that excludes unrealized gains and losses from commodity derivative transactions. Thus, the share-net figures from 2007 onward are not directly comparable with those from previous years.

The company has solid long-term prospects. Natural gas remains the fuel of choice in the markets served by South Jersey Gas, as it enjoys a considerable price advantage over alternatives. Indeed, the vast majority of new homes built have chosen natural gas as their main heating source. Moreover, the company expects economic development in the Atlantic City area will boost housing demand in the coming years. In addition, this business ought to continue to benefit from the Conservation Incentive Program (CIP). This initiative allows South Jersey to promote energy conservation and insulate itself from the negative impact of lower customer usage. The CIP protected $7.5 million of net income during 2007, offsetting reduced customer utilization. Elsewhere, the performance of the nonutility Commodity Marketing business should continue to have an important impact on earnings. This unit maintains 10 billion cubic feet of gas storage capacity, which allows it to take advantage of volatility in natural gas pricing and lock in attractive profit margins. Looking forward, we anticipate moderate share-earnings and dividend growth in the current year. This pattern seems likely to continue in 2009, as well.

These shares are ranked to lag the broader market for the coming six to 12 months. Looking further out, we project solid bottom-line growth at South Jersey over the pull to 2011-2013. Moreover, this issue scores high marks for Price Stability and Earnings Predictability. Thus, this stock offers worthwhile total return potential for a natural gas utility.

Michael Napoli, CPA *March 14, 2008*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02). Next egs. report due late April. (B) Div'ds paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. In 2007: $188.7 mill., $6.37 per shr. (D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	85

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WGL HOLDINGS NYSE-WGL

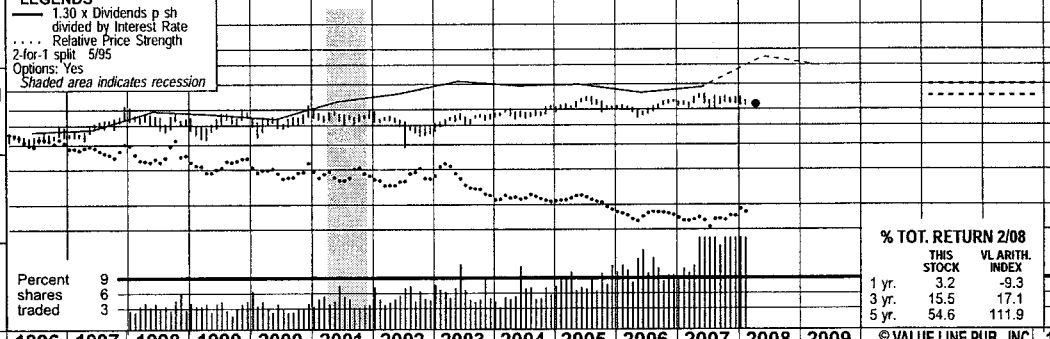
RECENT PRICE 31.83 | P/E RATIO 13.8 (Trailing: 14.9 Median: 15.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Raised 5/25/07
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Lowered 2/29/08
BETA .85 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	34.6
Low:	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	30.9

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/95
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	10%
Low	35	(+10%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	3	0	0
to Sell	0	1	0	0	0	0	3	0	1

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	94	90	92
to Sell	81	96	94
Hld's(000)	35310	34163	35393

Percent shares traded 9 6 3

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	3.2	-9.3
3 yr.	15.5	17.1
5 yr.	54.6	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
18.37	21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	*54.55*	*56.05*	Revenues per sh A	*60.70*
2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.93	3.89	*4.15*	*4.25*	"Cash Flow" per sh	*4.50*
1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.94	2.10	*2.30*	*2.35*	Earnings per sh B	*2.50*
1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.34	1.37	*1.40*	*1.44*	Div'ds Decl'd per sh C■	*1.56*
2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	*3.35*	*3.00*	Cap'l Spending per sh	*2.50*
10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.28	19.83	*21.15*	*22.00*	Book Value per sh D	*24.95*
40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	*49.50*	*49.60*	Common Shs Outst'g E	*50.00*
13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.82	*Value Line*		Relative P/E Ratio	*1.00*
6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	*2700*	*2780*	Revenues ($mill) A	*3035*
						68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	95.1	102.9	*114*	*117*	Net Profit ($mill)	*125*
						35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
						6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	*3.9%*	*4.0%*	Net Profit Margin	*4.2%*
						40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	38.5%	37.9%	*36.0%*	*35.0%*	Long-Term Debt Ratio	*32.0%*
						57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	60.3%	*62.5%*	*63.5%*	Common Equity Ratio	*66.5%*
						1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1497.8	1625.4	*1675*	*1720*	Total Capital ($mill)	*1875*
						1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	*2235*	*2325*	Net Plant ($mill)	*2615*
						8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.7%	7.6%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
						10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.3%	10.2%	*11.0%*	*10.5%*	Return on Shr. Equity	*10.0%*
						11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.2%	10.4%	*11.5%*	*11.0%*	Return on Com Equity	*10.5%*
						2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.1%	3.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						78%	82%	69%	67%	112%	56%	65%	62%	70%	66%	*61%*	*61%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $941.0 mill. **Due in 5 Yrs** $399.5 mill.
LT Debt $593.5 mill. **LT Interest** $40.1 mill.
(LT interest earned: 6.7x; total interest coverage: 5.7x)
Pension Assets-9/07 $740.7 mill. **Oblig.** $680.3 mill.
Preferred Stock $28.2 mill. **Pfd. Div'd** $1.3 mill.

Common Stock 49,464,057 shs. **as of 1/31/08**

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/07
Cash Assets	4.4	4.9	19.0
Other	556.9	568.8	878.3
Current Assets	561.3	573.7	897.3
Accts Payable	208.5	216.9	331.4
Debt Due	238.4	205.4	347.5
Other	113.9	134.8	237.5
Current Liab.	560.8	557.1	916.4
Fix. Chg. Cov.	465%	460%	460%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	9.0%	12.5%	3.0%
"Cash Flow"	3.5%	5.0%	2.5%
Earnings	2.0%	5.0%	3.5%
Dividends	1.5%	1.5%	2.5%
Book Value	4.0%	3.5%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	623.4	929.8	349.0	284.1	2186.3
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	*1140*	*458.4*	*350*	*2700*
2009	*770*	*1160*	*480*	*370*	*2780*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	.88	1.63	d.17	d.23	2.11
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.27	.22	d.31	2.10
2008	.95	*1.30*	*.20*	*d.15*	*2.30*
2009	*.97*	*1.33*	*.25*	*d.20*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.32	.325	.325	.325	1.30
2005	.325	.333	.333	.333	1.32
2006	.333	.338	.338	.338	1.34
2007	.34	.34	.34	.34	1.36
2008	.34				

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,046,201 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 8.2% of common stock; Off./dir. less than 1% (1/08 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings has been experiencing progress with its rate cases. The company recently received approval for a rate hike in the District of Columbia (DOC). The incremental cash flow from the rate hike, which was not expected to be approved until March, added approximately $0.05 per share to the bottom line in the first quarter (ended December 31st). Furthermore, the earlier-than-expected rate increase has prompted us to raise our annual estimate by 5%, to $2.30 per share.

The company's earnings will likely get a 2%–3% lift for the March interim. WGL's gas and light utility division has been experiencing higher usage volumes and system charges as a result of 12,310 new customers. And it is expected to add about 5,200 more accounts by the end of fiscal 2008. Furthermore, the asset management business likely continued to enjoy strong off-system sales as excess reserves are released in order to meet the heightened demand during the colder winter months. These results ought to be partially offset by increased operation and maintenance costs.

We look for the share net to advance approximately 10% this year. Lifts in the top-line volumes ought to stem from the heightened rates in the DOC, additional customer growth, and expansion of the company's asset management program. Meanwhile, gas sales at the Washington Gas Energy Services unit have been down as a result of warmer-than-normal weather patterns. However, this unit's margins have been widening on a per-therm basis, offsetting the lower volumes and boosting the bottom line.

In 2009, the bottom-line increase ought to moderate. The majority of benefits from efficiency initiatives and the effects of the recent DOC rate hike will have cycled through by next year. Therefore, we look for earnings advances to slow to a low single-digit rate.

These neutrally ranked shares may appeal to income-oriented accounts. The equity offers a solid dividend yield. Meanwhile, the stock garners our Highest Safety rank (1), and our best mark for Price Stability (100), indicating suitability for conservative accounts with an eye on capital preservation.

Bryan Fong *March 14, 2008*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available. (D) Includes deferred charges and intangibles. '07: $322.2 million, $6.51/sh. (E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

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ATTACHMENT B

Zacks.com Quotes and Research

ATLANTA GAS LIGHT (NYSE)

Scottrade

ATG	34.46	▼-0.09	(-0.26%)	Vol. 197,003	13:25 ET

AGL Resources principal business is the distribution of natural gas to customers in central, northwest, northeast and southeast Georgia and the Chattanooga, Tennessee area through its natural gas distribution subsidiary. AGL's major service area is the ten county metropolitan Atlanta area.

General Information

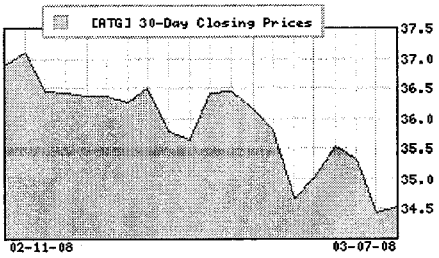
AGL RESOURCES
Ten Peachtree Place NE
Atlanta, GA 30309
Phone: 404 584-4000
Fax: 404 584-3945
Web: www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/07/2008

Price and Volume Information

Zacks Rank	2
Yesterday's Close	34.55
52 Week High	44.67
52 Week Low	34.44
Beta	0.46
20 Day Moving Average	437,597.56
Target Price Consensus	41.95



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.42	4 Week	-3.68
12 Week	-4.69	12 Week	8.18
YTD	-8.21	YTD	4.21

Share Information		Dividend Information	
Shares Outstanding (millions)	76.44	Dividend Yield	4.86%
		Annual Dividend	$1.68
Market Capitalization (millions)	2,640.97	Payout Ratio	0.60
Short Ratio	1.89	Change in Payout Ratio	0.04
Last Split Date	12/04/1995	Last Dividend Payout / Amount	02/13/2008 / $0.42

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.34	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	2.82	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	4.80	60 Days Ago	2.00
Next EPS Report Date	05/07/2008	90 Days Ago	1.88

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.26	vs. Previous Year	43.33%	vs. Previous Year	-3.11%
Trailing 12 Months:	12.66	vs. Previous Quarter	405.88%	vs. Previous Quarter:	85.64%
PEG Ratio	2.58				

Price Ratios		ROE		ROA	
Price/Book	1.59	12/31/07	12.72	12/31/07	3.57

Price/Cash Flow	7.45	09/30/07	11.67	09/30/07	3.27
Price / Sales	1.06	06/30/07	13.15	06/30/07	3.66
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	1.10	12/31/07	0.77	12/31/07	8.46
09/30/07	1.04	09/30/07	0.56	09/30/07	7.63
06/30/07	1.08	06/30/07	0.62	06/30/07	8.33
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	13.55	12/31/07	13.55	12/31/07	21.69
09/30/07	12.28	09/30/07	12.28	09/30/07	20.89
06/30/07	13.41	06/30/07	13.41	06/30/07	21.49
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	2.49	12/31/07	1.01	12/31/07	50.89
09/30/07	2.50	09/30/07	0.95	09/30/07	49.47
06/30/07	2.59	06/30/07	0.92	06/30/07	48.65

Zacks.com Quotes and Research

ATMOS ENERGY CP (NYSE)

Scottrade

ATO	25.81	▲0.03	(0.12%)	Vol. 347,800	12:58 ET

Atmos Energy Corporation distributes and sells natural gas to residential, commercial, industrial, agricultural and other customers. Atmos operates through five divisions in cities, towns and communities in service areas located in Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Missouri, South Carolina, Tennessee, Texas and Virginia. The Company has entered into an agreement to sell all of its natural gas utility operations in South Carolina. The Company also transports natural gas for others through its distribution system.

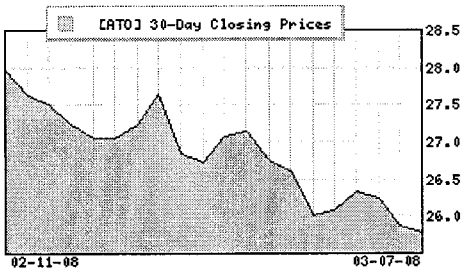
General Information

ATMOS ENERGY CP
Three Lincoln Centre, 5430 Lbj Freeway
Suite 1800
Dallas, TX 75240
Phone: 972 934-9227
Fax: 972 855-3040
Web: www.atmosenergy.com
Email: InvestorRelations@atmosenergy.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/07
Next EPS Date	05/07/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.78
52 Week High	33.47
52 Week Low	23.87
Beta	0.76
20 Day Moving Average	491,138.56
Target Price Consensus	30.29



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.29	4 Week	-3.54
12 Week	-4.09	12 Week	8.85
YTD	-8.06	YTD	4.38

Share Information		Dividend Information	
Shares Outstanding (millions)	89.96	Dividend Yield	5.04%
		Annual Dividend	$1.30
Market Capitalization (millions)	2,319.12	Payout Ratio	0.71
Short Ratio	6.61	Change in Payout Ratio	0.05
Last Split Date	05/17/1994	Last Dividend Payout / Amount	02/21/2008 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.38	Current (1=Strong Buy, 5=Strong Sell)	2.11
Current Year EPS Consensus Estimate	1.99	30 Days Ago	2.11
Estimated Long-Term EPS Growth Rate	4.60	60 Days Ago	2.00
Next EPS Report Date	05/07/2008	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.95	vs. Previous Year	-15.46%	vs. Previous Year	3.42%
Trailing 12 Months:	14.09	vs. Previous Quarter	2,150.00%	vs. Previous Quarter:	65.41%
PEG Ratio	2.82				

Price Ratios		ROE		ROA	
Price/Book	1.14	12/31/07	8.14	12/31/07	2.67
Price/Cash Flow	6.18	09/30/07	8.64	09/30/07	2.81
Price / Sales	0.39	06/30/07	10.30	06/30/07	3.24
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	1.14	12/31/07	0.72	12/31/07	2.74
09/30/07	1.16	09/30/07	0.60	09/30/07	2.89
06/30/07	1.22	06/30/07	0.80	06/30/07	3.32
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	4.22	12/31/07	4.22	12/31/07	22.62
09/30/07	4.45	09/30/07	4.45	09/30/07	22.05
06/30/07	5.05	06/30/07	5.05	06/30/07	22.39
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	9.87	12/31/07	1.05	12/31/07	51.11
09/30/07	9.98	09/30/07	1.08	09/30/07	51.96
06/30/07	10.11	06/30/07	1.07	06/30/07	51.68

Zacks.com Quotes and Research

LACLEDE GROUP INC (NYSE)

Scottrade

LG	34.30	▲0.35	(1.03%)	Vol. 59,200	12:59 ET

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

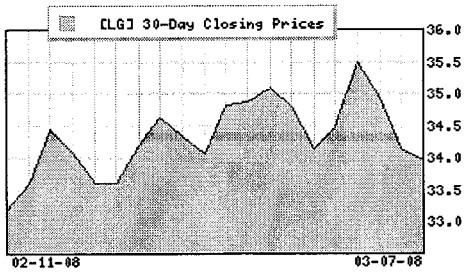
General Information

LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: -
Web: www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/07
Next EPS Date	04/25/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.95
52 Week High	35.72
52 Week Low	28.84
Beta	0.79
20 Day Moving Average	148,388.95
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.35	4 Week	5.35
12 Week	0.83	12 Week	14.44
YTD	-0.85	YTD	12.57

Share Information		Dividend Information	
Shares Outstanding (millions)	21.79	Dividend Yield	4.42%
		Annual Dividend	$1.50
Market Capitalization (millions)	739.74	Payout Ratio	0.63
Short Ratio	11.60	Change in Payout Ratio	-0.07
Last Split Date	03/08/1994	Last Dividend Payout / Amount	03/07/2008 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.94	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.28	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	04/25/2008	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.89	vs. Previous Year	8.99%	vs. Previous Year	0.33%
Trailing 12 Months:	14.15	vs. Previous Quarter	3,133.33%	vs. Previous Quarter:	67.46%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.67	12/31/07	11.91	12/31/07	3.20

Price/Cash Flow	8.34	09/30/07	11.64	09/30/07	3.12
Price / Sales	0.37	06/30/07	11.48	06/30/07	3.07
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	1.02	12/31/07	0.73	12/31/07	2.55
09/30/07	0.99	09/30/07	0.64	09/30/07	2.46
06/30/07	1.09	06/30/07	0.84	06/30/07	2.46
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	3.84	12/31/07	3.84	12/31/07	20.32
09/30/07	3.70	09/30/07	3.70	09/30/07	19.80
06/30/07	3.73	06/30/07	3.73	06/30/07	20.13
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	13.60	12/31/07	0.81	12/31/07	44.63
09/30/07	12.85	09/30/07	0.83	09/30/07	45.32
06/30/07	12.81	06/30/07	0.82	06/30/07	45.02

Zacks.com Quotes and Research

NICOR INC (NYSE)

Scottrade

GAS	33.11	▲0.10	(0.30%)	Vol. 341,691	13:00 ET

Nicor Inc. is a holding company and is a member of the Standard & Poor's 500 Index. Its primary business is Nicor Gas, one of the nation's largest natural gas distribution companies. Nicor owns Tropical Shipping, a containerized shipping business serving the Caribbean region and the Bahamas. In addition, the company owns and has an equity interest in several energy-related businesses.

General Information

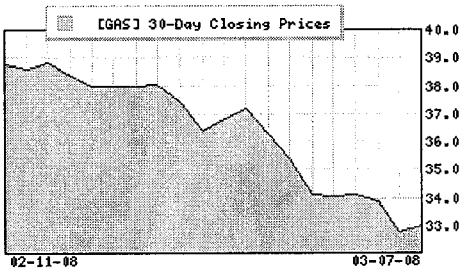
NICOR INC
1844 Ferry Road
Naperville, IL 60563-9600
Phone: 630 305-9500
Fax: 630 983-9328
Web: www.nicor.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/25/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.01
52 Week High	53.66
52 Week Low	32.74
Beta	0.91
20 Day Moving Average	865,557.50
Target Price Consensus	43.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-15.27	4 Week	-12.79
12 Week	-22.35	12 Week	-11.87
YTD	-22.05	YTD	-11.51

Share Information		Dividend Information	
Shares Outstanding (millions)	45.13	Dividend Yield	5.63%
		Annual Dividend	$1.86
Market Capitalization (millions)	1,489.91	Payout Ratio	0.65
Short Ratio	8.36	Change in Payout Ratio	-0.11
Last Split Date	04/27/1993	Last Dividend Payout / Amount	12/27/2007 / $0.47

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.71	Current (1=Strong Buy, 5=Strong Sell)	3.20
Current Year EPS Consensus Estimate	2.64	30 Days Ago	2.80
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.75
Next EPS Report Date	04/25/2008	90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.48	vs. Previous Year	-5.43%	vs. Previous Year	9.70%
Trailing 12 Months:	11.50	vs. Previous Quarter	281.25%	vs. Previous Quarter:	151.78%
PEG Ratio	3.12				

Price Ratios		ROE		ROA	
Price/Book	1.58	12/31/07	14.12	12/31/07	3.21

Price/Cash Flow	4.73	09/30/07	14.71	09/30/07	3.31
Price / Sales	0.47	06/30/07	14.81	06/30/07	3.29
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	0.80	12/31/07	0.68	12/31/07	4.09
09/30/07	0.73	09/30/07	0.48	09/30/07	4.29
06/30/07	0.79	06/30/07	0.74	06/30/07	4.24
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	5.80	12/31/07	5.80	12/31/07	20.95
09/30/07	6.05	09/30/07	6.05	09/30/07	20.15
06/30/07	6.35	06/30/07	6.35	06/30/07	20.35
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	22.95	12/31/07	0.45	12/31/07	30.89
09/30/07	18.26	09/30/07	0.47	09/30/07	31.73
06/30/07	19.79	06/30/07	0.54	06/30/07	35.18

Zacks.com Quotes and Research

NORTHWEST NAT GAS (NYSE)

Scottrade

NWN	42.23	▲0.22	(0.52%)	Vol. 119,600	13:02 ET

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

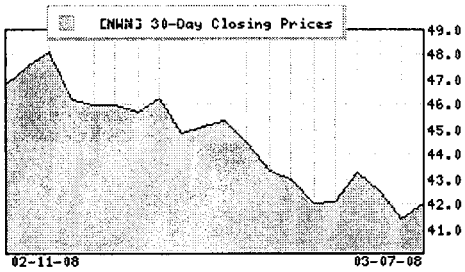
General Information

NORTHWEST NAT G
220 N.W. Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: Bob.Hess@nwnatural.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/24/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	42.01
52 Week High	52.85
52 Week Low	40.98
Beta	0.77
20 Day Moving Average	317,889.84
Target Price Consensus	52.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	-11.56	4 Week	-8.96
12 Week	-10.94	12 Week	1.08
YTD	-13.67	YTD	-1.99

Share Information		Dividend Information	
Shares Outstanding (millions)	26.41	Dividend Yield	3.57%
		Annual Dividend	$1.50
Market Capitalization (millions)	1,109.40	Payout Ratio	0.54
Short Ratio	11.06	Change in Payout Ratio	-0.11
Last Split Date	09/09/1996	Last Dividend Payout / Amount	01/29/2008 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.69	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.60	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.43
Next EPS Report Date	04/24/2008	90 Days Ago	2.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.15	vs. Previous Year	2.75%	vs. Previous Year	-1.57%
Trailing 12 Months:	15.22	vs. Previous Quarter	609.09%	vs. Previous Quarter:	166.90%
PEG Ratio	3.08				

Price Ratios	ROE	ROA

Price/Book	1.87	12/31/07	12.24	12/31/07	3.93
Price/Cash Flow	7.78	09/30/07	12.35	09/30/07	3.92
Price / Sales	1.07	06/30/07	11.69	06/30/07	3.77
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	0.71	12/31/07	0.50	12/31/07	7.21
09/30/07	0.69	09/30/07	0.39	09/30/07	7.21
06/30/07	0.76	06/30/07	0.47	06/30/07	6.91
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	11.47	12/31/07	11.47	12/31/07	22.48
09/30/07	11.43	09/30/07	11.43	09/30/07	22.01
06/30/07	10.96	06/30/07	10.96	06/30/07	22.61
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	9.07	12/31/07	0.86	12/31/07	46.26
09/30/07	9.62	09/30/07	0.88	09/30/07	46.67
06/30/07	9.10	06/30/07	0.85	06/30/07	45.86

Zacks.com Quotes and Research

PIEDMONT NAT GAS CO (NYSE)

Scottrade

PNY	25.96	▲1.59	(6.52%)	Vol. 568,900	14:05 ET

Piedmont Natural Gas Co, Inc., is an energy and services company engaged in the transportation and sale of natural gas and the sale of propane to residential, commercial and industrial customers in North Carolina, South Carolina and Tennessee. The Company is the second-largest natural gas utility in the southeast. The Company and its non-utility subsidiaries and divisions are also engaged in acquiring, marketing and arranging for the transportation and storage of natural gas for large-volume purchasers, and in the sale of propane to customers in the Company's three-state service area.

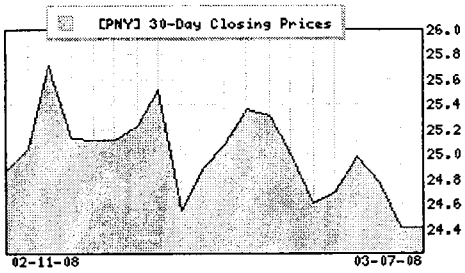
General Information

PIEDMONT NAT GA
4720 Piedmont Row Drive
Charlotte, NC 28210
Phone: 704 364-3120
Fax: 704 364-1395
Web: www.piedmontng.com
Email: margaret.griffith@piedmontng.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	October
Last Reported Quarter	01/31/08
Next EPS Date	03/11/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.37
52 Week High	27.98
52 Week Low	22.00
Beta	0.60
20 Day Moving Average	351,083.91
Target Price Consensus	28.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.97	4 Week	3.09
12 Week	-5.83	12 Week	6.92
YTD	-6.84	YTD	5.94

Share Information		Dividend Information	
Shares Outstanding (millions)	73.28	Dividend Yield	4.10%
		Annual Dividend	$1.00
Market Capitalization (millions)	1,785.76	Payout Ratio	0.00
Short Ratio	18.46	Change in Payout Ratio	0.00
Last Split Date	11/01/2004	Last Dividend Payout / Amount	12/20/2007 / $0.25

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.97	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	1.50	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	5.50	60 Days Ago	2.80
Next EPS Report Date	03/11/2008	90 Days Ago	2.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.23	vs. Previous Year	-37.50%	vs. Previous Year	-1.48%
Trailing 12 Months:	17.41	vs. Previous Quarter	8.33%	vs. Previous Quarter:	23.88%
PEG Ratio	2.95				

Price Ratios		ROE		ROA	
Price/Book	2.06	01/31/08	-	01/31/08	-
Price/Cash Flow	9.13	10/31/07	11.55	10/31/07	3.76
Price / Sales	-	07/31/07	11.77	07/31/07	3.86
Current Ratio		**Quick Ratio**		**Operating Margin**	
01/31/08	-	01/31/08	-	01/31/08	-
10/31/07	1.03	10/31/07	0.67	10/31/07	6.10
07/31/07	1.23	07/31/07	0.81	07/31/07	6.21
Net Margin		**Pre-Tax Margin**		**Book Value**	
01/31/08	-	01/31/08	-	01/31/08	-
10/31/07	9.93	10/31/07	9.93	10/31/07	11.86
07/31/07	10.69	07/31/07	10.69	07/31/07	12.18
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
01/31/08	-	01/31/08	-	01/31/08	-
10/31/07	8.44	10/31/07	0.94	10/31/07	48.43
07/31/07	8.46	07/31/07	0.92	07/31/07	47.81

Zacks.com Quotes and Research

SOUTH JERSEY IND (NYSE)

Scottrade

SJI	32.59	▲0.25	(0.77%)	Vol. 277,700	14:10 ET

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

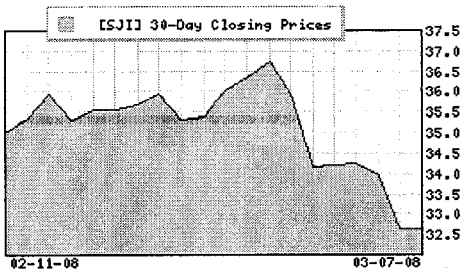
General Information

SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609 561-8225
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/06/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.34
52 Week High	41.27
52 Week Low	31.20
Beta	0.71
20 Day Moving Average	178,990.50
Target Price Consensus	41.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.65	4 Week	-2.88
12 Week	-7.23	12 Week	5.34
YTD	-10.39	YTD	2.61

Share Information		Dividend Information	
Shares Outstanding (millions)	29.62	Dividend Yield	3.34%
		Annual Dividend	$1.08
Market Capitalization (millions)	958.04	Payout Ratio	0.63
Short Ratio	15.35	Change in Payout Ratio	0.09
Last Split Date	07/01/2005	Last Dividend Payout / Amount	03/06/2008 / $0.27

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.91	Current (1=Strong Buy, 5=Strong Sell)	1.67
Current Year EPS Consensus Estimate	2.17	30 Days Ago	1.67
Estimated Long-Term EPS Growth Rate	7.50	60 Days Ago	2.00
Next EPS Report Date	05/06/2008	90 Days Ago	1.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.93	vs. Previous Year	-8.70%	vs. Previous Year	3.88%
Trailing 12 Months:	18.91	vs. Previous Quarter	1,360.00%	vs. Previous Quarter:	66.46%
PEG Ratio	1.99				

Price Ratios **ROE** **ROA**

Price/Book	1.99	12/31/07	10.82	12/31/07	3.38
Price/Cash Flow	10.10	09/30/07	11.31	09/30/07	3.44
Price / Sales	1.00	06/30/07	12.44	06/30/07	3.71
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	1.00	12/31/07	0.61	12/31/07	5.30
09/30/07	0.94	09/30/07	0.47	09/30/07	5.52
06/30/07	0.97	06/30/07	0.54	06/30/07	6.09
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	10.96	12/31/07	10.96	12/31/07	16.27
09/30/07	6.32	09/30/07	6.32	09/30/07	16.00
06/30/07	7.70	06/30/07	7.70	06/30/07	16.05
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	5.72	12/31/07	0.74	12/31/07	42.69
09/30/07	3.19	09/30/07	0.76	09/30/07	43.14
06/30/07	3.09	06/30/07	0.76	06/30/07	43.22

Zacks.com Quotes and Research

WGL HOLDINGS INC (NYSE)

Scottrade

WGL	31.15	▲0.37	(1.20%)	Vol. 644,700	13:07 ET

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

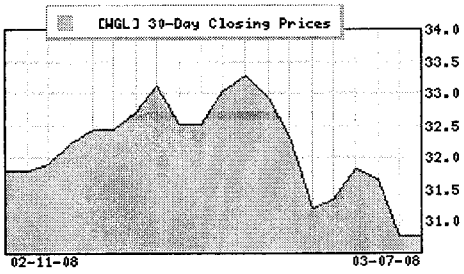
General Information

WGL HLDGS INC
101 Constitution Ave, N.W
Washington, DC 20080
Phone: 703 750-2000
Fax: 703 750-4828
Web: www.wglholdings.com
Email: madams@washgas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/07
Next EPS Date	04/24/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	30.78
52 Week High	35.91
52 Week Low	29.79
Beta	0.73
20 Day Moving Average	615,432.81
Target Price Consensus	35.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.44	4 Week	-1.64
12 Week	-4.44	12 Week	8.46
YTD	-6.04	YTD	6.67

Share Information		Dividend Information	
Shares Outstanding (millions)	49.46	Dividend Yield	4.45%
		Annual Dividend	$1.37
Market Capitalization (millions)	1,522.50	Payout Ratio	0.64
Short Ratio	6.93	Change in Payout Ratio	-0.05
Last Split Date	05/02/1995	Last Dividend Payout / Amount	01/08/2008 / $0.34

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.41	Current (1=Strong Buy, 5=Strong Sell)	2.20
Current Year EPS Consensus Estimate	2.35	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.50
Next EPS Report Date	04/24/2008	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.09	vs. Previous Year	4.35%	vs. Previous Year	2.55%
Trailing 12 Months:	14.38	vs. Previous Quarter	409.68%	vs. Previous Quarter:	130.78%
PEG Ratio	3.27				

Price Ratios **ROE** **ROA**

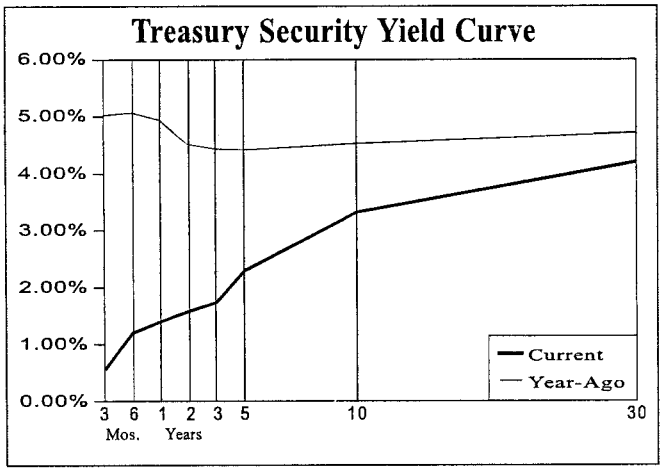
Price/Book	1.50	12/31/07	10.53	12/31/07	3.41
Price/Cash Flow	7.55	09/30/07	10.41	09/30/07	3.42
Price / Sales	0.57	06/30/07	11.26	06/30/07	3.72
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	0.88	12/31/07	-	12/31/07	3.96
09/30/07	1.03	09/30/07	0.47	09/30/07	3.89
06/30/07	1.15	06/30/07	0.72	06/30/07	4.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	6.81	12/31/07	6.81	12/31/07	20.49
09/30/07	6.73	09/30/07	6.73	09/30/07	19.89
06/30/07	7.27	06/30/07	7.27	06/30/07	20.50
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	9.33	12/31/07	0.59	12/31/07	36.30
09/30/07	8.69	09/30/07	0.63	09/30/07	37.92
06/30/07	12.06	06/30/07	0.60	06/30/07	36.86

ATTACHMENT C

Selected Yields

	Recent (3/19/08)	3 Months Ago (12/19/07)	Year Ago (3/21/07)
TAXABLE			
Market Rates			
Discount Rate	2.50	4.75	6.25
Federal Funds	2.25	4.25	5.25
Prime Rate	5.25	7.25	8.25
30-day CP (A1/P1)	2.65	5.59	5.24
3-month LIBOR	2.60	4.91	5.35
Bank CDs			
6-month	2.15	2.82	3.26
1-year	2.16	3.45	3.87
5-year	3.12	3.74	3.92
U.S. Treasury Securities			
3-month	0.56	2.89	5.03
6-month	1.20	3.31	5.07
1-year	1.40	3.31	4.94
5-year	2.30	3.43	4.43
10-year	3.33	4.03	4.54
10-year (inflation-protected)	0.90	1.71	2.12
30-year	4.21	4.45	4.72
30-year Zero	4.35	4.47	4.68

	Recent (3/19/08)	3 Months Ago (12/19/07)	Year Ago (3/21/07)
Mortgage-Backed Securities			
GNMA 6.5%	4.70	5.42	5.53
FHLMC 6.5% (Gold)	4.96	5.62	5.60
FNMA 6.5%	4.62	5.41	5.50
FNMA ARM	5.07	5.46	5.60
Corporate Bonds			
Financial (10-year) A	5.89	6.01	5.40
Industrial (25/30-year) A	5.87	5.99	5.68
Utility (25/30-year) A	5.96	6.14	5.86
Utility (25/30-year) Baa/BBB	6.14	6.24	6.01
Foreign Bonds (10-Year)			
Canada	3.45	3.99	4.08
Germany	3.76	4.28	3.93
Japan	1.28	1.49	1.57
United Kingdom	4.31	4.68	4.83
Preferred Stocks			
Utility A	6.34	6.33	6.08
Financial A	7.91	8.18	6.44
Financial Adjustable A	5.47	5.47	5.47



	Recent (3/19/08)	3 Months Ago (12/19/07)	Year Ago (3/21/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.94	4.46	4.13
25-Bond Index (Revs)	5.15	4.79	4.38
General Obligation Bonds (GOs)			
1-year Aaa	1.80	2.85	3.54
1-year A	1.90	2.90	3.64
5-year Aaa	2.87	3.19	3.51
5-year A	3.17	3.49	3.80
10-year Aaa	3.73	3.62	3.65
10-year A	4.02	3.91	3.95
25/30-year Aaa	4.92	4.33	4.00
25/30-year A	5.05	4.44	4.30
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.10	4.50	4.33
Electric AA	5.10	4.50	4.30
Housing AA	5.40	4.80	4.55
Hospital AA	5.50	4.75	4.57
Toll Road Aaa	5.10	4.60	4.40

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/12/08	2/27/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1413	1799	-386	1655	1640	1883
Borrowed Reserves	231	198	33	1634	1181	736
Net Free/Borrowed Reserves	1182	1601	-419	21	459	1147

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/3/08	2/25/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1391.8	1367.8	24.0	6.1%	-0.4%	1.6%
M2 (M1+savings+small time deposits)	7644.7	7630.3	14.4	12.2%	8.3%	7.3%

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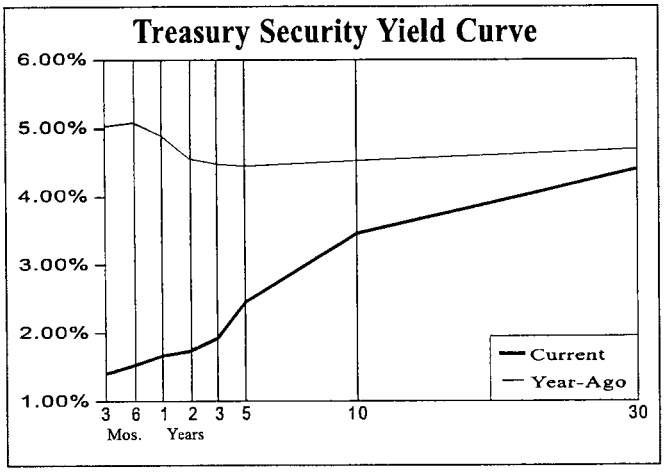
Selected Yields

	Recent (3/12/08)	3 Months Ago (12/12/07)	Year Ago (3/14/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	4.75	6.25
Federal Funds	3.00	4.25	5.25
Prime Rate	6.00	7.25	8.25
30-day CP (A1/P1)	2.84	5.10	5.25
3-month LIBOR	2.85	5.06	5.35
Bank CDs			
6-month	2.17	2.82	3.20
1-year	2.17	3.45	3.80
5-year	3.16	3.74	3.91
U.S. Treasury Securities			
3-month	1.41	2.86	5.04
6-month	1.53	3.22	5.09
1-year	1.67	3.09	4.90
5-year	2.46	3.47	4.45
10-year	3.46	4.09	4.53
10-year (inflation-protected)	0.84	1.78	2.17
30-year	4.41	4.54	4.70
30-year Zero	4.57	4.58	4.66

	Recent (3/12/08)	3 Months Ago (12/12/07)	Year Ago (3/14/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.02	5.54	5.59
FHLMC 6.5% (Gold)	5.04	5.67	5.66
FNMA 6.5%	4.94	5.53	5.57
FNMA ARM	5.07	5.46	5.60
Corporate Bonds			
Financial (10-year) A	6.05	6.26	5.40
Industrial (25/30-year) A	6.07	6.15	5.65
Utility (25/30-year) A	6.08	6.25	5.85
Utility (25/30-year) Baa/BBB	6.27	6.35	5.99
Foreign Bonds (10-Year)			
Canada	3.53	4.03	4.02
Germany	3.77	4.31	3.88
Japan	1.35	1.52	1.58
United Kingdom	4.42	4.80	4.74
Preferred Stocks			
Utility A	6.61	6.35	6.03
Financial A	7.83	7.80	6.42
Financial Adjustable A	5.46	5.46	5.46



	Recent (3/12/08)	3 Months Ago (12/12/07)	Year Ago (3/14/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.92	4.38	4.08
25-Bond Index (Revs)	5.11	4.74	4.39
General Obligation Bonds (GOs)			
1-year Aaa	2.05	2.90	3.54
1-year A	2.20	3.00	3.64
5-year Aaa	2.83	3.19	3.51
5-year A	2.93	3.29	3.60
10-year Aaa	3.66	3.63	3.66
10-year A	3.86	3.93	4.18
25/30-year Aaa	4.85	4.37	4.00
25/30-year A	5.04	4.57	4.30
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.05	4.65	4.30
Electric AA	5.10	4.70	4.30
Housing AA	5.35	4.80	4.50
Hospital AA	5.40	4.85	4.50
Toll Road Aaa	5.10	4.70	4.30

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/27/08	2/13/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1800	1660	140	1714	1615	1896
Borrowed Reserves	198	102	96	1630	1276	729
Net Free/Borrowed Reserves	1602	1558	44	84	339	1167

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/25/08	2/18/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1368.0	1360.7	7.3	2.4%	-0.3%	0.2%
M2 (M1+savings+small time deposits)	7630.3	7597.2	33.1	10.7%	7.2%	7.0%

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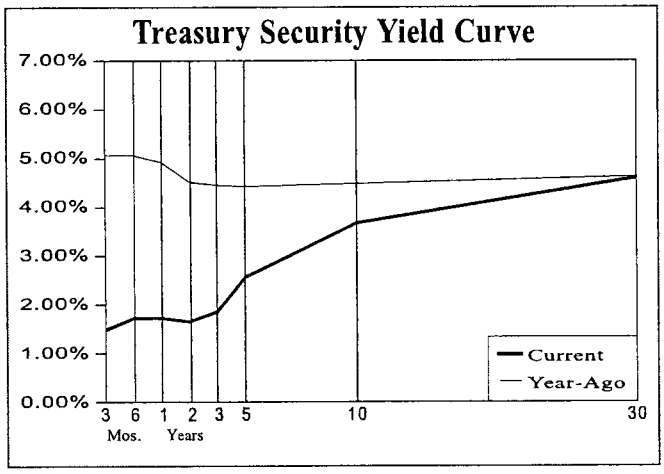
Selected Yields

	Recent (3/05/08)	3 Months Ago (12/05/07)	Year Ago (3/07/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	5.00	6.25
Federal Funds	3.00	4.50	5.25
Prime Rate	6.00	7.50	8.25
30-day CP (A1/P1)	2.97	5.23	5.24
3-month LIBOR	3.00	5.15	5.34
Bank CDs			
6-month	2.16	2.82	3.28
1-year	2.16	3.45	3.89
5-year	3.16	3.80	3.93
U.S. Treasury Securities			
3-month	1.49	3.05	5.08
6-month	1.72	3.24	5.07
1-year	1.72	3.11	4.92
5-year	2.57	3.32	4.43
10-year	3.67	3.96	4.49
10-year (inflation-protected)	1.02	1.70	2.16
30-year	4.60	4.44	4.63
30-year Zero	4.78	4.49	4.57

	Recent (3/05/08)	3 Months Ago (12/05/07)	Year Ago (3/07/07)
Mortgage-Backed Securities			
GNMA 6.5%	4.80	5.25	5.55
FHLMC 6.5% (Gold)	5.36	5.42	5.64
FNMA 6.5%	5.02	5.25	5.56
FNMA ARM	5.05	5.44	5.60
Corporate Bonds			
Financial (10-year) A	5.96	5.92	5.31
Industrial (25/30-year) A	6.35	5.96	5.60
Utility (25/30-year) A	6.26	6.07	5.59
Utility (25/30-year) Baa/BBB	6.39	6.22	5.86
Foreign Bonds (10-Year)			
Canada	3.64	3.93	3.99
Germany	3.86	4.03	3.92
Japan	1.38	1.50	1.63
United Kingdom	4.48	4.49	4.77
Preferred Stocks			
Utility A	6.26	6.25	6.01
Financial A	7.60	7.73	6.46
Financial Adjustable A	5.53	5.53	5.53



	Recent (3/05/08)	3 Months Ago (12/05/07)	Year Ago (3/07/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.11	4.39	4.10
25-Bond Index (Revs)	5.22	4.77	4.41
General Obligation Bonds (GOs)			
1-year Aaa	2.25	3.00	3.53
1-year A	2.35	3.04	3.63
5-year Aaa	3.30	3.18	3.49
5-year A	3.60	3.48	3.78
10-year Aaa	4.11	3.57	3.64
10-year A	4.40	3.86	3.94
25/30-year Aaa	5.10	4.29	3.96
25/30-year A	5.23	4.40	4.25
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.30	4.45	4.30
Electric AA	5.30	4.45	4.25
Housing AA	5.60	4.70	4.50
Hospital AA	5.70	4.65	4.50
Toll Road Aaa	5.30	4.65	4.36

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/27/08	2/13/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1807	1661	146	1715	1615	1897
Borrowed Reserves	198	102	96	1630	1276	729
Net Free/Borrowed Reserves	1609	1559	50	85	339	1168

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/18/08	2/11/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1360.8	1357.5	3.3	1.1%	0.1%	-0.2%
M2 (M1+savings+small time deposits)	7597.0	7584.4	12.6	10.7%	7.6%	6.9%

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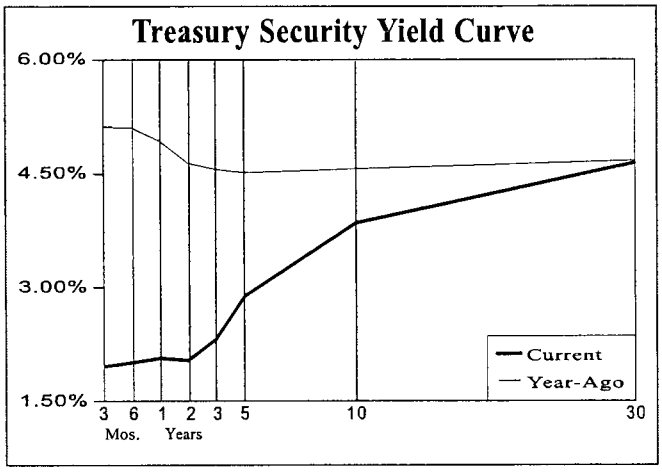
Selected Yields

	Recent (2/27/08)	3 Months Ago (11/28/07)	Year Ago (2/28/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	5.00	6.25
Federal Funds	3.00	4.50	5.25
Prime Rate	6.00	7.50	8.25
30-day CP (A1/P1)	3.21	4.65	5.23
3-month LIBOR	3.09	5.08	5.35
Bank CDs			
6-month	2.19	2.82	3.28
1-year	2.17	3.54	3.88
5-year	3.06	3.88	3.92
U.S. Treasury Securities			
3-month	1.96	3.03	5.12
6-month	2.01	3.36	5.11
1-year	2.07	3.26	4.93
5-year	2.89	3.50	4.52
10-year	3.85	4.04	4.57
10-year (inflation-protected)	1.30	1.70	2.19
30-year	4.65	4.42	4.68
30-year Zero	4.78	4.45	4.61

	Recent (2/27/08)	3 Months Ago (11/28/07)	Year Ago (2/28/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.04	5.39	5.63
FHLMC 6.5% (Gold)	5.21	5.61	5.73
FNMA 6.5%	5.12	5.41	5.63
FNMA ARM	5.19	5.87	5.60
Corporate Bonds			
Financial (10-year) A	5.81	5.94	5.38
Industrial (25/30-year) A	6.41	5.87	5.62
Utility (25/30-year) A	6.20	6.03	5.65
Utility (25/30-year) Baa/BBB	6.48	6.11	5.89
Foreign Bonds (10-Year)			
Canada	3.82	4.06	4.03
Germany	4.09	4.11	3.96
Japan	1.48	1.49	1.64
United Kingdom	4.70	4.68	4.80
Preferred Stocks			
Utility A	6.10	6.31	5.99
Financial A	7.12	7.84	6.44
Financial Adjustable A	5.53	5.53	5.53



	Recent (2/27/08)	3 Months Ago (11/28/07)	Year Ago (2/28/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.66	4.45	4.19
25-Bond Index (Revs)	4.94	4.80	4.48
General Obligation Bonds (GOs)			
1-year Aaa	2.20	3.25	3.56
1-year A	2.35	3.35	3.66
5-year Aaa	3.13	3.27	3.55
5-year A	3.23	3.37	3.64
10-year Aaa	3.92	3.64	3.67
10-year A	4.12	3.94	4.20
25/30-year Aaa	4.94	4.38	3.97
25/30-year A	5.14	4.58	4.28
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.15	4.65	4.39
Electric AA	5.20	4.75	4.38
Housing AA	5.45	4.85	4.44
Hospital AA	5.50	4.85	4.45
Toll Road Aaa	5.20	4.75	4.39

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/13/08	1/30/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1661	1446	215	1670	2152	1875
Borrowed Reserves	102	390	-288	1676	1281	723
Net Free/Borrowed Reserves	1559	1056	503	-7	872	1153

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/11/08	2/4/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1358.2	1382.5	-24.3	-2.0%	-0.2%	-0.7%
M2 (M1+savings+small time deposits)	7585.5	7569.2	16.3	11.0%	8.2%	6.8%

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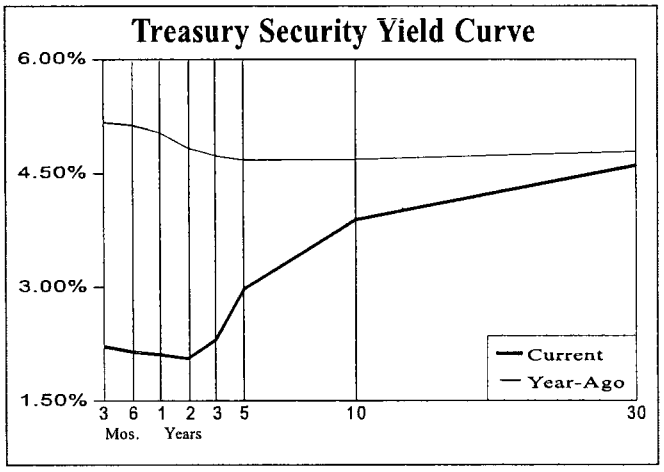
Selected Yields

	Recent (2/20/08)	3 Months Ago (11/20/07)	Year Ago (2/21/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	5.00	6.25
Federal Funds	3.00	4.50	5.25
Prime Rate	6.00	7.50	8.25
30-day CP (A1/P1)	3.05	4.59	5.23
3-month LIBOR	3.08	5.00	5.36
Bank CDs			
6-month	2.20	2.83	3.27
1-year	2.19	3.54	3.88
5-year	2.82	3.89	3.92
U.S. Treasury Securities			
3-month	2.22	3.28	5.17
6-month	2.15	3.42	5.14
1-year	2.11	3.43	5.04
5-year	2.98	3.55	4.68
10-year	3.89	4.10	4.69
10-year (inflation-protected)	1.41	1.70	2.33
30-year	4.61	4.50	4.79
30-year Zero	4.76	4.53	4.71

	Recent (2/20/08)	3 Months Ago (11/20/07)	Year Ago (2/21/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.10	5.50	5.67
FHLMC 6.5% (Gold)	5.31	5.77	5.75
FNMA 6.5%	5.09	5.56	5.67
FNMA ARM	5.19	5.88	5.61
Corporate Bonds			
Financial (10-year) A	5.82	6.01	5.51
Industrial (25/30-year) A	6.29	5.96	5.72
Utility (25/30-year) A	6.15	6.04	5.74
Utility (25/30-year) Baa/BBB	6.33	6.14	5.97
Foreign Bonds (10-Year)			
Canada	3.93	4.07	4.10
Germany	4.03	4.06	4.05
Japan	1.43	1.47	1.70
United Kingdom	4.69	4.62	4.89
Preferred Stocks			
Utility A	6.08	6.62	6.16
Financial A	7.00	7.97	6.44
Financial Adjustable A	5.52	5.52	5.52



	Recent (2/20/08)	3 Months Ago (11/20/07)	Year Ago (2/21/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.47	4.53	4.17
25-Bond Index (Revs)	4.82	4.85	4.51
General Obligation Bonds (GOs)			
1-year Aaa	1.70	3.30	3.58
1-year A	1.80	3.34	3.68
5-year Aaa	2.80	3.34	3.61
5-year A	3.10	3.64	3.90
10-year Aaa	3.55	3.71	3.73
10-year A	3.84	4.00	3.15
25/30-year Aaa	4.64	4.47	4.06
25/30-year A	4.77	4.62	4.38
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.80	4.67	4.40
Electric AA	4.80	4.67	4.35
Housing AA	5.10	4.90	4.60
Hospital AA	5.15	4.85	4.60
Toll Road Aaa	4.80	4.67	4.48

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/13/08	1/30/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1663	1459	204	1671	2153	1876
Borrowed Reserves	102	390	-288	1676	1281	723
Net Free/Borrowed Reserves	1561	1069	492	-5	872	1153

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/4/08	1/28/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1382.7	1362.6	20.1	2.3%	2.5%	0.5%
M2 (M1+savings+small time deposits)	7569.4	7535.6	33.8	10.0%	8.2%	6.6%

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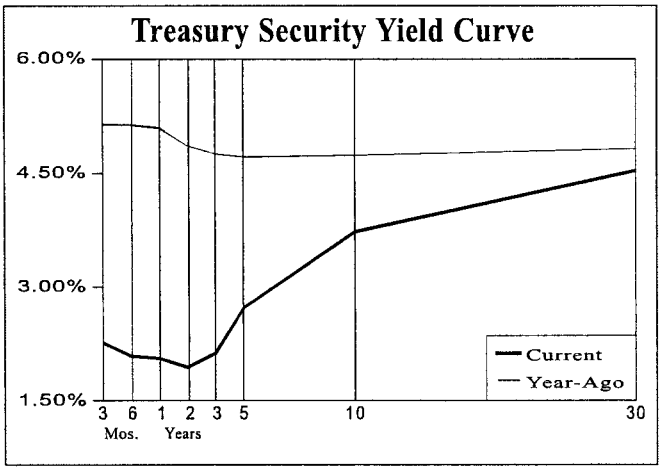
Selected Yields

	Recent (2/13/08)	3 Months Ago (11/14/07)	Year Ago (2/14/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	5.00	6.25
Federal Funds	3.00	4.50	5.25
Prime Rate	6.00	7.50	8.25
30-day CP (A1/P1)	3.00	4.56	5.23
3-month LIBOR	3.07	4.88	5.36
Bank CDs			
6-month	2.15	2.83	3.27
1-year	2.34	3.54	3.86
5-year	2.85	3.89	3.91
U.S. Treasury Securities			
3-month	2.26	3.39	5.15
6-month	2.09	3.68	5.14
1-year	2.06	3.68	5.10
5-year	2.73	3.82	4.72
10-year	3.73	4.25	4.74
10-year (inflation-protected)	1.34	1.86	2.39
30-year	4.54	4.60	4.83
30-year Zero	4.65	4.62	4.76
Mortgage-Backed Securities			
GNMA 6.5%	4.46	5.53	5.72
FHLMC 6.5% (Gold)	5.10	5.73	5.82
FNMA 6.5%	4.71	5.51	5.74
FNMA ARM	5.18	5.90	5.62
Corporate Bonds			
Financial (10-year) A	5.78	5.95	5.52
Industrial (25/30-year) A	6.29	5.98	5.77
Utility (25/30-year) A	6.20	6.09	5.77
Utility (25/30-year) Baa/BBB	6.35	6.18	6.02
Foreign Bonds (10-Year)			
Canada	3.87	4.21	4.15
Germany	3.96	4.15	4.10
Japan	1.43	1.53	1.74
United Kingdom	4.62	4.74	4.95
Preferred Stocks			
Utility A	6.13	6.43	6.14
Financial A	7.00	7.58	6.43
Financial Adjustable A	5.51	5.51	5.51



	Recent (2/13/08)	3 Months Ago (11/14/07)	Year Ago (2/14/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.33	4.54	4.21
25-Bond Index (Revs)	4.72	4.85	4.53
General Obligation Bonds (GOs)			
1-year Aaa	1.05	3.30	3.60
1-year A	1.15	3.40	3.70
5-year Aaa	2.67	3.44	3.63
5-year A	2.77	3.74	3.72
10-year Aaa	3.40	3.83	3.78
10-year A	3.60	4.13	4.30
25/30-year Aaa	4.36	4.55	4.08
25/30-year A	4.56	4.75	4.39
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.60	4.75	4.49
Electric AA	4.65	4.85	4.48
Housing AA	4.80	4.95	4.54
Hospital AA	4.85	4.95	4.55
Toll Road Aaa	4.65	4.85	4.49

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/30/08	1/16/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1458	1712	-254	1700	2144	1861
Borrowed Reserves	390	1377	-987	1699	1291	729
Net Free/Borrowed Reserves	1068	335	733	1	854	1132

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/28/08	1/21/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1362.3	1372.1	-9.8	-2.1%	-1.0%	-1.0%
M2 (M1+savings+small time deposits)	7529.2	7491.6	37.6	6.8%	6.9%	6.0%

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SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
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SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
COST OF CAPITAL SUMMARY

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 1

WEIGHTED COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST
1	LONG-TERM DEBT	51.00%	7.96%	4.06%
2	PREFERRED EQUITY	4.00%	8.20%	0.33%
3	COMMON EQUITY	45.00%	9.88%	4.44%
4	TOTAL CAPITALIZATION	100.00%		
5	**WEIGHTED COST OF CAPITAL**			8.83%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C) LINE 5: SUM OF COLUMN (C) LINES 1 THRU 3

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
COST OF CAPITAL SUMMARY

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 1

WEIGHTED COST OF DEBT

LINE NO.	DESCRIPTION	(A) NET PROCEEDS	(B) CAPITAL RATIO	(C) COST	(D) WEIGHTED COST
1	TOTAL DEBENTURES AND MTN'S (FIXED RATE)	$ 590,463,378	91.74%	8.11%	7.44%
2	TERM FACILITY (VARIABLE RATE)	53,169,199	8.26%	6.27%	0.52%
3	TOTAL CAPITALIZATION	$ 643,632,577	100.00%		
4	**WEIGHTED COST OF DEBT**				7.96%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2
COLUMN (B): COLUMN (A), LINES 1 AND 2 / COLUMN (A), LINE 3
COLUMN (C): SCHEDULE WAR-1, PAGE 3
COLUMN (D): COLUMN (B) x COLUMN (C)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
COST OF CAPITAL SUMMARY

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 1
PAGE 3 OF 4

WEIGHTED COST OF DEBT

LINE NO.	(A) DESCRIPTION	(B) PRINCIPPAL AMOUNT INTEREST	(C) UNAMORTIZED DEBT EXPENSE AND DISCOUNT	(D) NET PROCEEDS	(E) EFFECTIVE INTEREST RATE	(F) COST OF DEBT
	DEBENTURES					
1	8.0% DEBENTURE, DUE 2026	$ 75,000,000	$ 6,089,371	$ 68,910,630	8.89%	$ 6,126,155
2	8.375 NOTE, DUE 2011	200,000,000	1,485,867	198,514,134	8.61%	17,091,670
3	7.625 NOTE, DUE 2012	200,000,000	1,380,294	198,619,706	7.79%	15,472,475
4	TOTAL DEBENTURES	$ 475,000,000	$ 8,955,531	$ 466,044,469	8.30%	$ 38,690,300
	MEDIUM TERM NOTES					
5	7.59% MTN, DUE 2017	$ 25,000,000	$ 147,215	$ 24,852,785	7.68%	$ 1,908,694
6	7.59% MTN, DUE 2017	25,000,000	175,679	24,824,321	7.86%	1,951,192
7	7.59% MTN, DUE 2017	25,000,000	204,455	24,795,545	8.00%	1,983,644
8	7.59% MTN, DUE 2017	17,500,000	7,731	17,492,269	7.00%	1,224,459
9	7.59% MTN, DUE 2017	7,500,000	3,458	7,496,542	6.88%	515,762
10	7.59% MTN, DUE 2017	25,000,000	42,553	24,957,447	6.40%	1,597,277
11	TOTAL MEDIUM TERM NOTES	$ 125,000,000	$ 581,091	$ 124,418,909	7.38%	$ 9,181,028
12	**TOTAL DEBENTURES AND MTN'S**	**$ 600,000,000**	**$ 9,536,622**	**$ 590,463,378**	**8.11%**	**$ 47,871,328**
13	**TERM FACILITY**			**$ 53,169,199**	**6.27%**	**$ 3,332,516**

REFERENCES:
COLUMN (A) LINES 1 THRU 12: COMPANY SCHEDULE D-2, PAGE 2
COLUMN (B) LINES 1 THRU 12: COMPANY SCHEDULE D-2, PAGE 2
COLUMN (C) LINES 1 THRU 12: COMPANY SCHEDULE D-2, PAGE 2
COLUMN (D) LINES 1 THRU 12: COLUMN (B) - COLUMN (C)
COLUMN (D) LINE 13: COMPANY SCHEDULE D-2, PAGE 3
COLUMN (E) LINES 1 THRU 13: COLUMN (F) / COLUMN (D)
COLUMN (F) LINES 1 THRU 12: COMPANY SCHEDULE D-2, PAGE 2
COLUMN (F) LINE 13: COMPANY SCHEDULE D-2, PAGE 3

COST OF COMMON EQUITY CALCULATION

LINE NO.			
	DCF METHODOLOGY		
1	DCF - CONSTANT GROWTH MODEL ESTIMATE	9.73%	SCHEDULE WAR-2, COLUMN (C), LINE 9
	CAPM METHODOLOGY		
2	CAPM - GEOMETRIC MEAN ESTIMATE	9.20%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 9
3	CAPM - ARITHMETIC MEAN ESTIMATE	10.83%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 9
4	AVERAGE OF CAPM ESTIMATES	10.02%	(LINE 2 + LINE 3) / 2
5	**AVERAGE OF DCF AND CAPM ESTIMATES**	9.88%	(LINE 1 + LINE 4) / 2

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ATG	AGL RESOURCES, INC.	4.67%	+	5.92%	=	10.59%
2	ATO	ATMOS ENERGY CORP.	4.83%	+	4.48%	=	9.31%
3	LG	LACLEDE GROUP, INC.	4.36%	+	5.25%	=	9.61%
4	GAS	NICOR, INC.	5.08%	+	5.09%	=	10.18%
5	NWN	NORTHWEST NATURAL GAS COMPANY	3.35%	+	4.73%	=	8.09%
6	PNY	PIEDMONT NATURAL GAS COMPANY	3.97%	+	3.51%	=	7.47%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	5.92%	+	8.65%	=	14.58%
8	WGL	WGL HOLDINGS, INC.	4.23%	+	3.80%	=	8.03%
9	**AVERAGE**						9.73%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
DIVIDEND YIELD CALCULATION

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ATG	AGL RESOURCES, INC.	$1.68	/	$35.97	=	4.67%
2	ATO	ATMOS ENERGY CORP.	1.30	/	26.91	=	4.83%
3	LG	LACLEDE GROUP, INC.	1.50	/	34.39	=	4.36%
4	GAS	NICOR, INC.	1.86	/	36.60	=	5.08%
5	NWN	NORTHWEST NATURAL GAS COMPANY	1.50	/	44.74	=	3.35%
6	PNY	PIEDMONT NATURAL GAS COMPANY	1.00	/	25.21	=	3.97%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	2.06	/	34.78	=	5.92%
8	WGL	WGL HOLDINGS, INC.	1.36	/	32.15	=	4.23%
9	**AVERAGE**						4.55%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/14/2008
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 01/28/2008 TO 03/20/2008
STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) / COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ATG	AGL RESOURCES, INC.	5.75%	+	0.17%	=	5.92%
2	ATO	ATMOS ENERGY CORP.	4.00%	+	0.48%	=	4.48%
3	LG	LACLEDE GROUP, INC.	4.25%	+	1.00%	=	5.25%
4	GAS	NICOR, INC.	5.00%	+	0.09%	=	5.09%
5	NWN	NORTHWEST NATURAL GAS COMPANY	4.70%	+	0.03%	=	4.73%
6	PNY	PIEDMONT NATURAL GAS COMPANY	3.50%	+	0.01%	=	3.51%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	7.90%	+	0.75%	=	8.65%
8	WGL	WGL HOLDINGS, INC.	3.75%	+	0.05%	=	3.80%
9	**AVERAGE**						5.18%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M / B) + 1) / 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	ATG	AGL RESOURCES, INC.	0.55%	x	{ [((1.61) + 1) / 2] - 1 }	=	0.17%
2	ATO	ATMOS ENERGY CORP.	5.25%	x	{ [((1.18) + 1) / 2] - 1 }	=	0.48%
3	LG	LACLEDE GROUP, INC.	3.00%	x	{ [((1.67) + 1) / 2] - 1 }	=	1.00%
4	GAS	NICOR, INC.	0.25%	x	{ [((1.76) + 1) / 2] - 1 }	=	0.09%
5	NWN	NORTHWEST NATURAL GAS COMPANY	0.07%	x	{ [((1.95) + 1) / 2] - 1 }	=	0.03%
6	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((2.02) + 1) / 2] - 1 }	=	0.01%
7	SJI	SOUTH JERSEY INDUSTIES, INC.	1.50%	x	{ [((2.00) + 1) / 2] - 1 }	=	0.75%
8	WGL	WGL HOLDINGS, INC.	0.20%	x	{ [((1.52) + 1) / 2] - 1 }	=	0.05%
9	**NATURAL GAS LDC AVERAGE**						0.32%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/14/2008
COLUMN (C): COLUMN (A) x COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
DIVIDEND GROWTH COMPONENTS

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	WATER COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ATG	AGL RESOURCES, INC.	2003	0.4663		14.00%		6.53%	14.66	64.50	
2			2004	0.4956		11.00%		5.45%	18.06	76.70	
3			2005	0.4758		12.90%		6.14%	19.29	77.70	
4			2006	0.4559		13.20%		6.02%	20.71	77.70	
5			2007	0.3971		12.70%		5.04%	21.74	76.40	
6			GROWTH 2003 - 2007					5.84%	10.50%		4.32%
7			2008	0.4000		12.50%		5.00%		76.00	-0.52%
8			2009	0.4069		13.00%		5.29%		76.00	-0.26%
9			2011-13	0.4250		14.50%		6.16%	1.50%	80.00	0.93%
10											
11	ATO	ATMOS ENERGY CORP.	2003	0.2982		9.30%		2.77%	16.66	51.48	
12			2004	0.2278		7.60%		1.73%	18.05	62.80	
13			2005	0.2791		8.50%		2.37%	19.90	80.54	
14			2006	0.3700		9.80%		3.63%	20.16	81.74	
15			2007	0.3402		8.70%		2.96%	22.01	89.33	
16			GROWTH 2003 - 2007					2.69%	9.00%		14.77%
17			2008	0.3500		9.00%		3.15%		94.00	5.23%
18			2009	0.3714		9.50%		3.53%		99.00	5.27%
19			2011-13	0.4286		9.50%		4.07%	3.50%	115.00	5.18%
20											
21	LG	LACLEDE GROUP, INC.	2003	0.2637		11.60%		3.06%	15.65	19.11	
22			2004	0.2582		10.10%		2.61%	16.96	20.98	
23			2005	0.2789		10.90%		3.04%	17.31	21.17	
24			2006	0.4093		12.50%		5.12%	18.85	21.36	
25			2007	0.3723		11.60%		4.32%	19.79	21.65	
26			GROWTH 2003 - 2007					3.63%	4.50%		3.17%
27			2008	0.3660		11.50%		4.21%		22.00	1.62%
28			2009	0.3489		11.00%		3.84%		22.50	1.94%
29			2011-13	0.3889		11.00%		4.28%	5.00%	25.50	3.33%
30											
31	GAS	NICOR, INC.	2003	0.1185		12.30%		1.46%	17.13	44.04	
32			2004	0.1622		12.30%		2.12%	16.99	44.10	
33			2005	0.1806		12.30%		2.26%	18.36	44.18	
34			2006	0.3519		12.30%		5.17%	19.43	44.90	
35			2007	0.3212		12.30%		4.34%	20.40	45.20	
36			GROWTH 2003 - 2007					3.07%	2.50%		0.65%
37			2008	0.1733		12.30%		1.91%		45.00	-0.44%
38			2009	0.2692		12.30%		3.23%		45.00	-0.22%
39			2011-13	0.4154		12.30%		5.61%	4.00%	46.00	0.35%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/14/2008
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36 COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
DIVIDEND GROWTH COMPONENTS

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 5
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) 8.50% BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	NWN	NORTHWEST NATURAL GAS COMPANY	2003	0.2784		9.00%		2.51%	19.52	25.94	
2			2004	0.3011		8.90%		2.68%	20.64	27.55	
3			2005	0.3744		9.90%		3.71%	21.28	27.58	
4			2006	0.4085		10.90%		4.45%	21.97	27.28	
5			2007	0.4783		12.50%		5.98%	22.52	26.41	
6			GROWTH 2003 - 2007					3.86%	3.50%		0.45%
7			2008	0.4154		11.00%		4.57%		26.00	-1.55%
8			2009	0.4182		11.00%		4.60%		26.00	-0.78%
9			2011-13	0.4388		11.00%		4.83%	3.50%	28.00	1.18%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2003	0.2613		11.80%		3.08%	9.36	67.31	
12			2004	0.3307		11.10%		3.67%	11.15	76.67	
13			2005	0.3106		11.50%		3.57%	11.53	76.70	
14			2006	0.2578		11.00%		2.84%	11.83	74.61	
15			2007	0.2929		11.90%		3.49%	11.99	73.23	
16			GROWTH 2003 - 2007					3.33%	6.50%		2.13%
17			2008	0.3067		12.00%		3.68%		73.00	-0.31%
18			2009	0.3032		12.00%		3.64%		72.75	-0.33%
19			2011-13	0.3143		12.50%		3.93%	3.50%	72.00	-0.34%
20											
21	SJI	SOUTH JERSEY INDUSTIES, INC.	2003	0.4307		11.60%		5.00%	11.26	26.46	
22			2004	0.4810		12.50%		6.01%	12.41	27.76	
23			2005	0.4971		12.40%		6.16%	13.50	28.98	
24			2006	0.6260		16.30%		10.20%	15.11	29.33	
25			2007	0.5167		12.90%		6.67%	16.24	29.62	
26			GROWTH 2003 - 2007					6.81%	13.50%		2.86%
27			2008	0.5111		13.00%		6.64%		30.00	1.28%
28			2009	0.5265		13.50%		7.11%		30.50	1.47%
29			2011-13	0.5733		14.50%		8.31%	5.00%	32.00	1.56%
30											
31	WGL	WGL HOLDINGS, INC.	2003	0.4435		14.00%		6.21%	16.25	48.63	
32			2004	0.3434		14.00%		4.81%	16.95	48.67	
33			2005	0.3744		12.00%		4.49%	17.80	48.65	
34			2006	0.3093		10.20%		3.15%	18.28	48.89	
35			2007	0.3476		10.40%		3.62%	19.83	49.45	
36			GROWTH 2003 - 2007					4.46%	3.50%		0.42%
37			2008	0.3913		11.50%		4.50%		49.50	0.10%
38			2009	0.3872		11.00%		4.26%		49.60	0.15%
39			2011-13	0.3760		10.50%		3.95%	5.00%	50.00	0.22%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/14/2008
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36 COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
GROWTH RATE COMPARISON

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 6

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	ATG	5.92%	4.80%	3.50%	4.00%	1.50%	15.00%	4.00%	10.50%	6.19%	6.94%	10.25%	10.35%
2	ATO	4.48%	4.60%	4.50%	2.00%	3.50%	7.50%	1.50%	9.00%	4.66%	3.21%	1.63%	7.21%
3	LG	5.25%	-	3.50%	2.50%	5.00%	9.50%	1.00%	4.50%	4.33%	6.14%	1.99%	6.04%
4	GAS	5.09%	4.00%	4.00%	0.50%	4.00%	-3.00%	2.50%	2.50%	2.07%	6.75%	0.00%	4.46%
5	NWN	4.73%	5.30%	7.00%	5.50%	3.50%	3.50%	1.50%	3.50%	4.26%	11.90%	3.19%	3.64%
6	PNY	3.51%	5.50%	5.00%	4.00%	3.50%	6.00%	4.50%	6.50%	5.00%	5.97%	4.82%	6.39%
7	SJI	8.65%	7.50%	NMF	5.50%	5.00%	12.00%	3.50%	13.50%	7.83%	11.14%	6.67%	9.59%
8	WGL	3.80%	4.00%	3.50%	2.50%	5.00%	5.00%	1.50%	3.50%	3.57%	-2.25%	1.71%	5.10%
9				4.43%	3.31%	3.88%	6.94%	2.50%	6.69%		6.23%	3.78%	6.60%
10	AVERAGES	5.18%	5.10%		3.87%			5.38%		4.74%		5.54%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/14/2008
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/14/2008
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 8
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/14/2008

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	1.65%	+ [	0.85	x	(	10.40%	-	1.65%	)]	=	9.09%
2	ATO	k	=	1.65%	+ [	0.85	x	(	10.40%	-	1.65%	)]	=	9.09%
3	LG	k	=	1.65%	+ [	0.90	x	(	10.40%	-	1.65%	)]	=	9.52%
4	GAS	k	=	1.65%	+ [	1.00	x	(	10.40%	-	1.65%	)]	=	10.40%
5	NWN	k	=	1.65%	+ [	0.80	x	(	10.40%	-	1.65%	)]	=	8.65%
6	PNY	k	=	1.65%	+ [	0.85	x	(	10.40%	-	1.65%	)]	=	9.09%
7	SJI	k	=	1.65%	+ [	0.80	x	(	10.40%	-	1.65%	)]	=	8.65%
8	WGL	k	=	1.65%	+ [	0.85	x	(	10.40%	-	1.65%	)]	=	9.09%
9	**AVERAGE**					0.86								9.20%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 02/22/2008 THROUGH 03/28/2008 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
CAPM COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	1.65%	+ [	0.85	x	(	12.30%	-	1.65%	)]	=	10.70%
2	ATO	k	=	1.65%	+ [	0.85	x	(	12.30%	-	1.65%	)]	=	10.70%
3	LG	k	=	1.65%	+ [	0.90	x	(	12.30%	-	1.65%	)]	=	11.23%
4	GAS	k	=	1.65%	+ [	1.00	x	(	12.30%	-	1.65%	)]	=	12.30%
5	NWN	k	=	1.65%	+ [	0.80	x	(	12.30%	-	1.65%	)]	=	10.17%
6	PNY	k	=	1.65%	+ [	0.85	x	(	12.30%	-	1.65%	)]	=	10.70%
7	SJI	k	=	1.65%	+ [	0.80	x	(	12.30%	-	1.65%	)]	=	10.17%
8	WGL	k	=	1.65%	+ [	0.85	x	(	12.30%	-	1.65%	)]	=	10.70%
9	**AVERAGE**					0.86								10.83%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 02/22/2008 THROUGH 03/28/2008 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	1.90%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	3.90%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.20%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	2.50%	3.30%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	4.10%	2.20%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	CURRENT	4.00%	0.60%	5.25%	2.50%	2.25%	0.56%	4.72%	5.96%	6.14%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 03/28/2008
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 03/28/2008
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED APRIL 30, 2007
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. G-01551A-07-0504
SCHEDULE WAR - 9

AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES

LINE NO.		ATG	PCT.	ATO	PCT.	LG	PCT.	GAS	PCT.
1									
2									
3	DEBT	$ 1,622.0	50.2%	$ 1,965.7	48.0%	$ 355.5	45.3%	$ 497.5	36.3%
4									
5	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.6	0.1%	0.6	0.0%
6									
7	COMMON EQUITY	1,609.0	49.8%	2,126.3	52.0%	428.3	54.6%	872.6	63.7%
8									
9	TOTALS	$ 3,231.0	100.0%	$ 4,092.0	100.0%	$ 784.4	100.0%	$ 1,370.7	100.0%
10									
11									
12		NWN	PCT.	PNY	PCT.	SJI	PCT.	WGL	PCT.
13									
14	DEBT	$ 517.0	46.3%	$ 824.8	48.4%	$ 358.0	44.7%	$ 616.4	37.9%
15									
16	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	28.2	1.7%
17									
18	COMMON EQUITY	599.5	53.7%	878.3	51.6%	443.0	55.3%	980.7	60.3%
19									
20	TOTALS	$ 1,116.5	100.0%	$ 1,703.1	100.0%	$ 801.1	100.0%	$1,625.3	100.0%
21									
22									
23		NATURAL GAS LDC		SOUTHWEST GAS CORP.					
24		AVERAGE	PCT.	AVERAGE	PCT.				
25									
26	DEBT	$ 844.6	45.9%	$ 1,191.5	52.7%				
27									
28	PREFERRED STOCK	3.7	0.2%	100.0	4.4%				
29									
30	COMMON EQUITY	992.2	53.9%	970.3	42.9%				
31									
32	TOTALS	$ 1,840.5	100.0%	$ 2,261.8	100.0%				

REFERENCE:
MOST RECENT ANNUAL REPORTS OR SEC 10-K FILINGS

EXHIBIT
RUCO-8
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

DIRECT
RATE DESIGN TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

April 11, 2008

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ATTACHMENT A

INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any previous testimony in this proceeding?

A. Yes. On March 28, 2008, I filed direct testimony on the cost of capital issues that are associated with this case.

Q. What are your educational and professional qualifications in the field of utility regulation?

A. Appendix I, which is attached to my direct testimony on cost of capital describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Didn't you state in your direct testimony, filed on March 28, 2008, that you would only be testifying on the cost of capital issues associated with SWG's filing?

A. Yes I did. However, circumstances that have occurred since the filing of my direct testimony have made it necessary for me to serve as RUCO's witness on the revenue decoupling, weather normalization, and rate design change issues described above.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's positions on Southwest Gas Corporation's ("SWG" or "Company") requests for a decoupling mechanism that would guarantee Company-recovery of margins lost due to conservation, and a decoupling mechanism that would true-up margins lost or gained due to variations in weather. I will also address the Company's proposal to shift residential revenue recovery from variable to fixed rates. SWG requested these proposed mechanisms and rate design changes in the Company's application for a permanent rate increase ("Application"), which was filed with the Arizona Corporation Commission ("ACC" or "Commission") on August 31, 2007. SWG has chosen the period ended April 30, 2007 for the test year in this proceeding.

Q. Will you also be sponsoring RUCO's recommended rate design for SWG?

A. Partially. The "nuts and bolts" of RUCO's recommended rate design will be presented in the testimony of RUCO witness Rodney L. Moore. Mr. Moore previously filed direct testimony on the rate base and revenue requirement issues associated with SWG's Application. I will address the policy considerations that shaped RUCO's recommended rate design.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your direct testimony is organized.

A. My direct testimony is organized into five sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present RUCO's position on SWG's request concerning a revenue decoupling mechanism. Fourth, I will address the Company-proposed decoupling mechanism that would true-up margins lost or gained due to variations in weather. Finally, I will present RUCO's position on SWG's proposal to shift residential revenue recovery from variable to fixed rates.

Revenue Decoupling Adjustment Provision – I am recommending that the Commission reject SWG's proposed revenue adjustment provision. It is RUCO's position that the Company-proposed revenue adjustment provision would be counterproductive to conservation in that it will dilute the price message a customer receives when they reduce their demand.

Weather Normalization Adjustment Provision – I am recommending that the Commission reject SWG's proposed weather normalization adjustment provision based on findings obtained during meetings, pursuant to Decision No. 68487, which focused on the issue of decoupling.

Shift Residential Revenue Recovery from Variable to Fixed Rates – I am recommending that the Commission adopt RUCO's recommended rate

design (presented in the testimony of RUCO witness Rodney L. Moore). This rate design largely mirrors the Company-proposed rate design (that was based on SWG's cost of service study), and provides a positive move to mitigate the Company's risk of not recovering its authorized revenue requirement by placing more cost recovery into basic customer charge, while still retaining a conservation signal to consumers.

REVENUE DECOUPLING ADJUSTMENT PROVISION

Q. What is the revenue decoupling adjustment provision?

A. The revenue decoupling adjustment provision ("RDAP") is a rate design mechanism that would allow SWG to recover any margins that the Company would lose as a result of customer conservation. SWG complains that traditional rate designs do not allow the Company to recover all of its fixed costs when customer usage declines as a result of conservation. SWG further argues that if an RDAP is authorized it will "decouple" its incentive to promote conservation from its ability to realize its authorized margins.

Q. Has this been a problem for SWG?

A. SWG argues that its inability to recover is authorized margins due to declining average customer usage has been a big problem. In support of this position the Company has prepared an exhibit (JLC-1) that shows that

average usage has declined from 556 therms in 1986, to 332 therms in 2007.

Q. Does this mean that SWG is currently losing the margin on 224 therms per customer, representing the decline in average usage from 1986 until now?

A. No. The Company's Exhibit JLC-1 and its testimony on this issue is somewhat deceiving, and SWG is not currently losing 224 therms in margin per customer.

Q. Please explain.

A. Every time SWG has a rate case the Commission resets the billing determinants that are used to set the new rates. Thus, any decline in average consumption is trued-up in rates in the next rate case. This means that when looking at Exhibit JLC-1, the only potential under recovery is the 15 therms lost between the 2004 rate case and the current case. The circumstances are far less dire that the Company would have us believe.

Q. Isn't the declining average use of therms simply a regulatory lag issue?

A. Yes. Utilities operate in a dynamic environment. As a result, during the period between rate cases, a utility will experience all sorts of changes. Inflation will put pressure on costs, revenue will increase due to growth, return requirements will in(de)crease due to plant additions and

depreciation of existing plant, revenues may decline or incline depending on weather, interest rates may rise or fall. The list goes on and on. These types of changes are normal events that result because of regulatory lag. Regulatory lag is a two-way street that sometimes favors the utility – sometimes the ratepayer. The decoupling scheme promoted by SWG is nothing more than an attempt to mitigate the regulatory lag associated with declining consumption, yet to ignore other regulatory lag aspects that favor the Company, such as growth, declining interest rates, depreciating plant, etc. Approval of the decoupling scheme would result in unfair and biased rates, as often happens when a utility is allowed to engage in single issue ratemaking. The dynamics of change should be dealt with as a whole in the context of a rate case. It is only through the comprehensive view that is gained through a rate case that fair and balanced rates can be determined.

Q. Has consumption continued to decline at the same rate as it was declining twenty years ago?

A. No. The rate of decline has leveled off over the last twenty years. From 1986 through 1996 average consumption declined approximately 26%, yet from 1996 to 2007 it has declined approximately 19%. This data indicates that there is a limit to the amount customers can conserve and that this phenomenon is abating.

Q. Is there adequate justification for such a radical departure from traditional rate design?

A. No. In fact, pursuant to Commission instructions in Decision No. 68487, dated February 23, 2006, SWG, RUCO, Staff, and SWEEP met on several occasions to discuss innovative rate designs that would promote conservation. RUCO was interested in how much of SWG's claimed under recoveries of margin historically were related to declining usage and how much was related to variations in weather. The statistics showed that weather was as much responsible for under recoveries of margin as was conservation, and in some cases more so. Thus, SWG's problem isn't so much a continuing conservation problem, as it would have us believe, but rather variations in weather. SWG's insistent need for the RDAP to mitigate the effects of conservation appears to be a red herring used to justify SWG's desire to pass the risk of variations in weather from shareholders to ratepayers.

Q. Does RUCO support the proposed RDAP?

A. RUCO does not support the proposed mechanism, and believes it would result in biased rates. First, the mechanism would require customers to pay for a predetermined level of gas service regardless of whether that level was actually used. Second, despite the Company's argument that the mechanism is necessary because its costs are primarily fixed in nature so that decreases in consumption do not result in decreases in cost to

serve, the implementation of a mechanism that would have customers pay the margin on therms they did not consume is not warranted. In fact, a mechanism that sent such a price signal would be counterproductive when coupled with increased DSM conservation efforts.

Q. Does it appear that SWG needs to create additional incentives for customers to conserve?

A. No. Given the declining average gas usage of SWG customers, it appears that the Company's customers are already motivated to conserve, and/or new equipment and appliances are themselves becoming more efficient over time. The RDAP would be counterproductive to conservation in that it will dilute the price message a customer receives when they reduce their demand.

Q. Is RUCO recommending anything that addresses revenue losses attributable to conservation in lieu of the Company-proposed RDAP?

A. Yes. As I stated earlier in my testimony, RUCO believes that a more positive approach to mitigate the Company's risk of not recovering its authorized revenue requirement is by placing slightly more cost recovery into basic customer charge. This will be discussed in the last section of my testimony.

WEATHER NORMALIZATION ADJUSTMENT PROVISION

Q. Please describe SWG's proposed weather normalization adjustment provision ("WNAP").

A. SWG's proposed WNAP is a tariff mechanism that removes weather-related volatility from the non-gas component of customer bills for each winter season billing cycle.

Q. Has weather-related volatility been a problem for SWG?

A. Weather was identified as the real cause for SWG's under-recoveries (as opposed to conservation) during a series of workshops that were conducted pursuant to Decision No. 68487. As ordered in Decision No. 68487, RUCO, ACC Staff, SWEEP and SWG met for the purpose of seeking rate design alternatives that would truly encourage conservation efforts, while at the same time provide benefits to all affected stakeholders. Over the course of the meetings, the Company provided data, in response to questions from RUCO, which yielded a chart that demonstrated how much margin SWG had lost due to conservation and how much was lost due to weather over a three-year period. The chart demonstrated that over a three-year period, SWG had under-recovered by $22.5 million. Of this amount, $4.5 million, or approximately 20 percent was due to conservation, and $18.1 million, or 80 percent was attributable to weather. In RUCO's opinion, the data was conclusive: the real cause for SWG's under-recoveries was not conservation, but weather. None of

the actual participants in the meetings disagreed as to the meaning of the data.

Q. Does RUCO support the Company's request for the WNAP as a result of the findings obtained during the aforementioned meetings that were conducted pursuant to Decision No. 68487?

A. No. As stated in a report that RUCO filed with the Commission on July 26, 2007 (Attachment A), once weather was identified as the main source of the Company's under-recovery, discussions shifted away from decoupling and began to focus on subjects actually germane to SWG's under-recovery problem. The discussions included the following topics:

1) The merits of the current ten-year weather normalization for SWG vs. a weather decoupling mechanism;

2) Debate on stockholders' vs. ratepayers' responsibility to bear the weather risk;

3) The appropriate price signals that a conservation rate design should send; and

4) Potential adjustments to Return on Equity in light of any mechanism that would shift shareholder risk to ratepayers.

Q. Was any consensus reached by the parties during the meetings?

A. As further stated in RUCO's report, no consensus was ultimately reached between the parties on the relevant topics noted above. However, RUCO reported that the meetings proved useful in that the parties were able to identify weather as the true cause of SWG's inability to recover at approved levels, and that conservation efforts are of relatively little

significance to the under-recovery phenomenon. In that respect, the Commission's decision to ask the parties to confer on rate design alternatives was fruitful in narrowing the necessary scope of future consideration of possible remedies to the Company's earnings problems.

Q. What is RUCO's position on the merits of the current ten-year weather normalization for SWG as opposed to a weather decoupling mechanism?

A. RUCO believes that the ten-year (120 month) average of heating degree days, to represent normal weather conditions, utilized by SWG to calculate its weather normalization adjustment may well provide a truer picture of how weather impacts the Company. A number of states including Colorado, Connecticut, Indiana, Iowa, Maryland, New Hampshire, Ohio, Pennsylvania, Tennessee, and Virginia rely on a thirty-year average of heating degree days to represent normal weather conditions in the calculation of a weather normalization adjustment. Other states, such as Wisconsin, rely on a twenty-year average while Illinois (which typically relies on thirty-years) and Wyoming have had some experience with a ten-year average.

Q. Does RUCO believe that it is the stockholders responsibility to bear the weather risk as opposed to ratepayers?

A. Yes. Weather is certainly one of the risks that are associated with investment in a local distribution company such as SWG. Informed

investors would have to recognize the fact that earnings could fluctuate as a result of changes in weather patterns. This type of risk would certainly be reflected in the price of the Company's stock and also in the returns that investors obtain in the form of dividends.

Q. What are the appropriate price signals that a conservation rate design should send to ratepayers?

A. RUCO believes that for the most part, and whenever practical, a conservation oriented rate design should clearly send a message to ratepayers that the more natural gas they use, the higher their bills will be. RUCO generally supports a rate design that clearly sends this type of price message to ratepayers. This is one of the topics that will be discussed in the last section of my testimony.

Q. What adjustments to SWG's return on equity is RUCO advocating in the event of Commission approval of any mechanism that would shift shareholder risk to ratepayers?

A. RUCO believes that the approval of any mechanism that would shift shareholder risk to ratepayers, such as the RDAP and WNAP mechanisms being proposed by SWG in this proceeding, would certainly merit a downward adjustment to any recommended return on common equity. The reason for this is simple: once a decoupling mechanism is put into place, the risks associated with operating income volatility will shift

from SWG's investors to their ratepayers. That being the case, investors should not be entitled to a higher return on investment that reflects the possibility of less than stable earnings due to customer conservation, weather fluctuations or any other reasons.

Q. So RUCO is definitely opposed to the implementation of the Company-proposed WNAP?

A. Yes. For the reasons discussed above, RUCO is opposed to the implementation of the WNAP. RUCO further believes, as it did in SWG's prior rate case that a better method of addressing the Company's under-earning problem is through RUCO's recommended changes to rate design that will be discussed in the next section of my testimony.

SHIFT RESIDENTIAL REVENUE RECOVERY FROM VARIABLE TO FIXED RATES

Q. Briefly summarize the rate design changes that RUCO is recommending in this proceeding.

A. RUCO is recommending a rate design that slightly shifts residential revenue recovery from variable to fixed rates. The recommended changes from the Company's current rate design are consistent with the recommendations that RUCO advocated in the prior SWG rate case proceeding. RUCO's recommended rate design essentially mirrors the Company-proposed rate design with the exception of the percentages of

total revenues that are being generated by the fixed monthly basic service charge ("BSC"). RUCO believes that its recommended rate design is a better alternative to the Company-proposed decoupling mechanisms discussed earlier.

Q. What are the salient features of RUCO's recommended rate design?

A. RUCO's recommended rate design embodies the following four salient features:

1) Provides a positive move to mitigate the Company's risk of not recovering its authorized revenue requirement by placing more cost recovery into basic customer charge;
2) Is consistent with the Company's Cost of Service Study parameters;
3) Eliminates the two-tier volumetric rates to send appropriate price signals regarding gas consumption; and
4) Resets the beginning PGA to zero, by shifting all existing gas costs to base rates.

Q. Please describe RUCO's first fundamental change to SWG's existing rate structure.

A. In order to provide a more positive move to mitigate the Company's risk of not recovering its authorized revenue requirement, RUCO's recommended rate design places more cost recovery into the fixed monthly BSC. In

short, RUCO has reallocated some of the revenue that the Company currently recovers from its commodity charges to the fixed monthly BSC.

Q. Please explain how this reallocation was accomplished.

A. Currently, 39.61 percent of the residential class' revenue is generated from the monthly BSC. RUCO's recommended rate structure will generate 42.50 percent of the fixed residential revenue through the monthly BSC. RUCO also made minor changes to the monthly BSC's of SWG's other rate classes. For the most part, RUCO's adjustments to the monthly BSC's for the Company's various rate classes also have the effect of decreasing the percentage of revenue to be recovered through the respective commodity charges for those rate classes.

Q. Why are you recommending a shift in revenue recovery from the commodity rate to the fixed monthly BSC?

A. As discussed earlier, RUCO opposes the Company-proposed RDAP and WNAP decoupling mechanisms. However, this is not to say that the issues and concerns the Company cites for wanting these decoupling mechanisms do not have some validity. As RUCO stated in SWG's prior rate case proceeding, these concerns include the continued decline in average customer consumption, the relative proportion between SWG's fixed and variable costs to the Company's existing fixed and variable rates, and the resultant strain that puts on SWG's opportunity to recover

its authorized rate of return. RUCO's recommended incremental shift in revenue recovery from variable rates (i.e. commodity) to fixed rates (i.e. the monthly BSC) is designed to move the current rate structure to more accurately mirror the fixed vs. variable nature of the Company's cost of service. This shift will afford SWG with a better opportunity to recover its costs, even if average customer consumption declines. RUCO's recommended rate structure also more fairly addresses the Company's fixed vs. variable rate concerns because it applies the remedy to all of the Company's customers, whereas SWG's proposed decoupling mechanisms would hold residential customers largely responsible for the entire remedy.

Q. Please describe RUCO's second fundamental recommended change in the Company's rate structure.

A. RUCO's recommended rate design is consistent with the Company's Cost of Service Study parameters. As stated earlier, the rate structure that RUCO is recommending essentially mirrors the Company-proposed rate design with the exception of the percentages of total revenue that are being generated by the fixed monthly BSC. Thus, RUCO's recommended rate design largely adheres to the rate design which resulted from the Company's cost of service study.

Q. Is RUCO also recommending that there be no differential between summer and winter rates?

A. Yes. Since RUCO's recommended rate design includes a flat residential commodity rate across all therm usage, as does the Company's, there should be no distinction between summer and winter rates.

Q. Please describe RUCO's third fundamental recommended change in the Company's rate structure.

A. RUCO's recommended rate design eliminates two-tier volumetric rates to send appropriate price signals regarding gas consumption. Once again, RUCO is in agreement with SWG's proposed single commodity rate for each rate schedule. Thus, under RUCO's recommended rate structure each customer within each rate schedule will pay the same amount per therm regardless of the volume consumed.

Q. Why are you recommending a flat or one-tiered rate structure?

A. RUCO's recommended flat or one-tiered rate structure is consistent with its support for demand side management ("DSM") efforts. RUCO believes it would be counterproductive on the one hand to support increased spending to promote energy efficient usage, and at the same time recommend a rate structure that provides a discounted commodity rate to large users. RUCO further believes that the elimination of two-tier volumetric rates also sends an appropriate price signal to ratepayers.

Q. Wouldn't an inclining two-tiered rate structure also send a price message to customers to conserve?

A. It has to be remembered that one of RUCO's concerns in this case is to mitigate SWG's declining revenues through an increased BSC as opposed to a decoupling mechanism. RUCO views its recommendation as a trade-off. While it is true that an inclining two-tier rate structure would send a signal to customers to conserve, it is that very act of conservation that contributes to the declining revenue problem that RUCO is attempting to mitigate. Once again RUCO's position on an inclining two-tiered rate structure is consistent with its recommendations in the prior SWG proceeding. Admittedly, while an inclining two-tiered rate structure would send an even stronger energy efficiency price signal than a flat rate structure, the sole objective of an effective and fair rate design is not merely the promotion of energy efficiency. A rate structure that is based on the cost to serve the various rate classes can be the cornerstone of a fair and effective rate design. While cost of service is the starting point of a good rate design, it is sometimes warranted and even desirable to make small departures from pure cost of service rate structures in an effort to send price signals designed to elicit certain behaviors. A total departure from cost of service, however, is contrary to fundamental fairness and accepted rate design principles. As a gas distribution company, SWG's cost of service declines as usage increases. Thus, a recommendation to use an inclining tier rate structure in a declining commodity cost business

would depart too far from cost of service. At the same time, however, the current declining commodity rate structure is counterproductive to the energy efficiency goal of DSM programs. As stated earlier, RUCO's recommended flat rate structure adheres more closely to cost of service and at the same time does not send a price signal that discourages energy efficiency, as would continuation of the declining rate structure.

Q. Please discuss your fourth fundamental recommended change in the Company's rate structure.

A. Consistent with prior rate case proceedings, RUCO has reset the beginning purchased gas adjustor ("PGA") to zero. This allows for the existing purchased gas adjustor bank balance to be recovered in base rates on a going forward basis.

Q. Why should RUCO's recommended rate structure be approved?

A. RUCO's recommended rate structure was designed specifically to address some of Company's cost recovery problems, to send a price signal that will not discourage energy efficient gas usage, while at the same time protect ratepayers from extreme and abrupt changes in their monthly bill. I believe my recommended rate design addresses those objectives through adherence to basic rate design principles of cost of service, gradualism, and the appropriate price signals.

Q. Will your recommended rate design accomplish the three goals you identified earlier?

A. Yes, I believe it will. RUCO's recommended rates are fair and reasonable, are designed to encourage energy efficient usage, and afford the Company an opportunity to recover its authorized rate of return.

Q. Does that conclude your direct testimony?

A. Yes.

ATTACHMENT A

ORIGINAL

RESIDENTIAL UTILITY CON

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AZ CORP COMMISSION
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Janet Napolitano
Governor

Stephen Ahearn
Director

Arizona Corporation Commission
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July 26, 2007

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: RUCO's Report on Rate Design Alternatives to Encourage Conservation (Docket No. G-01551A-04-0876, Decision No. 68487)

Pursuant to Decision No. 68487, RUCO, ACC Staff, SWEEP and Southwest Gas met to "... seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders." (Decision, p. 34)

The first several meetings centered around Southwest Gas' presentations on decoupling mechanisms in general and with specific regard to SWG's perceived need for a decoupling mechanism. This included the following SWG arguments:

1) A history of declining usage;

2) Conservation and efficiency's role in declining usage;

3) Inability for SWG to earn its authorized rate of return;

4) Desirability of removing any disincentives for SWG to aggressively promote conservation.

Beginning with the third meeting, RUCO expressed its concern that SWG appeared to have reached a solution to a purported "problem", although the purported "problem" and its cause had not been conclusively identified. RUCO stated that it needed certain facts and data so the parties could establish what the problem really was and then seek a solution, rather than the other way around, and supplied the Company with a number of questions to answer.

Data responsive to RUCO's questions yielded a chart that demonstrated how much margin SWG had lost due to conservation and how much was lost due to weather over a three-year period. This chart showed that over the three-year period SWG had under-recovered by $22.5 million. Of this amount, $4.5 million, or approximately 20%, was due to conservation, and $18.1 million, or 80%, was attributable to weather (see Schedules on Attachment 1). The data was conclusive: the real cause for SWG's under-recoveries was not conservation, but weather. None of the actual participants in the meetings disagreed as to the meaning of the data.

The real problem having been identified, subsequent discussions shifted away from decoupling and began to focus on subjects actually germane to SWG's under-recovery problem. These discussions included the following topics:

1) The merits of the current 10-year weather normalization for SWG vs. a weather decoupling mechanism;

2) Debate on stockholders vs. ratepayers' responsibility to bear the weather risk;

3) The appropriate price signals that a conservation rate design should send;

4) Potential adjustments to Return on Equity in light of any mechanism that would shift shareholder risk to ratepayers.

No consensus was ultimately reached between the parties on these more relevant topics. However, the meetings proved useful in that the parties were able to identify weather as the true cause of SWG's inability to recover at approved levels, and that conservation efforts are of relatively little significance to the under-recovery phenomenon. In that respect, the Commission's decision to ask the parties to confer on rate design alternatives was fruitful in narrowing the necessary scope of future consideration of possible remedies to the Company's earnings problems.

RUCO is disappointed in the selective nature of the Company's "report" on this matter, and had supplied the Company with language that could have been used to more accurately reflect what actually transpired in the meetings, inclusion of which could possibly have earned our co-sponsorship of the report. That the Company did not accept our language and filed the report in the manner it did—replete with apologia for the very mechanism revealed through the meeting process to be inappropriate to the peculiar circumstances of this Company—has necessitated this more balanced and accurate retelling of the meeting process and its results.

In addition, the Southwest Gas report may have earned greater credibility in RUCO's estimation had it been written by someone from the Company who had actually attended the meetings.

Attached please find materials as counterpoint to the self-serving AGA attachment to the Company's "report," as follows:

- NASUCA's June 2007 Resolution opposing the sort of decoupling mechanism proposed by Southwest Gas in its most recent rate case (Attachment 2), and

- A slide presentation given by LSU's Center for Energy Studies to NASUCA members in June 2007 that covers the topic of incentives and energy efficiency more expansively than does AGA (Attachment 3).

It is my understanding that NASUCA President John Perkins presented this same information at NARUC's Summer Meeting last week.

Sincerely,

Stephen Ahearn
Director

SA:hs

attachments

cc: All Parties of Record

ATTACHMENT 1

SOUTHWEST GAS CORPORATION
ARIZONA STAKEHOLDER DECOUPLING WORK GROUP
RESPONSES TO RUCO'S QUESTIONS AT 3RD MEETING

Response 4 (Continued).

Data reflected in Responses 1 and 4 allow us to determine the impact on the recovery of Southwest's fixed cost of providing service of changes in actual use per customer (captures both weather and conservation), weather adjusted use per customer (captures conservation) and actual less conservation (captures weather) from amounts authorized in the last rate case. The calculations are reflected below for 2004, 2005 and 2006.

	Change From Revenue at Authorized Margin per Customer		
Description	Total	Conservation-Related	Weather-Related
(a)	(d)	(f)	(h)
2004			
Change in Average Use per Customer	11.7	(4.3)	16.0
Average Commodity Margin	$ 0.52579	$ 0.52579	$ 0.52579
Change in Margin per Customer	$ 6.15	$ (2.26)	$ 8.41
Average Number of Customers	785,673	785,673	785,673
Change in Annual Margin	$ 4,833,258	$ (1,776,326)	$ 6,609,584
Change in Fixed Component of Margin	**$ 4,587,102**	**$ (1,685,858)**	**$ 6,272,961**
Change in Variable Component of Margin	$ 246,156	$ (90,468)	$ 336,623
2005			
Change in Average Use per Customer	(26.3)	(1.8)	(24.5)
Average Commodity Margin	$ 0.52579	$ 0.52579	$ 0.52579
Change in Margin per Customer	$ (13.83)	$ (0.95)	$ (12.88)
Average Number of Customers	825,650	825,650	825,650
Change in Annual Margin	$ (11,417,317)	$ (781,413)	$ (10,635,904)
Change in Fixed Component of Margin	**$ (10,835,838)**	**$ (741,616)**	**$ (10,094,221)**
Change in Variable Component of Margin	$ (581,479)	$ (39,797)	$ (541,682)
2006			
Change in Average Use per Customer	(37.8)	(4.7)	(33.1)
Average Commodity Margin	$ 0.52579	$ 0.52579	$ 0.52579
Change in Margin per Customer	$ (19.87)	$ (2.47)	$ (17.40)
Average Number of Customers	864,201	864,201	864,201
Change in Annual Margin	$ (17,175,876)	$ (2,135,625)	$ (15,040,251)
Change in Fixed Component of Margin	**$ (16,301,115)**	**$ (2,026,858)**	**$ (14,274,257)**
Change in Variable Component of Margin	$ (874,760)	$ (108,767)	$ (765,994)
Three-Year Impact on Fixed Cost Recovery	**$ (22,549,850)**	**$ (4,454,333)**	**$ (18,095,518)**

SOUTHWEST GAS CORPORATION
ARIZONA STAKEHOLDER DECOUPLING WORK GROUP
RESPONSES TO RUCO'S QUESTIONS AT 3RD MEETING

Question 1.
For the last three years, provide weather adjusted and actual average use per residential customer data so we can see both the conservation and weather impacts on usage.

Response 1.
See table below for residential customer average usage and dollar impacts.

Description	2004	2005	2006
Average Usage			
Actual	358.7	320.7	309.2
Weather Adjusted	342.7	345.2	342.3
Last GRC	347.0	347.0	347.0
Difference From Last GRC			
Actual/Weather and Conservation-Related	11.7	(26.3)	(37.8)
Weather Adjusted/Conservation-Related	(4.3)	(1.8)	(4.7)
Weather-Related	16.0	(24.5)	(33.1)
Average No. of Customers	785,673	825,650	864,201
Average Commodity Rate	$ 0.52579	$ 0.52579	$ 0.52579
Dollar Impact of Change in Average Use			
Actual	$ 4,833,258	$(11,417,317)	$(17,175,876)
Conservation-Related	$ (1,776,326)	$ (781,413)	$ (2,135,625)
Weather-Related	$ 6,609,584	$(10,635,904)	$(15,040,251)

Question 2.
Over the same period, provide average use for newly installed customers versus vintage customers.

Response 2.
See table below. Results are based on weather-adjusted data for 12-months ending December 2006, and includes data for all customers installed prior to 2002 (vintage customers) and for customers installed in 2002, 2003 and 2004.

	Vintage	2002	2003	2004
Weather-Adjusted Average Use	343.4	339.2	334.5	334.0
Change From Vintage		(4.2)	(8.9)	(9.4)

ATTACHMENT 2

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES
RESOLUTION 2007-01

NASUCA ENERGY CONSERVATION AND DECOUPLING RESOLUTION

Whereas, the provision and promotion of energy efficiency measures are increasingly viewed by state commissions as a necessary component of utility service;

Whereas, many states are now encouraging rate-regulated utilities to adopt energy efficiency programs and other demand-side measures to decrease the number of units of energy each utility's customers purchase from the utility;

Whereas NASUCA has long supported the adoption of effective energy efficiency programs;

Whereas recent proposals by rate-regulated public utilities for the initiation or expansion of energy efficiency measures have featured utility rate incentives or revenue "decoupling" mechanisms that guarantee utilities a predetermined amount of revenues regardless of the number of units of energy sold;

Whereas, the utilities proposing decoupling measures seek guarantees from public utilities commissions that they will receive their allowed level of revenues;

Whereas, these utilities justify this departure from traditional rate-making principles on the theory they are being asked to help their customers purchase fewer energy units from them by promoting energy efficiency measures and other demand-side measures, thereby reducing their revenues and, consequently, their returns to their shareholders, and that decoupling mechanisms compensate utilities for revenues lost due to conservation;

Whereas, these utilities contend that because these measures reduce their revenues, they have a disincentive to encourage programs that aid their customers in purchasing fewer units of energy;

Whereas, historically, rates have been set in periodic rate cases by matching test-year revenues with test-year expenses, adding pro forma adjustments and allowing the utilities an opportunity to earn a reasonable rate of return on their investments in exchange for a state-protected monopoly;

Whereas revenue guarantee mechanisms allow rate adjustments to occur based upon one element that affects a utility's revenue requirement, without supervision or review of other factors that may offset the need for such a rate change;

Whereas, historically, rate-regulated utilities were not guaranteed they would earn the allowed return; rather, earnings depended on capable management operating the utilities in an efficient manner;

Whereas, many utilities proposing revenue decoupling request compensation for revenue lost per customer, implying that sales volumes are declining, when in fact these utilities' total energy sales revenues are stable or increasing;

Whereas, there are a number of factors that may cause a utility to sell fewer units of energy over a period of time, including weather, changing economic conditions, shifts in population, loss of large customers and switches to other types of energy, as well as energy efficiency and other demand-side measures;

Whereas many utilities have been offering cost-effective energy efficiency programs and actively marketing these programs for years without proposing or implementing rate incentives or revenue guarantee mechanisms such as decoupling, and have continued to enjoy financial health;

Whereas past experience has shown that revenue guarantee mechanisms such as decoupling may result in significant rate increases to customers;

Whereas some utilities have referenced the benefit of encouraging energy efficiency programs as a justification for revenue guarantee mechanisms without in fact offering any energy efficiency programs, indicating that the revenue guarantee mechanisms are attractive to utilities for reasons other than their interest in promoting energy conservation;

Whereas past experience has shown that rate increases prompted by revenue guarantee mechanisms such as decoupling are often driven not so much by reduced consumption caused by utility energy efficiency programs, as by reduced consumption due to normal business risks such as changes in weather, price sensitivity, or changes in the state of the economy;

Whereas utilities are better situated than are consumers or state regulators to anticipate, plan for, and respond to changes in revenue prompted by normal business risks, and the shifting of normal business risks away from utilities insulates them from business changes and reduces their incentive to operate efficiently and effectively;

Whereas the traditional ratemaking process has historically compensated utilities for experiencing revenue variations associated with normal business risks;

NOW THEREFORE NASUCA RESOLVES:

To continue its long tradition of support for the adoption of effective energy efficiency programs;

And to oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases;

BE IT FURTHER RESOLVED:

NASUCA urges Public Utilities Commissions to disallow revenue true-ups between rate cases that violate the matching principle, the prohibition against retroactive ratemaking, the prohibition against single-issue ratemaking, or that diminish the incentives to control costs that would otherwise apply between rate cases;

NASUCA urges State legislatures and Public Utilities Commissions to, prior to using decoupling as a means to blunt utility opposition to energy efficiency and other demand-side measures, (1) consider alternative measures that more efficiently promote energy efficiency and other demand side measures; (2) evaluate whether a utility proposing the adoption of a revenue decoupling mechanism has demonstrated a commitment to energy efficiency programs in the recent past; and (3) examine whether a utility proposing the adoption of a revenue decoupling mechanism has a history of prudently and reasonably utilizing alternative ratemaking tools;

If decoupling is allowed by any state commission, NASUCA recommends that the mechanism be structured to (1) prevent over-earning and provide a significant downward adjustment to the utilities' ROE in recognition of the significant reduction in risk associated with the use of a decoupling mechanism, (2) ensure the utility engages in incremental conservation efforts, such as including conservation targets and reduced or withheld recovery should the utility fail to meet those targets, and (3) require utilities to demonstrate that the reduced usage reflected in monthly revenue decoupling adjustments are specifically linked to the utility's promotion of energy efficiency programs.

NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:
Denver, Colorado

June 12, 2007

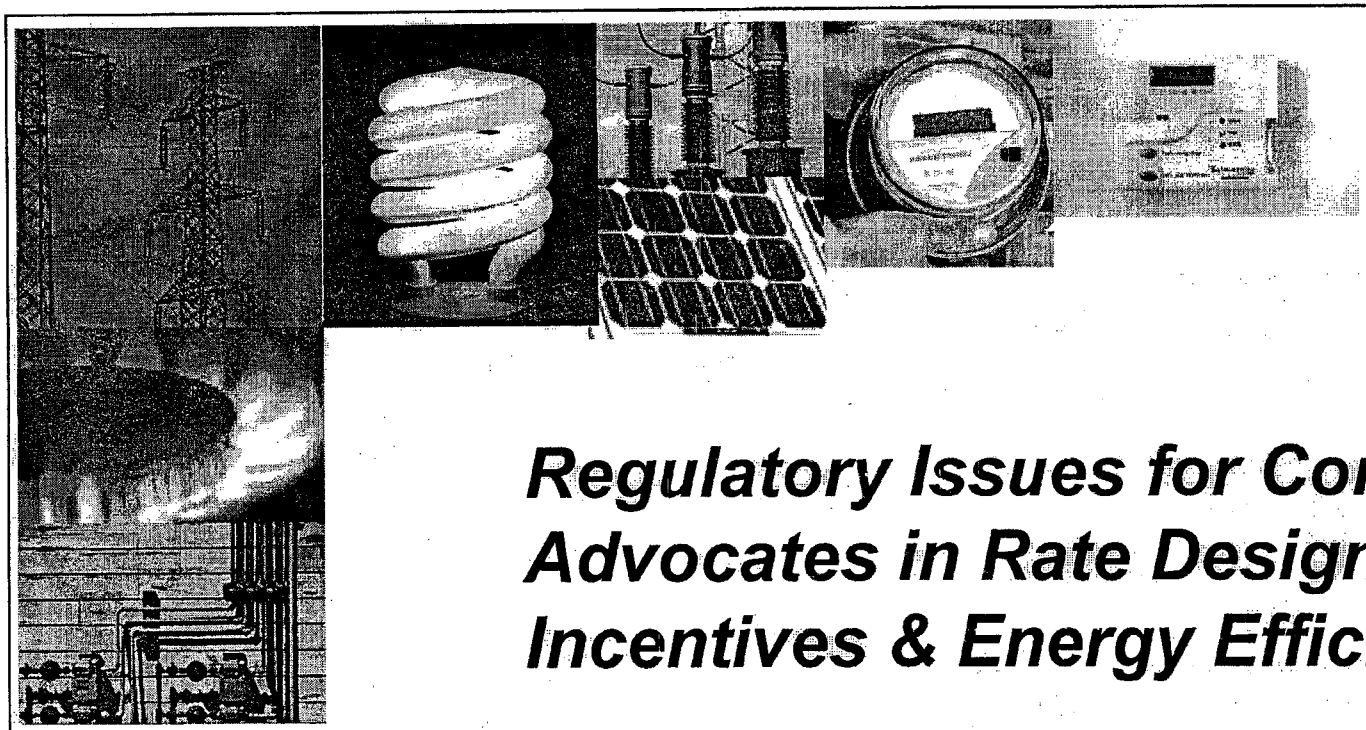
Submitted by:
NASUCA Consumer Protection Committee

June 11, 2007

Opposed:
Ohio
Indiana
Colorado
Wyoming

Abstained:
Massachusetts
California

ATTACHMENT 3



Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency

David E. Dismukes, Ph.D.
Professor & Associate Executive Director
Center for Energy Studies
Louisiana State University

National Association of State Utility Consumer Advocates (NASUCA)
Mid-Year Meeting
June 11, 2007

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Arguments In Favor of Revenue Neutrality

- Aligns utility incentives with energy efficiency.
- Assists utility in earning its authorized rate of return that is challenged by the decreasing use per customer problem (gas).
- Easier for customers to understand and reduces bill volatility.
- Reduces regulatory costs and the need for frequent rate cases.

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Common Types of Revenue Neutrality Programs

- Straight-Fixed Variable Rate Design: eliminates all variable distribution charges and DNG costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone (gas LDCs).

- Sales-Revenue Decoupling: separates revenue recovery from sales (sets annual revenues to a "per-customer" target.) Can be done on a full or partial basis.

- Sales-Margin Decoupling: separates margin recovery from sales (sets margin per customer target). Can also be done on a full or partial basis.

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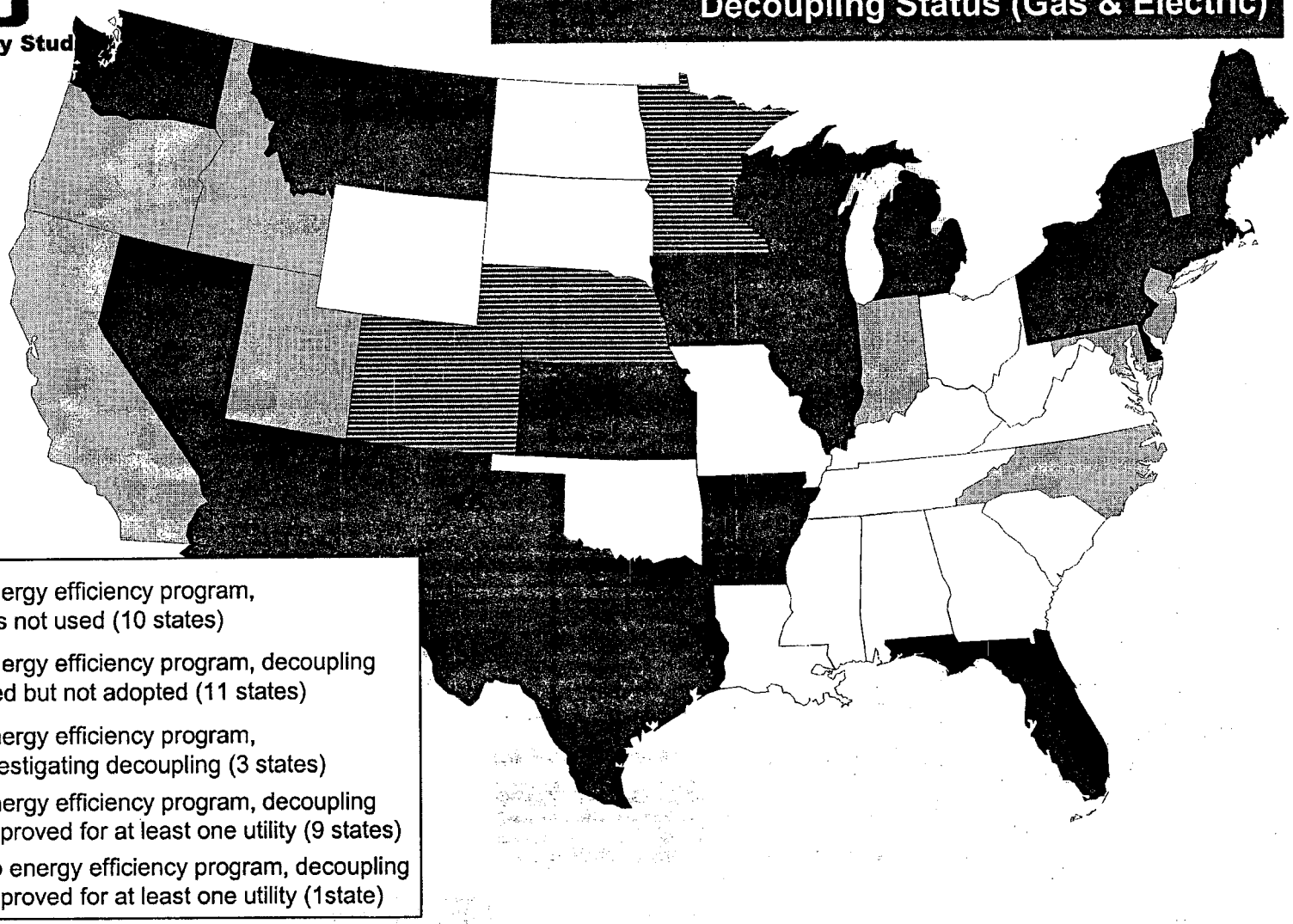
States with Energy Efficiency Programs – Decoupling Status (Gas & Electric)



- State has energy efficiency program, decoupling is not used (10 states)
- State has energy efficiency program, decoupling was proposed but not adopted (11 states)
- State has energy efficiency program, currently investigating decoupling (3 states)
- State has energy efficiency program, decoupling has been approved for at least one utility (9 states)
- State has no energy efficiency program, decoupling has been approved for at least one utility (1state)

Note: In Connecticut, the electric utilities do not have decoupling, but two natural gas LDCs have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers (a conservation adjustment mechanism). Washington has utilities with decoupling, but rejected the most recent utility proposal (January 2007). In Michigan, revenue decoupling was proposed by the Michigan Staff but opposed by the Michigan AG. The MPSC approved a stipulation that excluded revenue decoupling . In Kansas, revenue decoupling was proposed by Aquila. The parties involved agreed to a stipulation that excluded revenue decoupling while the Commission investigates it further in a general docket.

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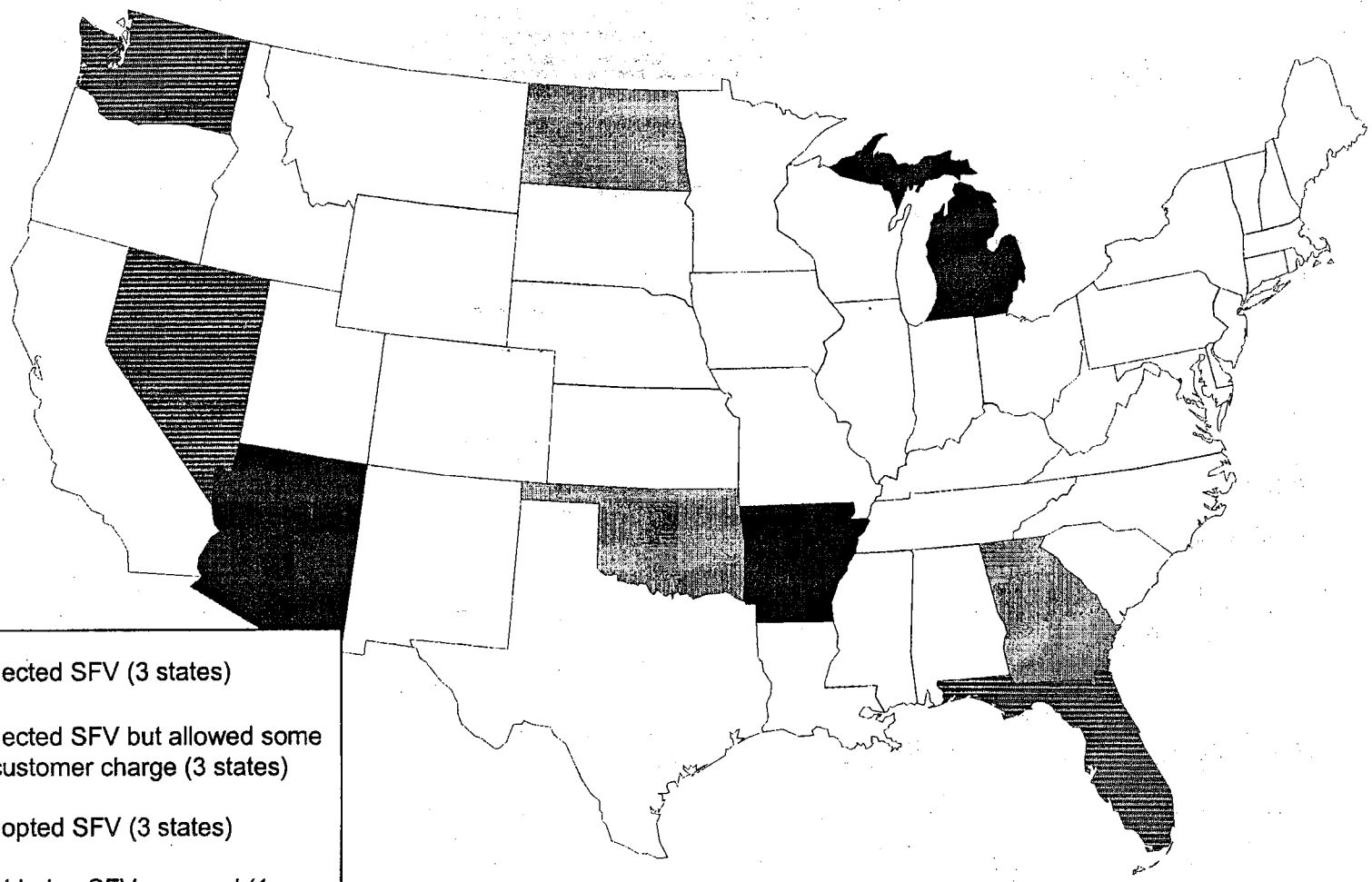
States that have Considered SFV



- State has rejected SFV (3 states)
- State has rejected SFV but allowed some increase in customer charge (3 states)
- State has adopted SFV (3 states)
- State is considering SFV proposal (1 state)

Note: In Michigan, SFV was proposed by SEMCO Energy but opposed by the Michigan AG. The MPSC approved a stipulation that excluded SFV .

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Common Reasons for Rejecting Revenue Neutrality

- Represents a significant departure from traditional regulation.
- Shifts sales risks from utilities to customers.
- The impact of changes in use per customer for the gas industry are overstated and address the wrong causes on changes in margins. Power industry faces an entirely different set of usage trends.
- At best, the incentive issue is not resolved and never can be with revenue decoupling.
- Current proposals, offered in conjunction with other "regulatory remedies" diminishes the simplicity argument and raises questions about the purpose of proposal.
- Proportionality issue – changing the rate design for all customers based upon programs for which an exceptionally small percentage of the customers will participate.
- Is actually contrary to "sound economic principles" and well-grounded regulatory policies.

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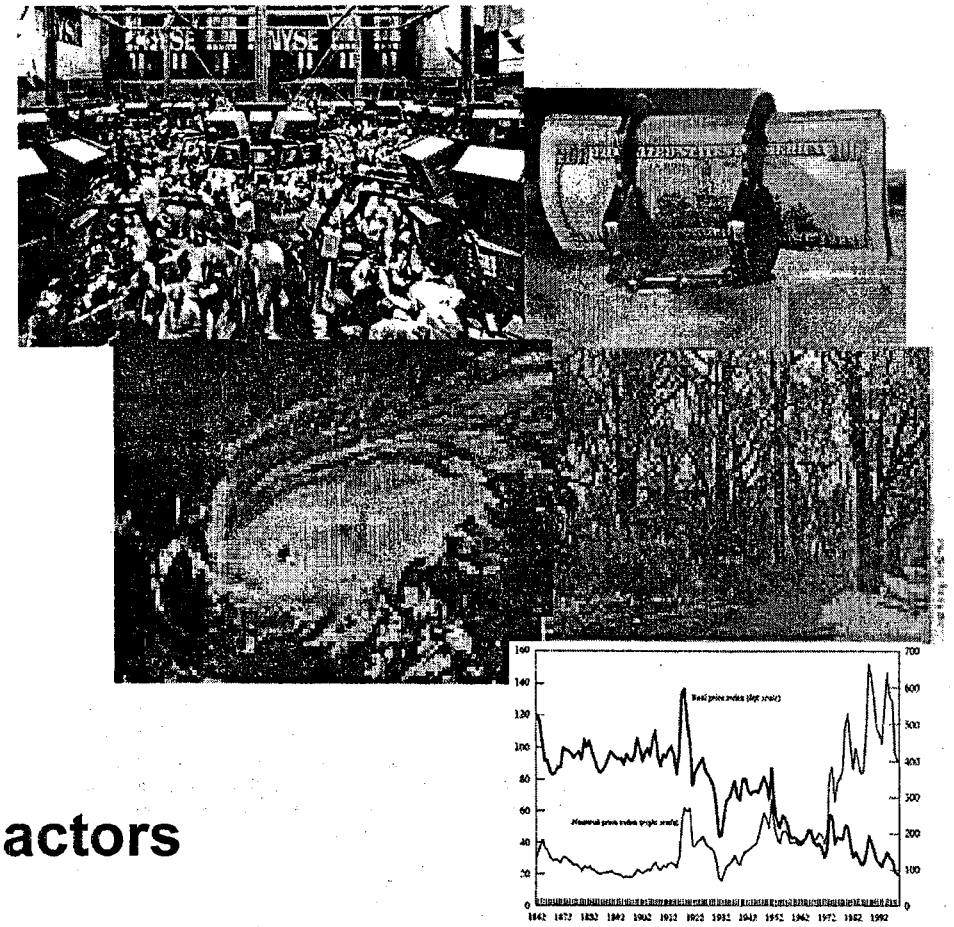
Risks that are Shifted to Ratepayers

Economy

Weather

Commodity Prices

Other Unanticipated Factors



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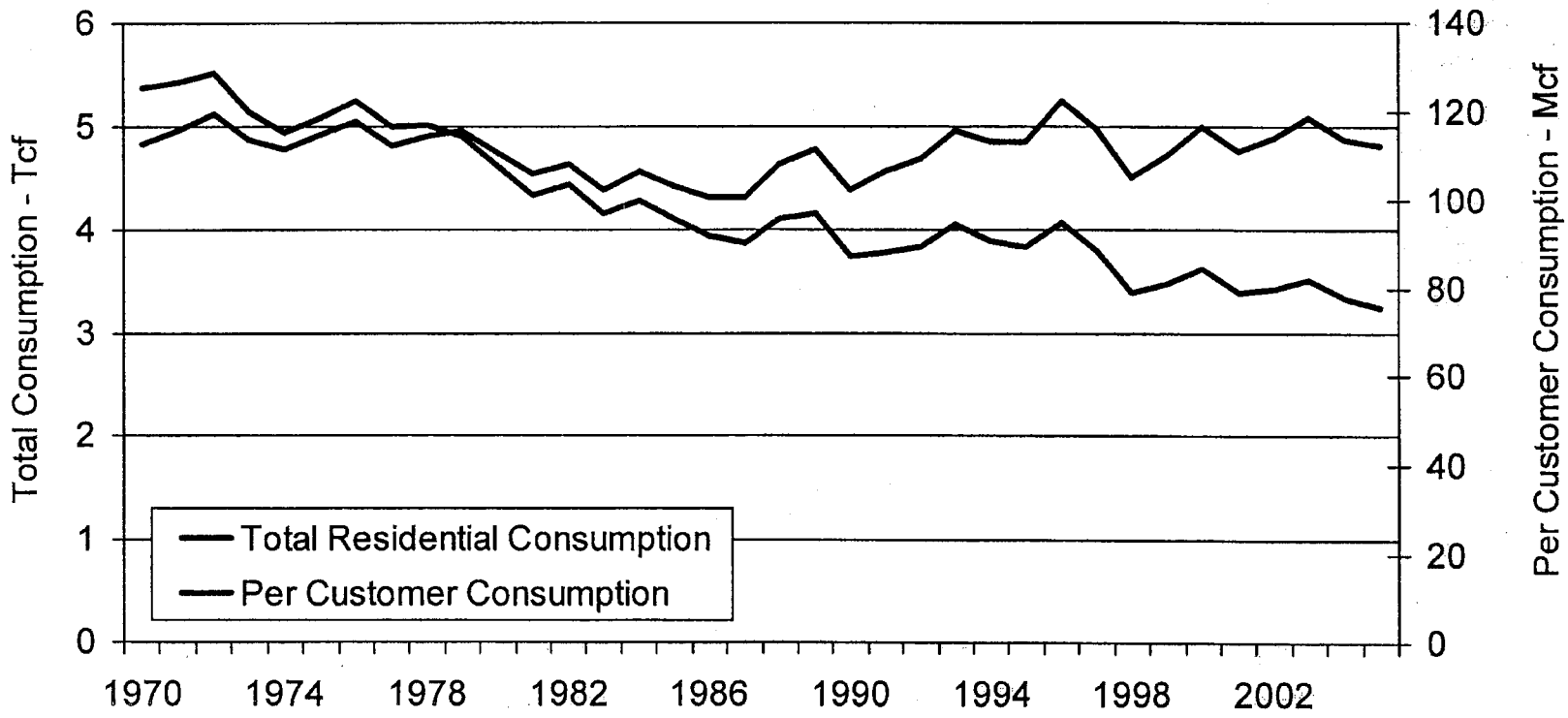
US Residential Natural Gas Use

While overall use per customer is decreasing, overall residential natural gas usage is flat to increasing.



Source: Energy Information Administration, US Department of Energy

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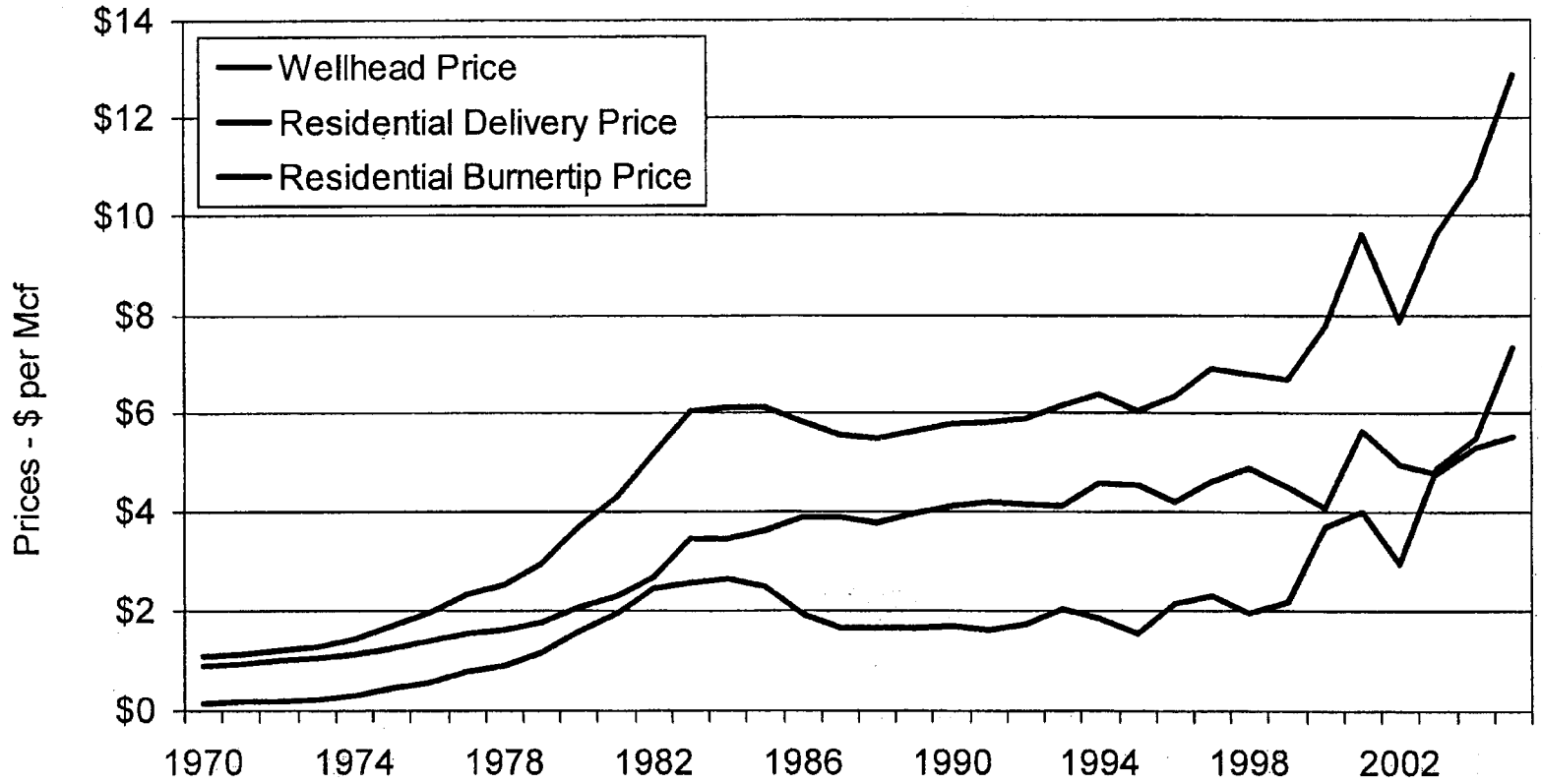
US Natural Gas Price Trends
Wellhead to Burner-Tip Price

Retail prices have increased significantly since 2000-2001.



Source: Energy Information Administration, US Department of Energy

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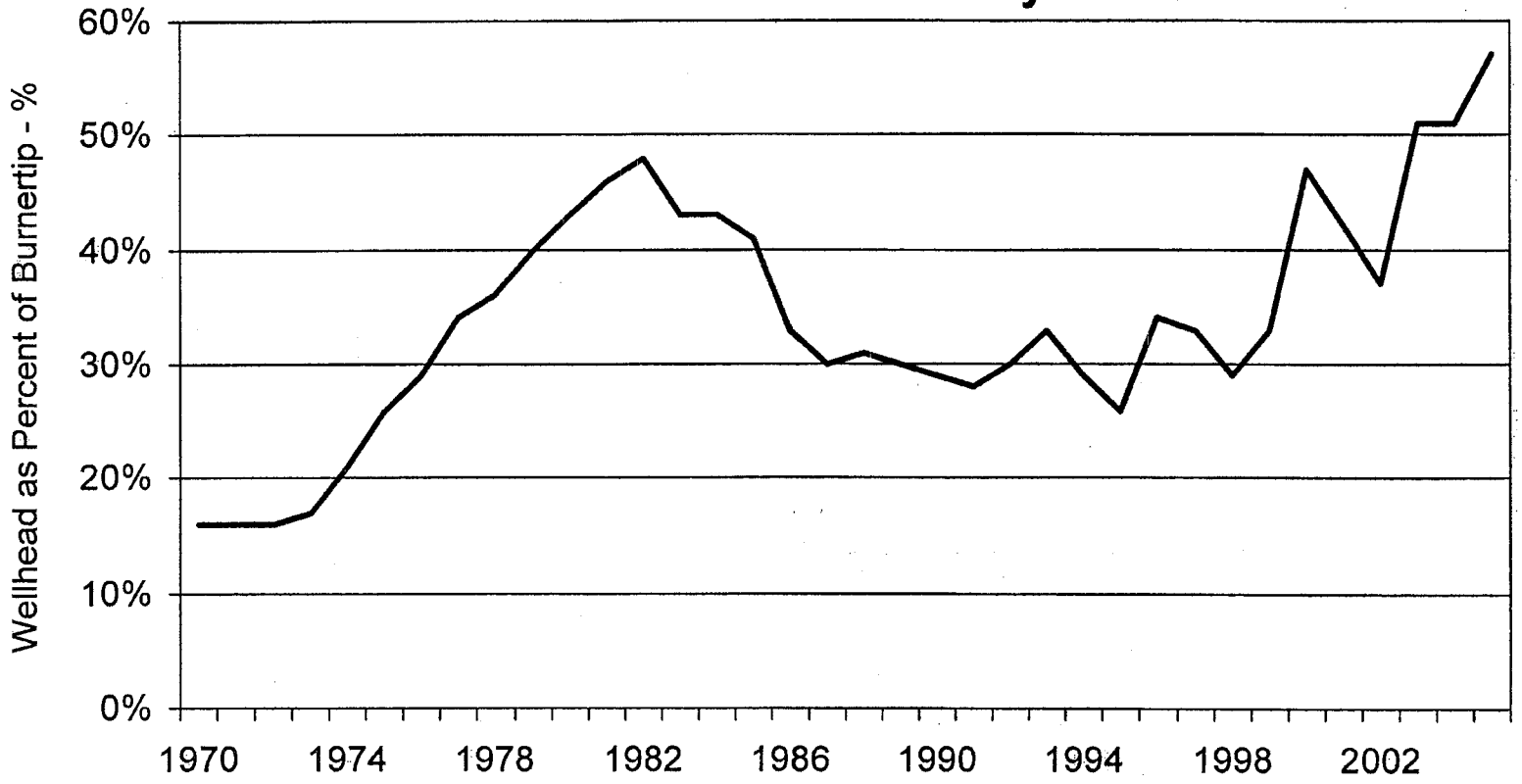
US Natural Gas Price Trends
Wellhead as a Percent of Burner-Tip Price

The commodity share of overall natural gas rate has increased over recent years.



Source: Energy Information Administration, US Department of Energy

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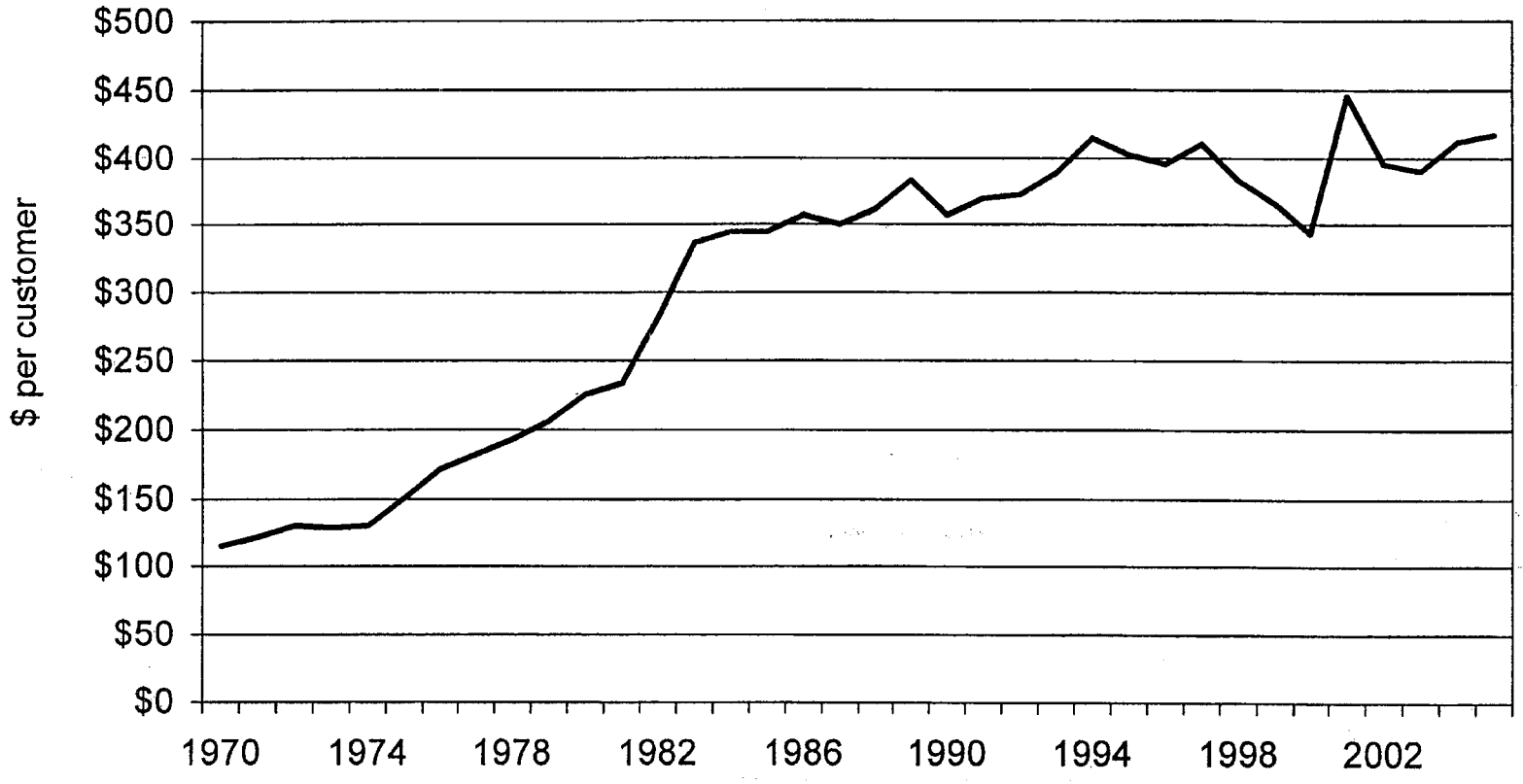
DNG Revenue per Customer

Yet despite high prices, and decreases in use per customer, overall DNG revenues per customer are at close to historic highs.



Source: Energy Information Administration, US Department of Energy

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Summary Financial Impact of Changes in Use and Customers, "Wild West Utility" (2001-2005)

Wild West LDC is facing significant growth challenges – ROE impacts of decreases in use per customer pale in comparison to change in rate base and new customer capital expenses.

	2001	2002	2003	2004	2005	2006
Return on Equity						
Allowed ROE	11.00%	11.00%	11.20%	11.20%	11.20%	11.20%
ROE Impact of Change in Use per Customer	0.00%	-0.60%	1.99%	-0.41%	-0.87%	-0.41%
ROE Impact Change in Customers	0.00%	1.04%	1.66%	1.17%	1.51%	1.51%
ROE Impact Change in Expenses Rate Base and Capital Elements	**-0.54%**	**-2.38%**	**-3.76%**	**-1.92%**	**-1.16%**	**-2.08%**
Actual Achieved ROE	10.46%	9.06%	11.09%	10.05%	10.68%	10.22%

Is decoupling a solution to the "use per customer problem" or an "end-run" on a rate case?

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Proportionality Issue

Significant change in rate design for a very small change in overall sales and very limited number of customers.

	Program Spending (million $)	Percent of Retail Revenues (%)	Gas Savings (Mcf/year)	Percent of Gas Sales Saved (%)	Volume saved per million $ (Mcf/year)	Benefit-Cost Ratio
Aquila	$ 2.10	1.4%	146,000	0.5%	69,000	-
Centerpoint	$ 5.60	0.5%	720,000	0.5%	128,600	2.60
Keyspan	$ 12.00	1.0%	490,000	0.4%	41,000	3.00
Northwest Natural Gas	$ 4.70	0.7%	85,000	0.1%	18,000	-
NSTAR	$ 3.90	0.8%	71,500	0.2%	18,000	2.29
PG&E	$ 13.50	0.4%	2,000,000	0.7%	148,000	2.10
PSE	$ 3.80	0.4%	311,000	0.5%	82,275	1.93
SoCal Gas	$ 21.00	0.6%	1,100,000	0.3%	52,000	2.67
Vermont Gas	$ 1.10	1.6%	57,000	1.0%	52,000	5.60
Xcel Energy (MN)	$ 4.00	0.7%	663,000	0.9%	166,000	1.56

Generally, less than one-half of one percent.

Source: S. Tegen and H. Geller, Natural Gas Demand-Side Management Programs: A National Survey. Boulder, CO: Southwest Energy Efficiency Project. January 2006. Based upon surveyed findings of the top ten gas utilities in 2004.

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Incremental Impact of DSM Implementation on Shareholders, Wild West Utility

	Change in Revenue			Income Impact				
	Use per Customer	DSM	New Customers	Use per Customer	DSM	New Customers	Shareholders Equity	Impact on ROE
2007	$ (1,971,361)	$ (288,537)	$ 7,052,203	$ (1,221,185)	$ (178,738)	$ 4,368,579	$ 313,071,056	0.95%
2008	$ (2,905,519)	$ (608,826)	$ 6,391,367	$ (1,799,862)	$ (377,145)	$ 3,959,215	$ 339,501,229	0.52%
2009	$ (4,485,340)	$ (943,652)	$ 6,213,829	$ (2,778,502)	$ (584,557)	$ 3,849,237	$ 363,965,179	0.13%
Total	**$ (9,362,220)**	**$ (1,841,015)**	**$ 19,657,399**	**$ (5,799,549)**	**$ (1,140,440)**	**$ 12,177,031**		**1.61%**
							Net Impact:	**$ 5,237,041.80**

Exaggerated Example

- Reduced revenues/income reduces overall taxes and needs to be considered.
- A one percent per year (3 percent cumulative) reduction is beyond current experience.
- The additional income created by customer growth from the test year is completely ignored (and its corresponding income effects).
- Net impact for a growing LDC is moderate – the net income impact is still positive, not negative.

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Decoupling Creates a Number of New Incentive Issues

- Reduces customers' ability to have full control of their energy savings. Reduces, in part, incentive to conserve particularly with SFV.
- If successful in reducing sales incentive, then also reduces incentive to measure sales losses and savings. You have "decoupled" DSM performance to any form of measurement.
- If successful in reducing sales incentive, then reduces incentive to promote efficient natural gas use and economic development.
- Revenues more difficult to estimate than costs, creating revenue certainty reduces incentive to push cost efficiency.

George A. Schreiber, Jr., SEMCO Company President and Chief Executive Officer, said, "I am very pleased with the Company's results for 2006. We achieved these results, despite warmer-than-normal temperatures and continued customer conservation, which, when combined, adversely impacted 2006 earnings by an estimated $3.5 million." Schreiber added, ***"One way we overcame the impact of the weather and customer conservation was to keep spending under control."***

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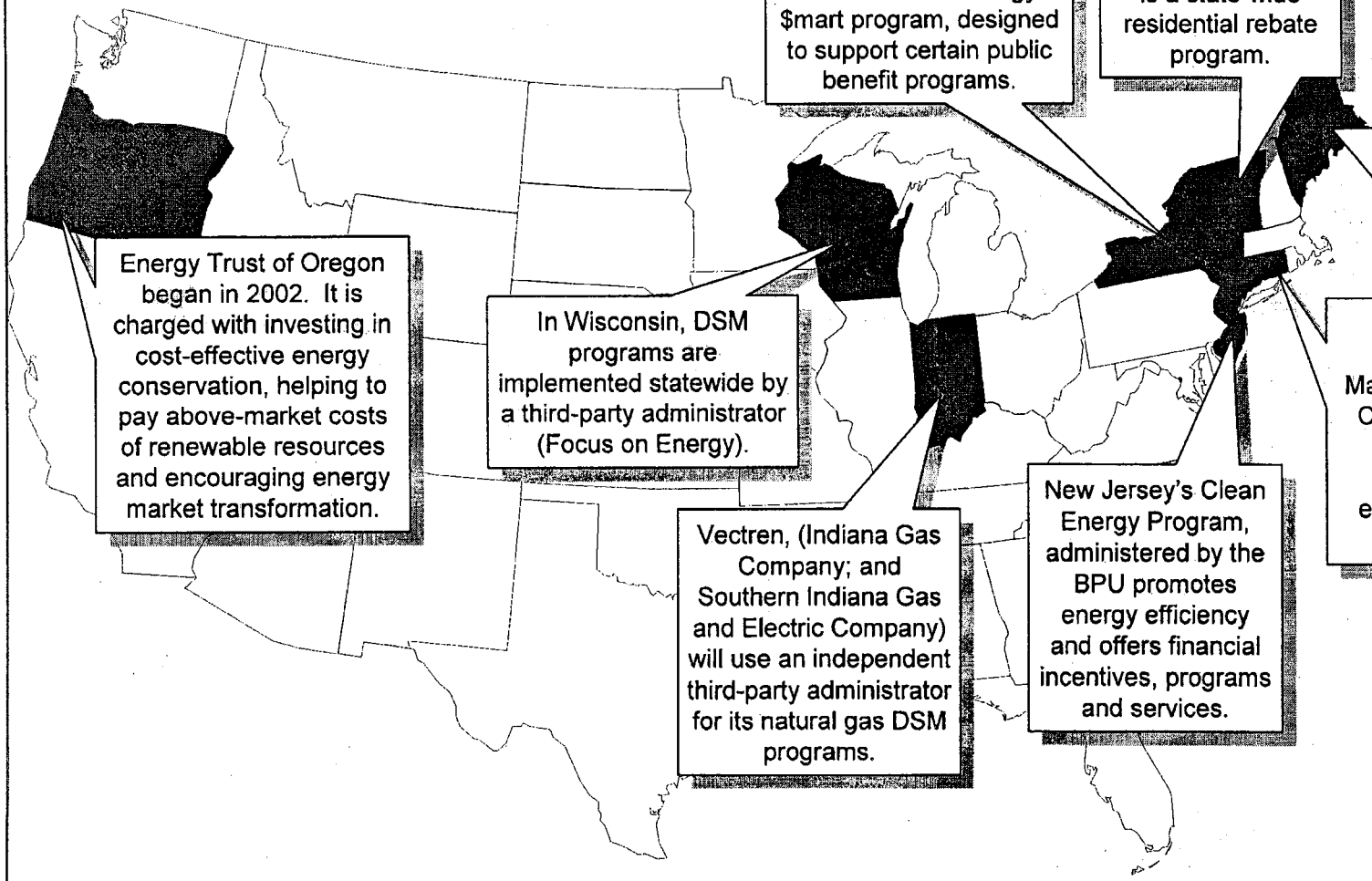
States with Third-Party Administrators



NYSERDA administers the New York Energy $mart program, designed to support certain public benefit programs.

Efficiency Vermont is a state-wide residential rebate program.

The Maine PUC may use a third-party administrator for electric DSM, but to date has administered these in house.

Energy Trust of Oregon began in 2002. It is charged with investing in cost-effective energy conservation, helping to pay above-market costs of renewable resources and encouraging energy market transformation.

In Wisconsin, DSM programs are implemented statewide by a third-party administrator (Focus on Energy).

The Energy Conservation Management Board in Connecticut has the responsibility to approve energy efficiency plans and budgets

Vectren, (Indiana Gas Company; and Southern Indiana Gas and Electric Company) will use an independent third-party administrator for its natural gas DSM programs.

New Jersey's Clean Energy Program, administered by the BPU promotes energy efficiency and offers financial incentives, programs and services.

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Revenue Neutrality Mechanisms Are Not the Only Options

- **Projected test years:** forecasts could account for anticipated energy efficiency savings.
- **Cost-effectiveness tests:** screening on RIM-passing measures only.
- **Lost Revenues (*ex post*):** periodic filings on proven, *ex post* lost revenues/sales.
- **Rate design (inclining blocks):** higher rates in upper blocks.
- **Repression adjustments:** usage adjustment to correct of DSM-related reductions in usage.
- **Direct Incentives:** performance-based incentives for programs.
- **Risk Management:** if volatility is an issue, then manage it.
- **More frequent rate cases:** traditional approach at correcting rates that get out of balance.

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Questions, Comments, & Discussion

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EXHIBIT
RUCO-9
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 27, 2008

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INTRODUCTION

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

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on March 28, 2008, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in SWG's application requesting a permanent rate increase based on a test year ended April 30, 2007, and presented RUCO's recommended hypothetical capital structure in addition to RUCO's recommended returns on debt and equity. On April 11, 2008, I also filed direct testimony on RUCO's policy considerations that shaped RUCO's recommended rate design.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to respond to SWG's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt, cost of preferred equity and cost of common equity) for the Company's natural gas distribution operations in Arizona.

...

Q. Will you also be filing surrebuttal testimony on rate design issues?

A. No. RUCO's Chief of Accounting and Rates, Marylee Diaz Cortez, CPA will adopt my prior direct testimony and provide surrebuttal testimony on the policy considerations associated with RUCO's recommended rate design.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of SWG's rebuttal testimony; a section on the capital structure and cost of debt issues associated with the case; and a section on the cost of equity capital issues associated with the case.

SUMMARY OF SOUTHWEST GAS' REBUTTAL TESTIMONY

Q. Have you reviewed the rebuttal testimony of Company witnesses Theodore K. Wood and Frank J. Hanley?

A. Yes. I have reviewed the rebuttal testimony, on cost of capital issues, filed by the aforementioned Company witnesses on May 9, 2008.

Q. Please summarize the testimony filed by Company witness Wood.

A. Mr. Wood's rebuttal testimony concentrates on the capital structures recommended by the Company, ACC Staff cost of capital consultant David C. Parcell, and RUCO. Mr. Wood also compares and comments on the overall rate of return recommendations being made by the Company,

ACC Staff and RUCO. Mr. Wood takes issue with the cost of common equity being recommended by Mr. Parcell and myself stating that our respective recommended costs of common equity of 10.00 percent and 9.88 percent are too low. He also comments on the overall weighed costs of capital that Mr. Parcell and myself have recommended.

Q. Please summarize the testimony filed by Company witness Hanley.

A. Mr. Hanley's rebuttal testimony focuses entirely on the cost of common equity recommendations of ACC Staff and RUCO. Mr. Hanley is critical of my reliance on the discounted cash flow ("DCF") model and the manner in which I arrived at my DCF growth estimates. This includes my reliance on the assumption that a utility's market to book ratio will move in the direction of 1.0 if regulators set a utility's rate of return at a level that is equal to the utility's cost of capital and my reliance on the sustainable growth concept that is expressed in the growth component of the DCF model. Mr. Hanley also takes issue with the inputs used in my capital asset pricing model ("CAPM") analyses and the use of a geometric mean in the calculation of the return on the market. Mr. Hanley further takes issues with the opinions I expressed on the ECAPM model which he relied upon in his cost of capital analysis. Mr. Hanley is also critical of the position that RUCO has taken in regard to the Company-proposed decoupling mechanisms (i.e. the RDAP, WNAP).

CAPITAL STRUCTURE AND WEIGHTED COST OF CAPITAL

Q. Have you made any changes to your recommended hypothetical capital structure, cost of debt, cost of preferred equity or cost of common equity?

A. No. I have not made any changes to the recommendations presented in my direct testimony.

Q. Briefly summarize the positions of the parties in the case in regard to capital structure, cost of debt, cost of preferred equity and cost of common equity.

A. Both RUCO and the Company are recommending identical hypothetical capital structures comprised of 51 percent long-term debt, 4 percent preferred equity and 45 percent common equity. RUCO and the Company are also in agreement on the Company-proposed 7.96 percent cost of debt and 8.20 percent cost of preferred equity.

ACC Staff consultant Parcell is recommending that the Commission adopt SWG's actual capital structure at the end of the test year which is comprised of 52.7 percent long-term debt, 4.4 percent preferred equity, and 42.9 percent common equity. Mr. Parcell is also in agreement with both RUCO and SWG in regard to his recommended costs of long-term debt and preferred equity.

The costs of common equity presently being recommended by the parties to the case are as follows:

SWG	11.25%
ACC Staff	10.00%
RUCO	9.88%

The weighted costs of capital presently recommended by the parties to the case are as follows:

SWG	9.45%
ACC Staff	8.86%
RUCO	8.83%

As can be seen above, there is presently a 62 basis point difference between the Company-proposed 9.45 percent weighted cost of capital and my recommended weighted cost of capital of 8.83 percent. RUCO and ACC Staff's recommended weighted costs of capital fall within 3 basis points of each other.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On April 30, 2008, the Fed cut interest rates for a seventh straight time. The reduction was a much smaller 25 basis point move as opposed to the 50 and 75 basis point cuts made earlier this year. As a result of the

Feds recent action, the federal funds rate now stands at 2.0 percent[1]. A list of the most recent yields of various financial instruments can be seen in Attachment A to my testimony.

Q. Please respond to Mr. Wood and Mr. Hanley's rebuttal positions that your recommended cost of equity is too low.

A. Given the fact that Mr. Parcell's and my cost of common equity estimates fall within 12 basis points of each other, I would have to say that just the opposite is true. As I stated in my direct testimony, Mr. Hanley's 11.25 percent recommendation (which I commented on in pages 52 through 59 of my direct testimony) ignored any results he obtained that were lower than 9.60 percent and therefore produced a higher estimate.

Q. Do you agree with Mr. Wood's position that your final recommended cost of equity for SWG should have been a midpoint figure that falls within your estimated range of 9.20 percent to 10.83 percent?

A. No, I do not. My final 9.88 percent recommended cost of equity for SWG was arrived at using the same calculation (i.e. a mean average of DCF and CAPM results) that ACC Staff has used in a number of rate case proceedings before the Commission. The Commission has consistently adopted ACC Staff's recommendations that were calculated in this manner. In addition, my recommended 9.88 percent cost of equity for

[1] Ip, Greg, "Fed Cuts Key Rate, Signals a Pause," The Wall Street Journal Online Edition, May 1, 2008.

SWG is 15 basis points higher than the 9.73 percent result derived from my DCF model (that relies on utility-specific data inputs), which I believe to be superior to the CAPM.

Q. Please address Mr. Wood's argument that you should have made an upward adjustment to your 9.88 percent cost of equity estimate based on SWG's credit rating in relation to the credit rating of your sample LDC's.

A. Mr. Wood disagrees with my position that the adoption of the Company-proposed capital structure provides SWG with adequate compensation for additional financial risk. Mr. Wood further believes that it is not enough to provide the Company with a level of equity that does not exist – a level of equity that also provides the Company with additional cash flow by way of a synchronized interest calculation (which produces a level of income tax expense that is higher than what the Company's actual level of deductible interest expense would produce) – and argues that an additional upward adjustment needs to be made.

Q. Does Mr. Wood's argument have any merit?

A. No. In addition to the additional cash flow that I noted above, the Company will realize additional operating income that it would not have realized under its actual capital structure. This does not include RUCO's recommended rate design changes, or other factors which I will discuss later, that also favor the Company. An upward adjustment to my

recommended cost of equity might well reduce the incentive for SWG to actually achieve a level of equity that would help raise the Company's current credit rating. Furthermore, the outlook for SWG is actually quite favorable despite the picture painted by Mr. Wood. This is evidenced from an April 24, 2008 Standard & Poor's credit rating report provided by the Company in its supplemental response to ACC Staff data request STF-2-7 (Attachment B).

On the subject of SWG's liquidity situation, the report states the following:

> Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses for liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.
>
> Given the low-risk nature of Southwest Gas' regulated utility operations and healthy service territory, the company should generate reasonably stable cash flow. The company reported cash from operations of almost $350 million for 2007, which will not fully cover annual dividends (about $36 million), annual capital expenditures (about $300 million forecast for 2008 and about $550 forecast for 2009-2010 combined), and near-term debt maturities ($38 million due in 2008 and $10 million in 2009). To bridge the funding gap, the company expects to raise $70 million to $80 million through stock offerings, borrow under its revolving credit facility, or through other external means.

The report goes on to present the following outlook (the second sentence of which Mr. Wood included in his testimony) for SWG:

> The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Rating Services' expectation that the company's improved financial performance could lead to a higher rating over the near-term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

Based on the information above, I believe that RUCO's recommendations, that provide additional and more stable revenue, will only further strengthen SWG's existing liquidity position.

Q. Do you agree with Mr. Wood's use of the Hamada adjustment to justify SWG's 25 basis point upward adjustment for financial risk, and to justify his arguement that RUCO's recommended 9.88 percent cost of equity is too low?

A. No. Although Mr. Wood employed the Hamada methodology presented by RUCO consultant Stephen G. Hill in his direct testimony in the Arizona Public Service Company ("APS") rate case proceeding[2] to arrive at changes in CAPM estimates (ranging from 63 to 107 basis points using a relevered beta of 0.97), he ignores the argument for lower market risk premiums of 4.0 percent to 6.0 percent that Mr. Hill presents in the "Hamada portion" of his APS testimony[3] (Attachment C). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two scholarly articles on the subject published over the past six years by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical market risk premiums (now published by Morningstar) have overstated investor expectations. Mr. Hill

[2] Docket No. E-01345A-05-0816 et al.

[3] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

also cites a paper authored by Carl Ibbotson himself which indicates that investors can expect future returns of 4.0 to 6.0 percent.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University in Washington D.C. on April 19 and 20, 2007, both Mr. Wood and myself had the opportunity to hear the views of Aswarth Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

...

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model with the 0.97 relevered beta calculated by Mr. Wood?

A. Using the 91-day T-bill rate of 1.65 percent (r_f) that I used in my analysis, Mr. Wood's relevered beta of 0.97, and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, in my CAPM model produces expected returns of 5.53 percent and 6.85 percent respectively. These results are much lower than the 9.20 percent and 10.93 percent estimates that I used to calculate my recommended 9.88 percent cost of equity.

For the sake of the arguments presented by Mr. Hanley on pages 27 through 29 of his rebuttal testimony, if the most recent 4.61 percent yield on a 30-year U.S. Treasury note (the same long-term Treasury instrument preferred by Mr. Hanley) were used in the CAPM model, the results would be as follows:

<u>Using a 4.0% Market Risk Premium</u>

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

$$k = 4.61\% + [\, 0.97\, (4.0\%)\,]$$

$$k = \underline{\underline{8.49\%}}$$

...

Using a 6.0% Market Risk Premium

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

$$k = 4.61\% + [\, 0.97\, (6.0\%)\,]$$

$$k = \underline{10.43\%}$$

As can be seen above, the range of CAPM estimates using a higher and more recent risk free yield (using Mr. Hanley's preferred financial instrument), the larger relevered beta coefficient (calculated by Mr. Wood using the Hamada methodology) and the 4.0 percent to 6.0 percent market risk premiums (advocated by Mr. Hill in his APS testimony), produces a lower estimate range of 8.49 percent to 10.43 percent (or an average of 9.46 percent) versus my higher original CAPM estimate range of 9.20 percent to 10.83 percent (or an average of 10.02 percent) presented in my direct testimony. Collectively this data demonstrates that my unadjusted recommended 9.88 percent cost of common equity appears to be reasonable compared to the Hamada methodology results advocated by Mr. Wood and the lower market risk premiums advocated by Mr. Hill.

Q. Please comment on the discussion of the DCF growth component that Mr. Hanley offers on pages 24 and 25 of his rebuttal testimony.

A. Mr. Hanley cites a 1990 presentation by Dr. Myron Gordon who refers to the findings he presented on analysts estimates of growth ("g") in a 1989

paper he coauthored titled *Choice among methods of estimating share yield*[4]. Mr. Hanley also cites the opinions of Dr. Roger Morin on the problems of estimating the DCF growth component which appear on pages 306 and 307 of Dr. Morin's 2006 text New Regulatory Finance.

Q. Do you believe that your 5.18 percent DCF growth estimate is unreasonable based on the information provided in the above-referenced documents?

A. No. As a matter of fact, on page 308 of his text, Dr. Morin provides a DCF growth rate check (Attachment D). The reasonableness test offered by Dr. Morin is expressed as follows:

Dividend Growth = Risk Free Return + Risk Premium – Dividend Yield

Under the above formula the dividend yield element of the DCF ("D_1/P_0") is subtracted from results of a CAPM calculation ("$r_f + [\ ß\ (r_m - r_f)\ ]$").

Q. How does your 5.18 percent growth estimate compare to the results obtained from the reasonableness test offered by Dr. Morin?

A Using the CAPM results presented above using Mr. Wood's relevered beta of 0.97, the most recent yield of a 30-year U.S. Treasury note (Mr.

[4] Gordon, David with Myron J. Gordon and Lawrence I. Gould, "Choice among methods of estimating share yield," The Journal of Portfolio Management, pp. 50-55, Spring 1989.

Hanley's preferred instrument), the 4.0 percent to 6.0 percent market risk premium (advocated by Mr. Hill in his APS testimony) and the average 4.55 percent dividend yield estimate presented in my direct testimony, the following growth rate check results are obtained:

Using a 4.0% Market Risk Premium

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.61\% + [\,0.97\,(4.0\%)\,] - 4.55\%$$

$$g = 4.61\% + 3.88\% - 4.55\%$$

$$g = \underline{3.94\%}$$

Using a 6.0% Market Risk Premium

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.61\% + [\,0.97\,(6.0\%)\,] - 4.55\%$$

$$g = 4.61\% + 5.82\% - 4.55\%$$

$$g = \underline{5.88\%}$$

As can be seen above, the growth rate check results, obtained from Dr. Morin's reasonableness test, range from 3.94 percent to 5.88 percent or an average of 4.91 percent which is 27 basis points lower than my 5.18 percent DCF growth rate estimate.

...

Q. In the examples that you've provided above you have used Mr. Hanley's preferred 30-year U.S. Treasury note as a proxy for the risk-free rate of return. Is it reasonable to assume that a 30-year horizon is appropriate for ratemaking purposes?

A. Not really. An argument can be made that the financial instrument used for a risk free rate of return should have a maturity that is close to the time frame that a utility typically files for new rates. If one assumes that a utility typically applies for new rates every three to five years, then a better instrument would probably be a 5-year U.S. Treasury note. As can be seen in Attachment A, the current yield on a 5-year U.S. Treasury note is 3.20 percent or 141 basis points lower than the 30-year 4.61 yield that I have used in the examples above.

Q. What would the average CAPM expected rate of return be if you substituted the current 4.61 percent yield on a 30-year U.S. Treasury note with the current 3.20 percent yield for a 5-year U.S. Treasury note and held all of the other components used in the above examples constant?

A. Substituting the 5-year U.S. Treasury note yield of 3.20 percent and holding all of the other inputs constant produces an average CAPM expected rate of return of 8.05 percent which is probably more reasonable given the fact that utility rates are typically not set for 30-year periods.

Using Dr. Morin's reasonableness test produces an average growth rate check result of 3.50 percent which is 168 basis points lower than my 5.18 percent DCF growth estimate.

Q. On page 26 of his rebuttal testimony, Mr. Hanley criticizes your DCF analysis, which takes into consideration the concept that a utility's market-to-book ratio will move toward a value of 1.0 if regulators set a utility's rate of return at a level that is equal to its cost of capital. Please explain why you believe that the market value of a utility's stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital of firms with similar risk.

A. A utility's market price should equal its book price over the long run if regulators allow a rate of return that is equal to the utility's cost of capital. *That is assuming that the utility's rate of return ("ROR") is comparable to the rates of return of other firms in the same risk class.*[5] For example, if a hypothetical utility's book price is $20.00 per share and regulators adopt a rate of return that is equal to the utility's cost of capital of 10.0%, the utility will earn $2.00 per share ("EPS"). With earnings of $2.00 per share, and a market required rate of return on equity of 10.00%, for firms in the utility's risk class, the market price of the utility's stock will set at $20.00 per share ($2.00 EPS ÷ 10.0% ROR = $20.00 per share price). If the utility records earnings that are higher than the earnings of other firms with similar risk,

[5] An in-depth discussion of market-to-book ratios can be found in Chapter 10 of Roger A. Morin's text Regulatory Finance, Utilities' Cost of Capital.

the market value of the utility's shares will increase accordingly ($2.50 EPS ÷ 10.0% ROR = $25.00 per share). On the other hand, if the utility posts lower earnings, the stock's market price will fall below book value ($1.50 EPS ÷ 10.0% ROR = $15.00 per share).

Because of economic forces beyond the control of regulators, it is not reasonable to assume that the utility will have earnings that match those of firms of similar risk in every year of operation. In some years, earnings may drop causing the market-to-book ratio to fall below 1.0, while in other years the utility may have earnings that exceed those of other firms in its risk classification. However, over the long run the utility's earnings should average out to the earnings that are expected based on its level of risk. These average earnings over time will result in a market-to-book ratio of 1.0. It has been suggested that regulators should set a utility's rate of return at a level that is slightly higher than that of firms in the same risk class of the hypothetical utility. In theory, this will send a message to investors that average long-term earnings will not be less than what is expected. A 1.0 ratio may never be achieved in practice and many investors may not even care what the market-to-book ratio is as long as they receive their required rate of return. In this respect, a utility stock is similar to a corporate bond whose value fluctuates as interest rates move above or below the stated yield on the bond. As long as the bond provides the level of income (i.e. the stated interest payment in the case of a bond or a dividend payment in the case of a utility stock) that the

investor expects, the price of the instrument at any given point in time is immaterial (so long as the intent is to hold the bond until maturity or the utility stock over a long-term period).

Q. Does your recommended cost of equity take into consideration the theoretical concepts that you have just described?

A. Yes. As I just explained, in theory, a market-to-book ratio of 1.0 would be achieved if a utility's rate of return equaled the cost of capital that is close to the returns of firms with similar risk. The CAPM analysis that I performed earlier in this testimony (using the current yield on a 5-year U.S treasury note and the revised beta and market risk premium inputs advocated by Mr. Wood and Mr. Hill) indicates that the rate of return for a firm with SWG's level of risk is 8.05 percent. This being the case, the adoption of my recommended 8.83 percent cost of capital would be consistent with the theory I have presented above since it is 78 basis points higher than the aforementioned average 8.05 percent expected rate of return that theoretically produces a market price that is equal to book value.

Q. Please explain why Mr. Hanley's criticism regarding the use of a geometric mean in your CAPM analysis is unfounded.

A. While it is true that an ongoing debate exists as to which mean is the better one to use, it is important to recognize that the information on both

means, published by Morningstar, is widely available to the investment community. For this reason, and the fact that the ACC has consistently accepted the use of both means, I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2006 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the differences between the two averages?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original $100 investment falls to $96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

(year 1 return + year 2 return) ÷ number of periods =

(20.0% + -20.0%) ÷ 2 =

(0.0%) ÷ 2 = 0.0%

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original $100 investment is still worth $100. But in reality, your original $100 investment is only worth $96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{year 2 value} \div \text{original value})^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{-2.02\%}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original $100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward-looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's Stocks Bonds Bills and Inflation 2007 Yearbook ("Morningstar").

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed,

the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms. That is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concludes that 4.0 percent to 5.5 percent is a reasonable forward-looking market risk premium (a point raised earlier in my testimony). Adding the current 5-year Treasury yield of 3.20 percent to these two estimates indicate a cost of equity of 7.20 percent to 8.70 percent or an average of 7.95 percent which is 88 basis points lower than my recommended 8.83 percent cost of capital for SWG.

Q. Has any of Mr. Hanley's testimony on the ECAPM persuaded you to make any adjustments to your recommended cost of common equity?

A. No. On this issue I disagree with both Mr. Hanley and Dr. Morin. The flatter security market line produced by the CAPM (which is referred to by Dr. Morin in Mr. Hanley's cite), is the result of a phenomenon known as regression toward the mean. The ECAPM using raw, or unadjusted betas, takes this phenomenon into account. This same phenomenon also occurs in the calculation of betas and results in the long term tendency of betas to

move toward a value of 1.00. As I explained my direct testimony, this is the reason why Value Line betas are adjusted. Since the ECAPM model already takes regression toward the mean into account, there is no need to use adjusted Value Line betas in the ECAPM. In short, the use of adjusted betas in the ECAPM will result in a double count. For this reason the appropriate beta to use in the ECAPM is a raw or unadjusted beta. As I further stated in my direct testimony, the Commission has consistently rejected the results of the ECAPM in a number of water company cases that have come before the ACC. For these reasons, Mr. Hanley's ECAPM results using adjusted betas should be given no weight.

Q. Are you recommending a lower cost of capital for SWG based on the lower CAPM estimates that you have just presented in your testimony?

A. No.

Q. Please address Mr. Hanley's argument that the adoption of a decoupling mechanism for SWG would not warrant a lower rate of return for the Company?

A. I agree with Mr. Hanley that this is simply a matter of common sense. However, I believe that common sense says that if SWG's revenues are stabilized, the risks are clearly shifted to the ratepayers as opposed to the Company – which has the ability to control the majority of its operating expenses and pass through its cost of natural gas to customers.

Q. Are there any states that you are aware of that have made downward adjustments to an LDC's authorized rate of return due to the implementation of a revenue decoupling mechanism?

A. Yes. On pages 11 and 12 of his April 2006 briefing paper titled Revenue Decoupling for Natural Gas Utilities (Attachment E), Ken Costello, a Senior Institute Economist with the National Regulatory Research Institute, cites the Maryland Public Service Commission's decision to reduce the authorized rate of return for Baltimore Gas and Electric by 50 basis points to reflect the reduced revenue risk associated with that utility's decoupling mechanism. Such an adjustment would lower my recommended cost of capital from 8.83 percent to 8.33 percent.

Q. Does your silence on any of the positions advocated by Mr. Wood or Mr. Hanley constitute your acceptance of them?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on SWG?

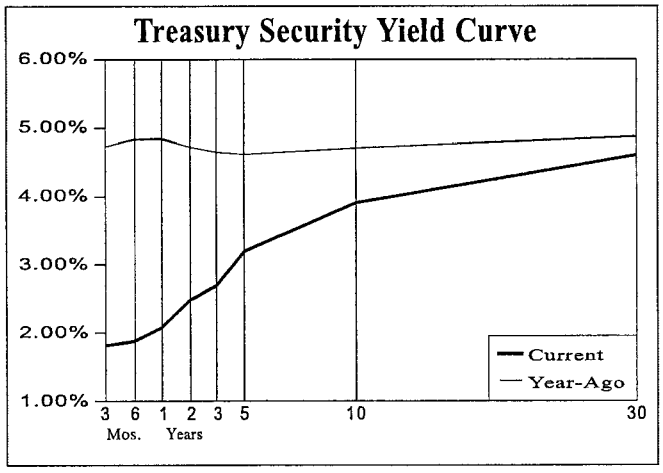
A. Yes, it does.

ATTACHMENT A

Selected Yields

	Recent (5/14/08)	3 Months Ago (2/13/08)	Year Ago (5/16/07)
TAXABLE			
Market Rates			
Discount Rate	2.25	3.50	6.25
Federal Funds	2.00	3.00	5.25
Prime Rate	5.00	6.00	8.25
30-day CP (A1/P1)	2.70	3.00	5.24
3-month LIBOR	2.72	3.07	5.36
Bank CDs			
6-month	1.77	2.15	3.11
1-year	2.05	2.34	3.73
5-year	3.16	2.85	3.91
U.S. Treasury Securities			
3-month	1.82	2.26	4.73
6-month	1.88	2.09	4.84
1-year	2.08	2.06	4.85
5-year	3.20	2.73	4.62
10-year	3.91	3.73	4.71
10-year (inflation-protected)	1.35	1.34	2.37
30-year	4.61	4.54	4.88
30-year Zero	4.71	4.65	4.85

	Recent (5/14/08)	3 Months Ago (2/13/08)	Year Ago (5/16/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.04	4.46	5.58
FHLMC 6.5% (Gold)	5.16	5.10	5.80
FNMA 6.5%	4.90	4.71	5.73
FNMA ARM	4.41	5.18	5.49
Corporate Bonds			
Financial (10-year) A	5.68	5.78	5.69
Industrial (25/30-year) A	6.06	6.29	5.89
Utility (25/30-year) A	6.10	6.20	6.07
Utility (25/30-year) Baa/BBB	6.41	6.35	6.21
Foreign Bonds (10-Year)			
Canada	3.60	3.87	4.24
Germany	4.17	3.96	4.30
Japan	1.68	1.43	1.67
United Kingdom	4.82	4.62	5.13
Preferred Stocks			
Utility A	6.28	6.13	6.07
Financial A	7.69	7.00	6.48
Financial Adjustable A	5.51	5.51	5.52



	Recent (5/14/08)	3 Months Ago (2/13/08)	Year Ago (5/16/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.62	4.33	4.24
25-Bond Index (Revs)	5.07	4.72	4.44
General Obligation Bonds (GOs)			
1-year Aaa	1.83	1.05	3.60
1-year A	1.93	1.15	3.70
5-year Aaa	2.97	2.67	3.63
5-year A	3.07	2.77	3.74
10-year Aaa	3.62	3.40	3.76
10-year A	3.83	3.60	4.26
25/30-year Aaa	4.55	4.36	4.13
25/30-year A	4.75	4.56	4.43
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.80	4.60	4.55
Electric AA	4.85	4.65	4.45
Housing AA	5.00	4.80	4.63
Hospital AA	5.05	4.85	4.65
Toll Road Aaa	4.85	4.65	4.55

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/7/08	4/23/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1980	1718	262	2201	1953	2042
Borrowed Reserves	129197	133027	-3830	89011	52907	27699
Net Free/Borrowed Reserves	-127217	-131309	4092	-86810	-50954	-25657

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/28/08	4/21/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1379.9	1372.1	7.8	4.6%	1.4%	-0.2%
M2 (M1+savings+small time deposits)	7654.1	7693.3	-39.2	7.6%	7.1%	6.1%

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ATTACHMENT B

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 THROUGH ACC-STF-2-22)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 19, 2007

Request No. STF-2-7:

Please provide copy of all reports on Southwest Gas by rating agencies for the period 2003 to the present.

Respondent: Treasury Services

Response: ***Supplemental Attachment Provided on May 9, 2008***

Supplemental Attachment Provided on March 6, 2008

Supplemental Attachment Provided on January 7, 2008

Southwest's credit rating agency reports for 2004-2007 were provided in response ACC Staff data request no. STF-1-10. Attached are the credit rating agency reports for 2003.

Summary:
Southwest Gas Corp.

Credit Rating: BBB-/Positive/--

Rationale

The ratings on Las Vegas, Nev.-based Southwest Gas Corp. reflect its strong business risk profile and aggressive financial risk profile. The ratings are based on the consolidated credit profile of its natural gas operations segment (87% of operating income in 2007) and its construction services business, Northern Pipeline Construction Co. (NPL; 13%).

Southwest Gas' strong business risk profile reflects a large, stable, residential, and commercial customer base of about 1.8 million customers, strong customer growth prospects in Arizona (54% of customers), Nevada (36%), and California (10%), the absence of competition, and relatively low operating risks. Challenges associated with improving its regulatory cost-recovery mechanisms, ownership of a small, unregulated construction and maintenance business, gradual reductions in total gas volumes, and limited geographic service territory temper the company's strong business profile.

The Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada, and the California Public Utilities Commission each regulate Southwest Gas. Each regulatory commission provides the company with various cost-recovery mechanisms. However, we view the ACC regulatory oversight as less supportive of credit than other jurisdictions due to its limitations on purchased-gas cost recoveries and rate design that is solely based on gas throughput. This type of rate design exposes the company to reduced cash flows as volumes decline related to conservation. Decoupling, an alternate rate design, separates the utility's margins and cash flow from commodity sales and encourages conservation. These mechanisms are currently under consideration as part of the company's most recent rate case.

Slowing customer growth, reduced total throughput, and improved rate design are among the reasons for Southwest Gas' recent rate filings. While Southwest Gas' annual customer growth averaged more than 4% over the past five years, the company expects future growth to be only 1.5% to 3% due to the depressed real estate market conditions. Despite strong historical customer growth statistics, annual total consumption has nevertheless dropped 1% per year, on average, since 2003, due to conservation efforts, making rate design a key credit driver for the company.

Southwest Gas' nonregulated subsidiary, NPL, is not currently a significant rating factor because most of its contracts shield Southwest Gas from the majority of costs. In addition, about 20% of NPL's revenues are derived from Southwest Gas' gas operations.

Southwest Gas has an aggressive financial risk profile, with bondholder protection measures that are currently strong for the rating, which supports the positive outlook. We expect near-term performance to remain strong for the rating with additional improvements from customer growth and regulatory rate increases. As of Dec. 31, 2007, total debt, including operating leases and tax-affected pensions and post-retirement obligations, was about $1.5 billion with debt to capital of almost 60%. Benefitting from customer growth and regulatory rate increases, cash flow metrics have improved over the past few years, with 2007 adjusted funds from operations (FFO) to total debt

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of 20% and FFO interest coverage of about 4x, compared with 14% and 3.4x, respectively, in 2005.

Liquidity

Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses of liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.

Given the low-risk nature of Southwest Gas' regulated utility operations and healthy service territory, the company should generate reasonably stable cash flow. The company reported cash from operations of almost $350 million for 2007, which will not fully cover annual dividends (about $36 million), annual capital expenditures (about $300 million forecast for 2008 and about $550 forecast for 2009-2010 combined), and near-term debt maturities ($38 million due in 2008 and $10 million in 2009). To bridge the funding gap, the company expects to raise $70 million to $80 million through stock offerings, borrow under its revolving credit facility, or through other external means.

Outlook

The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Ratings Services' expectation that the company's improved financial performance could lead to a higher rating over the near term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

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Southwest Gas Corp.

Major Rating Factors

Corporate Credit Rating

BBB-/Positive/--

Strengths:

- A low-risk natural gas distribution business;
- A favorable customer mix and high growth service territories;
- Purchased-gas adjustment (PGA) mechanisms that eliminate a majority of the company's exposure to commodity prices; and
- Strong cash flow measures and declining debt leverage.

Weaknesses:

- Absence of weather normalization and decoupling rate structures, which expose the company's earnings and cash flow to conservation and weather-related sales variations;
- Elevated projected capital expenditures of about $290 million per year;
- Moderate exposure to the effects of natural gas price volatility on PGA receivable balances and potential liquidity requirements; and
- Long-term capital or contracting requirements with regard to natural gas storage capability for the company's Arizona and Southern Nevada service areas.

Rationale

The ratings on Las Vegas, Nev.-based Southwest Gas Corp. reflect its strong business risk profile and aggressive financial risk profile. The ratings are based on the consolidated credit profile of its natural gas operations segment (87% of operating income in 2007) and its construction services business, Northern Pipeline Construction Co. (NPL; 13%).

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Slowing customer growth, reduced total throughput, and improved rate design are among the reasons for Southwest

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Gas' recent rate filings. While Southwest Gas' annual customer growth averaged more than 4% over the past five years, the company expects future growth to be only 1.5% to 3% due to the depressed real estate market conditions. Despite strong historical customer growth statistics, annual total consumption has nevertheless dropped 1% per year, on average, since 2003, due to conservation efforts, making rate design a key credit driver for the company.

Southwest Gas' nonregulated subsidiary, NPL, is not currently a significant rating factor because most of its contracts shield Southwest Gas from the majority of costs. In addition, about 20% of NPL's revenues are derived from Southwest Gas' gas operations.

Southwest Gas has an aggressive financial risk profile, with bondholder protection measures that are currently strong for the rating, which supports the positive outlook. We expect near-term performance to remain strong for the rating with additional improvements from customer growth and regulatory rate increases. As of Dec. 31, 2007, total debt, including operating leases and tax-affected pensions and post-retirement obligations, was about $1.5 billion with debt to capital of almost 60%. Benefitting from customer growth and regulatory rate increases, cash flow metrics have improved over the past few years, with 2007 adjusted funds from operations (FFO) to total debt of 20% and FFO interest coverage of about 4x, compared with 14% and 3.4x, respectively, in 2005.

Liquidity

Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses of liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.

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Outlook

The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Ratings Services' expectation that the company's improved financial performance could lead to a higher rating over the near term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

Accounting

Standard & Poor's adjusts Southwest Gas' financial statements for operating leases and pension and post-retirement obligations. The adjustment includes adding a debt equivalent, interest expense, and depreciation to the company's reported financial statements. As a result, debt equivalents of $24 million are added for operating leases and $90 million for pension and post-retirement obligations.

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Due to the distortions in leverage and cash flow metrics caused by the substantial seasonal working-capital requirements of gas utilities, Standard & Poor's adjusts inventory and debt balances by netting the value of inventory against the outstanding commercial paper for regulated subsidiaries. This adjustment provides a more accurate view of the company's financial performance by reducing seasonality, where there is a very high likelihood of recovery. As inventories are depleted and accounts receivable are monetized, with support from commodity pass-through mechanisms, these funds reduce the utility's short-term borrowings.

Standard & Poor's views Southwest Gas' $100 million of trust-preferred securities as having "intermediate equity content". Under our hybrid criteria, we calculate the company's financial ratios with 50% of the outstanding balance attributed to debt and 50% to equity. Similarly, we treat 50% of the associated distributions as dividends and 50% as interest.

Southwest Gas prepares its financial statements using SFAS No. 71, "Accounting for Effects of Certain Types of Regulation." Consequently, Southwest Gas recorded certain regulatory assets and liabilities as of Dec. 31, 2007, of $218 million and $226 million, respectively. Net regulatory assets represent less than 1% of total capitalization.

Table 1

Southwest Gas Corp. -- Peer Comparison*

Industry Sector: Gas

	--Average of past three fiscal years--			
	Southwest Gas Corp.	**NiSource Inc.**	**CenterPoint Energy Resources Corp.**	**Atmos Energy Corp.**
Rating as of April 17, 2008	BBB-/Positive/--	BBB-/Stable/--	BBB/Positive/A-2	BBB/Positive/A-2
(Mil. $)				
Revenues	1,963.7	7,776.3	7,791.3	5,670.9
Net income from cont. oper.	70.3	303.0	229.0	150.7
Funds from operations (FFO)	256.0	867.3	524.7	411.6
Capital expenditures	327.2	697.9	564.0	411.1
Cash and investments	26.8	46.2	12.3	97.8
Debt	1,490.6	7,705.8	2,685.9	2,639.1
Preferred stock	50.0	27.0	0.0	0.0
Equity	910.5	4,946.5	2,948.7	1,674.3
Debt and equity	2,401.1	12,652.4	5,634.6	4,313.4
Adjusted ratios				
EBIT interest coverage (x)	2.2	2.1	2.9	2.7
FFO int. cov. (x)	3.7	2.8	3.6	3.5
FFO/debt (%)	17.2	11.3	19.5	15.6
Discretionary cash flow/debt (%)	(4.3)	(0.1)	(14.4)	(3.9)
Net cash flow/capex (%)	66.8	88.2	75.3	74.7
Debt/total capital (%)	62.1	60.9	47.7	61.2
Return on common equity (%)	8.2	5.8	7.9	9.3
Common dividend payout ratio (un-adj.) (%)	47.9	82.9	43.7	69.2
Ratios before adjustments for postretirement obligations				
Oper. income/sales (bef. D&A) (%)	18.8	19.8	9.5	10.4

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Table 1

Southwest Gas Corp. -- Peer Comparison*(cont.)				
EBIT interest coverage (x)	2.2	2.1	2.9	2.6
FFO/debt (%)	17.9	11.4	19.9	16.8
Debt/EBITDA (x)	3.8	4.8	3.6	4.3
Debt/total capital (%)	60.0	59.1	47.0	59.2

*Fully adjusted (including postretirement obligations).

Table 2

Southwest Gas Corp. -- Financial Summary*					
Industry Sector: Gas					
	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB-/Positive/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--
(Mil. $)					
Revenues	2,152.1	2,024.8	1,714.3	1,477.1	1,231.0
Net income from continuing operations	83.2	83.9	43.8	56.8	38.5
Funds from operations (FFO)	290.6	260.0	217.4	252.0	228.5
Capital expenditures	344.7	343.0	294.1	301.9	239.8
Cash and investments	32.0	18.8	29.6	13.6	17.2
Debt	1,476.4	1,488.1	1,507.3	1,453.9	1,325.1
Preferred stock	50.0	50.0	50.0	50.0	50.0
Equity	1,033.7	951.4	746.4	684.6	619.3
Debt and equity	2,510.1	2,439.6	2,253.7	2,138.5	1,944.4
Adjusted ratios					
EBIT interest coverage (x)	2.5	2.4	1.8	2.0	1.7
FFO int. cov. (x)	4.0	3.7	3.4	3.9	3.8
FFO/debt (%)	19.7	17.5	14.4	17.3	17.2
Discretionary cash flow/debt (%)	(1.4)	(5.8)	(5.4)	(11.9)	(4.0)
Net cash flow/capex (%)	72.7	64.9	62.0	72.7	82.1
Debt/debt and equity (%)	58.8	61.0	66.9	68.0	68.2
Return on common equity (%)	8.7	9.8	5.7	8.4	5.9
Common dividend payout ratio (un-adj.) (%)	43.6	39.9	71.3	50.8	71.9
Ratios before adjustments for postretirement obligations					
Oper. income/revenues (bef. D&A) (%)	19.0	18.9	18.2	21.9	22.8
EBIT interest coverage (x)	2.4	2.4	1.8	2.1	1.7
FFO/debt (%)	20.3	18.2	15.2	18.2	17.8
Debt/EBITDA (x)	3.4	3.6	4.5	4.3	4.5
Debt/debt and equity (%)	57.3	59.3	63.7	64.5	65.0

*Fully adjusted (including postretirement obligations).

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Table 3

Reconciliation Of Southwest Gas Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--									
Southwest Gas Corp. reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	1,413.1	983.7	403.1	403.1	220.6	96.2	347.8	347.8	36.3	340.9
Standard & Poor's adjustments										
Operating leases	24.0	--	6.2	1.6	1.6	1.6	4.5	4.5	--	5.1
Intermediate hybrids reported as debt	(50.0)	50.0	--	--	--	(3.9)	3.9	3.9	3.9	--
Postretirement benefit obligations	89.2	--	5.4	5.4	5.4	--	8.9	8.9	--	--
Capitalized interest	--	--	--	--	--	1.3	(1.3)	(1.3)	--	(1.3)
Reclassification of nonoperating income (expenses)	--	--	--	--	6.6	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(73.2)	--	--
Total adjustments	63.3	50.0	11.5	7.0	13.6	(0.9)	16.0	(57.2)	3.9	3.8
Standard & Poor's adjusted amounts										
	Debt	**Equity**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	1,476.4	1,033.7	414.6	410.1	234.2	95.3	363.8	290.6	40.1	344.7

*Southwest Gas Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of April 24, 2008)*

Southwest Gas Corp.	
Corporate Credit Rating	BBB-/Positive/--
Preferred Stock	
Local Currency	BB
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
13-Mar-2007	BBB-/Positive/--

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Ratings Detail (As Of April 24, 2008)* (cont.)

11-Aug-2003	BBB-/Stable/--
01-Feb-2001	BBB-/Negative/--
Financial Risk Profile	Aggressive

Debt Maturities

As of Dec. 31, 2007:
2008: $38.1 mil.
2009: $10.4 mil.
2010: $5.4 mil.
2011: $202.6 mil.
2012: $350.1 mil.
Thereafter: $697.0 mil.

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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ATTACHMENT C

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis. The average beta coefficients for the electric utility sample group was 0.83. Schedule 8 shows a CAPM cost of capital for the electric companies ranging from 9.23% to 10.56%.

Schedules 9 and 10 shows the theoretical basis and the data and calculations, respectively, for the Modified Earnings Price Ratio (MEPR) analysis. The MEPR analysis indicates a current cost of equity capital for electric companies in a narrow range from 8.79% to 9.13%. Finally, Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital for the electric utility companies of 9.31% (near-term) to 9.38% (long-term).

C. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC UTILITY COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table below.

METHOD	Electric Utility Companies
DCF	9.44%
CAPM	9.23%/10.56%
MEPR	9.13%/8.79%
MTB	9.31%/9.38%

For the electric utility sample group, the DCF result is 9.44%. In addition, the corroborating cost of equity indications (MEPR, MTB, and CAPM) indicate that DCF result is reasonable. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces and equity cost range of 9.11% to 9.69%,

with a mid-point of 9.40%, only 4 basis points below the DCF result.

Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company like Arizona Public Service, facing similar risks as this group of electric utilities, ranges from 9.25% to 9.75%, with a mid-point of 9.50%.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED BEFORE DETERMINING A POINT-ESTIMATE FOR APS WITHIN A REASONABLE RAGE FOR SIMILAR-RISK FIRMS?

A. Yes. First, the electric sample group companies have similar operating risk to APS. The average S&P business risk score of my sample of electric utilities is 6—the same as that for APS. Therefore, on that basis there would be no reason to adjust the equity return from the mid-point of a reasonable range. However, because the capital structure I recommend for ratesetting purposes contains considerably more common equity and less debt than average for the sample group, APS, prospectively will have less financial risk than the sample group and should be awarded an equity return below the mid-point of a reasonable range.

Q. IS THERE A RECOGNIZED METHOD WITH WHICH DIFFERENCES IN FINANCIAL RISK CAN BE QUANTIFIED?

A. Yes. The cost of equity capital is affected by the capital structure a company employs. When a company increases the proportion of debt in its capital structure, it increases the riskiness of its equity. Financial risk (created by the use of debt in the capital structure) causes investors to demand a higher rate of return; that is, financial risk increases the cost of equity capital.

The impact of debt leverage on the cost of equity capital can be approximated through an examination of the changes in beta, which occur when leverage is increased or decreased. The Value Line betas for the sample companies used in my cost of capital analysis in this proceeding reflect the market's (investors') perception of both the business risks and the financial risks of a firm. That is, one portion of the beta of a firm is

related to the business risk of the firm (the risk inherent in its operations) and one portion of the beta is related to the financial risk of that firm (the risk associated with the use of debt). Therefore, if a firm elects to finance its operations with debt as well as equity, the beta coefficient of that firm will reflect both the business and financial risk. When a firm uses debt to finance its operations, the beta can also be referred to as a "levered" beta (i.e., a beta coefficient that includes the impact of debt leverage).

The average beta coefficient of the sample group of utilities can be "unlevered." That is, the beta-risk related to the level of debt capital used by the firm can be removed. "Unlevering the betas" amounts to estimating what the average beta would be if the companies were financed entirely with equity capital. Equation (2) is used to estimate the unlevered beta for a firm or a group of similar-risk firms.[19]

$$\beta_U = \frac{\beta_{Measured}}{(1+(1-t)D/E)} \qquad (2)$$

Equation (2) indicates that an estimate of the unlevered beta (β_U) of a firm can be calculated by dividing the measured beta ($\beta_{Measured}$, e.g. the beta coefficient reported by investor services such as Value Line) by one plus the average debt-to-equity ratio, adjusted to account for taxes. The debt-to-equity ratio is measured using the average market value of the sample group's common equity capital. Once the unlevered beta for the firm (or, in this case, for the sample group of market-traded utility companies) is calculated, the beta coefficient is "re-levered" and adjusted to conform to the less leveraged capital structure of APS, which contains 50% common equity. The formula used to "re-lever" the utility betas is shown below.

$$\beta_{Relevered} = \beta_U (1+ (1-t)D/E) \qquad (3)$$

[19]Equation (1) is a version of the Hamada equation which combines the Miller-Modigliani theories regarding capital structure and the logic of the CAPM: Hamada, R.S., "Portfolio Analysis, Market equilibrium and Corporation Finance," *Journal of Finance*, March 1969, pp. 13-31.

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free

rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often said that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. That is not a correct statement because bonds have a fixed cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate a flotation cost reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 69% above book value. (Exhibit__(SGH-1), Schedule 4, p. 1) The difference between the market price of electric utility stock and book value dwarfs any issuance expense the companies might incur. Therefore, if common equity flotation costs were exactly like flotation costs with bonds, then, if an explicit adjustment to the cost of common equity were necessary, it should be downward, not upward.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book

value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses related to increases in stock outstanding is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[22]. There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market

[22] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs that lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's INTEGRATED UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.25%?

A. Schedule 13 attached to my testimony shows that an equity return of 9.25%, operating through an appropriate ratemaking capital structure of 50% equity and 50% debt, and the Company's requested embedded capital cost rates, produces an overall return of 7.33% for APS. Schedule 13 also shows that a 7.33% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times.

According to APS's 2005 S.E.C. Form 10-K (Exhibit 12), the pre-tax interest coverage over the past five years has averaged 2.94x and has ranged from 2.81x to 3.17x. The return I recommend would allow the Company the opportunity to improve its historical average interest coverage. Therefore, the equity return I recommend fulfills the legal requirement of Hope and Bluefield of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

V. COMPANY COST OF CAPITAL TESTIMONY

Q. HOW HAS COMPANY WITNESS AVERA ESTIMATED THE COST OF EQUITY CAPITAL IN THIS PROCEEDING?

ARIZONA PUBLIC SERVICE COMPANY
LEVERAGE/BETA ADJUSTMENT TO THE COST OF EQUITY CAPITAL

COMPANY	COMMON EQUITY	FIXED INCOME CAPITAL	M/B RATIO	MKT. VALUE DEBT(1-t)/EQ.
Central Vermont P. S.	63.00%	37.00%	1.05	0.36
FirstEnergy Corp.	45.00%	55.00%	1.77	0.45
Green Mountain Power	56.00%	44.00%	1.30	0.39
Progress Energy	41.00%	59.00%	1.29	0.73
Ameren Corp.	50.00%	50.00%	1.58	0.41
Cleco Corporation	52.00%	48.00%	1.52	0.39
DPL, Inc.	35.00%	65.00%	4.51	0.27
Empire District Electric	46.00%	54.00%	1.37	0.56
Entergy Corp.	46.00%	54.00%	1.77	0.43
Hawaiian Electric	37.00%	63.00%	1.77	0.63
PNM Resources	38.00%	62.00%	1.31	0.81
Pinnacle West Capital	48.00%	52.00%	1.11	0.63
Unisource Energy	32.00%	68.00%	1.64	0.84
AVERAGES	45.31%	54.69%	1.69	0.53
TARGET CAP. STRUCTURE	50.00%	50.00%	1.69	**0.38**

AVERAGE (LEVERED) UTILITY BETA = 0.83

Beta (Unlevered) = Beta (Levered)/(1+D(1-t)/E)

Beta (Unlevered)= 0.83/(1+.53)= **0.54**

Beta (Relevered)= Beta (Unlevered)*(1+D(1-t)/E)

Beta (Relevered)= 0.54(1.38)= **0.75**

IMPACT ON COST OF EQUITY CAPITAL

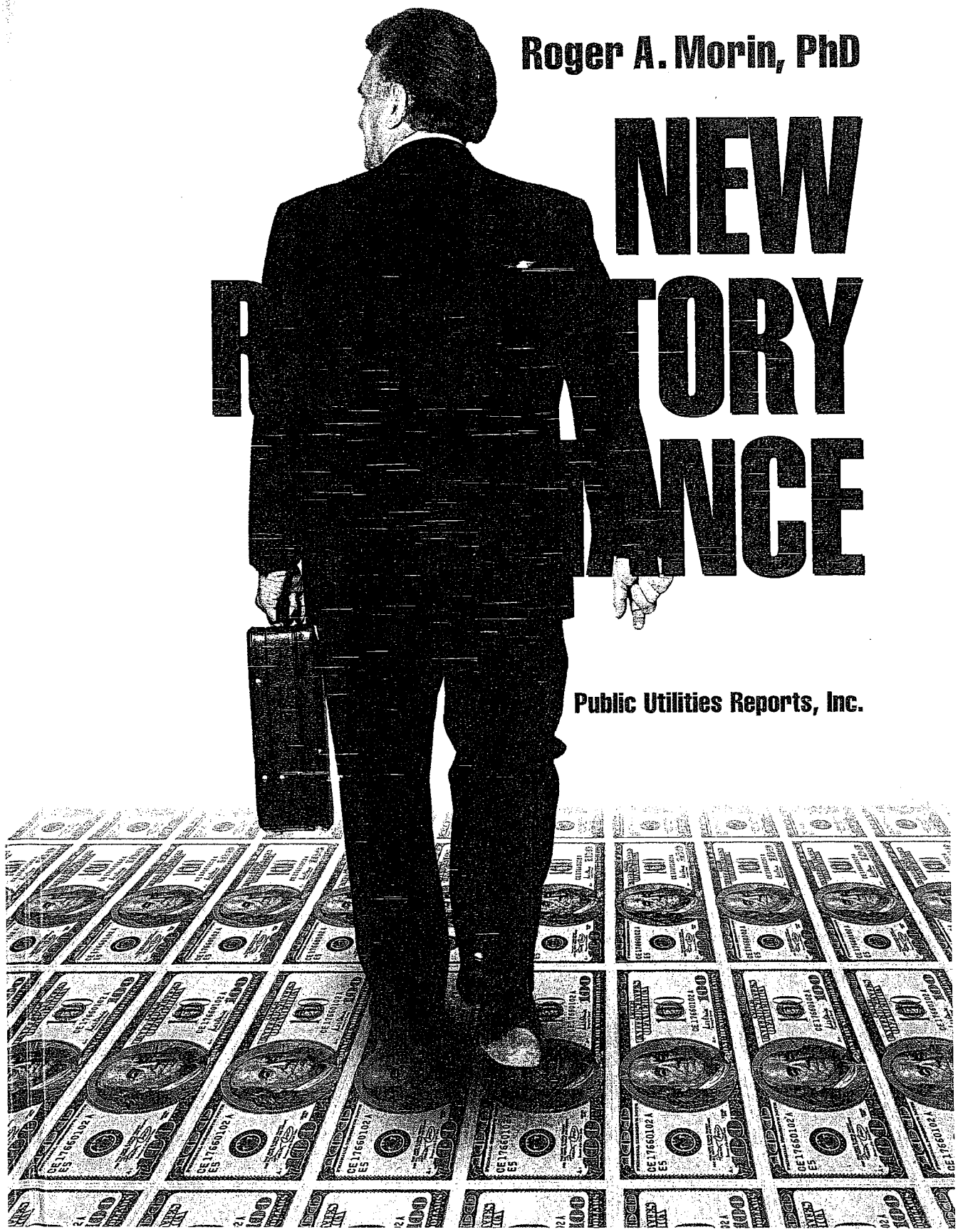
	Measured Beta	0.830
	Relevered Beta	0.751
[1]	Diff. in Beta	0.079
[2]	Market Risk Premium (rm-rf) =	4% to 6%

Average Cost of equity impact = [1] x [2] = **0.32% to 0.48%**

ATTACHMENT D

Roger A. Morin, PhD

NEW R TORY ANCE



Public Utilities Reports, Inc.

DCF Growth Rate Check

As a reasonableness check on the DCF growth rate, the growth rate in dividends can be verified using the following relationship:[16]

Dividend Growth = Risk-free Return + Risk Premium − Dividend Yield

For example, let us say that the yield on Treasury bonds as a proxy for the risk-free return is 5%, the utility risk premium is 5.5% derived from a Capital Asset Pricing Model (CAPM) analysis discussed in earlier chapters, and the expected dividend yield for the utility industry is 4.5%. Substituting these values in the above relationship, we obtain a dividend growth expectation of 6.0% as follows:

Dividend Growth = 5.0% + 5.5% − 4.5% = 6.0%

9.6 Growth in the Non-Constant DCF Model

Although the constant growth DCF model does have a long history, analysts, practitioners, and academics have come to recognize that it is not applicable in many situations. A multiple-stage DCF model that better mirrors the pattern of future dividend growth is preferable. There is a growing consensus and ample empirical support that the best place to start is with security analysts' forecasts, that is, assume that dividend policy is relatively constant and use analyst forecasts of earnings growth as a proxy for dividend forecasts. The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate. Accordingly, multiple-stage DCF models of this transition are available and were described in Chapter 8. It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

A reasonable alternative to the constant growth DCF model is to use a multiple-stage DCF model that more appropriately captures the path of future dividend

[16] Equating the expected return from the standard DCF equation and the required return from the CAPM equation:

$$K = D_1/P + g = R_f + \text{Risk Premium}$$
$$K = D_1/P + g = R_f + \beta(R_m - R_f) \text{ from the CAPM}$$

Solving for g:

$$g = R_f + \beta(R_m - R_f) - D_1/P$$

ATTACHMENT E

Briefing Paper

Revenue Decoupling for Natural Gas Utilities

The National Regulatory Research Institute

April 2006

Ken Costello
Senior Institute Economist

EXECUTIVE SUMMARY

High natural gas prices have provoked recent proposals to modify long-held ratemaking practices for gas utilities. Energy conservation has emerged as an option to address the serious problem of consumers suffering from accelerating gas bills. With a heightened emphasis on energy conservation, gas utilities have expressed concern about the implications of lower gas usage for their financial stability. In response to this situation, gas utilities as well as conservationists have advocated a ratemaking mechanism generically labeled revenue decoupling (RD). From the perspective of gas utilities, RD can prevent financial erosion from future reductions in consumption by gas consumers. Conservationists view RD as indispensable in eliminating the disincentive for gas utilities to promote energy conservation under standard ratemaking.

This briefing paper reviews the activities to date on the application of RD for gas utilities. Five gas utilities presently have commission-approved RD mechanisms. Several others have RD proposals pending before their state commissions. Consumer groups and others have posed several arguments in disfavor of RD. Some state commissions have endorsed RD while others have opposed it. This paper lists the arguments on both sides together with an assessment of their merits.

This briefing paper takes a balanced perspective of RD by directing attention to both the upside and downside of this ratemaking mechanism. It specifically analyzes the efficacy of RD in fostering prevailing regulatory and ratemaking objectives. The paper's primary intent is to make state commissions as well as other policymakers better informed on the likely outcomes of RD. While this paper concentrates on the natural gas industry, much of its content applies equally to both the electric and water industries.

Contents

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Capsule of State Activities	4
Impetus for Revenue Decoupling	6
Basic Structure of a Revenue Decoupling Mechanism	9
Divergent Views on Revenue Decoupling	14
Analysis of Major Arguments	16
Summary and Conclusions	22

The author appreciates the helpful comments of Commissioner Richard Morgan, District of Columbia Public Service Commission, Robert Harding, Minnesota Public Utilities Commission, Bob Pauley, Indiana Utility Regulatory Commmission, James F. Wilson, LECG LLC., and Dr. Vivian Witkind Davis on earlier drafts of this paper.

06-06

TABLE 2
EXPECTED OUTCOMES FROM REVENUE DECOUPLING

Reduced overall risk to the utility	Little effect on incentives for customer-initiated conservation
Less incentive for utility to promote sales, and less disincentive to promote energy efficiency	Increased rate volatility (although probably small relative to the volatility of the gas commodity cost)
Base rates inversely related to actual sales between rate cases	Effect similar to shifting recovery of fixed costs to customer charge, except for possible intra-class subsidy effect
Base rates would tend to be higher (as the utility's average cost would increase, assuming lower sales), although some offset from a possible lower cost of capital)	Uncertain of the risk and overall economic welfare effect on consumers

Source: Author's construct.

standard ratemaking, rate design is the third step in designing rates (the first two are revenue requirement and cost allocation). Rate design involves setting actual billing elements (for example, the customer charge and the volumetric charge) to recover revenues by customer class commensurate with the determined costs allocated to each class. As a rate design, RD would allow a utility to recover the same revenues for distribution service irrespective of actual sales.[48] In effect, RD predetermines how much in revenues the utility will collect from those customer classes subject to the mechanism. This fixity of revenues reduces the risk to a utility from under-recovering its revenues and suffering a cash flow deficiency.

Expected Outcomes from Revenue Decoupling

Table 2 lists the expected outcomes from revenue decoupling. *First, it would obviously reduce a utility's risk from sales fluctuations.* For a utility, this creates more stability in revenues, cash flows and earnings. Under revenue decoupling, for example, revenue volatility for the utility caused by a downturn in the local economy or higher gas prices leading to fewer sales would be less pronounced. Although a utility's overall risk would seemingly decline, exactly by how much would require a sophisticated quantitative analysis. In the order approving Piedmont Gas' revenue decoupling proposal, the North Carolina Utilities Commission said that "Piedmont argues that there is no evidence of reduced risk to shareholders, but the Commission disagrees on the basis of the Company's own case...In a period of declining per-customer usage, a mechanism that decouples recovery of margin from usage, without requiring the utility to file frequent rate cases or increase unpopular fixed charges, clearly reduces shareholder risk."[49] Because of the company's RD mechanism (Rider 8), the Maryland Public Service Commission reduced

Although a utility's overall risk might decline, determining how much would require sophisticated quantitative analysis.

the authorized rate of return on equity for Baltimore Gas and Electric by 50 basis points to reflect reduced revenue risk for the utility.

Essentially, the utility would become indifferent to its sales.

Second, revenue decoupling reduces a utility's incentive to grow its sales, or to offer new services, and, simultaneously, provides a lesser disincentive to promote energy efficiency. Essentially the utility becomes indifferent to the level of its sales, assuming the utility achieves the same earnings irrespective of actual sales. This is probably more valid in the short term. In the longer term, a utility may prefer promoting sales to the extent it helps support new capital expenditures, which are rate based and consequently add to the utility's earnings.

If a utility's customers collectively use less gas, rates could rise. But reduced benefits would be small relative to realized benefits.

Third, between rate filings revenue decoupling would result in an inverse relationship between the utility's base rate and actual sales. For example, if sales drop because of an aggressive effort by the utility to promote energy conservation, under revenue decoupling this would increase the base rate in the absence of a rate filing.

Fourth, as a corollary to fewer sales resulting, the utility's short-run average cost for non-gas service would tend to be higher.[50] Logically, as fixed costs cover less sales, average cost would rise. The assumption of lower sales seems valid even if the utility has no special energy-efficiency initiatives; the reason is that RD would make the utility less motivated than otherwise to increase its sales through promotional practices. Since non-gas service reflects a fixed cost business, any sales decline induced by revenue decoupling would have little effect on a utility's short-run non-gas costs. This outcome is implicit under a RD mechanism, as rates adjust upward to compensate for the utility's higher average cost stemming from fewer sales.

Fifth, RD would probably have little effect on customer-initiated energy efficiency.[51] The benefits to a customer from using less natural gas sums to the delivered price (i.e., the base rate plus the purchased gas costs) times the amount of gas saved. For an individual customer consuming less gas, RD would have a miniscule effect on a utility's rates. In other words, the presumption here is that an individual customer curtailing her use of natural gas by itself would have no visible effect on rates since the lost revenue to the utility would be imperceptible relative to total revenues. On the other hand, if a utility's customers collectively consume less gas, this could cause rates to rise. In this event, the benefits to individual customer from energy conservation could somewhat decline, but even here the reduced benefits would be small relative to the size of the realized benefits. In recent years, for many utilities the base rate for natural gas to residential customer has fallen to less than 30 percent of the total delivered price.[52] Assuming that RD causes the base rate to increase by 2 percent with the base rate representing 30 percent of the delivered price, customers would see an aggregated rate increase of 0.6 percent.[53] Consequently, customers would realize 0.6 percent less benefits from energy conservation.[54] As

EXHIBIT
RUCO-10
ADMIN NOTICE

5905

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
FEB 23 2006
DOCKETED BY AR

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. G-01551A-04-0876

DECISION NO. 68487

OPINION AND ORDER

DATES OF HEARING: October 3, 4, 5, 6, 7 and 11, 2005

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: William A. Mundell, Commissioner
Marc Spitzer, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Andrew W. Bettwy, Ms. Karen S. Haller and Mr. Justin Lee Brown, on behalf of Southwest Gas Corporation;

Mr. Scott S. Wakefield, on behalf of the Residential Utility Consumer Office;

Mr. Walter Meek, on behalf of the Arizona Utility Investors Association;

Mr. Peter Q. Nyce, Jr., on behalf of the United States Department of Defense;

Mr. Timothy M. Hogan, Arizona Center for Law in the Public Interest, on behalf of Southwest Energy Efficiency Project and Natural Resources Defense Council;

Ms. Laura Sixkiller, ROSHKA, DEWULF & PATTEN, PLC, on behalf of Tucson Electric Power Company; and

Mr. Jason Gellman and Ms. Diane Targovnik, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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BY THE COMMISSION:

On December 9, 2004, Southwest Gas Corporation ("Southwest Gas" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase.

On January 7, 2005, the Commission's Utilities Division Staff ("Staff") filed a Letter of Insufficiency.

On January 26, 2005, Staff filed a Letter of Sufficiency indicating that Southwest Gas' application met the sufficiency requirements outlined in Arizona Administrative Code ("A.A.C.") R14-2-103, and classifying the Company as a Class A utility.

By Procedural Order issued February 7, 2005, procedural timeframes were established and a hearing was scheduled to commence on October 3, 2005.

Intervention was granted to the Residential Utility Consumer Office ("RUCO"); the Arizona Utility Investors Association ("AUIA"); the United States Department of Defense ("DOD"); Southwest Energy Efficiency Project ("SWEEP") and the Natural Resources Defense Council ("NRDC") (collectively "SWEEP/NRDC"); Yuma Cogeneration Associates ("YCA"); Arizona Community Action Association ("ACAA"); Arizona Public Service Company ("APS"); and Tucson Electric Power Company ("TEP").

With its application, Southwest Gas filed the Direct testimony of Jeffrey W. Shaw, Christina A. Palacios, Steven M. Fetter, Christy M. Berger, James L. Cattanach, Vivian E. Scott, A. Brooks Congdon, Edward B. Gieseking, Randi L. Aldridge, Robert A. Mashas, Frank J. Hanley, and Theodore K. Wood.

Pursuant to the revised procedural schedule established by Procedural Order issued March 10, 2005, on July 26, 2005, RUCO filed the Direct testimony of Marylee Diaz Cortez, William A. Rigsby, and Rodney L. Moore; YCA filed the Direct testimony of Jeffrey L. Hoffman; AUIA filed the Direct testimony of Walter W. Meek; ACAA filed the Direct testimony of Brian Babiars (July 20, 2005); SWEEP/NRDC filed the Direct testimony of Jeff Schlegel; and Staff filed the Direct testimony of Stephen G. Hill, Jim Dorf, Dennis Rogers, Robert Miller, William Gehlen, Prem Bahl, William Musgrove, Bob Gray, and Steve Irvine.

On August 23, 2005, Southwest Gas filed the Rebuttal testimony of Ms. Palacios, Mr. Fetter,

Ms. Scott, Mr. Congdon, Mr. Gieseking, Ms. Aldridge, Mr. Mashas, Mr. Hanley, Mr. Wood, William N. Moody, Marti Marek, Robert M. Johnson, and Lisa E. Moses.

On September 13, 2005, RUCO filed the Surrebuttal testimony of Ms. Diaz Cortez, Mr. Rigsby, and Mr. Moore; AUIA filed the Surrebuttal testimony of Mr. Meek; SWEEP/NRDC filed the Surrebuttal testimony of Mr. Schlegel; DOD filed the Surrebuttal testimony of Dan L. Neidlinger; and Staff filed the Surrebuttal testimony of Mr. Hill, Mr. Dorf, Mr. Rogers, Mr. Gehlen, Mr. Musgrove, Mr. Gray and Mr. Irvine.

On September 23, 2005, Southwest Gas filed the Rejoinder testimony of Ms. Palacios, Mr. Fetter, Mr. Cattanach, Ms. Scott, Mr. Congdon, Mr. Gieseking, Mr. Moody, Ms. Marek, Ms. Moses, Ms. Aldridge, Mr. Mashas, Mr. Hanley, and Mr. Wood.

On September 26, 2005, a prehearing procedural conference was conducted to address order of testimony and exhibits.

The evidentiary hearing was commenced as scheduled on October 3, 2005, and additional hearing days were held on October 4, 5, 6, 7, and 11, 2005.

On October 21, 2005, Southwest Gas filed a substitute Exhibit A-50 (Annual Consumption Graph for Low Income and Non-Low Income Residential Customers) and Exhibit A-52 (information regarding the Company's Management Incentive Plan), a portion of which was submitted under seal.

On November 4, 2005, Southwest Gas filed Exhibit A-53 (compilation of regulatory commission orders from other states addressing decoupling mechanisms) and Exhibit A-54 (summary of Southwest Gas' revised position on cost of equity and rate of return).

Initial Post-Hearing Briefs were filed by DOD on October 31, 2005, by RUCO on November 3, 2005, and on November 4, 2005 by Southwest Gas, SWEEP/NRDC, AUIA, and Staff.

Reply Briefs were filed on November 14, 2005 by Southwest Gas, RUCO, SWEEP/NRDC, and Staff.

On November 23, 2005, Southwest Gas filed a Supplement to its Reply Brief.

Rate Application

According to the Company's application, as modified, in the test year ended August 31, 2004 Southwest Gas had adjusted operating income of $46,775,622 on an adjusted Original Cost Rate Base

("OCRB") of $943,110,070, for a 4.96 percent rate of return. Southwest Gas requests a revenue increase of $66,898,342. Staff recommends a rate increase of $51,625,135, and RUCO recommends an increase of $48,506,079. A summary of the parties' positions[1] follows:

	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			
Adjusted Rate Base	$943,110,070	$924,927,566	$919,607,846
Rate of Return	9.24%	8.40%	8.64%
Req'd Operating Inc.	87,140,541	77,693,916	79,478,947
Op. Income Available	46,775,622	46,644,274	50,211,496
Operating Inc. Def.	40,364,919	31,049,641	29,267,452
Rev.Conver. Factor	1.6573	1.6627	1.6573
Gross Rev. Increase	66,898,342	51,625,135	48,506,079
FAIR VALUE			
Adjusted Rate Base	$1,189,807,002	$1,418,205,879	$1,164,944,249
Rate of Return	7.32%	6.63%	6.82%
Req'd Operating Inc.	87,140,541	77,693,916	79,478,947
Op. Income Available	46,775,622	46,644,274	50,211,496
Operating Inc. Def.	40,364,919	31,049,641	29,267,452
Rev.Conver. Factor	1.6573	1.6627	1.6573
Gross Rev. Increase	66, 898,342	51,625,135	48,506,079

REVENUE REQUIREMENT

Rate Base Issues

Southwest Gas proposes an OCRB of $943,110,070 in this proceeding. Staff proposes an OCRB of $924,927,566, and RUCO recommends an OCRB of $919,607,846. Each of the disputed issues regarding rate base items is discussed below.

Deferred Income Taxes

Southwest Gas has proposed an adjustment to accumulated deferred income taxes that would result in an increase of more than $21 million to the Company's rate base. According to Southwest Gas, the deferred tax adjustment is necessary due to new regulations enacted by the Internal Revenue Service ("IRS") on August 3, 2005 which now require the Company to include in income in 2005 and

[1] Other intervenors in the proceeding raised non-revenue requirement issues which are discussed below.

2006 the cumulative tax deduction taken under the prior uniform capitalization ("UNICAP") rules (IRS Code Section 263A) with respect to the simplified service cost method ("SSCM") for self-constructed assets (Ex. A-27, at 6). This deferred tax adjustment is necessitated by the Company's voluntary election in 2002 to change from its historical method of accounting to SSCM.

Southwest Gas argues that the deferred tax adjustment is proper because the new IRS regulation is known and measurable, and because the change puts the Company in a similar position to where it would have been had it not made the election in 2002. The Company claims that its position is consistent with Commission precedent granting recognition of post-test year rate base adjustments where the impact is known and measurable, and is comparable to Staff's recommendation to recognize changes to property tax expenses that are required by post-test year legislation.

Staff disputes the Company's contention that the proposed deferred tax adjustment is proper in this proceeding. Staff argues that the deferred income tax adjustment proposed by Southwest Gas is due entirely to the Company's voluntary decision in 2002 to change its accounting methodology to the SSCM (Ex. S-6, at 2; Tr. 499-500). Staff also claims that the IRS regulations cited by Southwest Gas are temporary rules and the 2005 Energy Policy Act is likely to increase the amount of the Company's deferred taxes, thereby reducing rate base and offsetting the new IRS rule.

RUCO also opposes the Company's proposed adjustment, arguing that the IRS rule change occurred nearly a year after the end of the test year. RUCO further contends that Southwest Gas failed to include this proposal in its initial application and waited until Rebuttal testimony to propose the adjustment. RUCO also sides with Staff's argument that the IRS rules are temporary and subject to amendment before being made final. As a result, RUCO asserts that the IRS rule change does not meet the known and measurable standard employed for other post-test year adjustments.

We agree with Staff and RUCO that recognition of the new IRS regulation is not proper in this proceeding. As Staff points out, Southwest Gas made an entirely voluntary decision in 2002 to change its accounting methodology for self-constructed assets to SSCM, and it is that voluntary election that has caused the Company to now make accounting changes due to the new IRS regulation. The Company's witness, Lisa Moses, admitted that the 2005 Energy Policy Act would

result in an increase in deferred taxes, and thus a decrease in the Company's rate base, but she indicated that the Company had not quantified the impact of those changes. Although Ms. Moses stated that she does not believe the Energy Policy Act would have a significant impact on Southwest Gas, the Company did not present testimony to show how the Energy Policy Act, which is an equally known and measurable change in law, could have an offsetting effect on the Company's deferred tax liability and rate base (Tr. 495-497). We also believe RUCO's point is well taken, that Southwest Gas could have presented this proposal as part of its direct case to allow other parties more time to analyze the issue prior to the hearing. As a result, we will adopt Staff's position on this issue.

Completed Construction Not Classified

The National Association of Regulatory Utility Commissioners' ("NARUC") Uniform System of Accounts ("USOA"), Section 106, provides the following description of the appropriate regulatory treatment for Completed Construction Not Classified ("CCNC"):

> At the end of the year or such other date as a balance sheet may be required by the Commission, this account shall include the total of the balances of work orders for utility plant which has been completed and placed in service but which work orders have not been classified for transfer to the detailed utility plant accounts. (RUCO Ex. 9)

In its application, Southwest Gas proposed an adjustment to test year rate base to reflect its CCNC balance. Relying on the NARUC USOA section quoted above, RUCO argues that only work orders which have an in-service date that falls within the test year may be included in the adjustment for CCNC (RUCO Ex. 5, at 8). According to RUCO witness Rodney Moore, certain work orders that were included in the Company's CCNC adjustment were not in service by the end of the test year and should, therefore, be disallowed (RUCO Ex. 6, at 7-8).

Through her Rejoinder testimony, Company witness Randi Aldridge explained that "the direct gas plant portion of the CCNC adjustment is plant that was serving test year customers at the end of the test year" and the proposed CCNC adjustment "was made simply to match test year plant with test year customers" (Ex. A-31, at 17-18). Ms. Aldridge also testified on cross-examination that although the Company's work order system may have only a single in-service date for an entire project,

projects such as pipe replacements are completed incrementally to minimize customer outages, but all of the plant additions included in the CCNC account reflect pipe that was used and useful during the test year (Tr. 537-538, 589).

We agree with the Company's proposed CCNC adjustment. As Ms. Aldridge's testimony makes clear, only plant that was in service providing service to customers within the test year was included in the proposed CCNC adjustment. There is no evidence contrary to the Company's assertion that such plant was used and useful during the test year and we believe the Company's treatment of these plant accounts is consistent with the NARUC USOA and prior Commission decisions.

Pipe Replacement

RUCO has proposed disallowance of certain requested pipe replacement projects from the Company's rate base pursuant to the terms of a prior Commission Order that addressed regulatory treatment of defective pipe[2] installed in the former Tucson Gas & Electric system, which was subsequently acquired by Southwest Gas. In Decision No. 58693 (July 7, 1994), the Commission adopted a Settlement Agreement between Southwest Gas, Staff, and RUCO which required Southwest Gas to write-off a certain percentage of the replacement cost of defective pipe, and provided that the pipe replacement percentage write-off amounts would decline annually until the amounts reached zero (Decision No. 58693, at 3-4; RUCO Ex. 3, at 5-6). RUCO witness Marylee Diaz Cortez testified that the Company has continued to make the required pipe replacement write-offs since the prior Decision but the Company seeks in this docket to cease certain of the write-offs (RUCO Ex. 3, at 6).

In its application, Southwest Gas is requesting that the pipe write-off schedule required by Decision No. 58693 be modified to allow the affected write-offs to cease when the specific type of pipe reached an average life of 40 years. Thus, under the Company's proposal the 1960s steel pipe and the ABS pipe would no longer be subject to write-off and the scheduled write-offs for the Aldyl A and Aldyl HD pipe would cease in 2013 and 2020, respectively (*Id.*).

[2] The defective pipe was 1960s steel pipe, and plastic pipe known as Aldyl A, Aldyl HD, and ABS.

Although RUCO agrees that Southwest Gas is entitled to seek modification of the prior write-off requirements, RUCO disagrees with the Company's proposal to retroactively modify the write-off schedule starting in 2000. RUCO argues that Southwest Gas is required to comply with the requirements of Decision No. 58693 until such time as a subsequent Commission Order is issued modifying those requirements (*Id.* at 7-8). Ms. Diaz Cortez agreed that the Company's modified pipe replacement schedule, based on a 40-year life, should be permitted on a going-forward basis, but opposes the retroactive treatment proposed by the Company (*Id.*). Based on its position, RUCO recalculated the write-offs required by Decision No. 58693 and determined that the Company's proposed rate base should be reduced by $1,982,686.

Southwest Gas contends that RUCO misinterpreted the data provided by the Company with respect to pipe replacement amounts. The Company cites to Exhibit A-47, a data request response provided to RUCO that shows the amount of Aldyl A, 1960s steel, and ABS pipe replaced between 2000 and 2004. The Company claims the data request response indicates the costs provided for pipe replacement are "not necessarily for pipe replaced due to defective material or faulty installation practices" (*Id.*). However, the data request cited by Southwest Gas does not identify which costs are related to the prior Order's requirements. Company witness Robert Mashas testified that the Company disagrees with RUCO's recommendation because 1960s vintage steel pipe was never considered a defective material and was only included as part of the Settlement Agreement because it lacked cathodic protection, which has been installed on all of the Company's steel pipe since 1998 (Ex. A-33, at 16-17).

Contrary to the Company's assertions, neither the Settlement Agreement nor the Order adopting it mention cathodic protection for 1960s pipe as a distinguishing characteristic that would permit treatment that is different from the other types of pipe that were considered defective and required specific regulatory treatment. Rather, both the Settlement and the Order specifically state that "In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, Aldyl HD, steel installed in the 1960's, and ABS pipe related to defective materials and/or installation" (Decision No. 58693, at 3).

Mr. Mashas also claims that the effective date of the new write-off should be January 1, 2000, the day after the end of the test year in the Company's last rate case. He contends that this retroactive application of the write-off percentages more accurately reflects the determination of the remedial portion of eligible pipe replacement expenditures (*Id.*). Mr. Mashas stated that the Commission has the authority to make the proposed adjustment retroactive to 2000, and that even RUCO agrees that the Commission has such authority.

Although we may have the legal authority to make the retroactive adjustment proposed by Southwest Gas, we are not inclined to exercise such authority if it is not in accordance with a valid binding Commission Order which adopted a Settlement Agreement to which Southwest Gas was a signatory party. The Company may not unilaterally alter the terms of a Settlement Agreement and Commission Order simply because it has an understanding of the terms of the agreement that may differ from the belief of another party. Rather, the Company could seek an amendment to the requirements of the prior Order if it believed the terms are no longer applicable, which it has properly done in this docket. However, we agree with RUCO that Southwest Gas must continue to comply with the requirements of the prior Order until such time as those requirements are modified by the Commission. Therefore, based on the weight of the evidence, and in accordance with the directives set forth in Decision No. 58693, we adopt RUCO's position on this issue and will reduce the Company's proposed rate base accordingly.

Summary of Rate Base Adjustments

Based on the foregoing discussion, we adopt an adjusted OCRB of $922,944,881 and a Fair Value Rate Base ("FVRB") of $1,169,584,038.

	Commission Approved
ORIGINAL COST:	
Gas Plant in Service - Staff	$1,682,879,492
Less: Accumulated Depreciation	593,408,170
Net Plant in Service	1,089,471,322
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,468,076

Additions:	
Working Capital	881,148
Total OCRB	922,944,881
RCND RATE BASE:	
Gas Plant in Service - Staff	$2,439,429,196
Less: Accumulated Depreciation	856,679,561
Net Plant in Service	1,582,749,635
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,468,076
Additions:	
Working Capital	881,148
Total RCND	1,416,223,194
FAIR VALUE RATE BASE:	
Gas Plant in Service - Staff	$2,061,154,344
Less: Accumulated Depreciation	725,043,866
Net Plant in Service	1,336,110,479
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,691,328
Additions:	
Working Capital	881,148
Total FVRB	1,169,584,038

Operating Income Issues

In the test year, the Company's adjusted operating revenues were $322,865,978. In its Rebuttal Schedules, Southwest Gas reported adjusted test year operating expenses of $276,090,356, and test year net operating income of $46,775,622. As reported in its Surrebuttal Schedules, Staff's proposed adjusted test year operating expenses are $276,221,704, resulting in test year operating income of $46,644,274. RUCO's Surrebuttal Schedules show proposed adjusted test year total operating expenses of $272,654,482, yielding test year operating income of $50,211,496. The disputed expense adjustments are discussed below.

Sales and Marketing Wages for 37 Employees

RUCO witness Rodney Moore proposed disallowance of salaries and wages for 37 Southwest Gas employees who he claimed were engaged in sales, marketing and promotional activities. He

claimed that ratepayers should not be required to fund the cost of such activities and he proposed removal of almost $3 million in salaries from the Company's test year expenses (RUCO Ex. 5, at 15-16). In his Surrebuttal testimony, Mr. Moore modified his recommendation to exclude the entirety of the 37 employees' wages, stating that "RUCO would be willing to explore revisiting its position if a fair and reasonable quantification of the time/costs devoted solely to Customer complaint resolution and Regulatory affairs could be substantiated by the Company" (RUCO Ex. 6, at 18).

In her Rebuttal testimony, Company witness Christina Palacios disputed RUCO's analysis and stated that the Company had previously removed almost $600,000 in promotional and marketing expenses, consistent with prior Commission Decisions. Ms. Palacios testified that the employees' wages that RUCO seeks to disallow are responsible for interacting with individual customers and developers seeking information regarding extension of gas service, as well as maintaining oversight until service is extended to a requesting property (Ex. A-5, at 2-6). Ms. Palacios asserted that the job duties of the employees in question include: advising customers on gas products and availability; coordinating new business processes; working with customers to determine technical needs and specifications; investigating and settling customer complaints; ensuring satisfactory customer service; participating in customer business meetings as consultants/advisors; establishing programs to educate customers; interpreting and applying tariffs to main/service extensions; ensuring adequate and timely coordination of services; negotiating contracts and special agreements; preparing studies and analyses; making presentations to trade allies or potential customers; and staying up to date on government regulations and technology changes within the industry (*Id.* at 4). Southwest Gas cites to Decision No. 64172 wherein the Commission denied RUCO's proposal to remove half of the costs associated with Southwest Gas' sales and marketing employees because "these employees are necessary for processing a request for service" (Decision No. 64172, at 10-11). The Company also cites to a decision by the United States Supreme Court in *West Ohio Gas Co. v. Public Utilities Com'n of Ohio*, 294 U.S. 63, 72 (1935), which held that "[w]ithin the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes...."

We agree with RUCO that a portion of the salaries of employees associated with sales,

marketing, and promotional activities should be excluded from allowable test year expenses in this proceeding. It appears that the majority of these employees' time is dedicated to duties that enhance service to customers and potential customers, thereby providing benefits to both shareholders and ratepayers. However, by the Company's admission, a certain amount of these same employees' time is devoted to purely marketing or promotional activities that the Commission has previously found are expenses that should not be borne by ratepayers. For example, Ms. Palacios provided an estimate at the hearing that the employees in question devoted approximately 90 percent of their time to non-marketing duties, as described above, and approximately 10 percent to marketing activities (Tr. 109-110). In addition, Company witness Aldridge stated that approximately 17 percent of those same employees' compensation was obtained from the Company's Sales Incentive Plan (Tr. 573-574). Despite the admission by Company witnesses that at least some portion of these employees' time is devoted to sales and marketing activities, no attempt was made to allocate a portion of their wages out of test year expenses. Based on the best information in the record, we believe it is reasonable to perform such an allocation and we will therefore disallow 10 percent of the 37 employees' wages from test year expenses (*i.e.*, $289,243). In addition, we expect Southwest Gas in its next rate case to provide a detailed explanation of employee duties that are associated with sales, marketing, or promotional activities and offer a reasonable allocation of wage expense consistent with those duties.

Labor Annualization and 2005 Wage Increases

In this proceeding, Southwest Gas has included in proposed test year expenses an annualization of wage increases that were given to employees in 2004, as well as wage increases granted in 2005 after the end of the test year. However, the Company included only wage increases for employees who were employed as of the end of the test year to avoid a mismatch (Ex. A-31, at 3-5; Tr. 543-545).

Although RUCO accepts the 2004 wage increase, it disputes the inclusion of the post-test year wage increase because it believes inclusion of the 2005 increase constitutes a double counting of such expenses (RUCO Ex. 6, at 11; Tr. 929-930).

Staff witness Jim Dorf testified that Staff has accepted the reasonableness of including both the 2004 and 2005 wage increases because the costs are known and measurable (Tr. 1085).

We agree with Staff that the 2005 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses.

American Gas Association Dues

The American Gas Association ("AGA") is a national trade association for natural gas distribution and transmission companies. During 2004, Southwest Gas paid dues to the AGA (Arizona portion) of $211,934 (RUCO Ex. 5, RLM-9). The AGA provides services to its members in the following categories: Public Affairs; Communications; Corporate Affairs and International; General Counsel and Corporate Secretary; Regulatory Affairs; Marketing Development; Operating & Engineering Services; Policy & Analysis; Industry Finance & Administrative Programs; and General & Administrative Expense (Ex. A-30, RLA-3).

Although Southwest Gas claims that it has removed the amount of the dues that are attributable to the AGA's Marketing and Lobbying functions (1.54 percent and 2.10 percent, respectively), RUCO seeks an additional 39.09 percent disallowance ($75,385) for the Public Affairs and Communications functions performed by the AGA (RUCO Ex. 5, RLM-9). According to RUCO witness Moore, the Communications category of AGA operations promotes the use of gas over other fuels, while the Public Affairs category provides members with information on legislative and regulatory developments, provides testimony, comments, and filings regarding legislative and regulatory activities, and lobbies on behalf of the industry (*Id.* at 21-22).

Southwest Gas witness Aldridge countered that the Communications and Public Affairs categories are appropriate AGA functions that should be recovered in test year expenses because the Company removed the amounts specifically associated with marketing and lobbying. Ms. Aldridge testified that the Communications function of the AGA includes developing informational materials for member companies and consumers and coordinating all media activity (Tr. 550). With respect to the Public Affairs function, the AGA described its activities as follows: "The [AGA] monitored and represented the activities of Congress and Federal agencies that affected issues of importance to the natural gas industry and its customers. This division also monitored state and local legislative and

regulatory trends. In 2002 its major federal, legislative and regulatory efforts were pipeline safety legislation and regulation, Federal funding for Low Income Home Energy Assistance Program (LIHEAP), federal funding for research, and national energy policy legislation." (Ex. A-30, RLA-3).

We believe that the Company has demonstrated sufficiently that, having removed the portion of its AGA dues directly attributable to marketing and lobbying, the remainder of the AGA dues should be recoverable as legitimate test year expenses. Although the descriptions of AGA activities provided by the Company are somewhat nebulous, we find that Southwest Gas has met its burden of showing that the functions for which RUCO seeks exclusion have a benefit to the Company and its customers and should be allowed. However, in its next rate case filing the Company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona customers.

Transmission Integrity Management Program Expenses

The federal Pipeline Safety Improvement Act of 2002 directed the Office of Pipeline Safety and the Research and Special Programs Administration divisions of the U.S. Department of Transportation to enact regulations creating standards for transmission pipeline risk analysis and adopting a pipeline integrity management program (Ex. A-32, at 19-21). In Arizona, Southwest Gas has identified approximately 335 miles of transmission facilities located in high consequence areas that are subject to the federal legislation (Ex. S-3, at 6-7). The Company's application in this docket includes an expense adjustment to recover costs associated with compliance with this legislation, which Southwest Gas calls its Transmission Integrity Management Program ("TRIMP"). The Company seeks to recover costs incurred prior to the effective date of the rates in this proceeding, as well as a representative level of ongoing costs that it expects to incur due to ongoing TRIMP activities (*Id.*). Although the Company initially sought to recover a higher level of TRIMP expenses, it subsequently agreed to RUCO's recommendation to amortize 2004 and 2005 TRIMP costs over 7 years ($138,365 annually), with an additional test year allowance of $603,677 annually (RUCO Ex. 3, MDC-5).

Staff witness Dorf testified that although Staff encourages Southwest Gas to comply fully with the new pipeline safety regulations, Staff is concerned with the volatility of the Company's

estimated compliance costs, as exemplified by a comparison of the Company's original estimate of more than $12 million through 2009 compared to its revised estimate of just over $3 million (Ex. S-4, at 5). Due to this fluctuation in the estimated ongoing compliance costs, as well as Staff's belief that the expenses should be borne jointly by shareholders and ratepayers, Mr. Dorf recommended establishment of a surcharge mechanism that would allow recovery through rates of half of the baseline direct assessment, direct examination, and maintenance and repair TRIMP-related costs (but not capital replacements). Staff proposes that the surcharge be labeled on customer bills as "DOT Pipeline Safety Surcharge." Staff's proposed surcharge would have annual adjustments after the first and second year, and would terminate at the end of the third year (Ex. S-3, at 11-14). Mr. Dorf explained that Staff's rationale for its recommendation is based on the following factors: 1) the Pipeline Safety Act of 2002 has significantly modified pipeline safety regulations; 2) the estimated costs of complying with the new regulations are significant; 3) initial assessments must be performed in a compressed time period; 4) current rates do not provide for recovery of these incremental costs; and 5) the costs are estimated at this time and are therefore inappropriate for inclusion in base rates (*Id.* at 12).

We agree with the reasoning expressed by Staff witness Dorf that TRIMP costs should be borne equally by shareholders and ratepayers, and a surcharge mechanism is the appropriate means of recovery. As Mr. Dorf stated at the hearing, recovery of TRIMP expenses through a surcharge would mitigate potential volatility in the program's costs especially given the long projection period for completing the first cycle of TRIMP costs (Tr. 1082). With respect to the split of TRIMP costs, we also agree with Staff that because the pipeline safety program benefits both shareholders and ratepayers, the TRIMP expenses should be shared equally. We will therefore adopt Staff's recommendation for treatment of TRIMP costs.

Sarbanes-Oxley Compliance Expenses

Section 404 of the Sarbanes-Oxley Act of 2002 ("SOX") requires the establishment of an internal control structure and certain procedures for financial reporting, including a requirement that the company's annual report contain an internal control report (Ex. A-29, at 21-22). This legislation created the Public Company Accounting Oversight Board, and requires that publicly traded

1 companies' external auditors attest to and report on management's assessment of the effectiveness of
2 their internal controls and procedures. Companies were required to be in compliance with SOX by
3 December 31, 2004 (Ex. S-3, at 15).

4 Southwest Gas seeks an adjustment to recover expenses related to the initial assessment and
5 review of the Company's internal controls and additional post-test year expenses that it claims are
6 necessary to fully implement SOX requirements, as well as estimated incremental and recurring
7 compliance costs related to audit fees (Ex. A-30, at 9-13). Subsequent to filing its application, the
8 Company updated its estimated compliance costs to reflect actual expenses, and Ms. Aldridge
9 testified that those costs are reasonable in light of the Company's use of internal labor, including
10 exempt employee labor for which overtime pay was not required (*Id.*).

11 Staff recommends an equal sharing of ongoing SOX compliance costs between ratepayers and
12 shareholders based on its claim that the improved internal controls required by SOX provide a benefit
13 to both groups. Staff witness Dorf stated that the SOX requirements protect ratepayers with
14 improved compliance and benefits shareholders by protecting them from management impropriety
15 (Staff Ex. 3, at 17). Mr. Dorf also testified that Staff recommends a 25 percent reduction of initial
16 audit costs based on published reports by the American Institute of Certified Public Accountants that
17 original estimates were overstated, and Staff recommends disallowance of the Company's proposed
18 recovery of non-recurring implementation costs (*Id.*; Tr. 1085-1087).

19 Although it is important for Southwest Gas to comply fully with federally mandated audit and
20 reporting requirements, we believe Staff's recommendation more accurately reflects the actual SOX
21 compliance costs that will be incurred by the Company for the period that the rates set in this
22 proceeding are in effect. As Mr. Dorf points out in his testimony, Staff's recommendation is based
23 on numerous published articles that indicate there will be significant reductions to many companies'
24 first year implementation and audit costs. Mr. Dorf cited to a white paper published by Enterprise
25 Financial Consulting, LLP, which suggests numerous ways to reduce SOX costs in future years, and
26 indicates that use of a compliance software application alone could save a minimum of 30 percent of
27 the initial compliance costs (Ex. S-4, at 6).

28 We also agree with Staff's equal sharing of ongoing SOX compliance costs given the clear

benefit that shareholders will receive in addition to ratepayer benefits. If anything, shareholders are likely to be greater beneficiaries of the SOX legislation because compliance with the new law will provide additional assurance that companies' financial statements have a higher degree of reliability. Indeed, ratepayers are at best only secondary beneficiaries of the SOX compliance procedures. We will therefore adopt Staff's position on this issue.

Management Incentive Program

Southwest Gas provides compensation in addition to base salaries to certain eligible management employees through its Management Incentive Program ("MIP") based on achievement of the following five factors: 1) an improved customer-to-employee ratio when compared to the prior year; 2) a comparison of the Company's customer-to-employee ratio to its peer utilities; 3) the results of customer satisfaction surveys; 4) the achievement of a three-year return on equity ("ROE") target; and 5) a comparison of the Company's ROE to its peer utilities (Ex. A-33, at 7). Company witness Mashas claims that these five factors were designed to align customer and shareholder interests (*Id.*). Southwest Gas contends that achieving these goals increases productivity and helps the Company retain quality employees by deferring 60 percent of the MIP payout for three years (*Id.* at 6-11).

RUCO proposes to reduce MIP expenses by 67 percent to recognize that shareholders receive the majority of benefits through achievement of the MIP performance targets, especially between rate cases. Ms. Diaz Cortez testified that amounts awarded under the MIP could be viewed as bonuses because the eligible individuals also receive wage and salary increases. She also stated that the annual amount of MIP compensation is not known and measurable because the payouts depend on reaching the performance goals (RUCO Ex. 3, at 20-23).

Staff also recommends reducing MIP expenses, but proposes an equal sharing between shareholders and ratepayers. Staff witness Dorf stated that shareholders and ratepayers stand to benefit from the performance goals, but added that there is no assurance that the award levels achieved during the test year will be repeated in future years (Ex. S-4, at 9-10).

Southwest Gas responds that MIP payouts should be considered part of the employees' overall compensation package and no party in the case has suggested that the employees' total pay is unreasonable, and that the Company is penalized by the Staff and RUCO proposals by putting part of

its management's compensation at risk. According to Southwest Gas, if the Company put these amounts in the employees' base salary, Staff and RUCO would not claim that there should be a disallowance.

In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

Supplemental Executive Retirement Plan

Southwest Gas offers a Supplemental Executive Retirement Plan ("SERP") to the Company's officers. Company witness Mashas testified that the SERP is necessary "to ensure that the retirement and deferred compensation portions of [the officers'] total compensation are on parity with all other employees of Southwest whose retirement distribution is not impacted by certain IRS regulations" (Ex. A-33, at 3). Mr. Mashas claims that recovery of the SERP costs is reasonable due to restrictions on these employees' basic retirement plan ("BRP"), exclusion of deferred compensation from the BRP calculation, and the need to ensure attraction and retention of qualified employees. Mr. Mashas explained that IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service (*Id.* at 5-6). In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that "maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees" (*Id.* at 4-5).

RUCO witness Moore proposed a reduction in test year expenses of approximately $2.7

million associated with the SERP. Mr. Moore stated the cost of these supplemental retirement benefits for select executives is not a necessary cost of providing gas service to customers because the Company's officers are already fairly compensated with a wide array of benefits, including a retirement plan. Mr. Moore cited to the Company's most recent rate case before the Nevada Public Utilities Commission[3] where Southwest Gas' SERP expenses were excluded from the Company's operating expenses (RUCO Ex. 5, at 28-29).

We agree with RUCO's position on this issue. Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Miscellaneous Expenses

Through her Direct testimony, Company witness Aldridge indicated that the application included an adjustment to remove certain miscellaneous expenses for items such as gym memberships, donations and meals (Ex. A-29, at 23).

Based on his review of data requests, RUCO witness Moore proposed an additional adjustment to remove from test year expenses "payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service" (RUCO Ex. 5, at 25).

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[3] *Application of Southwest Gas Corporation for Increase in Rates*, Public Utilities Commission of Nevada, Order in Docket No. 04-3011 (August 30, 2004), at 41.

In her Rebuttal testimony, Ms. Aldridge stated that RUCO had failed to justify the exclusion of the various miscellaneous expenses identified by Mr. Moore. Ms. Aldridge claimed that the vast majority of the expenditures are reasonable, recurring, and necessary business expenses and should remain in cost of service. However, after additional review, Ms. Aldridge accepted exclusion of a portion of RUCO's proposed disallowance ($62,165 Arizona jurisdictional), but further testified that accepting RUCO's recommendation would result in exclusion of expenses related to moving expenses for a transferred employee; safety awards and costs related to the Company's Operations Center; alcohol and drug testing; and continuing professional education (Ex. A-30, at 15-16).

In his Surrebuttal testimony, Mr. Moore indicated that there were additional expenses the Company had not removed that RUCO believes should not be recoverable through rates. Examples of expenses that Mr. Moore claims remain in the Company's miscellaneous expenses include: liquor, coffee, water, ice, sodas, smoothies, bagels, donuts, subs, trophies, flowers, gift certificates, photographs, charitable/community service club donations, travel reduction programs, shareholder meetings, recognition events, sports events, club memberships, art work, and barbecues and accessories (RUCO Ex. 6, at 20-21). Mr. Moore stated that RUCO would agree to reduce its proposed disallowance by approximately 20 percent, from $346,299 to $277,039, "to avoid the tedious litigation of line-by-line examination of the 40 pages of workpapers" (*Id.* at 21).

In her Rejoinder testimony, Ms. Aldridge claimed that specific items identified by Mr. Moore (*i.e.*, liquor, club donations, sports events, club memberships, barbecues) were removed by the Company as part of the $62,165 adjustment described above (Ex. A-31, at 14-15). She indicated that certain meal costs and expenses related to employee appreciation and charitable events were not removed because she believes such expenses are reasonable business expenses. Ms. Aldridge also criticized RUCO's analysis of the workpapers provided through data requests as lacking sufficient detail which was "not even enough for <u>the Company</u> to determine whether a transaction should remain in cost of service" (emphasis original) (*Id.* at 16). She therefore concluded that "RUCO has simply presented insufficient evidence to support their proposed disallowance" (*Id.*). On cross-examination, Ms. Aldridge maintained that she had removed expenses related to barbecues, Jeep tours, and balloon rides as part of the $62,165 adjustment, but that other expenses for items such as

awards for meter reading accuracy, safe driving awards, shareholder meetings, photographs, sympathy cards and flowers are necessary business expenses that should be recovered through rates (Tr. 353-358, 583-587). She admitted that the exclusion of $62,165 of expenses (for barbecues, Jeep tours etc.) were removed only after RUCO raised the issue through its testimony (Tr. 583).

Although we appreciate Ms. Aldridge's attempt to exclude expenses that are clearly inappropriate for recovery from ratepayers, we do not believe that the Company has met its burden of proving the reasonableness of all of the miscellaneous expenses for which it seeks recovery. It is curious that Southwest Gas seeks to cast the burden of proving the unreasonableness of expenses on RUCO, especially once RUCO has provided some evidence that certain claimed expenses are inappropriate and which evidence, by the Company's own admission, should result in additional exclusions. Given the state of the record, it is unclear precisely which additional miscellaneous expenses should be excluded from cost of service, but we believe that at least a portion of the items that the Company believes are reasonable business expenses should be disallowed (*e.g.*, shareholder meeting expenses). Because the Company failed to sustain its burden of proof on this issue, but also recognizing that many of these miscellaneous expenses may be legitimate and reasonable business expenses, we will disallow half of RUCO's original proposed disallowance ($346,299 x 50% = $173,150 disallowance).

Southwest Gas Legal Arguments

Throughout its legal Briefs, Southwest Gas repeatedly cites the case of *Anaheim, Riverside, Banning, Colton, and Azusa, California v. Federal Energy Regulatory Commission*, 669 F.2d 799, 809 (U.S. App. D.C. 1981), to support its assertion that Staff's recommendations must fail because Staff failed to present sufficient evidence to raise a serious doubt as to the prudence of the Company's proposal. As Staff points out in its Reply Brief, the *Anaheim* case was based on the Federal Power Act which, pursuant to 16 U.S.C. §824d(e), imposes on the utility company the "burden of proof to show that the increased rate of charge is just and reasonable." The *Anaheim* case, while not controlling precedent, also stands for the proposition that once a party challenges the propriety of a particular aspect of the company's application with some credible evidence, it is incumbent upon the utility to demonstrate the reasonableness of its proposals. The evidence presented through sworn

testimony and other exhibits has been carefully weighed and a just and reasonable result achieved based on consideration of the competing evidence and arguments. As established by the Arizona Constitution and relevant case law, this Commission has broad discretion in setting just and reasonable rates and we believe our findings herein achieve that goal despite the Company's disagreement.

Southwest Gas also repeatedly cites *West Ohio Gas v. Public Utilities Commission of Ohio*, 294 U.S. 63 (1935), to support its contention that specific expense items, including advertising and promotional costs, must be presumed reasonable. While the *West Ohio Gas* case indicates that "good faith" should be presumed on the part of a company's managers with respect to the prudence of expenditures, we disagree with the position advocated by Southwest Gas that our consideration of the reasonableness of any particular expense may not include recognition of the relative benefits that may be derived from such costs. The test of reasonableness is based on a host of considerations presented in the record and may not be reduced to a simple pass through of costs claimed by the Company in order to pass legal muster. The Commission's ratemaking authority allows precisely the type of analysis that has been conducted with respect to these expense items and is consistent with case law interpreting that authority.

Net Operating Income

Consistent with the foregoing discussion, we will allow adjusted test year operating expenses of $275,031,605, which based on test year revenues of $322,865,978, results in test year adjusted operating income of $47,834,373, a 6.63 percent rate of return on FVRB.

COST OF CAPITAL

As amended at the hearing, Southwest Gas recommends that the Commission determine the Company's cost of common equity to be 11.42 percent if its proposed conservation margin tracker ("CMT") is not adopted and 11.17 percent with adoption of the CMT (see discussion of CMT below). The Company's weighted cost of capital recommendation is 9.24 percent without the CMT and 9.13 percent with the CMT (Tr. 783-784; Ex. A-54). Staff recommends a cost of common equity rate of 9.50 percent with an overall weighted average cost of capital determination of 8.40 percent (Ex. S-1, SGH-1, Sched. 11). RUCO proposes adoption of a cost of common equity of 10.15 percent and a

weighted average cost of capital of 8.64 percent (RUCO Ex. 1, WAR-1).

Capital Structure

During the test year, Southwest Gas had an average actual capital structure consisting of 34.5 percent common equity, 5.3 percent preferred stock, and 60.2 percent long-term debt (Ex. A-38, TKW-1). The Company, Staff, and RUCO agree that the Commission should employ a hypothetical capital structure for purposes of setting rates in this proceeding. However, Staff disagrees with the Company and RUCO as to the composition of the hypothetical structure.

Southwest Gas proposes adoption of a hypothetical capital structure of 42 percent common equity, 5 percent preferred equity, and 53 percent long-term debt (Ex. A-38, at 8-33). According to Company witness Theodore Wood, Southwest Gas has improved its actual common equity ratio from 31.1 percent in 1995 to 37.0 percent as of June 30, 2005, despite the financial challenges facing the Company from a combination of rapid customer growth and inability to earn its authorized rate of return (Ex. A-40, at 7). Mr. Wood stated that the Company's requested 42 percent hypothetical structure is consistent with past Commission practice to set the equity ratio above the Company's actual capital structure but below the average of similar risk natural gas distribution companies (*Id.* at 11). Mr. Wood criticizes Staff's proposed 40 percent capital structure and cites to Southwest Gas' issuance of approximately 15.8 million shares of common stock between 1994 and 2004, netting $313.7 million in proceeds, as well as the recent $60 million Equity Shelf Program, as examples of the Company's dedication to improve its equity ratio despite financial hurdles (*Id.* at 16; Ex. A-39, at 20-21). Mr. Wood was also critical of Staff's recommendation to require a formal recapitalization plan because of the dilution effect on existing shares and the potential negative impact on the Company's stock price. According to Mr. Wood, such a requirement would be detrimental to the integrity of existing capital and could hinder the Company's ability to maximize proceeds from subsequent stock offerings (*Id.* at 21-22).

Although, as discussed below, RUCO disagrees with Southwest Gas' overall cost of capital recommendation, it agrees with the Company's hypothetical capital structure proposal. RUCO witness William Rigsby stated that he adopted the Company's hypothetical structure in his analysis because Southwest Gas is close to the average debt and equity percentages in his sample group of

local distribution companies ("LDCs"). The capital structures for his sample group averaged 51.2 percent long-term debt, 0.3 percent preferred equity, and 48.5 percent common equity (RUCO Ex. 1, at 44-45). Thus, when Southwest Gas' preferred and common equity are combined under RUCO's proposed hypothetical structure, a 47 percent total equity ratio is achieved for purposes of analyzing the Company's cost of capital.

Staff recommends that the Commission adopt a 40 percent hypothetical structure, with 5 percent preferred stock and 55 percent debt, for purposes of determining Southwest Gas' overall cost of capital in this proceeding. Staff witness Stephen Hill testified that the equity ratio of Southwest Gas has been consistently low for more than a decade and that ratepayers should not be required to, in effect, subsidize the Company's equity return to the extent requested by Southwest Gas (Ex. S-1, at 20-27). Mr. Hill stated that Staff's recommended 40 percent equity ratio provides an appropriate balance between financial safety and economy for Southwest Gas and is consistent with the hypothetical structure adopted in the Company's last rate case (*Id.*). Mr. Hill also recommends that the Commission should require Southwest Gas to submit a re-capitalization plan for how the Company can reach an actual 40 percent equity goal prior to its next rate proceeding. Mr. Hill further proposes that if the Company elects not to increase equity capital to at least 40 percent, the Commission should set rates in the next case using the actual capital structure at that time (*Id.* at 26).

Although it did not present a specific cost of capital recommendation, AUIA criticized Staff's proposal to require Southwest Gas to adopt a recapitalization plan to increase its equity ratio to at least 40 percent by the Company's next rate case. AUIA argues that the cause of the Company's debt-heavy capital structure is its inability to earn its authorized rate of return over a number of years, which it claims is at least as damaging to shareholders as ratepayers. AUIA witness Walter Meek testified that shareholders would support a plan to achieve a 40 percent equity ratio if the Commission would adopt a rate design that would enable Southwest Gas to actually earn its authorized rate of return (AUIA Ex. 2, at 8).

We agree with Staff that use of a 40 percent equity ratio is appropriate in this proceeding. The 40 percent ratio is more than 5 points higher than the ratio in existence at the end of the test year and 3 points higher than the Company's equity at the end of June 2005. This hypothetical capital

structure is consistent with our Order in the Company's last rate case (Decision No. 64172, at 17). Although Southwest Gas has made some progress over the past decade to improve its equity position relative to debt, our continuing need to employ an inflated equity ratio for setting rates in case after case highlights the need to encourage even greater efforts to increase the equity ratio. Ultimately, however, the level of equity lies within the control of the Company's management and not with ratepayers who have been asked to shoulder the burden of rates set based on a hypothetical structure that does not actually exist.

As Staff witness Hill pointed out, ratepayers have for many years been burdened with an authorized return set using a hypothetical capital structure far greater than the Company's actual equity ratio. At some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its actual capital structure. Therefore, we believe it is also appropriate to adopt Staff's recommendation to require Southwest to submit a re-capitalization plan explaining how it intends to achieve a 40 percent equity prior to the Company's next rate case. We do not believe it is necessary, at this time, to determine whether failure to reach the 40 percent goal would result in use of the Company's actual capital structure in its next rate case. However, the possibility of such a determination in the next rate case will depend on the Company's efforts to make progress on this issue based on the plan it develops and implements pursuant to this Order.

Cost of Common Equity

Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimation that is both art and science. As evidenced by the competing methodologies employed by the three cost of capital witnesses in this case, there is no clear-cut answer as to which formula should be used for reaching the appropriate outcome. Rather, the three expert witnesses, Messrs. Hanley, Hill, and Rigsby, each rely on various analyses for their recommendations.

Southwest Gas

Southwest Gas' expert witness, Frank Hanley, based his common equity cost recommendation of 11.42 percent (or 11.17 percent with the CMT) on the results of his common equity models,

namely, the Discounted Cash Flow ("DCF"), Risk Premium Model ("RPM"), Capital Asset Pricing Model ("CAPM"), and Comparable Earnings Model ("CEM"). According to Mr. Hanley, use of these models is consistent with the Efficient Market Hypothesis ("EMH"), which is based on the premise that investors are aware of all relevant publicly available information in making their investment decisions (Ex. A-35, at 20-24). Mr. Hanley stated that, absent evidence to the contrary, it must be assumed that investors are aware of all of the models he used in his analysis and that those investors take the models into account in making their decisions (*Id.*).

In his analysis, Mr. Hanley developed two proxy groups of comparable gas distribution companies. Based on an historical comparison of financial data for the proxy groups and Southwest Gas, Mr. Hanley found that Southwest Gas has earned returns well below those of the proxy groups (Tr. 680-681). According to Mr. Hanley, during the period of 1997 through 2003, Southwest Gas achieved an average return on actual book common equity of 6.74 percent in Arizona, compared to the 11.62 percent and 12.11 percent average return on equity ("ROE") realized by the proxy groups (Ex. A-35, FJH-1).

The Company argues that there is an even greater disparity with the proxy group ROEs if Southwest Gas' greater level of business risk is taken into account, as evidenced by the Standard & Poor business profile of 3.0 for Southwest Gas compared to the proxy group average profiles of 1.8 and 2.0 (Ex. A-35, at 13-14, FJH-11). The Company also claims its ROE request is reasonable compared to other litigated cases for LDCs across the country the past several years, where the average ROE granted was 10.91 percent, for companies with a common equity ratio of 47.5 percent (Ex. A-36, at 41, FJH-24). The Company argues that these comparisons support the need for a higher ROE because Southwest Gas is more risky, from both a business and financial risk perspective.

Southwest Gas contends that Staff's recommended ROE understates significantly a reasonable return for the Company based on *Value Line* forecasts for other LDCs. Mr. Hanley cited to a *Value Line* survey from June 17, 2005, which reported an expected 12.5 percent ROE for such companies relative to a 45.5 percent common equity ratio (Ex. A-37, at 16). Mr. Hanley criticized Staff's reliance on the DCF method for determining ROE based on his claim that the DCF tends to understate the common equity cost rates when market values exceed book values and when such

market-based investors' required rates of return are applied to lower book values (*Id.* at 7).

The Company also cites to the *Hope* and *Bluefield* cases[4], as well as Article 15, §3 of the Arizona Constitution and *Residential Utility Consumer Office v. Arizona Corporation Com'n*, 199 Ariz. 588 (2001), for the proposition that the Commission must consider Southwest Gas' greater risk relative to other LDCs when determining an appropriate common equity cost rate.

RUCO

RUCO contends that its proposed 10.15 percent cost of common equity is appropriate given the Company's actual capital structure, the current environment of relatively low inflation and interest rates, and the Company's relatively higher financial risk compared to other similar LDCs (RUCO Ex. 1, at 43-45). RUCO witness Rigsby employed both a DCF analysis and CAPM to reach his recommendation. His DCF analysis yielded an 8.91 percent COE result, while the CAPM resulted in a range of 8.82 to 10.39 percent (*Id.* at 27). In reaching his 10.15 recommendation, Mr. Rigsby rounded up (to 10.40) the upper end of his CAPM results, and then reduced that result by 25 basis points to achieve RUCO's proposed 10.15 cost of common equity (*Id.*).

Mr. Rigsby acknowledged that his proposal is 124 basis points higher than the 8.91 percent DCF result, but contends Southwest Gas' heavily leveraged position and higher level of financial risk compared to his proxy LDCs warrants a recommendation at the higher end of his results. He also states that his recommendation is close to the 10.50 percent return on common equity adopted by the Nevada Public Utilities Commission in Southwest Gas' most recent rate proceeding (Docket No. 04-3011). Mr. Rigsby indicated that his decision to lower the COE recommendation by 25 basis points from the CAPM upper end was based on RUCO's recommendation to adopt a rate design that mitigates income volatility to Southwest Gas by shifting more of the revenue recovery from the Company's commodity charge to its fixed monthly charge, in lieu of adopting the Company's proposed CMT (*Id.* at 28). On the other end of the spectrum, his recommendation of 124 basis points above the DCF result reflects concern over the Company's inability to achieve higher levels of shareholder equity and the *Value Line* comparison to other proxy LDCs compared to Southwest Gas

[4] *Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, et al.*, 262 U.S. 679 (1923).

(*Id.* at 29).

Staff

In determining Staff's cost of common equity recommendation in this proceeding, Staff witness Stephen Hill conducted a DCF analysis which resulted in a cost of common equity estimate of 9.20 percent. Mr. Hill stated that, in order to support and temper his DCF results, he used three additional econometric models to estimate the cost of equity capital for a group of firms similar in investment risk to Southwest Gas. The three additional methods used by Mr. Hill are: 1) CAPM; 2) the Modified Earnings-Price Ratio ("MEPR"); and 3) the Market-to-Book Ratio ("MTB"). The sample proxy companies used for these models are the same as those employed by Mr. Hill for his DCF analysis (Ex. S-1, at 36-37). Mr. Hill's CAPM analysis resulted in a cost of capital for the proxy companies ranging from 7.71 to 9.38 percent (*Id.*, Sched. 7). For the MEPR model, the cost of equity capital ranged from 8.68 to 8.78 percent (*Id.*, Sched. 9). Finally, Mr. Hill's MTB analysis resulted in cost of equity capital ranging from 8.84 to 9.46 percent (*Id.*, Sched. 10).

Although Mr. Hill relied primarily on the 9.20 percent DCF result for determining his cost of equity recommendation, he also averaged the corroborative results (*i.e.*, CAPM, MEPR, and MTB) which produced a range of 8.41 to 9.21 percent, which he noted is almost entirely below the DCF result. As a result, Mr. Hill concluded that the DCF was a conservative (*i.e.*, high) estimate of the Company's estimated cost of equity capital and therefore the DCF result should be considered to be in the upper range of equity capital cost for Southwest Gas. However, due to his expectation of higher short-term interest rates in the near term, Mr. Hill stated that it was appropriate to set a range so that his DCF result is near the middle of a reasonable range. He therefore determined that the best estimate of the cost of equity capital for a company facing similar risks as that group of gas distribution companies ranges from 9.00 to 9.50 percent (*Id.* at 37). Because Southwest Gas' capital structure contains less common equity than the proxy group he used to estimate the cost of equity capital, Mr. Hill concluded that the additional risk faced by Southwest Gas warrants an equity return at the high end of his range, or 9.50 percent (*Id.* at 40).

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Conclusion on Cost of Equity

We believe that Staff's recommended cost of equity capital in this proceeding achieves an appropriate result that is supported by the evidence in the record. Staff witness Hill's use of the DCF as the primary basis for determining the Company's reasonable estimated cost of equity capital is a methodology that has been used for many years by this Commission, as well as other regulatory commissions across the country.

As Mr. Hill explained in his testimony, both historical and projected growth rates were calculated for his sample group of gas distribution companies. The companies in Mr. Hill's proxy group possess similar risk characteristics and, based on a sustainable growth rate supported by data published *Value Line* and other financial publications, produced a growth rate estimate of 5.12 percent (Ex. S-1, at 29-34). Although Staff's COE recommendation is based primarily on the DCF analysis, as explained above Mr. Hill also conducted a review of other COE formulas, including CAPM, to corroborate the DCF results.

Mr. Hill also testified that the methods utilized by the Company's witness, which depend heavily on beta (a relative risk measure which is designed to measure investor risk), does not provide an accurate portrayal of actual investment risk (Tr. 877). Staff points out that the Company's witness, Mr. Hanley, excluded 8 of 11 indicated DCF return rates from his proxy group based on his opinion that any result under 9.90 percent did not reflect returns being authorized in other jurisdictions. As Mr. Hill pointed out on the witness stand, if those 8 companies were included in Mr. Hanley's DCF calculation, the result would be approximately 9.2 percent, which is almost identical to Staff's DCF calculation (Tr. 876).

After reviewing the various proposals summarized herein, and as further described in the testimony prepared by the parties' expert witnesses, we believe Staff's cost of equity capital recommendation is an appropriate result for determining the Company's overall cost of capital in this proceeding. Staff's DCF calculation of 9.20 percent, with an upward adjustment of 30 basis points to 9.50 percent, gives recognition to the higher risk faced by Southwest Gas.

We are not persuaded by the Company's legal arguments that adoption of Staff's cost of equity recommendation would result in a violation of the Commission's authority under the Arizona

Constitution, the case law interpreting that authority, or of the *Hope* and *Bluefield* decisions. Article 15, Section 3 of the Arizona Constitution provides in relevant part that the Commission "shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein." In determining just and reasonable rates, the Commission has broad discretion subject to the obligation to ascertain the fair value of the utility's property, and establishing rates that "meet the overall operating costs of the utility and produce a reasonable rate of return." *Scates, et al. v. Arizona Corp. Com'n*, 118 Ariz. 531, 534, 578 P.2d 612 (Ct. App. 1978). Under the Arizona Constitution, a utility company is entitled to a fair rate of return on the fair value of its properties, "no more and no less." *Litchfield Park Service Co. v. Arizona Corp. Com'n*, 178 Ariz. 431, 434, 874 P.2d 988 (Ct. App. 1994), *citing Arizona Corp. Com'n v. Citizens Utilities Co.*, 120 Ariz. 184 (Ct. App. 1978). The oft cited *Hope* and *Bluefield* cases provide that the return determined by the Commission must be equal to an investment with similar risks made at generally the same time, and should be sufficient under efficient management to enable the Company to maintain its credit standing and raise funds needed for the proper discharge of its duties.

For the reasons described above, we believe that adoption of Staff's recommendation for a 9.50 cost of equity capital, and overall 8.40 percent weighted cost of capital comply with these obligations. Staff's expert witness, although primarily relying on the well-established DCF method for calculating his cost of equity capital, also employed two other tests as a check on the reasonableness of his results. He also pointed out that the Company's witness arbitrarily excluded 8 of the 11 companies in his proxy group because they produced DCF results less than 9.90 percent, and thus skewed downward the overall results on his analysis. Moreover, Staff's witness gave recognition to Southwest Gas' highly leveraged capital structure by adding 30 basis points to his DCF results. We therefore believe that adoption of Staff's recommendation results in a just and reasonable return for Southwest Gas based on the record of this proceeding.

We therefore adopt a cost of equity of 9.50 percent, which results in an overall weighted cost of capital of 8.40 percent.

	Percentage	Cost	Avg.Weighted Cost
Common Equity	40.0%	9.50%	3.80%
Preferred Equity	5.00%	8.20%	0.41%
Total Debt	55.0%	7.61%	4.19%
			8.40%

AUTHORIZED INCREASE

Based on our findings herein, we determine that Southwest Gas is entitled to a gross revenue increase of $49,345,636.

Fair Value Rate Base	$1,169,584,038
Adjusted Operating Income	47,834,373
Required Rate of Return	6.63%
Required Operating Income	77,508,617
Operating Income Deficiency	29,674,244
Gross Revenue Conversion Factor	1.6629
Gross Revenue Increase	49,345,636

RATE DESIGN ISSUES

Conservation Margin Tracker

Southwest Gas has proposed in this proceeding a decoupling mechanism that it calls a Conservation Margin Tracker ("CMT") to address the Company's ongoing inability to achieve its authorized rate of return due, at least in part, to declining per customer usage on its system. The Company has proposed that the CMT be imposed only on the residential class (although it does not oppose broader application). Under the CMT, if Southwest Gas does not achieve its authorized "margin" (*i.e.*, all costs of providing gas less the cost of the gas itself) per customer class, the CMT would track that shortfall and impose a surcharge on customers in that class the following year based on the prior year's revenue shortfall. In effect, the CMT would insulate Southwest Gas from the risk associated with declining gas usage by customers.

The Company claims that the CMT is a reasonable cost recovery mechanism for the following reasons: it would eliminate the Company's financial disincentive associated with promoting Demand Side Management ("DSM") programs; it would not discourage consumers from conserving natural gas because the more a customer conserves the more the customer would save; it would charge

customers only the fixed costs of service that the Commission authorized in the rate case; it would protect customers from the Company earning more than its authorized margin per customer during a colder than normal heating season; it would protect the Company from declining residential use per customer; and it would provide the Company with a more consistent revenue stream by reducing its dependency on gas sales to recover the authorized margin per customer, thus having a positive impact on the Company's ratings with credit agencies and reducing borrowing costs needed to fund infrastructure growth (Ex. A-19, at 18-23; Ex. A-20, at 14-22; Ex. A-21, at 5-9). Southwest Gas contends that it is willing to modify the CMT or accept another type of decoupling mechanism to address the declining usage problems that it claims all parties have acknowledged exist.

Staff opposes adoption of the CMT because customers would be charged more for gas that is not used the preceding year. Staff argues that if natural gas is relatively inelastic, as the Company contends, the potential for ongoing conservation would be mitigated and usage levels will stabilize over time, thus minimizing the declining usage that impacts the Company's revenues. However, if the declining usage trend continues, Staff claims that the CMT would result in customers incurring additional charges if their conservation efforts proved successful, thereby discouraging price signals that could lead to conservation. Staff also opposes the CMT on the basis that it could result in sharp increases for residential customers if the Company fails to recover its authorized margin. Staff argues that implementation of the CMT would provide Southwest Gas a guaranteed rate of return, rather than the opportunity to earn a reasonable return as required by law. Staff asserts that the Company's historical inability to earn its authorized return should be addressed through traditional rate design methodologies, such as gradually moving closer to a more cost-based rate design. Staff points out that the Nevada Commission rejected an almost identical decoupling mechanism proposed by Southwest Gas.

RUCO also opposes the Company's CMT proposal. Although RUCO agrees that the Commission should modify the existing rate design to allow greater recovery of fixed costs, it claims that the CMT is too extreme a remedy for addressing declining usage. RUCO argues that the approved rate design should not provide the Company with a guaranteed recovery of margin, and would allow recovery from customers who were not even on the system when the shortfall occurred.

RUCO further opposes the CMT on the basis that it would be applicable only to residential customers, and because the CMT would have the effect of requiring customers to pay the authorized margin for therms they do not consume (RUCO Ex. 3, at 29). RUCO argues that although the Company declined to propose a rate design that would recover all of the margin through the basic service charge, because it believes such a rate design would be inconsistent with the principle of gradualism, it has proposed the CMT which would have the same extreme effect on residential customers.

SWEEP/NRDC expressed understanding of the dilemma faced by Southwest Gas with respect to decreasing usage and revenues. However, SWEEP/NRDC opposes adoption of the CMT in this proceeding. Its witness, Jeff Schlegel, stated that a full analysis of the benefits and drawbacks of decoupling mechanisms for LDCs warrant consideration in a broader context (SWEEP/NRDC Ex. 1, at 7-8). SWEEP/NRDC suggests that the issue of financial disincentives should be addressed through the DSM policy process, via comments and/or workshops. SWEEP/NRDC contends that consideration of the decoupling issues should address questions such as who bears the risk of weather variations and variations in economic growth from forecasted levels and overall demographic and energy usage trends (*Id.*).

AUIA argues that the financial situation faced by Southwest Gas requires adoption of a decoupling mechanism, such as the CMT, or a significant increase in margin recovery through the fixed monthly charge. AUIA contends that the decoupling concept is not radical or drastic, as Staff and RUCO contend, given the adoption of such a mechanism in at least three other states. AUIA cites the testimony of Company witness Steven Fetter, former Chairman of the Michigan Public Service Commission, in support of the CMT. Mr. Fetter indicated that declining margin recovery from volume sales is a national phenomenon and NARUC has passed a resolution urging its members to consider decoupling mechanisms (Ex. A-7, at 6-8).

Conclusion on CMT

Although we recognize that Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis, we do not believe the proposed CMT should be adopted in this proceeding. The Company has suggested that it is open to other decoupling mechanisms as a

solution, and we believe that the issue should be fully explored as part of a broader investigation of usage volatility and margin recovery.

There is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers. Further, as RUCO points out, the likely effect of adopting the proposed CMT is that residential customers will be required to pay for gas that they have not used in prior years, a phenomenon that could result in disincentives for such customers to undertake conservation efforts. We are also concerned with the dramatic impact that could be experienced by customers faced with a surcharge for not using "enough" gas the prior year. The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case.

We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders. To that end, Southwest Gas should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties. Such efforts may be pursued through the DSM policy process, as suggested by SWEEP/NRDC, and through a proposal in the Company's next rate case.

Allocation of Margin Among Customer Classes

As a means of allocating margin costs between the various classes of customers it serves, Southwest Gas presented a cost of service study to support its rate design proposal. Company witness Congdon stated that the Company's allocation of margin methodology is based on this cost of service study, and the proposed allocation would move each class' rate of return closer to cost of service (Ex. A-17, at 22-24). The Company argues that its cost of service study was not challenged by any party and, because its proposed allocation is directly based on the cost of service study, the Company's allocation of margin should be adopted.

RUCO and Staff argue that cost of service is merely the starting point for designing

appropriate rates. They contend that in addition to affording the Company revenue stability, other factors must also be considered in designing rates, such as affordability, gradualism, sending appropriate price signals, and conservation goals.

We agree with Staff and RUCO that designing rates is not an exact science that may be achieved by the application of a formula tied directly to a cost of service study. Rather, the formulation of just and reasonable rates is accomplished only through consideration of multiple factors that balances the desire of the Company to recover as much of its margin as possible with recognition of the legitimate interests of customers in paying rates that are affordable, as well as advancing societal goals. As discussed below, we have attempted to determine just and reasonable rates based on these competing principles and interests.

Single-Family Residential Gas Service (G-5)

The residential rate class encompasses the vast majority of Southwest Gas customers and, not surprisingly, residential rate design garnered the most discussion and debate. Southwest Gas, Staff, and RUCO each proposed separate residential rate design recommendations.

Southwest Gas Proposal

Currently, Southwest Gas' single-family residential gas rates include an $8 basic monthly charge and a two-tier declining block rate of approximately $0.49 and $0.40 per therm, respectively. The break point between the first and second blocks is currently at 8 therms of usage in the summer (May-October) and 40 therms in the winter (November-April).

The Company has proposed an increase in the basic monthly charge from $8 to $16, and an increase in the first block volumetric charge from $0.49 to $0.66 per therm and a reduction in the second block from $0.40 to $0.25 per therm[5] (Tr. 283-287). Under the Company's proposal, the break point between blocks would remain at 8 therms during the summer months but would be reduced to 30 therms per month in winter months.

Southwest Gas is critical of RUCO's rate design proposal because, in the Company's view, it

[5] Southwest Gas proposed that if the CMT were adopted, the basic monthly charge should be increased from $8 to $12 per month, and the commodity charge would increase from $0.49 to $0.84 in the first block, and would decrease from $0.40 to $0.15 in the second block. Because we have not adopted the CMT, the rate design proposal described above is recommended by the Company.

does not shift enough of the volumetric charges to the fixed monthly charge and, by eliminating the declining block rate structure, it puts the Company at greater risk of not recovering its authorized margin (*See, e.g.*, Ex. A-51). With respect to Staff's recommendation, Southwest Gas concedes that low volume users will experience a significant increase in rates (Tr. 286-287). However, the Company contends that under either Staff's or RUCO's proposals, higher usage residential customers would fare substantially better under Southwest Gas' rate design because its second block rates would be reduced substantially compared to either current rates or the Staff and RUCO rates. Southwest Gas argues that its rate recommendation would be more beneficial to high volume residential customers, regardless of income, as evidenced by a chart in Mr. Congdon's testimony that shows substantial savings under the Company's plan for customers with usage over 100 therms in a given month (Ex. A-18, at 5). Based on its Exhibit A-50, which shows that usage by low income customers tracks closely the usage seen by non-low income customers, the Company argues that high use, low income customers may be affected even more dramatically because of an inability to pay increased costs associated with the higher second block rates under either the Staff or RUCO recommendations.

RUCO's Proposal

RUCO proposes an increase in the basic customer charge from $8 to $10.09 per month, and a flat volumetric rate of approximately $0.49 for all usage. According to RUCO, its rate design proposal gives recognition to the Company's concerns regarding revenue stability (*i.e.*, the Company's inability to recover margin costs due to declining per customer usage) by placing more cost recovery into the basic customer charge[6], while also flattening the current two-tier volumetric structure to send appropriate price signals regarding gas consumption. RUCO witness Diaz Cortez indicated that RUCO's rate design proposal would mitigate the Company's risk of not recovering its authorized revenue requirement due to declining usage (RUCO Ex. 4, at 7).

Staff's Proposal

Based on its revenue requirement recommendation, Staff proposes an increase in the basic monthly charge from $8 to $9.70, accompanied by a two-tier commodity rate of approximately $0.54

[6] RUCO claims that its recommendation would shift approximately $23 million per year from commodity charges to the basic service charge under current revenues and over $26 million under RUCO's proposed revenues in this case (Tr. 1003-1004).

for the first 15 therms in the summer and the first 35 therms in the winter, and $0.50 for usage in the second block. Staff claims that its proposed rate design moves significantly towards cost-based rates and properly balances the Company's revenue stability concerns with the concepts of gradualism, affordability, and conservation. Staff witness Bob Gray conceded that the Company's rate design recommendation provides greater rate stability than either Staff's or RUCO's proposals. He pointed out, however, that by "front-loading costs in the customer charge and the first usage block," the Company has offered a design that is inconsistent with Staff's goal of balancing stability with other important factors (Ex. S-15, at 9). Mr. Gray indicated it is "mathematically impossible for a customer with low usage, paying a much higher customer charge and a much higher first block rate to not see a large rate increase" (*Id.* at 8).

Conclusion

Although we are cognizant of Southwest Gas' desire to recover as much of its margin as possible through the monthly customer charge, it is simply untenable to saddle a substantial number of the Company's residential customers with rate increases in excess of 100 percent. Under the Company's recommendation, low usage residential customers would incur not only a doubling of their basic monthly charge (from $8 to $16 per month), but would pay a substantial commodity charge increase for usage up to 30 therms per month in the winter (from $0.49 to $0.66 per therm). While high usage customers may realize lesser overall increases under the Company's plan, relative to the Staff and RUCO proposals, the Southwest Gas rate design would have the effect of encouraging greater usage of natural gas at a time when, by all accounts, an increase in demand for natural gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of "the more you use, the more you save."

We are also aware that customers will likely face additional cost increases associated with the Company's purchased gas adjustor ("PGA"). Southwest Gas expected to reach its ten cent PGA cap in January 2006, thus increasing customer bills associated with the cost of gas for a customer using 105 therms a month by approximately $10.50 per month, regardless of the rate design adopted in this proceeding (Tr. 297-298). The Company will also likely in the near future seek Commission approval for imposition of a surcharge to recover its $30 million bank balance, adding an additional

$0.055 per therm (*i.e.*, an additional $5.50 per month for the same customer using 105 therms per month). Although the cost of gas may be largely beyond the Company's control, this additional rate impact must be considered as part of the overall rate impact on customers.

We agree with all parties that movement closer to cost-based rates is in principle a laudable goal. However, that goal must be balanced with consideration of the principles of gradualism, fairness, and encouragement of conservation. Based on consideration of competing interests and concerns, we agree that Staff's rate design recommendation appropriately makes significant movement towards cost based rates while providing a measure of protection for customers who will incur substantial rate increases as a result of this base rate case increase. Accordingly, we will adopt Staff's recommended basic monthly charge of $9.70 and, as adjusted for the revenue requirement adopted herein, a two-tier commodity rate of $0.54200 for the first 15 therms in the summer and the first 35 therms in the winter, and $0.50100 for usage in the second block.

Based on the G-5 residential rate design adopted in this case, and assuming an average monthly usage of 29 therms, single-family residential customers would experience an increase under summer rates of 8.9 percent, from $38.96 to $42.42 per month, and an increase under winter rates of 8.3 percent, from $39.71 to $42.99[7].

Multi-Family Residential Gas Service (G-6)

Southwest Gas proposes creation of a new multi-family residential rate schedule (G-6) that would, under the Company's revenue requirement recommendation, grant customers in multi-family residences a $1 per month reduction to the basic monthly charge compared to single-family residence customers (*See*, Ex. A-2, Sched. H-3). Mr. Congdon stated that creating this separate rate schedule for multi-family residence customers would allow the Commission to moderate the effect on the Company's smallest residential customer class as residential service rates are moved gradually towards cost of service (Ex. A-17, at 26-27). RUCO does not oppose this recommendation.

Staff witness Gray testified, however, that although Staff is not strongly opposed to creation

[7] An estimate of the seasonal impact of the increase can best be seen by viewing an average customer's summer usage in August (10 therms), where an average bill would increase by 11.8 percent, from $18.94 to $21.18; and an average customer's winter usage in January (72 therms), where an average bill would increase by 8.1 percent, from $84.04 to $90.83.

of a multi-family residential rate class, Staff does not believe it is advisable to create a separate rate structure for a small segment of the general rate class. Mr. Gray stated that while there are likely other segments of the residential class that have different characteristics, "a Balkanization of the residential rate class absent a compelling need to do so is not something Staff will support" (Ex. S-15, at 10).

We agree with Southwest Gas that customers in multi-family dwellings deserve a separate rate categorization to reflect their lower usage characteristics and relatively lower cost to serve as a class. Therefore, we will approve creation of a separate rate schedule for this residential customer class and, consistent with the Company's proposal, impose a basic monthly service charge of $8.70, plus the commodity charges applicable to Schedule G-5 customers.

Based on the rate design adopted in this case, and assuming an average monthly usage of 29 therms, customers in the new multi-family residential class would experience an increase under summer rates of 5.5 percent, from $38.96 to $41.09 per month, and an increase under winter rates of 8.3 percent, from $39.71 to $41.54[8].

Low-Income Residential Gas Service (G-10)

Southwest Gas proposed elimination of its low-income residential gas service tariff (G-10), with such customers being incorporated into the other residential classes (G-5 and G-6), and the current volumetric discount would be extended to the entire year rather than the current applicability to only winter months (Ex. A-17, at 27-29). However, the Company's proposal would lessen the amount of the discount applicable to low-income customers based on its assertion that there would be less of a need to shield such customers from high winter bills because the Company's rate design proposal, if adopted, would shift a portion of the margin recovery from the winter season to the summer season. Under the Southwest Gas recommendation, the existing $7.00 per month basic customer charge would be retained for low-income customers, and the current 20 percent discount on the first 150 therms of usage during winter months would be replaced with a year-round 15 percent

[8] An estimate of the seasonal impact of the increase can best be seen by viewing an average customer's summer usage in August (10 therms), where an average bill would increase by 5.9 percent, from $18.94 to $20.06; and an average customer's winter usage in January (72 therms), where an average bill would increase by 6.1 percent, from $84.04 to $89.14.

discount with no usage limit. RUCO does not oppose the proposal and the Company indicates that it has not received any opposition to the proposal from local community action advocates after explaining the plan to those representatives (*Id.* at 28-29). Mr. Congdon testified that, if the Commission does not accept the Company's rate design proposal, the current 20 percent low-income discount should not be modified (*Id.*).

Staff opposes the Company's proposal to eliminate Schedule G-10 and modify the low-income residential rate as described above. Staff witness Gray stated that Arizona utilities that offer such a discount typically have a separate, stand-alone tariff and Staff believes maintaining the existing tariff allows a higher profile for the tariff and advances ease of understanding. Mr. Gray agreed with the Company that the $7.00 customer charge for Schedule G-10 should be maintained at that level, and further indicated that the existing 20 percent discount for the first 150 therms of usage during winter months should be maintained because bills incurred for high winter usage is the critical element for low-income customers (Ex. S-15, at 36-38).

Given our adoption of Staff's residential rate design proposal, it appears Southwest Gas does not advocate adoption of its proposed modification of the low-income tariff. We agree with Staff's recommendation that the current Schedule G-10 should be maintained at its current level and we therefore adopt Staff's proposal to maintain the $7.00 customer charge and apply a 20 percent discount to the first 150 therms of consumption during winter months.

Special Residential Gas Service for Air Conditioning (G-15)

Southwest Gas recommended that its special residential service tariff for gas air conditioning (G-15) should be eliminated and the small number of customers covered under the tariff folded into the general residential tariff (G-5). Company witness Congdon explained that there is currently only a small difference in the second block rate between the two schedules and the Company's proposal would eliminate the need to administer a separate schedule for this small number of customers. Mr. Congdon added, however, that if the Commission adopts the rate designs proposed by either Staff or RUCO, the G-15 schedule should remain intact and the summer air conditioning margin rate should be set at $0.25 per therm (Ex. A-17, at 29).

Staff witness Gray opposes elimination of the G-15 tariff because typical usage by customers

under this schedule is significantly higher than general residential usage. Given this usage pattern differential, Mr. Gray indicated that it is reasonable to continue the separate tariff. Staff recommends that the G-15 tariff should continue to reflect the G-5 tariff rates, with the exception that the G-15 second summer usage block should be increased from approximately $0.19125 to $0.28200 per therm (Ex. S-15, at 41-42; Ex. S-16).

Given our adoption of Staff's residential rate design proposal, it appears Southwest Gas does not advocate adoption of its proposed modification of the residential air conditioning tariff. We agree with Staff's recommendation that the current Schedule G-15 should be maintained at its current level, with the exception of an increase to the summer second block.

Master Metered Mobile Home Park Gas Service (G-20)

In its application, Southwest Gas proposed increasing the basic monthly charge for master metered mobile home park service customers from $50 to $100, and increasing the commodity charge from approximately $0.314 to approximately $0.323 per therm (Ex. A-1, Sched. H-3). The Company did not present testimony on this issue, but argues that its recommendation better reflects its cost of service for this customer class, compared to Staff's proposal (*Id.*, Sched. H-6).

Staff witness Gray stated that Staff's recommendation is to increase the basic monthly charge from $50 to $60, and to increase the volumetric charge from $0.31415 to $0.38400 per therm (Ex. S-16).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff.

General Gas Service (G-25)

With respect to the Company's recommendations regarding this rate schedule, which includes various sizes of commercial customers, the following issues are addressed below: moving current Armed Forces customers on Schedule G-35 into Schedule G-25; appropriateness of creating a new sub-class for small use customers in the class and relative basic customer charge increase recommendations for different size customers within the class; and use of coincident peak or non-coincident peak for determining the demand charge for large G-25 customers.

Elimination of Armed Forces Rate Schedule (G-35)

In its application, Southwest Gas recommended elimination of Armed Forces Rate Schedule G-35, and movement of existing customers under that schedule into the large general gas service rate under Schedule G-25. The basis of the Company's proposal is that if G-35 customers were permitted to choose to take service under either G-25 or G-35, the Company would experience a shortfall in margins.

DOD witness Dan Neidlinger filed testimony supporting Southwest Gas' recommendation, stating that DOD customers should logically be classified with other large gas users for ratemaking purposes. Mr. Neidlinger's testimony indicates that if the overall revenue requirements are established near the levels recommended by Staff or RUCO, DOD recommends adoption of RUCO's proposed G-25 rates (DOD Ex. 1, at 2-3).

Although Staff initially suggested that Schedule G-35 should be maintained and customers should be able to choose between G-25 or G-35 (Ex. S-15, at 43-47), Mr. Gray subsequently withdrew Staff's opposition based on DOD's agreement with the Company's proposal (Tr. 1097-1098).

Given Staff's acquiescence on this issue, we will adopt the Company's proposal to eliminate Rate Schedule G-35 for Armed Services customers and to include those customers under the large general gas service tariff, Schedule G-25.

New Sub-Class for Small Use Customers and Basic Service Charge Recommendations

Southwest Gas' Schedule G-25 currently includes discrete prices for small (annual 0-7,200 therms), medium (annual 7,201-180,000 therms), and large (annual usage greater than 180,000 therms). The Company proposed the creation of a new sub-class within the small customer category, so that commercial customers with very low usage (*i.e.*, less than 600 therms annually) would be separated for rate design purposes from other small group customers that use between 601 and 7,200 therms annually (Ex. A-16, at 17-18). Mr. Congdon testified that the Company's proposal would allow pricing that more closely matches its cost of service while also mitigating the impact of the rate increase on the smallest customers within the class. He claimed that the Company's proposed tariff adjustments were made to minimize the differences in monthly bills at the cross-over volumes

between general service rate schedules (*Id.* at 19).

RUCO does not oppose creation of this sub-class category, but Staff contends that the members of the new sub-class "would see a much larger rate increase than if they had remained part of the current small commercial class presently in existence" (Ex. S-15, at 43). Therefore, Staff witness Gray recommends retaining the current usage levels for small, medium and large G-25 customers (*Id.* at 44).

The proposals for customers within the G-25 rate schedule, including the Company's claimed cost of serving the customer classes (Ex. A-1, Sched H-6), are as follows (Ex. A-17, at 30-32):

Proposed Schedule	Current	Staff	RUCO	SWG	Cost of Serv.
Small GS	$20.00	$24.00	$34.57	$25.00	$74.86
Medium GS	20.00	24.00	48.39	35.00	79.02
Large GS	90.00	105.00	207.00	150.00	145.81
Transport Elig.	500.00	540.00	1,037.00	750.00	754.99

Based on our review of the record, we find the Company's recommendation to create a separate sub-class of very small customers is reasonable and should be adopted. However, in order to mitigate the severity of the customer charge increases on customers in this class, we will adopt a modified increase in the customer charges as follows: customers in the new small use segment - $25.00; customers in the medium class - $33.00; customers in the large class - $145.00; and customers in the transportation eligible class - $720.00. We believe these approved customer charges move the customers in this rate schedule closer to the Company's cost of service while, at the same time, protecting customers from dramatic increases in rates.

Demand Charge Determination

Southwest Gas also proposed to change its method of measuring a large customer's peak demand from a coincident peak method (*i.e., system* peak month) to a non-coincident peak method (*i.e., customer* peak month). The Company claims that its non-coincident peak measurement would take some of the risk of revenue recovery out of rates while, at the same time, reflecting value to customers on an annual basis (Ex. A-17, at 33).

Staff opposes changing the demand charge calculation formula from use of coincident peak

due to the potential that "some customers may have structured their consumption and operations such that they reduce consumption on what is likely to be [the Company's] peak month" and, therefore, the change could have a significant rate impact on customers who have very different coincident and non-coincident peaks (Ex. S-15, at 44).

DOD agreed with the Company's recommendation, in part. DOD witness Neidlinger stated support for a modified non-coincident peak method "whereby a customer's billing demand would be based on the highest monthly demand experienced during any winter month" (DOD Ex. 1, at 3). DOD would exclude from the calculation demands during the summer months of May through September.

Although we believe DOD's proposed modification of the non-coincident peak method for determining the demand charge has merit, there is not sufficient data in the record to support its adoption. We will therefore adopt the Company's non-coincident peak measurement recommendation as a means of taking some of the risk of revenue recovery out of rates while, at the same time, reflecting value to customers on an annual basis.

Air Conditioning Gas Service (G-40)

Southwest Gas proposed the imposition of a single basic service charge of $25 for customers taking service under this tariff, rather than the Company's otherwise applicable basic service charge (Ex. A-16, at 14). However, the Company offered no testimony explaining the need for a distinct basic service charge for this tariff.

Staff witness Gray stated that the Company has a number of tariffs where the basic service charge is set by what it would be on the customer's otherwise applicable tariff, and this is the only tariff where Southwest Gas is proposing such a change (Ex. S-15, at 48).

We agree with Staff that there does not appear to be any reasonable justification for why the current tariff should be changed and it is more reasonable to have a larger basic service charge for a large commercial customer under the tariff compared to a small commercial customer taking service under the tariff (*Id.*). We therefore adopt Staff's recommendation on this issue.

Gas Service for Compression on Customer's Premises (G-55)

Southwest Gas proposes increasing the basic monthly charge for customers taking service

under Schedule G-55, gas service for compression on customer premises, from $8.00 to $12.00 for residential customers; from $20.00 to $25.00 for small customers; and from $170.00 to $350.00 for large customers. The Company also proposes increasing the commodity charge from $0.13305 to $0.13669 per therm for all customers served under the G-55 tariff (Ex. A-1, Sched. H-3). Although Southwest Gas offered no specific testimony explaining the level of proposed increases, the Company claims that its proposal for increasing rates under the tariff reflect the Company's cost to serve this class of customers.

Staff witness Gray filed testimony recommending lesser rate increases. Mr. Gray recommended increasing the basic monthly charge for residential customers under this tariff from $8.00 to $9.70; small customers from $20.00 to $24.00; and large customers from $170.00 to $190.00 (Ex. S-13, at 49; Ex. S-16). He also proposed increasing the commodity charge from the current $0.13305 to $0.17000 per therm (*Id.*).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff. However, since the small customer service charge is tied to Schedule G-25 (*i.e.*, $25.00), the customer charge for such customers shall be set accordingly.

Cogeneration Gas Service (G-60)

Southwest Gas proposes that its cogeneration gas service tariff (G-60) be made available to all electric generation customers, with the exception that customers whose facilities exceed 5 megawatts ("MW") would be required to take transportation service at the Schedule G-60 rates. Company witness Congdon stated that this exclusion is necessary to eliminate "the risk to Southwest Gas' sales customers associated with the procurement of the upstream gas supply and interstate pipeline requirements for these large customers" (Ex. A-17, at 35-36).

Staff witness Gray testified that, although the Company expressed legitimate concerns regarding the possibility of significant new electric generation loads straining its system, Staff recommends that Southwest Gas should develop provisions of the G-60 tariff that would provide sufficient protections for the system and other core customers (Ex. S-13, at 50-51). Mr. Gray indicated that, in his opinion, it would be unfair to impose a provision that has the effect of

potentially barring certain customers from taking service under this tariff due to the customer's size (*Id.*). Staff therefore proposes that the otherwise applicable general service and essential agricultural basic service charges should continue to be applied to G-60 customers, and that the per therm rate should be increased from $0.08934 to $0.11400 (*Id.* at 51; Ex. S-16).

We agree with Staff's recommendation regarding the Schedule G-60 tariff. We see no valid reason for restricting the Schedule G-60 tariff in the manner suggested by Southwest Gas. However, to the extent Southwest Gas believes additional protection for its system and core sales customers is necessary, the Company may separately propose in a tariff amendment filing, language that it believes would provide necessary safeguards.

Small Essential Agricultural User Gas Service (G-75)

Southwest Gas proposed increasing the basic monthly charge for customers taking service under the small essential agricultural user gas service tariff (G-75) from the current $75 per month to $150 per month, and increasing the Schedule G-75 commodity charge from $0.19468 to $0.22186 per therm (Ex. A-1, Sched. H-3). The Company also recommends freezing Schedule G-75 so no new customers could take service under the tariff and would instead be required to be served under the general service tariff, Schedule G-25. Currently, customers may choose to be served under either Schedule G-75 or the general service tariff, G-25. According to Southwest Gas, its request to reclassify customers on the G-75 tariff is consistent with Decision No. 58377 (August 12, 1993) in which, according to the Company, the Commission suggested that customers under this schedule be moved to the general service tariff "and to gradually eliminate Schedule G-75"[9] (Southwest Gas Initial Brief at 60).

Staff witness Gray testified that Staff opposes closing Schedule G-75 because elimination of the tariff would remove the option that currently exists for eligible agricultural customers to choose between general service and the G-75 tariff. Mr. Gray stated that "absent a powerful reason to take

[9] Decision No. 58377 concurred with Staff's recommendation "to retain the current SEA [small essential agriculture] rate schedule" (Decision No. 58377, at 42-43). Although the Decision directed Southwest Gas to "gradually move the SEA schedule to the general service level," the Commission specifically rejected Southwest Gas' request to close the small essential agriculture tariff to new customers because "closure may unfairly treat identical customers" (*Id.* at 43). Contrary to the Company's assertion in its Brief, the Commission did not state in Decision No. 58377 that Schedule G-75 should be eliminated.

this service option away" the G-75 tariff should be retained (Ex. S-13, at 52). In his surrebuttal testimony, Mr. Gray indicated his belief that the Company has not presented a compelling reason why eligible new customers should be precluded from exercising the same option that currently exists (Ex. S-15, at 12). With respect to the applicable charges, Mr. Gray recommended that the basic service charge should be increased from $75.00 to $90.00, and the per therm rate should be increased from $0.19468 to $0.22300 (Ex. S-13, at 52; Ex. S-16).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff. We agree with the principles stated in Decision No. 58377, that charges for this agricultural tariff should continue to move *gradually* closer to cost of service and the general service rate. However, we do not believe the Company's proposal to double the basic monthly charge for such customers, and to freeze new customers from taking service under the G-75 tariff, is consistent with the goals set forth in that prior Decision or with principles of fundamental fairness.

Natural Gas Engine Gas Service (G-80)

As described by Company witness Congdon, customers served under the natural gas engine gas service tariff (G-80), use natural gas engines to pump water for agricultural irrigation (Ex. A-17, at 36-38). Mr. Congdon stated that the G-80 tariff serves customers in a very price sensitive market in which the customers may decide, based on the cost of gas service, to either switch to electricity to operate their pumps or simply not to irrigate and produce crops at all (*Id.*). In its application, Southwest Gas proposes to increase the basic monthly charge in the peak season (April-September) from $80 to $100, but reduce the commodity margin from the current rate of $0.16189 to $0.15848 per therm (Ex. A-1, Sched. H-3). No customer charge applies during off-peak months (*Id.*). In support of its proposal, Mr. Congdon stated that it did not assign an increase in margin to this class of customers because the Company is concerned that it may lose some of the G-80 tariff customers due solely to increases in the price of gas, which gas cost is reset for this class semi-annually, on April 1st and October 1st (Ex. A-17, at 37). Due to these competitive concerns, Southwest Gas opposes Staff's recommendation to increase the margin recovery associated with the G-80 tariff class (*Id.*).

Staff witness Gray agrees that the off-peak basic service charge should remain at zero.

However, he recommends that the on-peak customer charge should be increased from $80 to $95 per month, and the per therm rate should be increased from $0.16189 to $0.17700 (Ex. S-13, at 53; Ex. S-16). In his surrebuttal testimony, Mr. Gray stated that Staff took into account the Company's competitive concerns concerning the G-80 rate class, but "Staff does not believe the potential for customers leaving a given rate class should totally exempt that rate class from bearing some, albeit small, portion of the overall rate increase" (Ex. S-15, at 12-13). He pointed out that, under Staff's recommendation, the Schedule G-80 customers would receive the smallest revenue increase (approximately 2.77 percent under Staff's revenue requirement proposal) of any rate class under Staff's recommended rate design (*Id.*).

We agree with Staff that the relatively small margin increase assigned to the G-80 tariff class is a reasonable outcome based on the competing concerns of all customers affected by this proceeding. Although we recognize that retention of customers on Southwest Gas' system may provide benefits to all customers, we are not inclined to broker prices between competing sources of energy by limiting increases that may otherwise be applicable to a given class of customers based on cost of service principles and other factors that are weighed in determining rates for all classes of customers. We will therefore adopt Staff's recommendation on this issue.

MISCELLANEOUS ISSUES

Billing Determinants

Billing determinants are established by developing an annualized number of bills and volumes for the test period under the Company's current rate schedules (Ex. A-16, at 3). Accurate billing determinants are important because if too few determinants are used, tariff prices would be set unnecessarily high and, likewise, too many billing determinants would result in tariff prices that are too low to capture the established revenue requirement (Tr. 241-244).

Company witness Congdon testified that the proposed billing determinants were compiled by taking the monthly recorded number of bills and therms, by rate schedule, for the 12-month test year period, with the following adjustments to the recorded bills and therms: (1) billing adjustments (to remove anomalies); (2) volume annualizations (customer specific adjustments to reflect a full year's consumption for each customer, excluding the residential and small commercial classes); (3)

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We agree with Staff that the relatively small margin increase assigned to the G-80 tariff class is a reasonable outcome based on the competing concerns of all customers affected by this proceeding. Although we recognize that retention of customers on Southwest Gas' system may provide benefits to all customers, we are not inclined to broker prices between competing sources of energy by limiting increases that may otherwise be applicable to a given class of customers based on cost of service principles and other factors that are weighed in determining rates for all classes of customers. We will therefore adopt Staff's recommendation on this issue.

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Company witness Congdon testified that the proposed billing determinants were compiled by taking the monthly recorded number of bills and therms, by rate schedule, for the 12-month test year period, with the following adjustments to the recorded bills and therms: (1) billing adjustments (to remove anomalies); (2) volume annualizations (customer specific adjustments to reflect a full year's consumption for each customer, excluding the residential and small commercial classes); (3)

customer reclassifications (to move customers and volumes between tariff schedules to reflect end of test year composition); (4) weather normalization (to accurately depict monthly volumes under normal weather conditions); (5) customer annualizations (for residential and small commercial classes, captures seasonal nature of test year customer growth); and (6) reclassification of full margin transportation customers to present rate schedules (to reflect pricing at present rate schedules) (Ex. A-16, at 3-8).

Although Staff does not oppose the Company's proposed billing determinants[10], RUCO witness Moore filed testimony reflecting modifications that RUCO believes are necessary to obtain accurate determinants. Mr. Moore initially revised the billing determinants to reflect updated bill frequency analyses, and imputed revised billing determinants into the Company's proposed rate design, and, finally, annualized the imputed billing determinants using the Company's pro forma adjustments (RUCO Ex. 5, at 5).

In his Rebuttal testimony, Mr. Congdon identified several errors he believes were made in RUCO's calculation. He stated that RUCO improperly attempted to utilize the Company's actual recorded bills and failed to utilize the residential bill frequency analyses ("BFAs") which are necessary to correctly price the first and second block volumes of the existing rates. Mr. Congdon indicated that RUCO's analysis understated first block revenues by approximately 88 million therms, which resulted in those therms being priced at the lower second block rate, thereby understating residential revenues by $7.4 million (Ex. A-17, at 24-25). Mr. Congdon also claimed that RUCO improperly used ratios to distribute the Company's total proposed adjustments to bills and volumes.

In his Surrebuttal testimony, Mr. Moore stated that following review of a data request response and several telephone conversations with Southwest Gas, the Company was unable to provide a set of test year billing determinants that generate its test year recorded revenues. Mr. Moore claims that RUCO analyzed the BFAs provided by the Company and determined a set of determinants that accurately reflect the size of the test year customer base, its usage patterns, and that

[10] Mr. Congdon stated that Staff accepted the Company's proposed test year bills and volumes, but not all of the Company's proposed reclassifications of customers to new rate schedules. The Company agreed that, to the extent Southwest Gas' proposed rate schedules and customer reclassifications are not adopted, use of Staff's bills and volumes would be appropriate (Ex. A-17, at 26). To the extent we have adopted Staff's recommendations on the various rate schedule issues, as discussed above, Staff's bills and volumes will be employed accordingly.

generate the test year recorded revenue. RUCO then added pro forma adjustments to create a normalized set of test year determinants to design a rate structure that would produce RUCO's recommended revenue requirement (RUCO Ex. 6, at 4-7). RUCO argues that it corrected whatever errors existed in its initial calculation through its surrebuttal testimony and that the workpapers for those calculations were provided to the Company. RUCO claims that there is no assurance that the Company's proposal is any more accurate than RUCO's revised calculations.

The Company provided a response to a RUCO data request to clarify the alleged errors, but Mr. Congdon claimed in his Rejoinder testimony that RUCO's continued insistence on adjustments to bills and volumes reflected several computational errors including: improper calculation of the Company's average test year cost of gas; incorrect pricing of bills and volumes for the Company's former Black Mountain Gas Company customers; and improperly pricing the gas cost and basic service charge revenue applicable to Schedule G-60 and G-80 (Ex. A-18, at 9-13). Despite attempting to reconcile RUCO's adjustments through data requests and telephone conversations, Mr. Congdon believed that RUCO's proposal continued to understate residential gas cost by $6 million, and overstated residential margin by the same amount (*Id.* at 12). On cross-examination, Mr. Congdon testified that the billing determinants proposal in RUCO's Surrebuttal testimony was closer than its original calculation, but RUCO's number of bills was still approximately 22,000 higher than the Company's calculation and RUCO's volumes were overstated by approximately 5 million therms (Tr. 244).

It is fairly clear that Southwest Gas and RUCO never achieved a meeting of the minds regarding the appropriate billing determinant methodology. There is little doubt that RUCO's initial calculations were flawed and, although subsequent amendments were made to its proposal, for the reasons identified by Mr. Congdon we believe that the billing determinant recommendation presented by Southwest Gas is the most reliable proposal and should be adopted in this proceeding (subject to the Staff modifications discussed above). In future cases, the parties would be wise to initiate discovery regarding complex issues such as this at an early stage in order to avoid the necessity of amendments to their recommendations at a later stage in the process.

Purchased Gas Adjustor

All of Southwest Gas' core customers are served under a purchased gas adjustor ("PGA") mechanism[11]. The PGA mechanism uses a 12-month rolling average, whereby a new PGA rate is calculated each month. Each month the Company calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then determined by subtracting the base cost of gas[12] from the 12-month average cost of gas. As explained by Staff witness Gray, the PGA rate is "banded," which means each month when the PGA rate is set it cannot be set at a rate that is more then $0.10 per therm different than the rate that was in place in any of the previous 12 months (Ex. S-13, at 8). The PGA currently has a $22.4 million bank balance "trigger," such that if the balance becomes over-collected by $22.4 million or more, the Company is required to take certain actions to address the under-collected balance (*Id.* at 18).

Staff made several recommendations regarding the PGA mechanism. Staff proposed that the base cost of gas should be set at zero and the full commodity cost of gas incorporated into the PGA. Staff also recommended that the current $22.4 million bank balance trigger should be increased to $29.2 million and an officer of Southwest Gas should be required certify each PGA report. Each of these issues is discussed below. Staff further recommended that the bank balance interest rate should be set based on the one-year nominal Treasury constant maturities rate, and that the PGA report should identify certain additional details regarding purchases and usage[13]. These issues are not in dispute and are not addressed further. The reporting details recommended by Staff are in addition to all current reporting requirements. Further, the Company's PGA monthly reports to the Commission should continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

Setting Base Cost of Gas at Zero

The base cost of gas is currently included along with the margin within the tariffed rate per

[11] Customers under Schedules G-60 and G-80 are served under a separate cost of gas which is reset twice annually, on April 1st and October 1st (Ex. A-13, at 8).

[12] The base cost of gas includes both the commodity cost and the cost of transport from its source to the Southwest Gas distribution system.

[13] Specifically, Staff recommends that Southwest Gas' report include a breakdown of "purchases" into fixed price and variable (such as index) contracts, and that the Company begin identifying in its monthly PGA reports average and median usage levels for G-5 and G-10 rate schedules (Ex. A-13, at 25).

therm for each rate class, with the monthly PGA listed as a separate line item on customer bills. Mr. Gray explained that in a rate case the Commission traditionally addresses all costs aside from the cost of gas component, which is treated separately through the PGA function. Because the margin rate recovers all of the other costs, such as metering, billing, customer service, personnel, and facility costs, the rates established in a proceeding such as this affect only the margin rate component, consisting of the tariffed rates and the basic service charge. As a result, the margin rate change for a given customer class is always much higher than the percentage increase on customer bills, given the treatment of the cost of gas component as a constant in the rate proceeding. Mr. Gray pointed out that including both a margin component and a base cost of gas in the tariffed (commodity) rate can result in significant confusion for customers who are trying to understand their bills, especially after rate increases are granted (Ex. S-13, at 8-16).

Southwest Gas' current base cost of gas is $0.37034 per therm, as established in the Company's last rate case (Decision No. 64172). In its application, Southwest Gas proposed increasing the base cost of gas to $0.53436 per therm, which Staff found to be reasonable. However, Staff witness Gray recommended, as an alternative, that the base cost of gas be set at zero as a means of minimizing customer confusion. Under Mr. Gray's recommendation, setting the base cost of gas at zero would effectively eliminate the base cost of gas component so that the PGA rate would include the previously separate base cost of gas amount. Thus, a single line item on customer bills would include the full commodity cost (absent a temporary surcharge or credit), allowing customers to easily see the changing cost of gas component separate from the margin component (Ex. S-13, at 13).

In order to alleviate short-term customer confusion from such a change, Staff further recommends that Southwest Gas should create specific customer education materials to explain the change (including, *e.g.*, a side-by-side bill comparison under the old and new rate structures) (*Id.* at 14-15). Mr. Gray also points out that setting the base cost of gas at zero would cause the monthly PGA rate component to significantly increase, and well beyond what a typical application of the $0.10 therm band would enable the monthly PGA rate to reflect. To remedy this problem, Staff recommends that, when applying the $0.10 per therm band for the first 12 months after this Decision,

Southwest Gas should compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA in prior months. Taking this approach would, according to Mr. Gray, provide a consistent benchmark for applying the $0.10 per therm band while transitioning to a base cost of gas of zero (*Id.* at 15-16).

Southwest Gas indicated that it does not oppose Staff's recommendation to set the base cost of gas to zero (*Id.* at 14; Tr. 270). Mr. Congdon also testified at the hearing that the Company does not oppose Staff's recommendation to create specific customer education materials, "like a bill stuffer" that would go out in customer bills to explain the change (Tr. 270).

We believe Staff's recommendation to set the base cost of gas at zero is appropriate and, once fully implemented, should enhance customer understanding of their bills. This proposal will allow customers to more easily track the separate components that go into the provision of gas service, especially the gas component during periods of volatility. We appreciate Staff's effort in devising this recommendation, as well as the Company's agreement with a proposal that should minimize customer confusion, while at the same time allowing the Company to recover its costs. As a final matter on this issue, we direct the Company to submit to Staff for its review a copy of all customer education materials related to this issue prior to the materials being distributed to customers.

PGA Mechanism Trigger Level

Southwest Gas' current PGA mechanism was implemented in June 1999, at a time when natural gas prices had remained relatively stable for a number of years. Staff witness Gray testified that, although no PGA structure can change or mitigate the fact that natural gas prices have increased dramatically in recent years, Staff believes the current PGA mechanism reasonably balances the protection of customers from wildly fluctuating gas prices with the goal of sending, to a certain extent, price signals to customers regarding gas prices (Ex. S-13, at 17). Therefore, Staff recommends that the existing PGA mechanism should be retained, subject to the limited modifications discussed below.

Mr. Gray explained that when the rolling average PGA mechanism was established by Decision No. 61225 (October 30, 1998), the $22.4 million trigger level was set on the basis of consumption levels for Southwest Gas in 1996 and 1997 (approximately 447 million therms

annually). For 2003 and 2004, the Company had an average annual consumption of 516 million therms (*Id.* at 18). Mr. Gray stated that although there is not necessarily one right trigger level, given the increasing annual cost of gas (among other relevant considerations regarding the impact on customers and the Company), Staff believes the trigger level for the PGA bank balance should be increased from $22.4 million to $29.2 million. According to Staff, the proposed trigger level increase should provide a level of flexibility to absorb higher usage and higher natural gas costs in the PGA bank balance, while also providing a measure of protection for customers and the Company if a positive or negative balance were to be carried within the balance for a period of time (*Id.* at 19-21).

Company witness Gieseking testified that while Southwest Gas is not necessarily opposed to an increase in the PGA bank balance trigger level, to the extent such an increase were to be adopted the Company believes the current $0.10 per therm PGA adjustment rate band should also be increased to $0.20 per therm[14] (Ex. A-21, at 10-11). Company witness Congdon stated that an increase in the bank balance trigger level would potentially increase the amount of money carried in the balancing account, thereby increasing the Company's business risk in the eyes of the financial community (Ex. A-17, at 40). Southwest argues that an increase in the adjustment cap would save customers in the long-term by minimizing deferrals to the balancing account, thereby reducing carrying costs on the PGA balance, and resulting in less cost to customers in a future period (*Id.*). Southwest Gas also contends that leaving the current $0.10 band in place would hinder the adjustment of gas rates that are used to reflect the 12-month average cost and would distort the true marginal cost of natural gas, thus failing to send appropriate price signals to customers (Ex. A-21, at 10-11).

We agree with Staff that the PGA bank balance trigger level should be increased to $29.2 million for the reasons set forth in Staff witness Gray's testimony. As stated above, the Company is not opposed to the trigger level increase as long as the change is accompanied by a corresponding increase in the $0.10 per therm adjustment band. We believe that an increase in the trigger amount is a reasonable adjustment based on various factors, including the significant increase in gas

[14] Southwest Gas initially proposed a corresponding increase in the adjustment band of only three cents, from $0.10 to $0.13 (Ex. A-17, at 40).

consumption levels since the trigger was originally established.

Given the current volatility in the price of gas we believe a slight adjustment of the current adjustment band is appropriate. According to Mr. Gray, the purpose of the band is to limit the amount by which the monthly PGA rate could adjust automatically within a 12 month period, without further action by the Commission (Ex. A-15, at 5-6). Staff does not oppose an increase of the band in principle, but does not believe there is a need to link what it considers a moderate trigger level increase with an expansion of the adjustment band, as proposed by the Company (*Id.*). Although the trigger level and the adjustment band are not inextricably intertwined, limiting the band to its current level could result in greater long-term costs for the Company's customers. Mr. Gieseking testified that the Company's rolling 12-month average cost was expected to exceed the $0.10 upper band by January 2006, an indication that an increase in the band is warranted at this time. As Mr. Gray stated in his Rebuttal testimony, the band was expanded once before by the Commission, from $0.07 per therm to $0.10 per therm, and "Staff is not conceptually opposed to a possible expansion of the band" (Ex. A-15, at 5). However, we believe the Company's proposed increase to $0.20 is excessive. We find that an increase to $0.13 per therm reflects a more reasonable balance between the interests of the Company and its customers.

Officer Certification of Monthly PGA Reports

Staff recommends that an officer of Southwest Gas be required to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. Mr. Gray stated that this recommendation is consistent with action taken by the Commission in other gas and electric cases dealing with adjustor mechanisms (Ex. A-13, at 24-25). Staff does not believe there is any basis for Southwest Gas to be treated differently than the other companies that are required to provide such certification (Ex. A-15, at 5).

Southwest Gas opposes Staff's recommendation to require officer certification of the monthly PGA reports. Company witness Moody testified that although Southwest Gas is committed to providing the Commission with accurate information, the Company does not believe the certification requirement is necessary. Southwest Gas believes the person most knowledgeable regarding the

report should sign it, as opposed to an officer (Ex. A-22, at 7; Tr. 454-455).

We do not believe it is an undue burden for an officer of Southwest Gas to be required to familiarize herself or himself with the workings of the PGA mechanism and the monthly reports that are filed to support the required information. While Southwest Gas argues that Staff failed to provide a valid reason for why this requirement is necessary, the underlying basis of the Company's opposition rings hollow. The officer certification requirement would not only put Southwest Gas in a position that is comparable to other companies for which the issue has been addressed, but will provide a measure of assurance to the Commission, as well as the Company's customers and shareholders, that a level of oversight exists that reaches to the Company's highest ranks. Although we are not suggesting that Southwest Gas' prior PGA reports have been deficient, given the financial accounting scandals that have been exposed in the recent past, certification of a report that deals with millions of dollars of gas costs on a monthly basis seems a small price to pay for a higher level of oversight. Indeed, it is surprising that AUIA has not taken a position in support of Staff's recommendation given the inherent interest of shareholders in transparency and accountability for a publicly filed report regarding the Company's purchased gas costs. We will therefore adopt Staff's recommendation.

Gas Procurement Practices

Staff witness Gray and William Gehlen conducted a detailed review of Southwest Gas' procurement practices during the test year, and offered several recommendations with respect to those practices. Mr. Gray identified price stability as one of the Commission's goals of the gas procurement process for Arizona LDCs, including Southwest Gas (*See*, Decision No. 61225).

Staff witness William Gehlen testified regarding the Company's procurement practices and indicated that having a mix of spot market gas and long-term fixed price contracts enhances price stability (Ex. S-8). Staff recommended that Southwest Gas further explore procurement opportunities in order to enhance greater price stability for customers. According to Staff, the Company has agreed to a number of recommendations, including: conducting a fuel and procurement practice best practices review; separating the contract award group from the invoice approval authority within the Company; reviewing the Company's portfolio evaluation software; eliminating the use of cell phones

in term bidding and negotiating activities; and having a neutral party observe these activities (Tr. 433-434).

It is also Staff's position that employees involved in gas procurement should not have "substantial" stock ownership in companies with which it is dealing (Tr. 1108). Company witness Moody agreed that Southwest Gas would review its definition of stock ownership rules for employees involved in gas procurement and meet with Staff within 60 days of the Decision in this case (Tr. 434).

Mr. Moody also agreed Southwest Gas shares Staff's concerns regarding El Paso, shortfall of service, and other lateral issues. It is Staff's recommendation that Southwest Gas should construct and own its laterals absent a compelling reason to do otherwise. However, Mr. Moody indicated that the best course of action is to take a look at a cost-effective and reasonable means for the Company to either own its system or own access to supplies that come onto its system. He explained that the Company has a long history of trying to purchase laterals from El Paso, but to do so would often require also purchasing undesirable lateral facilities (Tr. 455-456).

Although there does not appear to be any dispute between the Company and Staff regarding these gas procurement issues, we direct the Company to initiate discussions with Staff, within 60 days of this Decision, regarding the stock ownership issues discussed above, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system. Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding the stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above.

Interest on Customer Deposits

In its Application, Southwest Gas proposed a reduction of the interest rate applied to customer deposits from 6 percent to 3 percent (Ex. A-29, at 31-32). As noted above, Staff proposed that the interest rate on PGA balances be set based on a monthly one-year nominal Treasury constant maturity rate (Ex. S-13, at 22). Staff also recommends that the same interest rate be applied to the Company's other balancing accounts (*i.e.*, DSM and LIRA) (*Id.* at 54). Company witness Congdon testified on rebuttal that an equitable approach to the customer deposit interest rate issue would be to synchronize the interest rates on both customer deposits and the balancing accounts maintained by Southwest Gas

(Ex. A-17, at 39).

Staff witness Gray testified that Staff recommends maintaining the customer deposit interest rate at 6 percent consistent with the rate in effect for a wide variety of other utilities. Mr. Gray stated that although interest rates are currently relatively low, a significant rise in rates would not be equitable to customers if the customer deposit interest rate were reduced to 3 percent as requested by the Company (Ex. S-13, at 57).

We agree with Staff that the customer deposit interest rate should be maintained at the current level of 6 percent. We believe that subjecting such deposits to a constantly varying interest rate could lead to customer confusion and would be inconsistent with the practices in effect for other utilities in the State. We therefore adopt Staff's recommendation on this issue. We also agree with Staff that maintaining the 12-month customer deposit period is appropriate.

Four-Hour Service Window

In his Direct testimony, Staff witness Gray indicated that the Commission's Consumer Services Division has received a number of customer contacts expressing concern that Southwest Gas asks customers to be available at the service location for most or all of a day when a technician is scheduled for service. Mr. Gray stated that the Company's policy imposed a burden on customers and is inconsistent with the practices of other gas and electric utilities, which provide a four-hour window for service calls. Mr. Gray pointed out that the service window length is not established by Commission rule, but is set according to each company's practice. Mr. Gray recommended that Southwest Gas be required to establish a company practice of giving customers a four-hour window, in accordance with the policies in effect for other similar utility companies (Ex. A-13, at 54-55). Mr. Gray stated that there is no compelling reason why Southwest Gas cannot adopt the four-hour standard and he recommends that the Commission order the Company to adopt such a standard within 6 months from the date of this Decision (Ex. A-15, at 14).

Company witness Palacios responded that a directive from the Commission is not necessary because Southwest Gas currently offers several service options including two-hour, four-hour, and eight-hour service windows "based on the customer's request" (Ex. A-6, at 5). She indicated that only 10 to 15 percent of customers requesting service establishment (which requires entry into the

premises) request service appointments of four hours or less. Ms. Palacios claims that if Staff's recommendation were adopted, Southwest Gas would likely have to increase its workforce to provide every customer, regardless of need, a four-hour service window (*Id.* at 4-5). She stated that such a mandate would also likely require significant restructuring of existing work practices and replacement of or major modification to the Company's customer appointment software. Ms. Palacios noted that gas utilities differ from electric companies because, for safety reasons, an employee must always enter the premises when service is established, and because service technicians must give their highest priority to emergencies which may interfere with their ability to meet four-hour window requirements (*Id.* at 6-7).

We do not believe that the four hour service window requirement recommended by Staff would place an onerous burden on the Company's customer service capabilities. Mr. Gray testified that the Commission's Consumer Services Division has received comments regarding the lack of such a window being offered, and Staff's proposal to allow Southwest Gas 6 months to develop a program to meet this requirement is a reasonable length of time for compliance. Although the Company's witness attempted to distinguish electric from gas service providers to support the Company's position, she failed to recognize that UNS Gas, Inc. ("UNS") has a tariff in effect that requires appointments to be scheduled "within a maximum range of four (4) hours during normal working hours" unless another time frame is established that is mutually agreeable to both UNS and the customer (Ex. S-27). Consistent with the tariff in effect for UNS, we agree with Staff that Southwest Gas should adopt a tariff which requires customers to be offered a maximum four-hour service window. Staff's recommendation is therefore adopted.

Energy Share Contributions

Southwest Gas currently participates in the Energy Share program, which allows customers the opportunity to make voluntary contributions to help other customers with financial difficulties pay their utility bills. Other companies, such as APS and Salt River Project, also participate in the program, which is administered by the Salvation Army.

Staff witness Gray stated that Southwest Gas currently provides customers with a separate bill insert that can be returned with donations for Energy Share. In comparison, APS provides a box on

its actual bills that can be checked and an amount indicated for donation. Staff recommends that, at the time the new rates from this proceeding are reflected on customer bills, Southwest Gas should provide a place on its customer bills to allow donations to the Energy Share program (Ex. S-13, at 55-56).

In response, Company witness Congdon testified that Southwest Gas strongly supports retention of allowing customer contributions via bill inserts. He stated that the current practice should be maintained "unless Staff presents clear and convincing evidence that a change in the program notification process would result in a greater benefit than its cost" (Ex A-17, at 38).

We believe Staff's recommendation should be adopted. We appreciate Southwest Gas' participation in the Energy Share program. However, we agree with Staff that inclusion of a line on customer bills is preferable to a bill insert, which may be discarded when customers open their bills. We do not believe that a cost/benefit analysis is necessary to recognize that contributions are likely to be enhanced if, at the time customers sit down to write out their monthly checks, the opportunity to donate is clearly shown on the billing statements alongside the amount due. We believe Staff's recommendation represents a common sense approach to encouraging contributions to the program. The Company should implement this change within 60 days of the effective date of this Decision.

Gas Technology Institute

The Gas Technology Institute ("GTI"), which was formerly known as the Gas Research Institute, is a non-profit entity that does research, development and training regarding energy markets. GTI's Operations Technology Development ("OTD") programs focus on projects pertaining to pipe and leak locating and detection, reduced construction costs, gas main integrity and safety, while its Utilization Technology Development ("UTD") program focuses on developing increased-efficiency and safety end-use equipment for residential, commercial, and industrial gas customers. Although GTI was previously funded through a FERC surcharge, it now must solicit donations via state public utilities commissions and the LDCs they regulate (Ex. S-13, at 2-8).

Staff recommends that Southwest Gas participate in funding GTI's OTD and UTD programs at a level of $688,712 annually, which amount would be recovered on a per therm basis from the Company's sales customers, excluding G-30 and B-1 customers. Mr. Gray stated that the per therm

surcharge would amount to approximately $0.00113, which would increase an average residential customer's bill by approximately three cents per month (*Id.*).

Southwest Gas witness Marti Marek testified that the Company supports funding gas research but opposes Staff's mandatory contribution of all research funding to a single entity. She indicated that, although the Company is pleased with the projects it has participated in with GTI, there are other competing research organizations that perform equally valuable work (Ex. A-24, at 2-6).

We agree with Southwest Gas that the funding provided for research should not be allocated to a single entity. The Company should have flexibility to tailor the research funds to the projects and organizations best suited for a specific need, subject to oversight by the Commission (*Id.* at 7). We will therefore adopt the recommended level of research funding, which would be collected through a surcharge, and held and disbursed through a balancing account. Adoption of Southwest Gas' proposal will allow the Company flexibility to select specific projects on a case-by-case basis, but will permit Staff to have input and oversight regarding the program expenditures.

Demand Side Management/Energy Efficiency Programs

Southwest Gas proposed increasing its current level of demand side management ("DSM") funding of $600,000 per year to $4,385,000 annually[15], subject to the Commission's approval of a decoupling mechanism. The DSM programs would be directed at all classes of customers instead of just residential customers as currently exists. The specific programs, and the associated funding proposed by Southwest Gas are as follows: Low-Income Energy Conservation ("LIEC") ($500,000); Energy Star Home Certification ($250,000); Multi-Family New Construction ($1,200,000); Residential Energy Construction ($200,000); Energy Star Appliances ($800,000); Food Service Equipment ($500,000); Efficient Commercial Building Design ($500,000); Technology Information Center ($35,000); and Distributed Generation ($400,000).

Staff, RUCO, and SWEEP/NRDC all support the DSM programs proposed by the Company, with a few minor exceptions. SWEEP/NRDC witness Schlegel recommended that an additional $750,000 should be added to the Energy Star Home Certification program, and that Southwest should

[15] The DSM funds are collected through a DSM surcharge and held and disbursed through a balancing account.

be allowed to impose a performance incentive mechanism to recover up to 10 percent of DSM funding if minimum goals are met (SWEEP Ex. 1, at 6). Company witness Vivian Scott testified in support of SWEEP/NRDC's proposals because she believes increasing funding for the Energy Star Home Certification program would enable the Company to expand the program to larger parts of its service territory (currently offered only in the Tucson area) (Ex. A-15, at 3). She also supports the performance incentive mechanism proposal which is comparable to a program in effect for APS (*Id.*).

Staff witness Steve Irvine supports the Company's initial proposed DSM funding level, with the exception of $50,000 included in the LIEC program that is specifically allocated for rate assistance to low-income customers. Mr. Irvine stated that such rate assistance is not DSM-related and should therefore be considered as a separate and distinct program (Ex. S-19, at 3). He acknowledged that a similar program was included in a recent APS case, but points out that the rate assistance component of that case was part of a settlement agreement involving a number of diverse parties. Mr. Irvine also opposes the SWEEP/NRDC proposal to increase the Energy Star Home Certification program by $750,000 on the basis that Southwest Gas previously indicated that "the market has sufficiently transformed and that incentives are no longer necessary to ensure more energy-efficient construction" (*Id.* at 6) (*See also*, Decision No. 67878, June 1, 2005, granting Southwest Gas' request to reduce the annual Energy Advantage Plus program funding from $900,000 to $250,000). In addition to these adjustments to proposed DSM revenues, Staff recommends the following with respect to the Company's DSM programs: semi-annual DSM reports certified by an officer of the Company; requirement that Company docket within 120 days of this Decision, in a separate docket, detailed descriptions of the DSM programs that would be subject to Commission approval; requirement that the Company implement and maintain the collaborative DSM working group to solicit and facilitate input from any interested party (prior to submission to Commission of specific programs); responsibility of Southwest Gas to demonstrate appropriateness of specific DSM programs; and no performance incentive mechanism should be approved (*Id.* at 9-10).

With one exception, we agree with Staff's recommendations regarding DSM. Despite Staff's concerns, we believe the $50,000 currently included in the LIEC program for rate assistance funding should be maintained. Although such funding may not in a strict sense be considered DSM-related,

we agree with Mr. Schlegel that it represents a relatively small percentage of the overall DSM budget and is to be used for emergency situations for low-income customers. To the extent any portion of this $50,000 is not spent yearly on bill assistance emergencies, the balance should be allocated to general LIEC programs. With respect to SWEEP/NRDC's proposal to increase by $750,000 funding for Energy Star Home Certification, we share Staff's concern that the Company has previously offered conflicting views of whether such an increase in such funding would be cost effective. As Mr. Irvine pointed out, through data request responses the Company indicated that it could offer the program throughout its service area at the initial funding level and specifically requested a reduction in funding for a similar program in the Tucson area due to market transformation (Ex. S-19, at 6-7). We also agree with Staff that the performance incentive mechanism, which was suggested for the first time in Mr. Schlegel's testimony, is not sufficiently developed for approval at this time. The parties to the DSM collaborative process may wish to pursue this issue through further discussions but the proposal contained in the record of this proceeding lacks sufficient detail to determine whether it is appropriate at this time. In all other respects, we agree with and adopt Staff's recommendations as described above.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On December 9, 2004, Southwest Gas filed an application with the Commission for an increase in rates.

2. On January 7, 2005, the Commission's Utilities Division Staff filed a Letter of Insufficiency.

3. On January 26, 2005, Staff filed a Letter of Sufficiency, notifying the Company that its application met the sufficiency requirements and classifying Southwest Gas as a Class A utility.

4. By Procedural Order issued February 7, 2005, procedural timeframes were established and a hearing was scheduled to commence on October 3, 2005.

5. Intervention was granted to RUCO, AUIA, DOD, SWEEP/NRDC, YCA, ACAA,

APS, and TEP.

6. Southwest Gas filed Direct testimony with its application on December 9, 2004. Pursuant to Procedural Order issued March 10, 2005, Direct testimony was filed on July 26, 2005 by Staff, RUCO, YCA, AUIA, ACAA, and SWEEP/NCRA.

7. Rebuttal testimony was filed by Southwest Gas on August 23, 2005. Surrebuttal testimony was filed on September 13, 2005 by Staff, RUCO, AUIA, SWEEP/NRDC, and DOD. Rejoinder testimony was filed by the Company on September 23, 2005.

8. An evidentiary hearing was conducted at the Commission's offices in Phoenix, Arizona commencing on October 3, 2005 and concluding on October 11, 2005.

9. Late-filed exhibits were filed by Southwest Gas on October 21, 2005 and November 4, 2005.

10. Initial Post-Hearing Briefs were filed by DOD on October 31, 2005, by RUCO on November 3, 2005, and on November 4, 2005 by Southwest Gas, SWEEP/NRDC, AUIA, and Staff.

11. Reply Briefs were filed on November 14, 2005 by Southwest Gas, RUCO, SWEEP/NRDC, AUIA, and Staff. Southwest Gas filed a Supplement to its Reply Brief on November 23, 2005.

12. According to the Company's application, as modified, in the test year Southwest Gas had adjusted operating income of $46,775,622 on an adjusted Original Cost Rate Base of $943,110,070, for a 4.96 percent rate of return.

13. In its application, as modified, the Company requested a revenue increase of $66,898,342, based on OCRB of $943,110,070, and rate of return of 9.24 percent.

14. Staff recommends a rate increase of $51,625,135, based on OCRB of $924,927,566, and a recommended rate of return of 8.40 percent.

15. RUCO recommends a revenue increase of $48,506,079, based on OCRB of $919,607,846, and recommended rate of return of 8.64.

16. For purposes of this proceeding, we determine that Southwest Gas has an Arizona Fair Value Rate Base of $1,169,584,038.

17. A rate of return on FVRB of 6.63 percent is reasonable and appropriate.

18. Southwest Gas is entitled to a gross revenue increase of $49,345,636.

19. The Company's proposed Conservation Margin Tracker decoupling mechanism proposal is not adopted in this proceeding.

20. The class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness.

21. For residential customers under Schedule G-5, the basic monthly customer charge should be increased from $8.00 to $9.70, and a two-tier declining block structure remains appropriate in accordance with Staff's recommendation.

22. A separate multi-family residential basic monthly customer charge of $8.70 is appropriate under the new Schedule G-6 rate.

23. The low-income residential rate (G-10) should be maintained at its current $7.00 per month with the current commodity discount of 20 percent for the first 150 therms of winter usage.

24. Staff's rate design recommendations for Special Residential Gas Service for Air Conditioning (G-15) and Master Metered Mobile Home Park Gas Service (G-20) should be adopted.

25. The current Armed Forces Rate Schedule G-35 should be eliminated and customers currently on that schedule would receive service under Schedule G-25.

26. For General Gas Service customers on Schedule G-25, a new sub-class should be created for small customers using less than 600 therms annually, and the demand charge for large G-25 customers should be calculated based on DOD's recommendation of using a modified non-coincident peak during any winter month.

27. For Air Conditioning Gas Service (G-40); Gas Service for Compression on Customer's Premises (G-55); Cogeneration Gas Service (G-60); Small Essential Agricultural User Gas Service (G-75); and Natural Gas Engine Gas Service (G-80), Staff's recommended rate design should be adopted.

28. The billing determinants proposed by the Company should be employed for setting rates in this proceeding.

29. With respect to the Company's Purchased Gas Adjustor mechanism, the base cost of gas should be set at zero in accordance with Staff's recommendation; the trigger level for the PGA

bank balance should be increased from $22.4 million to $29.2 million as recommended by Staff; and the current $0.10 per therm adjustment band should be increased to $0.13 per therm.

30. The interest rate for the Company's PGA, DSM, and LIRA balancing accounts should be based on the one-year nominal Treasury constant maturities rate, in accordance with Staff's recommendation.

31. The Company's PGA monthly reports to the Commission should continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

32. Staff's recommendation to require an officer of Southwest Gas to provide certification of the accuracy of the monthly PGA reports is reasonable and should be adopted.

33. Southwest Gas should initiate discussion with Staff within 60 days regarding gas procurement issues identified by Staff, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system.

34. The current interest rate of 6 percent on customer deposits should be maintained in accordance with Staff's recommendation. The 12-month customer deposit period should also be maintained.

35. Southwest Gas should develop within 6 months a tariff proposal that would require that customers be offered a four-hour window for service calls.

36. Southwest Gas should implement, within 60 days of the effective date of this Decision, Staff's recommendation to allow donations to the Energy Share program by an indication on the Company's billing statements.

37. Gas research should be funded at the level recommended by Staff, but Southwest Gas should have the flexibility, subject to Staff oversight, to select appropriate entities for use of the research funds.

38. DSM programs should be funded at the level initially recommended by Southwest Gas ($4,385,000) and the Company should comply with the recommendations made by Staff regarding, among other things, compliance filings and working with the DSM collaborative group.

39. Arizona customer bills should contain information relevant to Arizona customers.

Information specific only to Nevada and/or California customers should be removed from the back of Arizona customer bills. Furthermore, the back of Arizona customer bills should contain explanations for two billing line items "Base Tariff Rate" and "Rate Adjustment."

40. We also agree with Staff that anytime Southwest Gas initiates participation in a new natural gas docket at the FERC which relates to its service in Arizona, the Company should be required to provide Staff with a copy of Southwest Gas' initial filing in that FERC docket.

CONCLUSIONS OF LAW

1. Southwest Gas is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250, 40-251 and 40-367.

2. The Commission has jurisdiction over Southwest Gas and the subject matter contained in the Company's rate application.

3. The rates, charges and conditions of service established herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that Southwest Gas Corporation is hereby authorized and directed to file with the Commission, on or before February 28, 2006, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after March 1, 2006.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall notify its customers of the revised schedules or rates and charges authorized herein by means of an insert in its next regularly scheduled billing, in a form acceptable to Staff.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall provide a detailed explanation of employee duties that are associated with sales, marketing, or promotional activities and offer a reasonable allocation of wage expense consistent with those duties.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall

provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its customers.

IT IS FURTHER ORDERED that Southwest Gas Corporation should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties. Such efforts may be pursued through the DSM policy process, as suggested by SWEEP/NRDC, and through a proposal in the Company's next rate case.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall submit to Staff for its review a copy of all customer education materials related to setting the base cost of gas at zero prior to the materials being distributed to customers.

IT IS FURTHER ORDERED that the Company's PGA monthly reports to the Commission shall continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

IT IS FURTHER ORDERED that, for all future PGA monthly reports, an officer of Southwest Gas shall be required to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall initiate discussions with Staff, within 60 days of this Decision, regarding the stock ownership issues discussed herein, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system.

IT IS FURTHER ORDERED that Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding the stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall, within 6 months of the effective date of this Decision, propose a tariff which requires customers to be offered a maximum four-hour service window.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall implement, within 60

days of the effective date of this Decision and in a form acceptable to Staff, Staff's recommendation to allow donations to the Energy Share program by an indication on the Company's billing statements.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall comply with the recommendations made by Staff regarding, among other things, DSM compliance filings and working with the DSM collaborative group.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 23rd day of Feb., 2006.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: SOUTHWEST GAS CORPORATION

DOCKET NO.: G-01551A-04-0876

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Congdon Direct Testimony at Page 10

EXHIBIT
RUCO-11
ADMITTED

be balanced with consideration of the princ
gradualism, fairness, and encouragemen
conservation."

D. Commodity Charge

In Decision No. 68487, the Commission encouraged the parties to seek rate design alternatives that would promote conservation efforts, while benefiting all affected stakeholders.

Southwest addressed these concerns through its proposal to flatten the sales rate (commodity charge) of its proposed residential rate design, while stabilizing its non-gas revenues through an innovative allocation of the non-gas and gas cost components of the sales rate as reflected below.

Illustrative "Average" and Proposed "Allocated" Single-Family Residential Rates

Description	Delivery (Non-Gas) Charge	Monthly Gas Cost & Rate Adj	Effective Sales Rate
Illustrative Average Rate Components			
Basic Service Charge	$12.80		$12.80
Commodity Charge per Therm			
All Usage	$.55376	$0.93689	$1.49065
Proposed Rate Components			
Basic Service Charge	$12.80		$12.80
Commodity Charge per Therm			
Summer			
First 15 Therms	$.88069	$0.60996	$1.49065
Over 15 Therms	.00000	1.49065	1.49065
Winter			
First 35 Therms	$.88069	$0.60996	$1.49065
Over 35 Therms	.00000	1.49065	1.49065

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
AN AVERAGE RATE DESIGN AND SOUTHWEST'S PROPOSED RATE DESIGN
FOR WINTER SEASON BILLS

Description	Average (Normal) Rate Design	Southwest Proposed Rate Design	Difference Proposed less Average
Consumption			
20 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	11.08	17.61	6.54
PGA/Gas Cost	18.74	12.20	(6.54)
Total	$ 42.61	$ 42.61	$ -
40 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	22.15	30.82	8.67
PGA/Gas Cost	37.48	28.80	(8.67)
Total	$ 72.43	$ 72.43	$ -
55 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	30.46	30.82	0.37
PGA/Gas Cost	51.53	51.16	(0.37)
Total	$ 94.79	$ 94.79	$ -
60 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	33.23	30.82	(2.40)
PGA/Gas Cost	56.21	58.61	2.40
Total	$ 102.24	$ 102.24	$ -
80 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	44.30	30.82	(13.48)
PGA/Gas Cost	74.95	88.43	13.48
Total	$ 132.05	$ 132.05	$ -
100 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	55.38	30.82	(24.55)
PGA/Gas Cost	93.69	118.24	24.55
Total	$ 161.87	$ 161.87	$ -
120 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	66.45	30.82	(35.63)
PGA/Gas Cost	112.43	148.05	35.63
Total	$ 191.68	$ 191.68	$ -
140 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	77.53	30.82	(46.70)
PGA/Gas Cost	131.16	177.87	46.70
Total	$ 221.49	$ 221.49	$ -

	Average Rates	Proposed Rates
Basic Charge	$ 12.80	$ 12.80
Non-Gas Rates		
All Usage/First 35 Therms	$ 0.55376	$ 0.88069
Second Block		0.00000
Gas Cost Rates		
All Usage/First 35 Therms	$ 0.93689	$ 0.60996
Second Block		1.49065

Diaz Cortez

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
A TYPICAL RATE DESIGN VS. THE COMPANY-PROPOSED
"ALLOCATED" RATE DESIGN

SURREBUTTAL EXHIBIT A

LINE NO.	CONSUMPTION	AVERAGE (NORMAL) RATE DESIGN	COMPANY PROPOSED "ALLOCATED" RATE DESIGN
	20 THERMS		
1	MONTHLY MINIMUM	$12.80	12.80
2	BASE COMMODITY	11.08	17.61
3	PGA	18.74	12.20
4	PGA ADJUSTOR	0.00	6.54
5	TOTAL	42.61	49.15
	40 THERMS		
6	MONTHLY MINIMUM	$12.80	12.80
7	BASE COMMODITY	22.15	30.82
8	PGA	37.48	28.80
9	PGA ADJUSTOR	0.00	8.67
10	TOTAL	72.43	81.10
	55 THERMS		
11	MONTHLY MINIMUM	$12.80	12.80
12	BASE COMMODITY	30.46	30.82
13	PGA	51.53	51.16
14	PGA ADJUSTOR	0.00	0.37
15	TOTAL	94.79	95.15
	60 THERMS		
16	MONTHLY MINIMUM	$12.80	12.80
17	BASE COMMODITY	33.23	30.82
18	PGA	56.21	58.61
19	PGA ADJUSTOR	0.00	(2.40)
20	TOTAL	102.24	99.84
	80 THERMS		
21	MONTHLY MINIMUM	$12.80	12.80
22	BASE COMMODITY	44.30	30.82
23	PGA	74.95	88.43
24	PGA ADJUSTOR	0.00	(13.48)
25	TOTAL	132.05	118.58
	100 THERMS		
26	MONTHLY MINIMUM	$12.80	12.80
27	BASE COMMODITY	55.38	30.82
28	PGA	93.69	118.24
29	PGA ADJUSTOR	0.00	(24.55)
30	TOTAL	161.87	137.31
	120 THERMS		
31	MONTHLY MINIMUM	$12.80	12.80
32	BASE COMMODITY	66.45	30.82
33	PGA	112.43	148.05
34	PGA ADJUSTOR	0.00	(35.63)
35	TOTAL	191.68	156.05
	140 THERMS		
36	MONTHLY MINIMUM	$12.80	12.80
37	BASE COMMODITY	77.53	30.82
38	PGA	131.16	177.87
39	PGA ADJUSTOR	0.00	(46.70)
40	TOTAL	221.49	174.79

	AVERAGE RATES	"ALLOCATED" RATES
BASIC SERVICE CHRG.	12.8	12.80
BASE COMMODITY		
ALL USAGE	0.55376	
FIRST 35 THERMS		0.88069
SECOND 35 THERMS		0.00000
PGA		
ALL THERMS	0.93689	
FIRST 35 THERMS		0.60996
SECOND 35 THERMS		1.49065

EXHIBIT
RUCO-13
Admin Notice

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
MAY 27 2008
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQEUST FOR APPROVAL OF RELATED FINANCING.

DOCKET NO. E-04204A-06-0783

DECISION NO. 70360

OPINION AND ORDER

DATES OF HEARING: September 10, 11, 12, 13, 14, 20, 21, and October 2, 2007.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Teena Wolfe[1]

IN ATTENDANCE: William A Mundell, Commissioner
Kristin A. Mayes, Commissioner

APPEARANCES: Mr. Michael W. Patten and Mr. Jason Gellman, ROSHKA, DEWULF & PATTEN, PLC, on behalf of UNS Electric, Inc.;

Ms. Michelle Livengood on behalf of Unisource Energy Services;

Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Marshall Magruder, in propria persona; and

Ms. Maureen Scott, Senior Attorney, and Mr. Kevin Torrey, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

RECEIVED
JUN 3 2008
BY RUCO

[1] Administrative Law Judge Teena Wolfe conducted the hearing in this case and Administrative Law Judge Dwight Nodes drafted the Recommended Opinion and Order.

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We agree that, as a general principle, rewarding employees for performance and longevity provides at least an indirect benefit to customers because service is likely to be enhanced by recognizing employees. However, the Company and its shareholders also benefit from improved employee performance, at least as much as ratepayers, a fact that UNSE fails to acknowledge. If the Company wishes to provide gifts, awards, and other social events as a reward to employees, it should bear at least a portion of the burden associated with these discretionary expenditures. We will therefore reduce expenses by half of the amount identified by RUCO ($5,806).

Worker's Compensation (Injuries and Damages)

UNSE argues in its brief that, although it proposed a reduction of $98,161 to test year expenses booked in FERC Account 925, Staff and RUCO improperly advocated greater reductions. Mr. Dukes conceded that the test year level of $173,456 for worker's compensation appeared to be "abnormally high" and the Company therefore agreed to reduce that expense by $98,161 to reflect a three-year average of such costs (Ex. A-24, at 4-5). However, Mr. Dukes disagreed with Staff's and RUCO's proposals to reduce all of the expenses in FERC Account 925, because, according to Mr. Dukes, such reductions would not recognize costs associated with general liability insurance and Officers and Directors liability insurance (Ex. A-25, at 2).

Staff points out in its reply brief that its witness, Ralph Smith, agreed at the hearing to modify Staff's position in accordance with the Company's recommendation, and that Staff's revised position is included in its Final Schedules (Staff Initial Brief, at 15). Therefore, despite UNSE's protestations to the contrary, Staff has been in agreement with the Company's position on this issue since the date of Mr. Smith's testimony at the hearing[8]. RUCO did not address this issue in its briefs, and presumably has conceded its position on this issue.

Incentive Compensation

UNSE proposes to increase test year expenses by $39,026 to reflect a two-year average of expenses for incentive compensation programs maintained by the Company. UNSE recommends

[8] In this case, as well as the recent UNS Gas case the Company's brief failed to recognize changes in the positions taken by other parties (or its own witnesses), either through surrebuttal testimony, or at the hearing, and which changed positions were incorporated into the final schedules of that party (*See, e.g.*, Decision No. 70011, at 4, 29-31, 41).

Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders. However, 40 percent of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area. For the same reasons, we also adopt Staff's recommendation to disallow 50 percent of the Officer's Long-Term Incentive Program (Ex. S-58, at 32). Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent Decision.

We also stated in Decision No. 70011 that although we believe, on balance, that the 50/50 sharing is reasonable, we share RUCO's concerns that the SRA offered to employees in 2005 may have the effect of undermining the very goals the PEP is intended to achieve (*i.e.*, providing an incentive for participating employees to improve performance and thereby benefit both the Company and its customers). As described by Mr. Moore, despite failing to meet the PEP goals, the UniSource Board of Directors decided nonetheless to provide the affected employees with a surrogate means of compensation. As we indicated in Decision No. 70011, it appears that the SRA sends a signal to employees that they will be compensated regardless of performance, which places the entire premise of the PEP at issue. We expect the program to be scrutinized in the Company's next rate case to determine the appropriateness of providing incentive compensation above base salaries to employees.

Supplemental Executive Retirement Plan and Stock Based Compensation

UNSE allows select executives to participate in a Supplemental Executive Retirement Plan ("SERP"). The SERP provides to eligible executives retirement benefits in excess of the limits allowed under Internal Revenue Service ("IRS") regulations for salaries in excess of specified amounts. UNSE contends that the $83,506 of test year SERP costs are reasonable and that neither Staff nor RUCO have shown that the Company's overall executive compensation costs are excessive or out of line with industry standards.

EXHIBIT
RUCO-14
Admin Notice

BEFORE THE ARIZONA CORPORA

Arizona Corporation Commission
DOCKETED
NOV 27 2007
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COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831 DECISION NO. 70011 **OPINION AND ORDER**

DATES OF HEARING: April 16, 17, 18, 19, 20, 24, and 25, 2007.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: Mike Gleason, Chairman
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Michael W. Patten and Mr. Timothy Sabo, ROSHKA, DEWULF & PATTEN, P.L.C. and Ms. Michelle Livengood, UNISOURCE ENERGY SERVICES, on behalf of Applicant;

Mr. Scott S. Wakefield, Chief Counsel, on behalf of the Residential Utility Consumer Office;

Ms. Cynthia Zwick, Executive Director, Arizona Community Action Association;

Mr. Marshall Magruder, in propria persona; and

Mr. Keith Layton and Ms. Maureen Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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miscellaneous expenses, it would be akin to proclaiming the acceptability of the proverbial "death by 1,000 cuts."

Performance Enhancement Program

UNS allows its non-union employees to participate in its parent company's Performance Enhancement Program ("PEP"), which provides eligible employees compensation above their base pay for meeting financial targets (30 percent), cost containment goals (30 percent), and customer service goals (40 percent) (Ex. A-13 at 8-9). Company witness Dukes claims that the PEP is an integral part of its compensation package for employees and that UNS would be required to increase base salaries to attract and retain qualified employees if the program were eliminated (*Id.*).

Staff proposes to adjust the PEP expenses by 50 percent, based on Staff's claim that incentive compensation programs benefit both ratepayers and shareholders. Staff cites to the Southwest Gas Decision to support its position. In that case, the Commission adopted Staff's recommendation to disallow 50 percent of a similar program's costs, based on a finding that the Southwest Gas management incentive program benefited both customers and shareholders. Staff witness Ralph Smith stated that there is no relevant distinction between the UNS and Southwest Gas incentive programs and that the 50/50 sharing of costs is equally appropriate in this case (Ex. S-25 at 29).

RUCO proposes a complete disallowance of the PEP costs, based on its claim that it is not clear that the program is necessary to achieve the PEP's goals. RUCO witness Moore testified that during the test year (2005), no PEP payments were made because UniSource did not meet the program's financial goals. However, the UniSource Board of Directors authorized payment of a Special Recognition Award ("SRA") in 2005 to the employees eligible for the PEP. As a result, UNS is seeking in this proceeding to recover the average of the 2004 PEP payments and the 2005 SRA costs. Mr. Moore contends that the SRA is unique and does not meet the criteria of a typical and recurring test year expense for which rate recovery should be granted (RUCO Ex. 3 at 16-17). He also stated that 60 percent of the PEP payments are related to financial performance and cost containment, which are goals that primarily benefit shareholders. Finally, Mr. Moore asserts that because the PEP does not apply to 60 percent of its employees (*i.e.*, union employees), it is not clear that the program is necessary or will achieve the stated goals (*Id.*; RUCO Ex. 4 at 8).

We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders. However, 40 percent of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area. For the same reasons, we also adopt Staff's recommendation to disallow 50 percent of the Officer's Long-Term Incentive Program (Ex. S-25 at 26).

Although we believe, on balance, that the 50/50 sharing is reasonable, we share RUCO's concerns that the SRA offered to employees in 2005 may have the effect of undermining the very goals the PEP is intended to achieve (*i.e.*, providing an incentive for participating employees to improve performance and thereby benefit both the Company and its customers). As described by Mr. Moore, despite failing to meet the PEP goals, the UniSource Board of Directors decided nonetheless to provide the affected employees with a surrogate means of compensation. It appears that the SRA sends a signal to employees that they will be compensated regardless of performance, which places the entire premise of the PEP at issue. We expect the program to be scrutinized in the Company's next rate case to determine the appropriateness of providing incentive compensation above base salaries to employees.

Supplemental Executive Retirement Plan

UNS Gas allows select executives to participate in a Supplemental Executive Retirement Plan ("SERP"). The SERP provides to eligible executives retirement benefits in excess of the limits allowed under Internal Revenue Service ("IRS") regulations for salaries in excess of specified amounts. UNS contends that the SERP costs are reasonable and that neither Staff nor RUCO have shown that the Company's overall executive compensation costs are excessive or out of line with industry standards.

Staff and RUCO recommend disallowance of the SERP costs ($93,075), in accordance with the Commission's Decision in the Southwest Gas case (Decision No. 68487, at 18-19). In that case, we disallowed Southwest Gas's SERP costs, finding:

> [T]he provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. (*Id.* at 19).

We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case,[9] and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

More disturbing than the Company's advocacy on the relative merits of the SERP is the statement in its initial brief that "[h]ad UNS Gas been notified that SERP costs would not be allowed, it could have restructured its executive compensation package to take that into account. It would not be fair to hold UNS Gas to this new, unexpected standard." (UNS Initial Brief at 28.) Implicit in the Company's argument is the concept that "if we don't recover fully what we believe are our reasonable costs in our preferred manner, we'll simply shift those costs to another account to disguise the costs and ultimately ensure recovery." The approach to rate recovery seemingly advocated by UNS can serve only to increase the cynicism often expressed by ratepayers regarding the reasonableness of a given utility company's proposed rates and, if allowed, would at its essence turn the ratemaking process into a veritable regulatory version of "Three-Card Monte." We trust that in

[9] *See also Arizona Public Service Co.*, Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.

future rate applications, Staff and RUCO will explore thoroughly the merits of individual expenses sought by UNS, as well as other companies, to ensure that customers are paying rates that include only the costs necessary to provide quality service.

Fleet Fuel Expense

UNS witness Dukes proposed that the Company's fleet fuel expense be established based on an average gasoline cost of $2.48 per gallon (Ex. A-13 at 19). Mr. Dukes stated that the average fuel price used by UNS reflects the Company's actual costs and that lower cost recommendations made by Staff and RUCO should be rejected. He testified that it is not surprising that UNS would have slightly higher fuel costs than some other utilities because the UNS Gas service area is farther from large metropolitan areas like Phoenix and Tucson and covers a larger number of square miles given its more rural location (*Id.*). In response to a proposed disallowance made by Staff witness Ralph Smith, Mr. Dukes reduced the Company's request by $12,657 (pre-tax) (*Id.* at 23-24).

In his surrebuttal testimony, Staff witness Smith agreed with Mr. Dukes' proposed reduction to fleet fuel expense (Ex. S-27 at 39). Although Staff appears to have reconciled its recommendation with the Company on this issue, UNS's brief continues to advocate rejection of Staff's position (UNS Initial Brief at 29-30). We assume that the Company failed to notice Mr. Smith's surrebuttal testimony agreeing with Mr. Dukes' rebuttal testimony, and we believe that there is no remaining dispute between UNS and Staff.

RUCO agrees that it is appropriate for UNS to annualize its fuel expense to reflect additional employees included in its payroll annualization adjustment. However, RUCO witness Diaz Cortez stated that because gasoline prices were abnormally high in early 2006, the Company's calculation inflated the annualized level of fuel expenses (RUCO Ex. 5 at 14-15). Instead of the proposal to base fuel expenses on an average of $2.48, RUCO recommends using $2.43 per gallon as the average cost (*Id.* at Sched. MDC-3). In addition, RUCO claims that UNS understated the actual miles per gallon (10.28 mpg) achieved by the UNS fleet (*Id.* at 15). On cross-examination, Mr. Dukes admitted that the Company did not respond to the second part of RUCO's recommendation (*i.e.*, the UNS fleet miles per gallon) (Tr. at 241-42). Nor did UNS address the miles per gallon issue in its brief.

Decoupling Tariffs (as of May 2008)

APPROVED - 13 States

1. AR – Arkansas Oklahoma
2. AR – Arkansas Western
3. AR – CenterPoint Energy
4. CO – PSC of Colorado
5. CA – Pacific Gas and Electric
6. CA - San Diego Gas and Elec.
7. CA – Southern California Gas
8. CA – Southwest Gas

9 &10 IL – Integrys - Peoples Gas/North Shore Gas

11. IN – Citizens Gas & Coke

12&13 IN – Vectren Indiana/ Southern Indiana

14. MD – Baltimore Gas and Elec.
15. MD – Washington Gas
16. NJ – NJ Natural Gas
17. NJ – South Jersey Gas
18. NY – Consolidated Edison
19. NY – National Fuel Gas Dist.
20. OH – Vectren Ohio
21. OR – Cascade Natural Gas
22. OR – NW Natural Gas
23. NC - Piedmont Natural Gas
24. UT – Questar Gas
25. WA – Avista
26. WA – Cascade Natural Gas

20 Million Residential Customers

PENDING - 5 Additional States

1. AZ – Southwest Gas
2. AZ – UNS Gas
3. DE – Chesapeake Utilities
4. IL – CILCO
5. IL – CIPS
6. IL – Illinois Power
7. IL - Nicor
8. KS – Atmos Energy
9. NC – PS Co. of North Carolina
10. MA – Generic Proceeding
11. OH – East Ohio Gas
12. OH – Duke Energy Ohio
13. WA – NW Natural Gas

5 Million Residential Customers

** Of 63 Million Customers in U.S. **

AGA
American Gas Association

EXHIBIT
RUCO-16

EXHIBIT
RKO-17
ADMITTED

[Go to End of PURbase 146285]

96 MD PSC 334

Re Baltimore Gas and Electric Company

Case No. 9036
Order No. 80460

Maryland Public Service Commission

December 21, 2005

APPLICATION by natural gas local distribution company (LDC) for authority to increase rates by $52.7 million; granted as modified in the amount of $35.645 million, with an authorized rate of return on equity of 11.0% and an overall return of 8.49%. The return on equity is calculated based on the actual capital structure of the LDC's parent company, even though that structure included no short-term debt. Two dissenting commissioners argue that the absence of a lower-cost short-term debt component translates into a higher burden for ratepayers. They therefore assert that the increase as granted is over $3 million more than can be justified.

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2. PROCEDURE, § 16

[MD.] Evidence — Burden of proof — Effect of challenges by party who did not materially participate in hearings — Rejection of allegations of failure to meet burden — Local gas distribution company rate case. p. 341.

3. RATES, § 184

[MD.] Burden of proof — Effect of challenges by party who did not materially participate in hearings — Rejection of allegations of failure to meet burden — Local gas distribution company rate case. p. 341.

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4. EVIDENCE, § 16

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[MD.] Natural gas — Conservation of supply — Interruptible service — Penalties for noncompliance with interruption order — Need for compliance enforcement — Local gas distribution company. p. 370.

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46. RATES, § 384

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[MD.] Factors affecting reasonableness — Intercorporate relations — Concerns about use of parent company's actual capital structure — Absence of lower-cost short-term debt component — Reliance on money pool shared with affiliates — Both as unfairly adding to ratepayer burden — Local gas distribution company — Dissenting opinion. p. 375.

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51. INTERCORPORATE RELATIONS, § 18.3

[MD.] Intercorporate arrangements — Contributions to affiliates — Via shared money pool — As one concern about use of parent company's actual capital structure — Absence of lower-cost short-term debt component as another — Both as unfairly adding to ratepayer burden — Local gas distribution company — Dissenting opinion. p. 375.

52. RATES, § 129

[MD.] Factors affecting reasonableness — Capitalization — Concerns about use of parent company's actual capital structure — Absence of lower-cost short-term debt component — Reliance on money pool shared with affiliates — Both as unfairly adding to ratepayer burden — Local gas distribution company — Dissenting opinion. p. 375.

APPEARANCES: Daniel P. Gahagan, Beverly A. Sikora, and Kevin D. Ryan, for Baltimore Gas and Electric Company. David A. McCormick, for the United States Department of Defense and Federal Executive Agencies. Michael C. Powell and Todd R. Chason, for the Maryland Industrial Group and United States Gypsum Company. Gary R. Alexander and Chantel R. Ornstein, for the Maryland Alliance for Fair Competition and Blue Dot Services of Maryland. Nancy A. White and Robert I. White, for ISG Sparrows Point, LLC., Telemac N. Chryssikos, for Washington Gas Energy Services, Inc., Brian R. Greene, for Amerada Hess Corporation. Theresa V. Czarski, Cynthia Green-Warren, and Stacey E. Andersen, for the Maryland Office of People's Counsel. Michael A. Dean, Janice M. Flynn, Annette B. Garofalo, and Todd E. Givens, for the Staff of the Public Service Commission of Maryland.

BY THE COMMISSION:

I. INTRODUCTION AND TEST YEAR

On April 29, 2005, Baltimore Gas and Electric Company ("BGE" or "Company") filed an application to increase its base rates for gas service by $52.7 million annually, representing an increase of approximately 4.7 percent in gas distribution rates. The application was based on a test year ending July 31, 2005, and thus comprised eight months of actual data and four months of projected data. During the course of the proceeding, the Company provided actual results for all 12 months of its test year.

In the application, the Company notes that it last filed for revisions to its gas base rates in 1999. The Commission docketed that filing as Case No. 8829, and set rates for the Company in Order No. 76260, issued on June 19, 2000. [1] (1)

The Company further states that since the issuance of Order No. 76260, its costs have increased substantially due to inflation and to numerous changes in the business environment in

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general and the energy industry in particular. Furthermore, BGE asserts that it has made significant capital investments and examined and altered its business practices in order to improve service and operating efficiencies. Thus, the Company contends that its present gas base rates are no longer just and reasonable and do not yield a reasonable return. Accordingly, the Company filed for the rate increase, and included pre-filed testimony and exhibits of various witnesses in support of the application.

By Order No. 79955, issued on May 4, 2005, the Commission suspended the proposed rates for a period of not more than 150 days from the proposed effective date of May 31, 2005 and instituted proceedings as to the justness and reasonableness of the proposed rates. A pre-hearing conference in this matter was held on June 9, 2005, notice of which was published in newspaper advertisements throughout the service area of the Company.

At the pre-hearing conference, intervention of various parties was granted and argument was heard on a Motion to Dismiss ("Motion") the rate application. Filed by the Maryland Alliance for Fair Competition and Blue Dot Services of Maryland (collectively "the Alliance"), the Motion sought dismissal of the application for the alleged failure to comply with § 4-208 of the Public Utility Companies ("PUC") Article, *Md. Ann. Code.* [2] (2) By Order No. 80072, issued on June 24, 2005, the Commission determined that a November 2001 Arthur Andersen independent audit opinion that had been submitted by the Company with the application was, in fact, too dated to satisfy the requirements of the statute. Therefore, the Commission held the rate case application in abeyance, while granting BGE leave to perfect its application by filing a new independent audit opinion on the Company's Cost Allocation Manual ("CAM") pursuant to the statutory requirement. [3] (3)

On June 24, 2005, BGE filed a copy of a report from the independent audit firm Ernst & Young, LLP regarding BGE's CAM for the 2004 calendar year. The Commission then issued Order No. 80076 on June 27, 2005, suspending the proposed rates for a period of not more than 150 days from the June 24, 2005 date of the perfected filing. [4] (4)

Hearings in this matter were held on September 26-30, 2005, in Baltimore, Maryland. In addition, evening hearings for the purpose of receiving public comment were held on October 5 in Baltimore City, October 6 in Baltimore County, October 17 in Anne Arundel County, and October 18 in Harford County. Notice of all hearings, both the evidentiary and the evening hearings, was published in a newspaper of general circulation throughout the service area of the Company.

During the course of the hearings, BGE presented eight witnesses in support of its application for a rate increase. Kenneth W. DeFontes, Jr., President and Chief Executive Officer of BGE (as well as Senior Vice President of BGE's parent company, Constellation Energy Group, Inc. ("CEG")), presented overview testimony in support of the Company's rate application, stating the increase is designed to provide full recovery of expenses and a fair return to the Company which has not had a rate increase for approximately six years. E. Follin Smith, Chief Financial Officer and Chief Administrative Officer of CEG and Chief Financial Officer and a member of the Board of Directors of BGE, testified with respect to the relationship between BGE and CEG and the requirements of the investment community.

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Jonathan Weinstein, a principal in Towers Perrin's Compensation Practice, a management and human resources consulting firm, testified in regard to the compensation practices of the Company, including the incentive compensation program for which the Company seeks recovery in this proceeding. Anne A. Hahn, Controller and Manager of the Finance and Accounting Department for BGE, and Robert G. Castagnera, Director of Accounting in the Company's Finance and Accounting Department, presented testimony with respect to the Company's financial data and ratemaking adjustments proposed in this proceeding.

William E. Avera, principal in Financial Concepts and Applications, Inc., an economic consultant retained by the Company in this proceeding, and Steven M. Fetter, President of REGULATION UnFETTERED, an energy advisory firm, provided testimony with regard to the appropriate rate of return and credit rating agencies' perspectives as to fair and economically prudent regulation. Finally, Laurie H. Duhan, Director of Gas Pricing and Tariffs in the Company's Pricing and Regulatory Services Department, presented the Company's gas cost of service study, rate design and tariff modification proposals.

The Office of People's Counsel ("OPC") presented four consultant witnesses in this proceeding; its final position is that the Commission should limit any rate increase for the Company to $19,805,000. David J. Effron, consultant for OPC, presented proposed rate base and operating income adjustments. Ralph E. Miller, an economic consultant, testified with respect to matters of regulatory policy and benefits to the parent company, CEG, of BGE ownership. Charles W. King, President of the consulting firm Snavely King Majoros O'Connor & Lee, Inc., presented OPC's cost of capital recommendations, while Paul L. Chernick, President of Resource Insight, Inc., presented proposed cost allocation and rate design proposals.

The Commission Staff presented five witnesses in this proceeding, concluding that the Commission should grant a rate increase of $24,571,000. Kenneth J. Lee, Staff Public Utility Auditor with the Accounting Investigations Division, presented proposed rate base and operating income adjustments. Gloria Prettiman and R. Andrew Lawson, both Staff Regulatory Economists in the Commission's Rate Research and Economics Division, presented testimony with respect to the Company's cost of service study and rate design, respectively. Darius T. Bailey, also a Staff Regulatory Economist, presented testimony with respect to supporting various Company-proposed tariff changes. Phillip E. VanderHeyden, Staff Regulatory Economist, testified with respect to the appropriate rate of return and capital structure.

The United States Department of Defense ("DOD"), which intervened on behalf of DOD as well as other Federal Executive Agencies, presented Thomas J. Prisco, Staff Accountant and Financial Advisor with the Department of the Army, as a witness with regard to specific accounting, return and rate design issues. In its final position, DOD concludes that the need for a rate increase of $14,738,000 has been demonstrated.

The Maryland Industrial Group and United States Gypsum Company ("MIG") presented three witnesses from its member companies: Gene Q. Eng, Environmental Manager for American Sugar Refining, Inc., and also Chairman of MIG; John Dippold, President of Locke Insulators, Inc.; and John Hunter, Purchasing Manager-Eastern Region for W.R. Grace and Company. These witnesses testified with regard to interruptible service and interruptible testing. MIG also

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presented Richard A. Baudino, Director of Consulting with the firm of Kennedy and Associates, with respect to cost of service and rate design issues. Mr. Baudino also commented on selected issues of operating income and return on equity. [5] (5)

Nicholas Phillips, Jr., a principal with Brubaker & Associates, Inc., economic and regulatory consultants, testified on behalf of intervenor ISG Sparrows Point, LLC ("ISG") with regard to setting rates for ISG based upon the specific utility plant serving that Company. [6] (6)

The three remaining parties that were granted intervention status in this proceeding — Washington Gas Energy Services, Inc. ("WGES"), Amerada Hess Corporation, and the Alliance — did not participate in the evidentiary hearings in this proceeding and sponsored no witnesses. [7] (7) On October 28, 2005, however, the Alliance filed a post-hearing letter asking the Commission to deny the BGE rate petition. The Alliance claims that the Company did not meet its burden of proof because no witness from the independent auditor testified in this proceeding with respect to the CAM review.

As noted above, evening hearings for the purpose of receiving public comment were held on four separate nights at various locations throughout the Company's service territory. At these hearings, no members of the public attended or commented upon the Company's proposed rate increase.

Following the hearings, [8] (8) initial briefs were required to be filed by October 28, 2005, with reply briefs due November 16, 2005. All of the testimony and other evidence on the record, as well as the arguments of the parties included on brief, have been carefully reviewed and considered by the Commission in rendering a decision in this matter.

A. Preliminary Matter — Motion to Strike

Prior to our consideration of the merits of the rate application, we consider BGE's Motion to Strike the Alliance's letter of October 28, 2005. As noted above, the Alliance opines that the rate application should be denied on burden of proof grounds because the Company presented no representative from the independent auditor on the results of the CAM audit. In its November 16, 2005 Motion to Strike, BGE argues that the Alliance letter is an improper and untimely attack on the Commission's earlier decisions in this proceeding that determined the Alliance may subpoena the independent auditor to testify at the hearing, but at its own expense (Order Nos. 80208 and 80259). BGE also notes the Alliance did not subpoena the auditor, has failed to make any effort to develop the evidentiary record, and did not participate in the hearings in any meaningful way.

The Alliance filed a response opposing the Motion to Strike, noting that it did not participate in the hearings because it had no interest in incurring what would be to it a significant expense. The Alliance also said that cross-examining a BGE employee about a CAM audit not produced by the employee would be a waste of time.

[1-5] The Commission agrees with BGE's assessment that the Alliance failed to participate in any meaningful way in the hearings in this matter, producing no witnesses and engaging in no cross-examination of other parties' witnesses during the hearings. Furthermore, the record does

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not disclose any meaningful discovery by the Alliance regarding the CAM audit report. All parties were given full and fair opportunity to investigate issues they believe are relevant to this proceeding, including the independent audit report, and yet the record is totally devoid of any party raising any issues concerning the CAM report. The Alliance was given the explicit opportunity to subpoena the auditor for the hearing, but at its own expense in conformance with the Maryland Rules. It did not choose to do so. Nor did it submit data requests or conduct other discovery of the auditor.

We find no merit to the Alliance's argument that the Company has failed to meet its burden of proof. The Company and other parties presented extensive testimony and other evidence regarding the appropriate rates that should be set in this proceeding. That evidence covers revenue requirement, cost allocation and rate design issues, the components of the ratemaking process. The Company's application and evidentiary presentation, its updated cost allocation audit opinion, and the evidence and arguments of the other parties, comprise an extensive and full record on which the Commission has based its decisions herein. Rather, the Commission finds no merit in the arguments of the Alliance, as the Alliance failed to pursue the opportunity to examine the auditor and presented no evidence whatsoever raising any creditable issues concerning the Company's CAM.

However, neither that finding nor the Company's Motion provides a reason to strike the Alliance's letter. The Commission considers the letter to be the Alliance's final argument in this case, apparently filed in lieu of a brief. As such, the Commission allows it as part of the record in this proceeding.

B. Test Year

As to the merits of this case, the Company initially proposed a base rate increase of $52.7 million in the filed application, representing an approximate 4.7 percent rate increase that would increase a typical residential gas heating bill by approximately $4.00. During the course of the proceeding, the Company has modified its rate proposal based on updated actual results and positions of other parties. The other parties that have made a full review of the Company's proposal also conclude an increase is warranted: DOD recommends an increase of $14,738,000; OPC suggests an increase of $19,805,000; and Staff proposes an increase of $24,571,000.

[6] In making their recommendations, all parties utilized the 12 months ending July 31, 2005 as the test period in this proceeding, which represents the most recent period for which actual results were submitted for review during the course of the hearings in this case. Accordingly, the Commission accepts the 12-month period ending July 31, 2005 as the test year.

For the test year, the parties proposed many adjustments to which they agree are appropriate in setting the rates to be established in this proceeding. The Commission now moves to discussions of the issues for which the parties are not in agreement.

II. RATE BASE

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All parties who have testified and presented recommendations with respect to the rate base for the Company agree with the per book unadjusted rate base of $793,665,000. Certain adjustments were accepted by all parties and are not contested, while others produced differences of opinion, as discussed below.

A. Cash Working Capital

Cash working capital ("CWC") is the component of rate base that represents the amount of cash a firm must obtain from its investors in order to provide necessary funds for operation of the business on a day-to-day basis. Based upon a lead/lag study, which examines in great detail the Company's payment of expenses and cash in-flow, a return is provided upon revenue lags that exceed expense lags. This is because investor funds must be utilized until the Company is reimbursed through revenues received.

In this case, the Company seeks a change from prior Commission policy, proposing to exclude from the CWC calculation the impact of interest payments on long-term debt and preferred stock dividends. BGE witness Castagnera states that years ago, the Commission recognized that funds collected to pay interest and preferred stock dividends are the property of investors. He notes, however, that the Commission changed that policy in the early 1980's and required Maryland utilities to include such elements in the determination of the cash working capital. However, Mr. Castagnera contends that the timing of such payments to investors does not alter the fact that these elements are the property of investors and the Commission is in effect penalizing investors because of the timing difference between earning and using that portion of operating income. Therefore, he excludes the lag for interest and preferred dividends from his CWC calculation.

Both OPC witness Effron and Staff witness Lee oppose BGE's exclusion of interest and preferred stock dividends from the CWC calculation, noting such proposal is contrary to recent Commission practice. Accordingly, they each recommend including in the CWC calculation the lag associated with preferred dividends and interest expense, which adjustment decreases CWC by $2.7 million. Mr. Effron notes that payment of interest on long-term debt is made semi-annually in arrears, and indicates it is therefore implicitly taken into account in the interest rate on such long-term debt. Furthermore, he notes the beneficiaries of BGE's proposed change to exclude such payments would be the common equity investors rather than investors in long-term and preferred stock, and therefore the Company's proposal would amount to a windfall to common shareholders. Mr. Effron further notes that while the issue with regard to preferred dividends has only a small effect, long-term debt is a significant component of the capital structure for which the lag in payment of interest is significantly greater than the revenue lag. Mr. Effron, as well as Mr. Lee, recommends continuation of including the lag for payment of interest as well as preferred stock dividends in calculating cash working capital consistent with the practice over the past 20 years.

[7] Upon review of the parties' positions, the Commission declines to exclude interest and preferred dividends from the CWC calculation. The Commission policy for more than twenty

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years has included these elements, as such payments are not in fact the property of investors until paid to them. We see no reason to change this practice. We agree with Mr. Effron's observation that the payment date implicitly accounts for the interest rate of debt instruments, and any change at this time would result in a windfall to the detriment of ratepayers. Therefore, we will retain interest and preferred stock dividends in the CWC calculation in accordance with our long-standing policy, and will decrease CWC by $2,744,000.

Mr. Lee also notes that while Staff has accepted BGE's lead/lag study, with the exception of the Company's proposed change with respect to preferred dividends and interest expense discussed above, the Company's study is based upon 2002 data. Mr. Lee states that the use of such data ignores the growth and utilization of electronic payment methods by customers, which he believes most likely understates the revenue lag. He further notes the revenue study caps revenue lags at 120 days, although the Company does not deem accounts uncollectible until 210 days have elapsed, thereby understating a portion of revenue lag. While Mr. Lee has accepted the Company's lead/lag study, he recommends the Commission direct BGE to provide a more up-to-date study for use in its next rate filing.

Company witness Castagnera does not disagree with the recommendation of Mr. Lee for use of an updated lead/lag study for cash working capital. However, he notes such studies are expensive and time consuming. On brief, BGE indicates a willingness to update the lead/lag study, including updates related to electronic payment advances, but does not support the necessity of a complete new study.

The changes that have occurred since the 2002 lead/lag study, such as increased use of electronic means of payment, support an update of that study in the next rate proceeding. Accordingly, the Commission directs the Company to perform an updated lead/lag study to better reflect changes in billings and payments that have occurred in recent years, with the updated results available for use and review in the next rate case.

B. Construction Work In Progress

Pursuant to long-standing Commission policy, the Company has included in rate base construction work in progress ("CWIP") with a corresponding offset to operating revenues as an allowance for the funds used during construction ("AFUDC"). Staff witness Lee proposes an adjustment to exclude CWIP from rate base as well as AFUDC from operating income, arguing that the property is not used or useful in providing service and should therefore be excluded. Mr. Lee recognizes that this proposal departs from prior Commission practice, but contends such an exclusion is appropriate based upon the "used and useful" principle, as the property is not yet used and useful in providing service to customers. On Brief, Staff acknowledges that its proposal represents reversal of Commission precedent, but indicates it considers this case an appropriate opportunity to review CWIP/AFUDC policy. Mr. Lee's adjustment would reduce rate base by approximately $14 million, and reduce net income by slightly under $600,000.

[8] No other party has indicated support for Staff's proposal to change the Commission's past practice and now exclude both CWIP from rate base and also AFUDC. Similar to our resolution

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to retain interest and preferred dividends in the CWC calculation in conformance with long-standing practice, we see no reason to change our general policy with respect to inclusion of CWIP with an AFUDC offset. While Staff notes it considers this case an opportunity to review the Commission's practices, we are not persuaded that any change is necessary or desirable at this time.

The inclusion of CWIP in rate base provides protection to utilities from rate attrition that would inevitably follow if construction is never reflected in rate base, which is the effect of the Staff proposal. It also could have an adverse effect on a company's decision to proceed with a new capital project. Furthermore, when paired with the inclusion of the AFUDC income adjustment, the adjustment ensures equitable treatment to the Company and to current and future ratepayers. While this treatment might require revision in a period of acute financial circumstances, present financial conditions, such as interest rates, inflation rates, and construction requirements, do not warrant a change. Rather, the Commission's long-standing CWIP/AFUDC policy has worked well in helping protect companies against rate obsolescence, while promoting rate stability for customers by the inclusion of certain construction projects which reduce the need for construction-driven rate proceedings. It also promotes equity between current and future customers as the AFUDC offset reduces the rate impact. Therefore, we decline the Staff proposal to change our long-standing policy to include CWIP in the rate base with an AFUDC offset.

C. Allocation of Common Costs

As a combination electric and gas company, BGE must allocate certain common costs between the two operations for both cost of service and rate base purposes. The Company has updated its allocation of common costs between its electric and gas operations for the test period. Full application of BGE's long-standing allocation formula would have allocated approximately 30 percent of such common costs to gas operations. However, since electric deregulation, the Company has utilized a phased-in approach of the formula that results in a 25.5 percent allocation of common costs to the gas business in this case. Utilization of the prior formula would result, in comparison, in an allocation of 21.3 percent to gas operations.

According to the Company, this phase-in approach is intended to more gradually reflect actual costs of gas operations that would otherwise be higher due to the spin-off of electric generation-related activities to deregulated affiliates following enactment of Maryland's electric restructuring statute. [9] (9) In accordance with this phase-in approach, the Company includes a rate base adjustment reflecting the 2005 25.5 percent allocation rate, which increases rate base by approximately $3.5 million, while also reflecting a companion operating income adjustment of $2.2 million. Both Staff and People's Counsel accept BGE's adjustment, effectively recognizing an increase in the allocation to gas operations from 21.3 percent to 25.5 percent, but still below the 30 percent allocation factor that represents the full allocation of common costs since electric deregulation.

In contrast to Staff's and People's Counsel's acceptance of the updated allocation factor, DOD opposes the increase in the adjustment, alleging it amounts to a windfall to the Company. In this

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regard, DOD witness Prisco contends the Company will enjoy a "double recovery" windfall by including the common utility plant in both the gas operations and the electric operations portion of the rate base, as there is no corresponding change in electric rates reflecting the revision to the allocation factor. He therefore opposes the updated allocation and recommends elimination of the increased allocation, thereby retaining the existing 21.3 percent allocation factor.

In response to Mr. Prisco's opposition to the updated allocation factor to the gas service business, BGE witness Castagnera stresses the Company has consistently used the same allocation formula to determine the appropriate apportionment factor of common utility costs since 1984. [10 (10)] Furthermore, the Company's detailed apportionment calculations have consistently demonstrated that the gas business should be assigned approximately 30 percent of common costs since the July 1, 2000 transformation of the Company resulting from electric deregulation, according to the witness. He states he has further analyzed the Company's common expenses, and concludes the Company's current electric transmission and delivery rates combined with the Company's proposed allocation of expenses to gas for the test period recover only approximately 65 percent of the total common expenses in the period, [11 (11)] so that the Company is not double recovering common expenses. Mr. Castagnera and Mr. DeFontes conclude that DOD's proposed disallowance effectively penalizes the Company for being a combination utility, since combination utilities (providing both gas and electric) or utilities that operate in multiple jurisdictions must allocate common costs, and will not always have simultaneous rate reviews.

[9, 10] Upon consideration of the record, the Commission accepts the Company's proposed adjustment to increase the allocation factor from 21.3 percent to 25.5 percent. The record is clear that the percentage of common plant related to gas has increased since electric restructuring, and there is no real dispute that the full allocation at this time would actually exceed the Company's proposed 25.5 percent allocation factor to gas operations. DOD is the only party opposing the increase to the existing allocation factor, claiming it would result in an improper double recovery as no corresponding change has been made to the electric operations. However, as the record shows the Company in fact remains in a significant under-recovery position for common costs, even with the proposed allocation factor, the Commission finds no merit to DOD's allegation of double recovery. The Commission therefore accepts the Company's adjustment to both rate base ($3.5 million) and operating income ($2.2 million) to reflect the gradual implementation of the increased allocation factor until the phase-in is complete.

D. Home Products and Services Operations

BGE proposes in this case to fully separate all aspects of its Home Products and Services ("HPS") subsidiary from BGE-regulated operations, including exclusion of all HPS assets and revenues from the rates to be set in this proceeding. Company witness Hahn testified to the history and current status of HPS. HPS, among other offerings, services appliances, but no longer provides gas safety functions as it did in the past, as gas safety work is now charged solely to BGE. Ms. Hahn states that this reorganization, which occurred in 1995, accomplished the separation of regulated and non-regulated operations. She notes further that HPS has

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discontinued utilizing BGE's customer call center and phone number, and BGE's interactive voice response system no longer provides callers an option to be transferred directly to HPS or receive HPS telephone numbers. HPS maintains its own books of account, invoice processing and cash disbursements, while HPS continues to utilize BGE's bill. However, there are 12 gas retail suppliers and 11 electric retail suppliers also using BGE's billing services at this time. Ms. Hahn states that the minimal level of services currently provided by BGE to HPS are charged utilizing the fully distributed cost methodology described in the Company's Cost Allocation and Transfer Pricing Manual, which assures there is no cost subsidization between BGE's operations and HPS' operations. Accordingly, BGE proposes its adjustments to fully separate the revenues and expenses associated with the appliance work performed by HPS from BGE's operations for ratemaking purposes. This adjustment represents a change from the prior rate case in which a contribution from HPS, both assets and revenues, was allocated to the regulated operations.

In contrast to BGE's proposed separation of HPS revenues and expenses from the regulated operations, OPC, through witness Effron, proposes continuing the inclusion of assets related to HPS in the rate base ($4.5 million) with a 50/50 split of profits from HPS contributed to the regulated operations ($408,000 operating income adjustment). This treatment continues the contribution found by the Commission in prior cases, specifically retaining the same 50 percent inclusion of investment in rate base and 50 percent inclusion of profits as directed in the preceding rate case, Case No. 8829. Mr. Effron notes that HPS is still an affiliate of BGE, and states it must be assumed that HPS benefits from such affiliation. He therefore concludes it would not be unreasonable to continue the prior Commission treatment for rate-making purposes, resulting in both a rate base adjustment for HPS assets and operating income adjustment for HPS profits.

Staff does not make the adjustment recommended by People's Counsel to include a contribution from HPS to BGE-regulated operations, as Staff accepts BGE's separation of HPS assets and profits. In this regard, Staff witness Lee notes that the prior Commission treatment was based upon the Commission's concerns regarding benefits to HPS of the affiliation with BGE, and possible cross-subsidization. Mr. Lee states that if there are in fact benefits to HPS arising from its association with BGE, or there is in fact any subsidy, the Commission should construct a better pricing mechanism, including possible revision of the Cost Allocation Manual.

[11-13] Upon consideration of the record, the Commission accepts the full separation of HPS assets and profits from BGE's regulated operations, as the record shows that the Company has complied with fully distributed cost principles pursuant to the Cost Allocation Manual, so that no subsidy has been demonstrated. In this regard, it is clear that the findings in the prior rate reviews were based upon the record in those cases, which showed interaction and support between HPS and BGE to the extent that an allocation of assets and revenues was necessary and appropriate to avoid any improper subsidization of the HPS activities by the regulated utility operations. However, the record in this proceeding reflects that HPS has now been sufficiently separated from BGE, and that its remaining use of the BGE billing system is no different than many other companies' and for which HPS pays full costs.

The record in this case also indicates the separation has been accomplished pursuant to the Cost Allocation Manual, and no party has presented any evidence regarding deficiencies in the

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separation of the Company's operations to justify continuation of a contribution from HPS profits to BGE's regulated operations. OPC's argument to continue the contribution is not based on any showing of cross-subsidization or failures to adhere to proper CAM principles, but essentially is a request to continue the split of profits from prior cases on the theory that HPS must receive benefits from the association. However, the prior cases showed clear commingling of services and resources, such as joint service calls and preferences in the BGE phone system accruing to HPS. These factors are no longer present, and therefore the record shows the operations of HPS are now sufficiently distinct and separated making further automatic sharing of assets or profits unwarranted at this time. The Commission therefore accepts the Company's proposed treatment to fully separate HPS operations from BGE's regulated operations, in both rate base and operating income.

E. Voluntary Special Early Retirement Program

In prior years, the Company has engaged in early retirement programs, including a 2000 Retirement Program and a 2002 Voluntary Special Early Retirement Program ("VSERP"). The cost of such programs, which provide inducements to encourage employees to retire and therefore result in subsequent cost savings to the Company by the reductions in force, have been amortized over a five-year period, with the unamortized balances included in rate base. The 2000 early retirement program has been fully collected and completed by the Company prior to the rate-effective period. Upon the review by various parties in this proceeding, the Company agrees to eliminate such costs from this proceeding. However, for the 2002 VSERP, the Company includes the unamortized balance in rate base while proposing collection of the amounts through a five-year amortization period pursuant to prior Commission practice recognizing such costs in past rate cases. OPC and Staff are in agreement with the Company's final position with respect to rate base treatment as the Company modified its initial treatment through a $7.9 million reduction to rate base by including the associated liabilities and deferred income taxes related to the VSERP. However, OPC and Staff, while now agreeing with the Company's final rate base treatment of VSERP, do not agree with the Company's treatment as to operating income, as discussed later in this Order.

Although Staff and People's Counsel agree with the Company's final rate base treatment for early retirement program costs, DOD and MIG disagree with the Company's treatment on both rate base and operating income. These parties seek to exclude the unamortized costs in rate base of the 2000 early retirement program (to which the Company has agreed, as noted above). However, they also seek full exclusion of the 2002 unamortized balance in rate base as such costs were incurred in an historic period prior to the test year. In addition, MIG witness Baudino states the Company has in fact been compensated for such costs through lower operating costs and increased productivity over the last two years, and therefore no economic harm has occurred to the Company or its shareholders.

Furthermore, Mr. Baudino notes that the Company's five-year amortization period ends in 2007, and that the rates set in this proceeding will be effective in 2006 and possibly beyond the amortization period's expiration in 2007. Allowing rate base treatment of the currently

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unamortized portion of VSERP, he contends, could result in ratepayers supporting increased expenses and rate base well beyond 2007 (until the Company files its next rate case).

DOD argues the Company booked the 2002 VSERP as a regulatory asset without prior authorization from the Commission, which Mr. Prisco considers to violate proper regulatory procedures. As the Commission did not explicitly provide such advance authorization, he also considers the Company's treatment to constitute retroactive ratemaking. Mr. Prisco further notes the cost of the 2002 VSERP is substantially more expensive than the prior 2000 early retirement program, as the 2000 program affected 30 gas employees for a total cost of approximately $3 million, while the 2002 VSERP affected 108 employees at a cost of nearly $31 million. He states that no opportunity was provided to review the proposed expenditure to ensure that it was justified. He acknowledges that BGE's effort will eventually reduce labor costs embedded in rates, but contends disallowance of such costs will not harm the Company as it has reaped benefits of payroll savings for the past three years.

In rebuttal to the proposed exclusion of the 2002 VSERP from rate base, Company witness Hahn states that while the Company has benefited from the absence of labor costs, it is undeniable that customers also benefit from lower labor costs. She observes that this and other cost containment efforts contributed to the Company's ability to avoid seeking rate relief, including avoidance of a gas base rate increase for almost six years. Furthermore, she notes that the Commission has consistently included early retirement costs, which are initially funded by investor capital, as regulatory assets in rate base and used a five-year amortization period for such costs, allowing full recovery as the reduction in labor costs benefits both customers and the Company. [12 (12)]

Ms. Hahn further disputes the contention that prior Commission approval was required to establish the VSERP costs as a deferred regulatory asset, noting there is in fact no such requirement and that accounting rules permit the establishment of a regulatory asset if the Company can show that cost recovery is likely in a future proceeding. [13 (13)] She states that the Company relied on the Commission's strong history of utilizing a regulatory asset for recovery of such early retirement program costs in establishing the regulatory asset. Ms. Hahn further contends that disallowing VSERP costs that enable cost savings would be bad public policy and fundamentally unfair, in addition to contradicting prior Commission precedent on this issue. Finally, she notes that the argument that the rates would continue beyond 2007 while the VSERP would end that year is speculative in that it singles out one future potential cost decrease in an era of rising costs, and is therefore unreasonable and inconsistent with establishment of just and reasonable rates.

[14] The Commission notes the Company's final position eliminates the 2000 early retirement from rate base, and therefore only the 2002 retirement program remains in dispute. Furthermore, Staff and OPC agree with the Company's final rate base treatment of the 2002 program costs, which includes associated liabilities of the VSERP. In contrast, DOD and MIG contest the rate base effect as discussed above.

Upon consideration of the evidence and arguments of the parties, the Commission accepts the Company's rate base treatment, and rejects the contention that the costs of such retirement

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programs have already been fully recovered or should be rejected as unauthorized retroactive ratemaking. As cited by the Company, there is a long history of recovery of such early retirement costs previously authorized by the Commission. Such programs have been encouraged as necessary and proper methods of reducing payroll expenses, ultimately benefiting ratepayers by such savings. The Commission sees no reason to depart from its prior treatment, and therefore allows full reflection of and recovery on the unamortized balance of the 2002 VSERP costs in rate base. The Commission discusses the companion operating income adjustment of the appropriate amortization period for the remainder of the VSERP costs in the Operating Income section of this Order.

F. Capital Structure Adjustment to Rate Base

Staff witness Lee proposes a hypothetical accounting adjustment to impute short-term debt in the capital structure. This hypothetical adjustment is rejected by the Commission. While the proposed adjustment is to the rate base, it is advanced by the witness for capital structure purposes. Therefore, the Commission discusses the adjustment in the capital structure section of this Order.

G. Rate Base Conclusion

Upon consideration of the record in this proceeding, the Commission finds that the fair value of Baltimore Gas and Electric Company's property used and useful in providing gas service to the public is $791,907,000, as calculated on Appendix I attached hereto and incorporated herein by reference.

III. OPERATING INCOME

A. VSERP

In addition to the proposed exclusion from rate base of the 2002 Voluntary Special Early Retirement Program costs, discussed above, DOD and MIG seek exclusion of the VSERP expenses from operating income as well. Staff and OPC, who have accepted the Company's proposed rate base treatment of the 2002 VSERP, dispute the Company's expense treatment of these costs.

Staff witness Lee proposes an adjustment to remove early retirement program expenses from the Company's revenue requirements as he believes such costs have been recovered through rates in prior years and cost savings that pay back the program costs by September 2005. In this regard, while he recognizes prior cases have utilized a five-year amortization period as a reasonable period for early retirement program costs, he believes the record in this case differs from prior cases. That is, Mr. Lee asserts that including other benefits, such as overhead costs that are also reduced by the reduction in labor, results in a three-year payback period, which he considers to be

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the appropriate, and now-concluded, amortization period in this instance.

DOD and MIG continue their position advocating no inclusion for VSERP expenses, as noted above with respect to the VSERP issue in rate base. Their opposition is based in large part upon cost savings realized by the retirement programs and upon rates set in this case potentially lasting beyond the amortization period of the VSERP expenses, thereby continuing the expense in rates beyond the recovery of the expense.

OPC witness Effron recommends the recovery of the unamortized expense existing at the commencement of the rate-effective period over a three-year period, resulting in a reduction in VSERP expenses in the cost of service from the Company's proposal. Specifically, Mr. Effron's adjustment reduces expenses by $2.4 million, while the exclusion recommended by Staff and the other two parties results in a $3.9 million adjustment compared to the Company's position.

Ms. Hahn continues her opposition to changing the Commission precedent of utilizing a five-year amortization period for recovery of early retirement program costs, noting that revised amortization periods are speculative when based in part upon predictions of future base rate proceedings. BGE witness DeFontes also expresses surprise at the other parties' recommendations to disallow some or all of its amortization of the VSERP expense. He states such a disallowance would be a complete reversal of numerous prior Commission decisions, which reversal would call into question issues of regulatory risk relating to investment in utilities as it is important for utilities to rely upon Commission precedent when making decisions. Therefore, if the Commission wishes to make changes to long-standing practices such as this one, he states it is only fair that the Commission give notice and apply such changes prospectively rather than retroactively. This would allow opportunity for utilities and others to participate in the process of making such changes. He further notes the Commission has previously granted full recovery for early retirement expenses as advocated by the Company, because customers benefit from the overall cost savings. Mr. DeFontes concludes it would be bad public policy and fundamentally unfair for the Commission to incorporate the full benefits of a labor cost reduction in base rates while simultaneously disallowing full recovery of the early retirement program costs that enable the labor cost reduction.

[15] Upon review of the record, the Commission reiterates its long-standing acceptance of recovery of costs for early retirement programs, as discussed above in the rate base section of this Order. However, the Commission's treatment of any specific program must be based upon the particulars of that program, including examination of cost, savings, and amortization period details.

In this regard, while it is true that the Commission has accepted five-year amortization periods for other early retirement programs of the Company, the programs at issue in this case were initiated well before the filing of the rate application, and have brought greater examination and scrutiny by the parties than in many prior such cases. In this case, the greater scrutiny has engendered specific and detailed criticism by intervenors of the appropriate amortization treatment.

After considering the issue carefully, the Commission accepts OPC's proposal for a three-year amortization period for the remaining unrecovered amounts. Specifically, the Commission will

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allow the amortization of the remaining balance over a three-year period from December 2005. This amortization period and treatment of the remaining balance reflects the most appropriate weighing and resolution of the factual circumstances presented herein.

The Commission observes that the Company's five-year amortization period, begun in 2002, would expire in 2007. However, absent the adjustment proposed by OPC and adopted above, the full impact of that amortization would continue in rates beyond that period unless and until BGE files its next rate case. This shifts too much of the always-present risk that an amortization period may not match the rate-effective period to customers. Undeniably, the five-year period may have been appropriate at the time the program was first established, and certainly conforms with the guidance of past decisions. However, full reflection in rates of the amount corresponding to a five-year amortization period is inappropriate when the end of that five-year amortization period is only a year and a half away.

Accordingly, the Commission intends to assure that ratepayers are not unduly burdened by continuation of an expense amortization long beyond its recovery. We reject BGE's contention that adjusting the amortization period violates matching principles; rather, it revises the remaining recovery period for the outstanding balance to a more realistic time frame that provides full recovery of the expense to the Company while also treating ratepayers fairly. In short, the Commission believes Mr. Effron's recommendation appropriately weighs these factors, and accepts the revised amortization period of the remaining amount, thereby reducing the VSERP expense by $2.4 million.

B. Incentive Compensation

As part of its compensation practices, BGE has an Incentive Compensation Program in which incentive payments to employees are determined through the use of a "balanced scorecard" approach. According to the Company, the scorecard is comprised of five components that are measured throughout the year, each of which provides benefits to BGE customers. These five components include customer satisfaction, reliability and public safety, team well being, cost management, and profitability and growth. The Company seeks full inclusion in rates of the costs of its Incentive Compensation Program, as its total compensation package, including the incentive programs, provides significant benefits to customers through both service excellence and lower costs.

Furthermore, Mr. Weinstein testified that total compensation levels are within the competitive market range for peer utilities, noting that all companies in BGE's peer group maintain a formal annual incentive plan for at least some portion of their employee population. Mr. Weinstein further concluded that BGE's compensation would be slightly below competitive market levels if it did not provide annual incentive opportunities with respect to base salary levels, and that executive level positions would be significantly below median target levels.

OPC witness Effron recommends that the Commission include only one-half of the costs for the Incentive Compensation Program in rates because the other half primarily benefits shareholders rather than ratepayers. This treatment conforms to the Commission's decision in the

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Company's prior rate case, Case No. 8829.

In Case No. 8829, the Commission determined that the Company must show that incentive compensation program goals clearly benefit ratepayers, and that the incentive awards would be necessary to raise employees' overall compensation to market level in order to seek full recovery from ratepayers. [14 (14)] In this case, Mr. Effron notes that the final component of the balanced scorecard approach involves profitability and growth of the Company. Mr. Effron acknowledges the first four goals of the program benefit ratepayers, but notes that the profitability and growth goal is determined based upon earnings before interest and taxes, which he asserts is plainly a shareholder goal. Therefore, as the entire balanced scorecard is subject to achievement of the profitability and growth goal, Mr. Effron contends that the Company has not clearly demonstrated that the Incentive Compensation Program primarily benefits ratepayers; therefore, he opines that shareholders, rather than customers, should bear the cost of incentive compensation. Accordingly, he recommends continuation of sharing the expenses of the Incentive Compensation Program with shareholders pursuant to the treatment in the prior case, and recommends elimination of one-half of the $2,060,000 expense, thereby reducing operation and maintenance expense by $1,030,000.

Staff witness Lee has also testified with respect to this issue. Mr. Lee believes that the Company has addressed the Commission's concerns expressed in the prior case, and accepts the Company's inclusion of the full costs of the program in rates.

[16] Upon review of the testimony and evidence with respect to this issue, the Commission accepts the Company's inclusion in rates of the full costs of the Incentive Compensation Program. OPC is correct that the prior case directed sharing of such incentive costs between ratepayers and shareholders. However, in Case No. 8829 the Commission noted that full recovery of incentive compensation costs could occur in the future if the Company clearly demonstrates that program goals benefit ratepayers and the awards would be necessary to raise employees' overall compensation to the market rate.

OPC does not dispute four of the five goals of the Company's balanced scorecard approach. However, OPC argues that the costs of the incentive compensation program should be shared between shareholders and customers because the fifth goal, profitability and growth, is a shareholder goal rather than a ratepayer goal. OPC notes in fact that the entire program is contingent upon attainment of this particular goal.

While it is true that this goal is important to shareholders, profitability and growth also benefit ratepayers, because financially sound companies can raise capital at more favorable rates, thereby keeping costs low for customers. This benefit is clearly noted by Mr. DeFontes, who further notes that a financially sound company is less likely to need rate relief to continue providing safe, reliable, and quality service to customers. That is borne out by the approximate six-year period between the instant rate proceeding and the last one. In addition, Mr. Weinstein's testimony shows that incentive compensation programs like BGE's are widespread throughout the industry, and are necessary to allow the Company to reach median compensation levels for peer companies with respect to total compensation.

Based on the record, the Commission concludes that the Company has presented adequate

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evidence of the reasonableness of its incentive program for the benefit of ratepayers through achievement of the target goals while also maintaining total compensation, including the incentives, within the overall market rate of compensation for employees. Accordingly, the Commission finds that the full program costs are now properly included in the rates charged to customers and rejects the OPC proposal to eliminate one-half the incentive program costs.

C. Uncollectible Accounts

OPC proposes an adjustment to the uncollectible accounts expense. Mr. Effron states that the $8 million in uncollectible accounts expense in the test year appears to be relatively high in relation to customer revenues, at least in comparison to other recent years' experience. He therefore proposes an adjustment based on the average net charge-off rate for the five-year period 2000 to 2004. [15 (15)] He states that a five-year normalization is reasonable, as it provides an adequate sample size without reaching too far back in time to include obsolete data. He further contends that the average net charge-off rate for this five-year period is 1.03 percent, and states that in the last two Washington Gas Light Company rate cases, a five-year average charge-off rate was utilized to determine the appropriate uncollectible accounts expense. Mr. Effron's proposed adjustment increases net operating income by $224,000.

In opposition to OPC's proposed adjustment, Company witness Castagnera notes that commodity costs have risen significantly over the five years utilized in Mr. Effron's normalization period, including significant price rises for this winter, with no expectation that prices will decrease in the near future. Mr. Castagnera contends that OPC's adjustment includes the flawed assumption that increases in prices affect both revenues and uncollectibles equally. However, he states the Company's experience over the years indicates that as prices increase there is a disproportionate and greater impact on the amount of uncollectibles, as increasing numbers of customers experience difficulty in meeting their payment obligations as the monthly bills grow.

[17] Upon consideration of the evidence with respect to this issue, the Commission rejects OPC's proposed adjustment to normalize the amount of uncollectible accounts expense. The record reflects, through OPC's own calculations, that the percentage of uncollectible accounts appears to be slightly more than one percent of revenue. It is clear that when considering revenues resulting from this rate proceeding, and such percentage is applied to the revenues expected during the rate-effective period, no disallowance as advocated by People's Counsel is warranted based on the historical percentage of uncollectibles. In addition, the record indicates that gas commodity prices have increased significantly recently, and the Commission is therefore reluctant to reduce test year uncollectibles expense when gas commodity prices are now higher than they were during the test year. In fact, it is unlikely that the expense will decrease from the test year level in light of the conditions present today and expected during the commencement of the rate-effective period. Therefore, the Commission accepts the Company's proposal for uncollectible accounts expense.

In this regard, on brief, the Company further states that it agrees with Staff witness Lee's proposal that uncollectible expense be included in the "gross-up" factor as the means for recovery

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of this expense. BGE indicates that OPC acknowledges such a recovery methodology is not unreasonable, and BGE requests in its final comments adoption of the Staff proposal. As there appears to be no opposition to this method of recovery, the Commission will accept the inclusion of the uncollectible expense, at the amount proposed by BGE, in the gross-up conversion factor (whereby the net operating income deficiency is converted into the revenue requirement). With inclusion of the uncollectible expense, the conversion factor is now 0.5849.

D. Executive Travel

OPC witness Effron recommends continuation of a 50/50 sharing of executive travel expenses as occurred in the Company's last rate case. [16] (16) Mr. Effron's proposed treatment to eliminate one-half of the executive travel expense would increase operating income by $10,000.

The Company opposes OPC's proposed elimination of one-half of the executive travel expenses. Company witness Hahn notes that travel costs are a prudent and necessary part of running a business with benefits that accrue to customers, as the travel includes trade group meetings and conferences where sharing of information related to the industry takes place. She specifically cites trips by Company officials to American Gas Association meetings, where issues impacting the gas business, such as pipeline integrity regulations were discussed, as well as Department of Transportation meetings relating to Distribution Pipeline Integrity Steering Committee matters.

The only other party who addresses this issue is Staff. Mr. Lee indicates that prudent travel costs should be included as an appropriate cost of service. He states that if executives are engaging in activities that provide no benefit to ratepayers, then such costs should be borne by the shareholders rather than divided with ratepayers. Mr. Lee also notes that the record indicates BGE executives use the same travel arrangements, stay at the same lodgings, and eat at the same or similar restaurants as non-executives attending the same conferences and functions. He concludes there is no reason to single out this particular item of expense for sharing, and so does not join in OPC's disallowance recommendation.

[18] This dispute essentially involves whether executive travel should be treated as determined in the previous rate case. However, a review of the Proposed Order in that case reveals that the Hearing Examiner made such disallowance based upon apparent insufficient documentation of the travel expenses, which decision was then accepted by the Commission. In addition, a unique factor of that decision involved refusal of the reviewing accountant for one party to sign a confidentiality agreement, and the Hearing Examiner determined that there was shared responsibility for lack of a sufficient record in support of such travel expense. This unique factor contributed to his decision to split the cost equally between the Company and ratepayers.

In this case, OPC's proposed disallowance is based primarily upon the prior case's splitting of such costs. However, the Company presented evidence by Ms. Hahn of appropriate executive travel, and there is no indication of disputes with respect to responding to other parties' information requests on this issue. Therefore, the Commission allows the Company's full executive travel costs as a necessary and proper expense based upon the record in this case.

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Accordingly, we reject OPC's proposed disallowance of one-half of the executive travel costs.

E. Interdepartmental Sales

Interdepartmental sales involve the internal use by BGE operations of gas and electric services similar to any other facility's use of such services. That is, BGE's gas business utilizes electric distribution service, while BGE's electric business may also use gas distribution services. In this case, BGE is proposing that interdepartmental sales be priced in the same manner as sales to any other customer by charging the appropriate tariff rates. Such pricing would apply to both revenues that the gas operations earn from electric operations for gas service, as well as expenses incurred by gas operations for electric service received. This proposal differs from treatment in prior cases, whereby the Commission required the Company to utilize "interdepartmental rates," which were calculated rates that differ from tariff rates charged to other customers for the same service.

According to Company witness Hahn, the Commission denied BGE's request to use tariff rates in the previous rate case, Case No. 8829, until the end of the electric rate freeze implemented for BGE. This decision also reflected the fact that some of the Company's facilities lacked metering equipment necessary to register actual consumption. Ms. Hahn contends that such treatment by the Commission discriminates against the Company as a combination utility, and she therefore urges tariff pricing bc implemented in this proceeding. She further notes that BGE has now installed meters at essentially all Company locations (excluding substations) in order to obtain accurate consumption information, and charging tariff rates will allow the operations to reflect their true cost of doing business. In addition, she notes the Company utilizes tariff rates for financial reporting purposes, and it is only for purposes of rate proceedings that an adjustment for interdepartmental sales has been utilized.

Staff witness Lee expresses support for the Company's proposal to utilize tariff rates rather than interdepartmental sales adjustments. He notes that the prior treatment was based upon fears of circumventing the electric rate freeze, but notes that the electric moratorium is due to expire in June 2006, minimizing the rate freeze consideration. He also observes that the Company has rectified the lack of metering equipment.

In contrast to Staff's acceptance of the Company's proposal to use the tariff rates for interdepartmental sales for ratemaking purposes, OPC and DOD oppose it. OPC witness Effron recommends maintaining the use of an internal rate for interdepartmental sales, resulting in a $121,000 adjustment. DOD witness Prisco reiterates fears of a "windfall" to BGE from the failure to make a similar adjustment to electric rates, and therefore opposes the change to tariff sales rates at this time. However, Mr. Prisco does express support for utilizing arms-length pricing for transactions of inter-company sales, rather than the current practice of using an internally calculated rate solely for ratemaking purposes. He therefore recommends that the Commission authorize collection and escrowing of any difference between the tariff rate and an internally calculated rate, to be used as an offset in a future electric rate proceeding.

[19] Upon consideration of this issue, the Commission accepts the Company's (and Staff's)

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proposal to utilize tariff rates for interdepartmental sales of gas and electricity between the electric and gas operations. OPC's competing recommendation is primarily based upon the continuation of the prior treatment. However, the record reflects there is now sufficient metering at Company facilities, undercutting one rationale of the prior decision. Additionally, the upcoming expiration of the remainder of BGE's electric rate caps is a further consideration to now use tariff rates. Therefore, the Commission concludes that it is no longer appropriate to utilize an internal rate, because the tariff rates charged to other customers should also be applied to accurate measurements of usage of BGE's two utility lines of business.

The Commission further notes that while DOD recommends establishment of an escrow account based on concerns about windfall profits, witness Prisco expresses support for the policy of properly charging each entity for the appropriate utility use by the affiliated entity. However, use of his recommended escrow account essentially penalizes the Company for its status as a combination utility. In any event, accurate and widespread metering and the coming expiration of the remaining rate caps also undercut the perceived need to establish an escrow account for the timing difference between electric and gas rate revisions. Therefore, the Commission finds no reason to continue pricing of such services at an internal rate. Rather, the Commission finds it is proper to now utilize the tariff rates as the fair measure for establishing sales between the utility's operations, and we accept the Company's proposal to utilize the tariff rates for such sales without an interdepartmental sales adjustment or necessity to establish an escrow account.

F. The Commission Assessment

[20] Staff witness Lee proposes an adjustment to reflect the most recent approved assessment factor for the Company's payment to the State for Commission activities. The Company provides no testimony rebutting this proposal and raises no argument against it on brief. Accordingly, we will utilize the most recent assessment factor that will be in effect during the rate-effective period, as proposed by Staff.

G. Interest Synchronization

As in prior rate cases, a cost of service adjustment is necessary to synchronize the Company's actual interest expense and the amount of interest expense authorized by the Commission in establishing base rates, which is determined by multiplying the weighted cost of debt by the appropriate rate base. The synchronization involves the tax savings associated with the difference between actual interest expense and authorized interest expense. Failure to do so would result in subsidization of either investors, or customers. As in prior cases, in this case the Commission will make an adjustment based upon the final determinations of cost of debt and the size of the rate base.

Additionally, a dispute has arisen between the Company and People's Counsel with respect to the correct interest expense to use in the calculation of the adjustment. In this respect, OPC witness Effron urges utilization of the Company's interest expense noted in its federal tax return, while BGE witness Castagnera believes use of the Company's actual interest is properly utilized in the calculation.

Mr. Castagnera notes there are four items that create a difference between a financial

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statement interest amount and the income tax return interest amount. Two of the reconciling items increase the tax return interest expense, while two items reduce it. He states that the net effect of these four reconciling items is to lower the tax return's interest expense. He further contends that OPC fails to take into consideration that each of the reconciling items creates a tax timing difference with either a deferred tax expense or deferred tax credit recorded on the Company's income statement.

Mr. Castagnera also states that the Commission traditionally includes the total of the Company's deferred tax credits, deferred tax expenses, current income tax expense, and investment tax credit adjustments as valid components of the Company's total tax expense in determining the cost of service in setting rates. He observes that the Commission adopted this "normalization" long ago, which is also required by the Financial Accounting Standards Board, the Federal Energy Regulatory Commission, and the Securities and Exchange Commission. Mr. Castagnera concludes that OPC's use of the tax return amount ignores the fact that reconciling items associated with actual interest expense have been normalized. He states that the actual income tax expense included in the Company's financial statements are what is used in setting base rates, not just the current tax expense obtained from the Company's tax return.

Mr. Effron states that two of the reconciliation items, interest on customer deposits and other expense interest, do not create tax timing differences, although he acknowledges that two items (capitalized interest and amortization of loss on re-acquired debt) may create tax timing differences. However, he further states that BGE has not identified where the deferred tax credits related to these items appear, and he does not believe that the Company has established that it would be appropriate to accept the Company's calculation of actual interest in its operating adjustment.

[21] No other party has commented on this issue, although Staff accepts the Company's interest expense in its interest synchronization calculation. Upon consideration of the record and arguments of the parties, the Commission accepts the Company's approach and utilizes actual interest expense in the synchronization calculation rather than the interest amount noted in the federal tax return. Tax return amounts may fail to include widely accepted normalizations that are properly used for ratemaking purposes; therefore, we accept the Company's interest expense in the calculation.

H. Deferred Environmental Costs

During the course of this case, the parties agreed to the Company's amortization treatment of past environmental remediation expenses regarding clean up costs of the Spring Garden coal-gas plant, which were previously authorized recovery over a 10-year period. In the Company's supplemental filing of August 31, 2005, BGE agreed with the positions of OPC, DOD, and Staff to remove $2,212,000 of clean up costs from the rate filing because those costs will be recovered prior to the rate-effective period of this case.

However, while no issue remains outstanding as to rate treatment of prior costs, Staff suggests that the Commission direct BGE to amortize any future costs over the remaining life of

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the period authorized in this case. Staff says that retention of a 10-year amortization period will result in a 20-year cost recovery period for any future costs. Staff therefore proposes that the Commission establish a new amortization period for future expenditures. BGE, however, opposes the Staff suggestion as the Company on brief states it sees no need to change the existing policy, which provides for a 10-year amortization period for recovery of costs after they have been incurred.

[22] The remediation costs under discussion arise out of activities that once were accepted and common practices in the industry but which, unfortunately, produced damage to the environment that requires remediation. In any rate case, it is possible that a party may raise an issue regarding the appropriateness of recovery of remediation costs, disputing either the incurrence of the damage or the prudency of the remediation effort. Assuming for the sake of this discussion that there are no issues on that front, it still remains to determine an appropriate period over which the remediation expenses should be recovered.

The environmental damage occurred over time, making it appropriate for remediation cost recovery to also occur over time. The extent of the damage and the remediation effort involved may or may not be known and certain at this time, making it appropriate to put in place a general rule governing amortization and cost recovery, so as to provide the Company and other parties guidance on the Commission's general expectations. Any such guidance, of course, is offered pending the existence and advocacy of an issue pertaining to either the Company's behavior leading to the damage or the efficacy or reasonableness of its remediation efforts, as noted above. With that caveat, and after considering the record on this issue, the Commission reaffirms that a 10-year amortization period for recovery of costs after they have been incurred is appropriate.

I. Depreciation Study

[23] Staff proposes that the Commission direct the Company to perform an updated depreciation study. Staff notes that the last major revision of BGE depreciation rates occurred in 1995 (as a 1999 review revised only one account). Staff observes that industry literature and prior Staff recommendations indicate that depreciation reviews occur every three to five years. Accordingly, Staff recommends that the Company perform and submit an updated depreciation study no later than December 31, 2006.

On brief, BGE indicates agreement with the Staff proposal to file a new study by December 31, 2006, but notes it does not support the Staff suggestion that such studies be performed every three to five years.

The Commission accepts the parties' consensus that BGE should file a new depreciation study by the end of 2006. With respect to the recommendation that such studies are appropriate every three to five years, the Commission declines to adopt a blanket, specified timeframe for the production of these expensive studies.

J. Cost Allocation Manual

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The purpose of the Cost Allocation Manual is to properly identify and charge BGE and its affiliated companies for services provided to each other, in order to protect BGE ratepayers from bearing costs of non-utility activities. The Company's CAM allocates costs on a fully distributed cost allocation basis.

Staff witness Lee states the CAM is a conscientious effort by BGE to properly identify and assign costs; in his opinion, its application results in acceptable assignment of such costs. However, Mr. Lee notes that since the Company's initial CAM, the BGE corporate structure has changed. He observes that the CAM was initially developed when BGE was the lead company of the corporation, with most corporate costs incurred within BGE's utility operations. Therefore, the focus was on ensuring costs were transferred out, whereas the present CEG structure creates a concern regarding the transfer of costs into BGE, according to Mr. Lee. He notes that during 2004, BGE allocated over $12 million of costs to affiliates, about one-fifth of the costs allocated into BGE from CEG. He further states that the CAM is devoted primarily to describing allocation of BGE costs, but notes that allocators may no longer be appropriate when assigning costs among regulated and non-regulated activities. Mr. Lee suggests that it may be time for an extensive review of CEG's inter-company cost allocations and states the Public Utility Holding Company Act of 2005 removes any doubts that may have existed regarding the Commission's authority to review the books and records of CEG.

Also with regard to the CAM, the Company expresses support for institution of a rulemaking with respect to the CAM audit requirements of Section 4-208 of the *PUC Article.*

[24] The cost allocation provisions in the PUC Article exist to preclude public service companies with unregulated service offerings, or having affiliated companies that provide unregulated services, from improperly allocating costs away from the competitive unregulated services and into the regulated service arena. The advent of competitive retail choice in Maryland's gas and electricity markets make these provisions more important than ever.

No evidence of improper cost shifting has been presented in this proceeding, and in fact the CAM audit report from the independent accounting firm affirms the appropriateness of BGE's practices. However, Staff proposes an extensive Commission review of BGE's cost allocations in view of recent industry changes and the shift in BGE's relative position within the CEG corporate family. Given the importance of appropriate cost assignment to the customers of regulated utility services, and to the functioning of Maryland's competitive gas and electric industries and BGE's and its corporate siblings' roles in those industries, the Commission accepts Staff's recommendation. Staff shall consult with the Company, People's Counsel and interested parties and then propose for the Commission's consideration a timetable and procedures for the review.

Also, as noted previously in Order No. 80245, the Commission has indicated an intention to separately consider a regulation interpreting Section 4-208 of the *PUC Article.* Therefore, Staff shall consult with the Company, People's Counsel, interested parties and other companies subject to the provisions of that section with respect to possible regulations implementing the CAM audit requirements of that section of the law. In both instances, Staff shall report its recommendations to the Commission on or before February 15, 2006.

K. Conclusion

Upon consideration of the record in this proceeding, the Commission finds that for the 12 months ended July 31, 2005, Baltimore Gas and Electric Company experienced adjusted operating income of $46,384,000, as detailed in Appendix II attached hereto and incorporated herein by reference.

IV. RATE OF RETURN
A. Capital Structure

[25] BGE's requested capital structure is the actual capital structure of its parent corporation, CEG. That capital structure consists of 45.7 percent long-term debt, 5.9 percent preferred stock and 48.4 percent common equity. BGE witness Avera testified that no short-term debt is included in the capital structure since BGE does not actually have any short-term debt. Staff witness VanderHeyden and DOD witness Prisco also accept the Company's capital structure for ratemaking purposes.

OPC witness King testified that a reasonable capital structure would include a short-term debt component. He recommends that the Commission use a capital structure containing a short-term debt component of 7.9 percent, long-term debt of 42.1 percent, 5.4 percent of preference stock, and 44.6 percent common equity. The witness opined that the proposed use by BGE of the capital structure of its parent company, CEG, produces a result that is not reflective of the actual operations of a stand-alone gas utility.

Mr. King observes that BGE, an affiliated subsidiary of CEG, does not issue its own stock. Therefore, in order to properly develop a capital structure, an analyst would consider and compare the gas distribution utility, BGE, with other regulated gas distribution companies to the extent possible.

Mr. King explains that when BGE is considered as a stand-alone gas distribution company, the financing needs for short-term capital to purchase gas supply and materials and to finance short-term assets during the course of a year require the use of short-term funds. Mr. King also notes the existence of working capital in BGE's rate base. For these reasons, Mr. King imputes the aforementioned short-term debt component into BGE's capital structure.

Staff witness Lee proposes a $32.9 million adjustment to rate base because BGE does not have short-term debt in its capital structure. Mr. Lee's adjustment reflects what he perceives to be a funding disparity caused by an absence of short-term debt in the Company's capital structure. Upon cross-examination, Mr. Lee admits he would not propose this rate base adjustment if the Company included short-term debt in its capital structure or if the Staff cost of capital witness had proposed a capital structure for ratemaking purposes that contains a hypothetical short-term debt component.

Mr. Lee believes that his adjustment to rate base is appropriate because, were BGE a stand-alone company, short-term assets would be financed through short-term financing hypothetically at a cost lower than that for the long-term debt or equity which actually funded the short-term assets. Therefore, Mr. Lee proposes elimination of net short-term assets from rate base

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as an alternative to the hypothetical capital structure rejected by Staff's cost of capital witness.

After considering the Company's criticism that he overstated his adjustment, Mr. Lee reduced his proposed rate base deduction from roughly $70 million to $32.9 million. In his final position, Mr. Lee excludes only the level of non-permanent short-term assets from rate base, on the theory that equity or longer-term debt instruments could appropriately finance the "permanent" average monthly balance of short-term assets. MIG expresses support for the Staff proposal in its final position on brief.

The Company objects to Staff's proposed rate base exclusion for short-term financing, observing that Mr. Lee's adjustment is merely another means of proposing a hypothetical capital structure, although use of a hypothetical capital structure was not proposed by Staff's cost of capital witness, Mr. VanderHeyden. BGE notes that there was in fact no short-term debt in the capital structure during the test year or for the two and one-half years prior to the test year, and there has been no showing of imprudence by the Company that would warrant the rate base exclusion proposed by Staff. Also, in the event an adjustment is made, Mr. Castagnera notes that the average net level of short-term assets should be considered a permanent level that is appropriately financed on a long-term basis with long-term financing (as many short-term assets are in fact continually replaced with new short-term assets). According to BGE, such a modification to remove the average level of short-term assets would reduce Mr. Lee's proposed adjustment to $11 million.

The Company criticizes both OPC's capital structure adjustment and Mr. Lee's accounting adjustment, citing Commission precedent favoring the use of the actual capital structure for ratemaking purposes. BGE further comments that Mr. Lee declined to characterize the actual capital structure as "imprudent."

Mr. Castagnera also testified to the reasons behind and validity of the actual capital structure. He notes that the Company has not needed to engage in short-term borrowing over the last two and a half years, and considers this a prudent time to lock in long-term debt when considering interest rates. In this regard, the Commission takes notice that the Federal Reserve Board has been systematically increasing short-term interest rates at a measured pace, resulting in 13 increases since June 2004, six of which have occurred since BGE filed the rate case.

The Company further notes that Staff witness VanderHeyden agrees that the actual capital structure is reasonable, similar to the averages of other companies in the proxy group, and consistent with the Commission's historical preference for using a company's actual capital structure. For all of those reasons, the Company urges the Commission to reject both Mr. Lee's accounting adjustment and Mr. King's hypothetical capital structure proposal.

In considering this matter, the Commission notes that People's Counsel and Staff have presented two different methods of imputing short-term debt into the capital structure. Mr. King imputes a short-term debt component, and assigns it a cost rate. Mr. Lee artificially reduces the level of rate base to assess the Company for not including short-term debt in the capital structure.

Staff makes this recommendation even though Mr. Lee declines to characterize the Company's actions as "imprudent" and even though the Staff cost of capital witness accepts the Company's capital structure. Mr. Lee fully acknowledges that he would not propose the

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adjustment if the capital structure included short term financing. Therefore, his proposed adjustment is an attempt to circumvent his fellow Staff witness' acceptance of the reasonableness of the Company's capital structure by proposing a novel accounting adjustment to exclude prudent investments from the rate base.

As to imputing a hypothetical level of short-term debt into the capital structure, the Commission is not persuaded in this instance that customers are better served through a hypothetical construct than they are by the use of an actual capital structure. The Commission has stated a preference for the use of a company's actual capital structure in the absence of sufficient evidence justifying the need to use an alternate capital structure. In this proceeding, only People's Counsel advocates the use of a capital structure containing a hypothetical short-term debt component, although Mr. Lee's accounting adjustment is based on the same reasoning. While the Commission has used a hypothetical capital structure on rare occasions, the circumstances in this case do not rise to the level that would cause the Commission to deviate from its long-standing principle to use the actual capital structure unless doing so results in customers bearing unreasonable or undue financial costs.

The capital structure proposed by the Company herein is that of BGE's parent. The investment community understands actual capital structures and the risks associated with regulators selecting hypothetical capital structures (or novel accounting adjustments proposed because a capital structure is not one favored by a witness). The use of the actual capital structure also helps maintain the Company's financial and credit ratings at their current levels, both of which provide benefits to customers.

It is settled law that the Commission is not to substitute its judgment for that of a Company's management, and that the Commission does not sit as an over-arching "super" board of directors. 17 (17) The importance of these principles should not be minimized. Thus, while the Commission has in very limited instances in the last twenty years substituted its judgment on capital structure for that of company management (for ratemaking purposes only), in this proceeding there has been no showing that the Company was imprudent in its choices or that customers are ill-served by those choices. In cases where a hypothetical capital structure has been utilized, it has usually been to protect ratepayers from excessive reliance upon the more expensive equity component rather than debt, whereas the Dissent supports Mr. Lee's adjustment which is based solely upon the lack of short-term debt in the capital structure as Mr. Lee advocates use of short-term debt (rather than long-term) for short-term assets. However, the undisputed steady rise in short-term rates supports the reasonableness and prudency of the Company's management decision to lock in historically low cost levels of long term debt, so that no adjustment to the capital structure is warranted at this time.

The Dissent concedes that no "imprudence" has been displayed by the Company, but contends the record indicates that the Company's actual capital structure will unnecessarily burden ratepayers. However, Staff, the party proposing the adjustment supported by the Dissent, expressly contradicts this determination by concluding in its final position on Brief: "Staff submits that the Company's capital structure is not one that will unnecessarily burden the ratepayers." (Staff Brief at p. 21, Oct. 28, 2005). The adjustment that the Dissenting opinion would accept also does not take into account the real but indefinable benefits to customers of

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having a financially sound utility company whose cost of service was determined based on the actual components of that cost of service. One need not look very far to find utility companies with poor credit ratings, and to note that increased borrowing costs and other consequences attend those poor credit ratings.

In sum, our decision affirms sound financial management practices, helps manage regulatory risk, and rejects artificial decreases to the actual cost of providing service. Certainly, nothing in the record suggests that the Company has been anything but prudent in its financing decisions, and the current lack of short-term debt is but a continuation of a Company practice extant for the past two and one-half years.

The Commission has another reason for specifically rejecting the Staff proposal which is now advocated by the Dissent. There is no contention on the record that the assets were improperly or inefficiently procured, or otherwise unnecessary or imprudent. Rather, the assets are part of the Company's rate base, reflecting legitimate and proper investment used to provide service to customers. Such a disallowance would be an artificial distortion of the Commission's responsibility under Section 4-206 of the *PUC Article* to determine the fair value of a public service company's property used and useful in providing service to the public. Accordingly, the Commission declines the invitation to reduce the Company's legitimate costs of service for reasons unrelated to the prudence or reasonableness of these investments, and rejects the adjustment to rate base.

In view of the discussion and determinations set forth above, the Commission rejects the use of a hypothetical capital structure, and accepts BGE's proposed capital structure for ratemaking purposes. It is as follows:

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Capital	*Ratio*
Long-Term Debt	45.70%
Preferred Stock	5.90%
Common Equity	48.40%
Total	100.00%

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B. Rate of Return

1. Cost of Debt

[26] Using the latest figures, BGE calculates a cost of long-term debt of 6.03 percent, a number accepted by Staff. Mr. King recommends use of a 5.97 percent cost of long-term debt, reflecting the cost of that debt as of the time the application was filed. DOD witness Prisco recommends a rate of 5.78 percent for long-term debt, reflecting his belief that issuance fees should not be included in debt (and preference stock) cost rates.

The Commission finds that BGE and Staff have accurately computed the Company's cost of long-term debt at 6.03 percent, and accepts that figure for ratemaking purposes. The Commission rejects DOD's proposed adjustment, finding that issuance costs are a necessary component of debt issuances.

2. Cost of Preference Stock

BGE, Staff, and OPC find that the cost of the Company's preference stock is 7.02 percent. DOD witness Prisco reduces that figure to account for issuance costs, in line with his similar recommendation for long-term debt costs.

The Commission rejects DOD's proposal for the reasons expressed above in discussing long-term debt costs, and finds that the cost of BGE's preference stock is 7.02 percent.

3. Cost of Common Equity

[27] This Commission has for many years used the legal standard for its rate of return determinations set forth by the Supreme Court in the cases of *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 US 679, 67 L.Ed. 1176, 43 S.Ct. 675 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 US 591, 88 L.Ed. 333, 64 S.Ct. 281 (1944). The Commission continues to find that standard to be appropriate. Accordingly, the rate of return we will set is one that will be sufficient to allow BGE to maintain its financial integrity; to allow it to attract capital on reasonable terms; and to provide the Company with an opportunity to earn a return that is comparable with other investments of equal risk.

A central component of the overall rate of return is the return found to be appropriate for common equity capital. The Company's request is based on a cost of common equity of 11.90 percent. The recommended common equity cost rates from the other parties are lower than BGE's proposal. Staff witness VanderHeyden proposes a return on common equity of 10.32 percent. OPC witness King finds a return of 9.7 percent appropriate, while DOD witness Prisco recommends a return of 10.75 percent on common equity.

BGE witness Avera employs Discounted Cash Flow ("DCF") and several Risk Premium

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("RP") analyses, including the Capital Asset Pricing Model ("CAPM"), in determining the cost of common equity for BGE. He uses a proxy group of 14 publicly traded local gas distribution companies ("LDCs") that are generally considered to be comparable to BGE. Dr. Avera notes that "no single method or model should be relied upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable." The "bare bones" [18] (18) results of each of these five methods are noted below. BGE proposes a bare bones result for ratemaking purposes of 11.25 percent.

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Methods	*Range*	
DCF	10.00 percent	
Risk Premiums	Current Yields	Projected Yields
Authorized Return	10.60 percent	11.20 percent
Historical Return	10.60 percent	11.80 percent
CAPM Forward	11.70 percent	11.90 percent
CAPM Historical	10.40 percent	11.20 percent
DCF + Risk Premiums	10.75 percent	11.75 percent

Staff witness VanderHeyden recommends a return on equity of 10.32 percent that is equal to a simple average of the results of his constant growth DCF analysis, a risk premium approach, and a single application of the CAPM. Mr. VanderHeyden's recommendation is based upon application of the above-listed methods to the same proxy group of 14 publicly traded LDCs used by BGE witness Avera.

Staff witness VanderHeyden contends that his DCF result differs from that of Dr. Avera because BGE's analysis is exclusively based on earnings whereas Staff considered three other factors in calculating the growth rate. Mr. VanderHeyden opines that his approach improves the accuracy of the DCF method. He also testifies that Dr. Avera's authorized risk premium method is an incomplete indicator of investors required returns, and that Dr. Avera "has not demonstrated a reliable connection between authorized return on equity and investor's requirements."

Staff also takes exception with Dr. Avera's time period (1955-2004) for establishing a 4.68

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percent gas utility risk premium. Staff states that Dr. Avera was unable to corroborate a 12.1 percent growth rate obtained from the S&P 500. As a result, "his determination of the RP [Risk Premium] of 9.0 percent is inconsistent with historical trends."

OPC offered its position regarding BGE's cost of capital through the testimony of witness King. Mr. King uses the same proxy group as the Company to derive his recommended return on equity. Using classic DCF analyses, Mr. King derived costs of equity of 8.9 percent and 9.7 percent. A third DCF analysis using a sustainable growth in retained earnings and book value method yields a result of 9.2 percent. OPC's witness, noting difficulties in developing useful risk premium values, modified the Company's analyses with the following results: 10.6 percent for an authorized rate of return risk premium using Company witness Avera's inputs and time period; 10.1 percent using 2004 data; and 9.8 percent applying 2004 data to Washington Gas Light Company, the only Maryland company Mr. King considers appropriately situated for such an analysis. OPC's witness notes the Company's 10.6 percent cost of equity based on realized returns and its CAPM of 10.4 percent, and includes these numbers in his own analysis. Using the results specified above, Mr. King applied a weighting scheme and averaged these values for a cost of equity of 9.8 percent. He adds 10 basis points for flotation and subtracts 20 basis points to reflect the reduced business risk he attributes to BGE's Rider 8, to arrive at OPC's final recommended return on common equity of 9.7 percent.

DOD presented its position on the cost of capital through the direct testimony of witness Prisco. Mr. Prisco did not perform any independent study to arrive at a return on equity. Rather, he adopts the return on equity of 10.75 percent authorized by the Commission in the most recently litigated gas utility rate case proceeding in Maryland, Case No. 8959, which pertains to Washington Gas Light Company. [19] (19) Mr. Prisco notes that although he considered a cost of equity primarily for the purposes of performing accounting calculations, 10-year Treasury note rates have declined since the Commission approved the 10.75 percent return on equity for Washington Gas Light Company.

In addition to the parties' general positions on the cost of common equity, the record contains proposals to increase the return on common stock by specified amounts to account for factors somewhat tangential to the "bare bones" cost rate. The first of these is a proposal by BGE and OPC to provide for an increase in the cost of common equity to account for "flotation costs." BGE proposes an adder of 25 basis points to reflect flotation costs. OPC supports an adder of 10 basis points for this purpose, while no other party supports any adder for flotation costs.

[28] The Commission has included flotation costs as a reasonable component of the cost of common equity in prior proceedings, if the record reflects the need to include flotation costs. Generally, those circumstances are encountered when the applicant for a rate increase has shown the Commission that it intends to issue common equity during the rate-effective period, and thus will be incurring expenses for the issuance of the stock that should be reflected in rates. [20] (20)

However, the record in this proceeding is devoid of any need for flotation costs either in the test year or the rate-effective period; that is, there is no evidence in the record that BGE intends to or plans to issue any common equity or debt in the foreseeable future. Absent such evidence, the inclusion of flotation costs would be speculative. Accordingly, the Commission does not find

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flotation costs to be necessary for the Company at this time, and makes no separate provision for them for ratemaking purposes.

[29] Another "adder" to the cost of common equity proposed in this proceeding is BGE's recommendation that the Commission provide the Company with a 40 basis point adder for exceptional performance. Proposed by witness DeFontes and reflected in witness Avera's cost of capital computations, it is intended to reflect BGE's operational, customer satisfaction and financial performance results, in comparison to industry peers. That is, the performance adder is intended to reward BGE for exceptional corporate performance by providing it with a tangible bonus in its return on equity, thereby mimicking the fact that an unregulated company would likely garner increased profits were it to achieve similarly outstanding results.

No other party supports this request. Those that comment on it express the general sentiment that good performance is to be expected, and that achieving it may well result in the utility earning a return level over and above that authorized by the Commission.

The Commission is not unalterably opposed to the Company's proposal. Since rate regulation of monopoly service providers is intended to produce results similar to those encountered by companies that operate in competitive markets, the proposal's general thrust is tenable. Additionally, the Commission certainly possesses the authority to recognize exceptional performance in the setting of rates, just as it can recognize substandard performance.

However, the Commission further observes that the timing of this particular proposal is one-sidedly advantageous to the Company. That is, the Commission doubts the Company would have proposed a 40 basis point reduction to its requested return if it were in the midst of a period of poor performance. In other words, the corollary to the Company's proposal should be that the Commission could or should impose a performance penalty on a jurisdictional utility that under-performs.

Additionally, the Commission expects good results and sets rates to recognize that expectation. Therefore, for the reasons provided above, we decline to include a specific performance adder in this proceeding.

The Commission is open, however, to a proposal for overt recognition in rates of performance levels, provided that the proposal is balanced, comprehensive, and consistent with the statutory provisions governing the setting of base rates for jurisdictional gas public service companies. The Commission will seriously consider a proposal for a comprehensive alternative form of regulation that provides both the Company and its customers with opportunities to realize benefits through incentives, provided that it also contains appropriate consequences for poor performance.

A final proposal to adjust the "bare bones" return on equity arises out of Rider 8. Rider 8 is a tariff provision that serves as a "weather/number of customers adjustment clause." That is, when the weather is warmer, Rider 8 will increase BGE's revenues because gas demand is lower than normal. However, when the weather is colder than normal and gas demand is high, Rider 8 decreases BGE's revenues. The Company opposes any reduction in its rate of return based on the effect of Rider 8, which reduces its risk of loss. OPC recommends a 20 basis point adjustment while no other party supports a Rider 8 adjustment.

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For example, Staff witness VanderHeyden states that the proxy group data he analyzed already incorporates the reduction in risk for weather or conservation mitigation. For this reason, Staff recommends no reduction in the Company's return on equity to account for any lowered risk due to Rider 8. The Company concurs with Staff that a reduction on return on equity in this case is unwarranted. BGE witness DeFontes states that Rider 8 only allows BGE to recover approved revenues and the Company does not see the need for a downward adjustment on return on equity.

[30] Based on the reasons provided by Staff and the Company, the Commission declines to order a specific adjustment for Rider 8 effects.

The parties are separated by 220 basis points in recommended returns on equity, with OPC recommending a return on equity, after adjustments, of 9.7 percent, and BGE recommending a return on equity, after adder adjustments, of 11.9 percent.

As stated earlier herein, the rate of return must be sufficient to allow BGE to maintain its financial integrity, attract capital on reasonable terms, and provide an opportunity to earn a return that is comparable with other investments of equal risk. The Commission has reviewed in detail all of the evidence and finds that there exists a range of returns within which the above can be secured. That range of reasonable return on equity is between 10.8 percent and 11.1 percent. We have placed the low end of the range near our finding in the WGL case previously cited herein, Case No. 8959. Since that time, the costs of borrowing have been on an upward trend, as noted earlier in this Order. Accordingly, it is reasonable to assume that investors expect long-term capital costs to increase in response to the Federal Reserve's actions. Additionally, inflationary pressures, particularly in the energy sector, have been affecting the economy. In short, since the WGL case the reasonable finding is that investors expect modestly higher returns on equity.

The evidence here is also of a company that has a very high level of management and superior performance as compared to its peer population. We declined above to make specific provision for an adder based on performance, but will consider the Company's good performance as an intangible.

After considering the evidence in this proceeding and the factors discussed above, the Commission finds that a return on equity at the upper end of the range of acceptable returns is in order. The Commission, therefore, finds that the appropriate return on equity in this case is 11.0 percent.

4. Overall Rate of Return

Utilizing the capital structure, cost of debt, cost of preference stock and cost of common equity identified above, the Commission determines that BGE's cost of capital is 8.49 percent, as set forth in the following chart:

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Capital	Ratio	Cost	Weighted Average
Long-Term Debt	45.70%	6.03%	2.76%
Preferred Stock	5.90%	7.02%	0.41%
Common Equity	48.40%	11.0%	5.32%
Total	100.00%		8.49%

When applying the 8.49 percent rate of return to the adjusted rate base of $791,907,000, the Company's operating income requirement totals $67,233,000. After reflection of the adjusted Test Year Operating Income of $46,384,000, we find the Company experienced a net operating income deficiency of $20,849,000, which becomes a total revenue requirement of $35,645,000, as noted in Appendix I.

V. COST ALLOCATION AND RATE DESIGN

A. Allocation of Proposed Increase.

1. General

Laurie H. Duhan presented the Company's 2003 Cost of Service Study ("COSS"). She states that the purpose of a COSS is "to allocate a utility's embedded costs and revenue requirement, and attribute cost causation, among customer classes." [21] (21) She further explains that three steps are necessary to measure rate base and expense responsibility by customer class: functionalization, classification and allocation. BGE functionalizes assets and expenses by supply, storage and distribution functions. BGE's COSS classifies its functions as demand related, commodity related, or customer related. Rate base and expenses in each of these categories are then allocated to rate classes.

BGE witness Duhan proposes to allocate the revenue increase among customer classes in a manner that moves each class's embedded rate of return (based upon the 2003 Cost of Service Study) to within ten percent ("+/-10 percent") of the system average return, with the exception of Schedule PLG. Next, Ms. Duhan allocates the proposed overall revenue increase, net of the expected reduction in late payment charge revenues and adjusted to +/-10 percent of the system

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average return, to customer classes in proportion to adjusted test-year base revenues. Schedule PLG, which had a relative rate of return of -.30 is moved to a relative rate of return of zero. As a result of revisions to the Cost of Service Study subsequent to her Direct Testimony, Ms. Duhan revised her proposal with respect to ISG. She proposes that ISG's return be adjusted to equal the system average since the revised Cost of Service Study put ISG within the +/-10 percent band.

OPC presented the testimony of Paul L. Chernick. He maintains that BGE's +/-10 percent bandwidth approach is inappropriate because it does not permit adjustments to maintain rate continuity or to avoid rate shock. Mr. Chernick argues that reallocations beyond those proposed by BGE need to be made in order to reduce the impact upon residential customer bills and bring the residential return closer to the system average. Mr. Chernick argues that revenues earned from the residential class have been too high and that the revenue allocated to Schedules IS, AIS, and ISG should be increased so that the returns of these three classes are closer to the system average. Additionally, he argues that any reduction in BGE's requested rate increase should be applied first to the residential class until the point where the residential class increase equals the Company's allowed rate of return, with any remaining reduction after that point is reached distributed among all rate classes.

Staff witness R. Andrew Lawson supports the Company's allocation approach, including both the +/-10 percent band objective and the allocation to customer classes in proportion to adjusted test-year base revenues, subject to Staff's adjustments to the revenue requirement. MIG, through witness Richard A. Baudino, asserts that the IS and AIS customers should receive no more than a system average increase.

As discussed below, cost allocation issues can be particularly complicated, and their resolution inherently involves judgments on the part of the parties and the Commission. In the sections below, the Commission discusses and resolves the basic differences between the parties on particular cost allocation issues, followed by the overall decision on the allocation of the rate increase authorized herein.

2. Distribution Main Classification

A major cost of service study component is the classification of distribution mains. BGE classified its distribution mains as demand-related, and allocated this investment to customer classes based on each class's contribution to the Winter Non-Coincident Peak ("NCP"). [22] (22) According to BGE, its mains are installed and sized to meet the demands customers place on the distribution system during the winter heating season. Consequently, Ms. Duhan treats distribution main costs as demand-related, not customer-related. BGE notes that it operates a highly integrated and interconnected gas distribution system, which is designed to serve all customers, and concludes that its allocation of distribution mains using the NCP method is in accordance with Order No. 68706 in Case No. 8070. [23] (23)

OPC witness Chernick raised several issues regarding the allocation of distribution mains, including four issues regarding the exclusion of loads from the NCP allocator. He says BGE did not consider the hourly demands of AIS and IS customers on demand-free days in determining

their NCPs, even though their maximum hourly demands could have occurred on these days. Mr. Chernick asserts that BGE only considered loads in three winter months even though the maximum hourly demand of large customers may occur in off-peak months. Third, the 2003 NCP of the AIS class may not reflect the elimination of the automatic interruption at a preset temperature. He says recognition of this change could result in an increase in the class NCP of AIS customers. Finally, Mr. Chernick says the NCPs used in the COSS for interval-metered customers are not equal to and may be less than their actual 2003 maximum hourly demand. According to Mr. Chernick, BGE does not explain why the actual data for AMR (automatic meter reading) customers had to be adjusted.

Mr. Chernick is particularly critical of BGE for limiting the NCP to winter months. He asserts that a significant portion of interruptible service distribution revenues are derived from a commodity charge that is not seasonally differentiated. In addition, the firm commercial delivery rates are not seasonally adjusted at all. Mr. Chernick concludes that BGE has not demonstrated that high-class loads in months other than January-March do not have an effect on distribution costs. Finally, he notes that in Case No. 8829 the COSS used annual NCP data.

Mr. Chernick asserts that BGE has overstated the NCP of the residential class. BGE estimated the NCP of the residential class by sub-class rather than for the class as a whole. OPC says the Company's approach ignores the diversity of load between heating and non-heating customers. According to Mr. Chernick, if the NCP for the residential class as a whole is used, it is about one percent less than the sum of the heating and non-heating NCPs.

Addressing OPC's concerns, Ms. Duhan observes that BGE defines its winter heating season as November through March, and that it developed the NCP allocation using all hours during those months. Ms. Duhan also states that gas use during every day of the winter was considered when determining the NCP for the interruptible classes. Thus, the NCPs would be the same whether or not they occurred on demand-free days. Ms. Duhan also clarified that the NCP for AIS customers does not reflect any interruptions because there were none in 2003. Finally, BGE states that it scales each interval-metered sub-class, whether they are equipped with an Automatic Meter Reading device or if sample meters are used, to estimate the load for the sub-class population to calendar month consumption as reported on BGE's financial statements. This prevents over or understating loads and the contribution to the NCP allocator. BGE says this same methodology is applied to each and every class, so as to be non-discriminatory.

Ms. Duhan states that BGE did not use non-winter months for the NCP allocator because BGE designs its system to meet the demands of the cold winter heating season. Since non-winter peaks do not cause BGE to invest in its infrastructure, they were excluded from the NCP allocator because they do not cause additional peak demand costs.

BGE notes OPC's concern that BGE overstated the residential NCP since it is estimated by sub-class rather than for the entire rate class. BGE says that to adequately allocate costs and rate base to each sub-class the NCP allocator is determined by sub-class. BGE says that using the entire class to develop the NCP results in an allocator that remains essentially unchanged.

MIG witness Baudino asserts that BGE's NCP factor allocates too much cost responsibility to the interruptible classes. Mr. Baudino argues that it is necessary to reduce the NCP allocator to

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reflect the reduced reliability of service for interruptible customers. He recommends a 10 percent or 20 percent reduction for the IS and AIS classes as a reasonable adjustment.

BGE disagrees with MIG's proposal, stating that the costs associated with distribution mains are properly allocated using each customer class's contribution to the NCP. BGE concludes that the MIG proposal is arbitrary because it reflects interruptions that might not, and in the recent past have not, occurred. Ms. Duhan notes that the NCP allocation could be lower for IS and AIS customers if there were a distribution system interruption.

[31, 32] The Commission finds that BGE's 2003 COSS appropriately allocates the costs of distribution mains on the basis of the Non-Coincident Peak methodology. As BGE testified, the gas distribution system is designed based on the NCPs of customer classes. Consequently, allocating costs on the NCP basis is consistent with customer class cost causation. Moreover, Staff notes that BGE's allocation methodology is consistent with Commission precedent. Finally, the NCP methodology provides a reasonable compromise between use of a coincident peak or a total throughput allocation method. For these reasons, the Commission adopts BGE's use of the NCP methodology for allocation of distribution mains.

3. Service Lines Allocation

OPC alleges that BGE's Services Allocator (lines that connect customers to the distribution main) is based on an outdated analysis that is impossible to review and on annual updates since 1990 that over-allocate costs to the residential class. Mr. Chernick cites three flaws with BGE's updates. He says BGE's updating method improperly assumes that retirements and replacements are equally likely for brand new services as for older services; assumes that the large number of residential conversions do not reduce the service investment for residential non-heating customers; and allocates to the residential non-heating class replacements for services that no longer exist.

Mr. Chernick presents his own analysis, which results in a reduction of over one percentage point in the share of services costs allocated to the residential class as a whole. However, Mr. Chernick says even his analysis has deficiencies. First, a lack of data prevented him from analyzing all of the annual updates since 1990, and second, it is unclear how well the base study (in 1990 or before) accounted for the effect of the customer class and usage on the diameter, length and cost of a service. Moreover, he says it is unlikely that BGE has accounted for the sharing by many residential customers of a single service line to a multi-family building. Mr. Chernick concludes that correction of these deficiencies would probably result in shifting more of the allocator (particularly residential non-heating) to commercial classes.

BGE witness Duhan states that OPC's approach for allocating services relies on complicated and capricious assumptions. She states that BGE allocates service retirements and replacements based on each customer sub-classes' investment at the end of the prior year. She says Mr. Chernick treats replacements and retirements separately, adjusting the replacement allocator by reducing the balance of the Company's investment in replacement costs by retirement expenditures. Ms. Duhan points out that over time OPC's approach would result in a negative

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investment used to allocate service replacements.

Ms. Duhan asserts that Mr. Chernick incorrectly adjusted the allocation of retirements because he mistakenly assumed that conversions are residential customers that switch from the non-heating to the heating sub-class. However, since these residential customers are adding new gas service to an existing home without gas, OPC's adjustment overstates the retirements attributed to the non-heating sub-class. Moreover, BGE says its 2003 COSS reflects the reduction for investment in services associated with the residential non-heating sub-class. According to BGE, the residential non-heating sub-class received approximately two-thirds of the total reduction associated with BGE's service rate base. Finally, BGE says OPC incorrectly attempts to correlate the housing stock in the Baltimore area with the number of shared residential services because there is no one-for-one correlation between the type of house and whether a service is shared or not. Ms. Duhan notes that only OPC expressed concern about the Company's service allocation methodology. She concludes that BGE's Service Study fairly allocates service related costs among its customer classes.

The Commission has reviewed the record and finds that BGE's Services Study should be accepted. BGE addressed the flaws in OPC's analysis. No other party supports OPC. Therefore, the Commission accepts BGE's Service Allocator.

4. ISG Cost Allocation and Rate Design

Nicholas Phillips, Jr. testified on behalf of ISG. According to Mr. Phillips, rates for ISG should reflect the fact that only a portion of BGE's gas system can be used to serve this large customer. Mr. Phillips recommends three alternatives to establish ISG's rates: 1) allocating to ISG only (a portion of) the costs of mains of sufficient size to provide service to ISG (*i.e.*, pipes 12 inches or larger in diameter); 2) directly assigning the costs of the Manor Line to ISG; or 3) recognizing a customer component to distribution mains. While Mr. Phillips prefers his first alternative, he says that allocating costs to ISG using any of these alternative methods demonstrates that even BGE's existing rates are excessive. Mr. Phillips says allocating only the cost of mains that are of a sufficient size to provide service to ISG most accurately assigns to ISG the costs of facilities that BGE uses to serve its largest customer. Additionally, Mr. Phillips argues that BGE has failed to support its proposal to allocate production and storage facilities to ISG.

As to ISG's observation, Ms. Duhan states that BGE's gas system is designed to deliver gas to firm service customers, including ISG, up to its Billing Demand level, plus Critical Use Gas volumes, during extreme weather conditions. In addition, she states that the primary purpose of BGE's LNG and Propane facilities is to augment its ability to meet distribution design capacity needs of firm customers. This allows the company to reduce its investment in distribution pipes. As a (partially) firm customer, ISG contributes to BGE's peak day costs. Therefore, BGE concludes that ISG should be allocated a portion of these system costs.

BGE opposes ISG's second and third alternatives, but proposes developing a COSS based upon ISG's preferred approach for its next gas base rate case. Ms. Duhan noted that BGE

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typically uses the Manor line to provide gas service to ISG, however BGE also has the flexibility to use, and has used, other mains to deliver gas to ISG. Since ISG benefits from the system's interconnectivity, BGE concludes that direct assignment of the Manor Line is not appropriate. Ms. Duhan did concede that there is "some merit" to Mr. Phillips' recommendation that ISG should only be allocated a portion of mains sufficient to serve its load. Therefore, she recommends developing an alternative COSS based on ISG's preferred allocation methodology for presentation in the Company's next gas base rate case. Finally, Ms. Duhan notes that BGE recommends holding ISG's return to 91 percent of the system average to recognize ISG's contribution to the system and Maryland's economy.

[33, 34] Based upon the record in this proceeding, the Commission accepts BGE's allocation and BGE's tariff proposal for ISG. The record reflects that ISG is a firm service customer, up to its billing demand, and that BGE's gas system is designed to meet the needs of all firm service customers. However, the Commission agrees with the Company's proposal to present a new Cost of Service Study that would include, as at least one alternative, an analysis based upon ISG's preferred methodology in its next gas base rate proceeding. That study should examine cost causality in a manner that distinguishes between high-pressure mains and low-pressure mains that are not capable of serving ISG. Therefore, the Commission directs the Company to provide testimony and information on this issue in its next gas base rate case application.

5. Allocation of Environmental Costs.

BGE allocates environmental clean-up costs for the Spring Gardens site as part of total demand-related costs. OPC witness Chernick argues that, to the extent environmental clean-up costs are allocated based upon cost causation, these costs should be allocated according to annual commodity costs, and since there was no delivery service at the time of cost causation, the commodity measure should be throughput, not sales. Mr. Chernick concedes that a portion of the clean-up costs might appropriately be allocated on some distribution basis if the current use of the site increases the clean-up costs. He argues that the Company has not established that current use of the site has any effect upon the clean-up costs, or that any part of the clean-up costs relates to any factor other than the manufacture of the commodity. Further, Mr. Chernick argues that some customers' loads are no longer included in the coincident peak allocator, so use of that allocator is no longer appropriate.

[35-37] The Commission is not persuaded that the change in allocation advocated by OPC is warranted or supported by the record evidence. The environmental clean up of the Spring Gardens site is an unusual expense that is appropriately allocated across customer classes in the same manner as demand-related costs. Significantly, no party other than OPC objects to this treatment, and this treatment is consistent with the last two rate cases. Therefore, BGE's allocation of these costs is accepted.

6. Cost of Service Study Finding and Conclusion

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The Commission finds that BGE's 2003 COSS appropriately allocates the costs of providing service to its gas customers, a conclusion supported by Staff in all essential aspects. Staff also notes that BGE's allocation methodology is consistent with Commission precedent. For these reasons, the Commission adopts BGE's 2003 Cost of Service Study for use in this proceeding.

7. Revenue Requirement Allocation Findings and Conclusion

[38, 39] On the broader issue of assignment of the rate increase among the customer classes, the Commission finds, subject to its revenue requirement analysis, that BGE's proposed allocation of the rate increase is supported by the record. As noted above, the 2003 Cost of Service Study, the foundation upon which implementation of rate increase allocations for the customer classes is based, is consistent with the Commission's previous decisions. The allocations using the banding proposal move all customer classes closer to the system average rate of return, consistent with the Commission's long-standing precedents of avoiding rate shocks to any particular customer class when possible. Staff also supports the allocation methodology.

As to ISG, Ms. Duhan's revised proposal provides appropriate recognition at this time of ISG's circumstances. The Commission further directs additional investigation of ISG's allocation proposals, as noted above.

In sum, BGE's allocations are fair, reasonable, consistent with precedent, based on an appropriate cost of service study, and in the public interest. Therefore, they are adopted for use with the revenue requirement findings also adopted in this Order.

B. ISG Tariff.

As alluded to above, BGE witness Duhan proposes that ISG's billing demand level be locked in at 160,000 therms per day. The proposed delivery price has two blocks, with a price decrease after the 6,000,000 therm mark. Delivery up to the billing demand level is under Schedule C, Non-Standby service. Delivery above that level is under Schedule IS, with the Company able to call for interruption on only two hours notice, of up to 100,000 therms per day. The Commission finds this proposal reasonable and hereby approves it.

C. Customer Charges

BGE proposes raising the residential (Schedule D) Customer Charge from $12.25 to $13.25. According to BGE, this change will result in all residential customer-related costs being recovered through the customer charge. BGE also proposes raising the Schedule C Customer Charge from $27.00 to $35.00. Company witness Duhan says that with this increase the Schedule C Customer Charge will now recover 71 percent of customer-related costs. No party opposed the increase in the Schedule C Customer Charge.

OPC opposes an increase in the residential customer charge. According to OPC, BGE's Cost

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of Service Study is flawed and does not justify the increase. OPC witness Chernick says the customer charge is based on the average cost per customer, which fails to account for the effect of customer size on cost. Since many customer-classified costs vary with the size of the customer, Mr. Chernick says these costs should be recovered through the commodity charge. He concludes that it would make more sense to increase the delivery charge and encourage more efficient use of gas. OPC also asserts that BGE's COSS incorrectly classifies certain costs as customer-related, which is particularly burdensome for non-heating residential customers.

BGE responds that its goal is to move toward recovering 100 percent of customer-related costs through the customer charge. BGE concurs with OPC that using an average cost per customer does not take into account the effect of customer size on cost. However, BGE states that it did not use the average cost per customer because it would have over 600,000 combinations of customer charges. BGE concludes that its proposed residential customer charge of $13.25 is appropriate because it is cost based for that class as a whole, and that the differences per customer are not so great as to make that averaging unsuitable.

[40-42] Customer charges are designed and established to collect certain costs that do not change with consumption level. For example, the Company maintains meters and performs billing functions the costs of which it must incur regardless of whether any specific customer uses $1 or $100 worth of natural gas in a given month. The costs for such items are fixed — it is the existence of the customer, not the amount of gas that he or she uses, that results in BGE incurring the charges.

The Commission has for some time moved towards greater recovery of fixed costs from fixed customer charges because, to the extent practical and reasonable, costs should be recovered in a manner reflecting how and why they are incurred. Setting customer charges at something less than the level needed to recover fixed costs means that fixed costs get recovered through the rates for usage, which results in higher volume users subsidizing low usage customers. While OPC rightly observes that such practices provide additional inducements to conservation, the subsidization components of OPC's proposal make those inducements unfair.

OPC also takes issue with the averaging that does occur within the residential customer class. Such averaging is a necessary component of ratemaking, unless one is to design a different rate for each customer, which is impractical for BGE's residential customer class.

The Commission finds that BGE has supported its proposed change to the residential customer charge. However, Staff points out that residential customer costs have been decreasing recently. Consequently, the Commission will establish the residential customer charge at $13.00 per month. [24] (24) No party contests the proposed $35 Schedule C Customer Charge and it will be adopted because it moves toward full fixed cost recovery through the customer charge.

D. Penalty for Failure of Interruptible Customers to Interrupt as Required.

BGE witness Duhan proposes demand prices designed to recover 100 percent, instead of 50 percent, from the non-volumetric rate components for the twelve-month period following a failure to interrupt by an interruptible customer. This results in a demand price increase for that

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twelve-month period, as a consequence of the failure to interrupt, from $2.97 per decatherm ("dth") of gas to $7.32 per dth for IS Schedule customers, and from $3.49 per dth to $10.15 per dth for AIS Schedule customers. In her rebuttal testimony, Ms. Duhan agrees with OPC witness Chernick that the penalty provisions for interruptible customers may not provide sufficient economic incentive for them to comply with the interruptible provisions of their rate schedules.

OPC witness Chernick criticizes BGE's penalty provisions on two bases. First, he argues that the penalties are so low that interruptible customers have no incentive to interrupt since their bills will remain lower than the bills of Schedule C customers even if they pay the penalty. Second, the penalty provisions do nothing to encourage shortening of an interruption failure or to prevent repetition of a failure to interrupt. Mr. Chernick does not propose specific penalty provisions, but he does list features that he believes a penalty structure should include. Mr. Chernick opines that the penalties should be designed so that customers who fail to interrupt as required end up paying more than firm Schedule C customers. Mr. Chernick asks the Commission to require BGE to demonstrate that "few, if any, customers could reduce their bills by being non-complying interruptible customers, rather than by being on the applicable firm tariff." [25] (25)

OPC also criticizes the Company's proposal to eliminate the alternative fuel capability requirement for IS customers. Mr. Chernick notes that eliminating this requirement reduces costs for a customer selecting this interruptible rate schedule, but increases a customer's costs if there is an interruption. He says that as long as the IS penalty charges for an interruption are too low, eliminating this requirement will likely attract more customers to the IS rate schedule but with reduced incentives to comply with an interruption request. OPC concludes that until BGE has adequate interruptible rates in place, the alternative fuel capability requirement should not be eliminated.

BGE notes that eliminating the alternative fuel capability requirement does not jeopardize the integrity of BGE's distribution system, provided that an interruptible customer complies with an interruption request. Ms. Duhan states that all Schedule IS customers are required by the tariff to stop using gas during a Distribution System Interruption. She argues that it does not matter how customers interrupt; what is important is that they do interrupt. She notes that for some customers it may be more economical to shut down operations rather than maintain alternative fuel capability. BGE concludes that as a last resort, if the system is in jeopardy, it can and will physically shut off an interruptible service customer who fails to interrupt.

Staff witness Lawson agrees that neither the existing nor the proposed penalty structure is entirely sufficient to ensure that all interruptible customers will in fact interrupt as required. In this connection, Mr. Lawson notes OPC's point that failure to interrupt will still result in lower bills for interruptible customers than firm customers under Schedule C receive. Mr. Lawson does not call for alterations to the penalty structure, but does ask that the Company be required to monitor compliance. MIG witness Baudino disagrees with OPC's and Staff's assessments, asserting that the penalty provisions provide sufficient incentive to ensure compliance with interruption requirements.

[43-45] The Commission accepts the penalty provisions proposed by the Company because no evidence was presented that interruptible customers will not interrupt if required to do so. However, the Commission is concerned that these penalty provisions may prove insufficient to

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ensure full compliance. Consequently, the Commission directs BGE to monitor compliance and to report any problems with compliance to the Commission. If the Company believes changes to the penalty provisions are necessary, it should work with Staff, MIG, OPC and other interested parties in devising proposed revisions.

E. Annual Interruption Test.

BGE witness Duhan initially proposed adding a provision to Schedule AIS that mirrors existing language in Schedule IS that permits the Company to run annual interruption tests with a minimum of six hours notice. MIG opposed this proposal, and offered a counter-proposal, which the Company accepted.

The new proposal includes two parts, the first of which is an annual mandatory test of BGE's and the customers' communications systems. The second part of the proposal requires either certification by a licensed professional engineer that equipment or procedures are in place to interrupt for at least four hours with six hours notice, or active participation in the test interruption. Rather than an annual test, the new proposal requires either testing or certification every three years, except that material changes to a customer's equipment or processes require a new certification by a licensed professional engineer.

Customers that elect the certification process rather than testing are also required to provide annual certifications from the plant manager that no material changes to equipment or processes have been made, and that the customer will interrupt if called upon. The new proposal also provides for a one-time waiver of the interruption penalties to allow for correction of problems and the evaluation of the appropriateness of the rate schedule for the customer. Customers that fail the interruption test must submit to a second test; failure of the second test results in the application of penalties.

Upon review, the Commission concludes that the BGE/MIG proposal is worthy of implementation in the effort to ensure that interruptible customers are capable of interrupting when called upon, thus enhancing the integrity of the system and aiding the reliability of service for firm service customers. The Commission accepts the settlement proposal.

F. Elimination of Gas Air Conditioning Rider.

[46] BGE witness Duhan proposes the elimination of Rider 5, the Gas Air Conditioning Rider. She notes that the market for gas air conditioning did not develop as anticipated when Rider 5 was created, and also notes that only four customers take advantage of Rider 5. Ms. Duhan explains that continuing Rider 5 would require the calculation and approval of a delivery rate that is applicable to only four customers for only seven months of the year. She states that the Company contacted all four customers, and that none object to the discontinuation of Rider 5; two of the four no longer even have their gas air conditioning equipment in place.

The only party objecting to the elimination of Rider 5 is OPC. OPC witness Chernick asserts that the costs of continuing the program are outweighed by the potential benefits of the program,

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and that gas air conditioning technology may gain acceptance in the future.

The Commission observes that the affected customers do not object to the Rider's discontinuance. The Commission agrees that it is appropriate to eliminate Rider 5 since the program is not used and therefore provides little to no net benefit to the system as a whole. The Company or others may propose to re-institute the Rider if future circumstances warrant it.

G. Service Upgrade Charges

While BGE witness Duhan agrees that upgraded service facilities for "standard" gas use applications should continue to be provided without charge to the customer, she asserts that upgrades for non-standard applications that will not produce a fair return to the Company should require a customer contribution. Ms. Duhan argues that residential customers, as a rate class, should not have to bear the costs of these non-standard applications, which instead should be borne by those causing the costs. Ms. Duhan urges the Commission to allow BGE to treat installations of upgrades intended to accommodate non-standard gas service applications in the same manner as new service installations.

OPC witness Chernick argues that BGE has not provided any economic tests to support its assessment regarding the lack of a fair return from non-standard gas service applications and has not identified a complete list of non-standard applications. Mr. Chernick does agree that assessing such charges would reduce BGE's investment in uneconomic new service lines. He contends, however, that the capability of new load to yield a return on the investment in pipe "depends on the amount of gas used by the load and the shape of the load, particularly its distribution between summer and winter, as well as the load's tendency to follow system load, exacerbating peaks." [26 (26)] He argues that assessing a charge based solely on arbitrarily selected end uses, without evidence that the particular end use will likely not cover the costs of the installation, discriminates against particular end uses.

Mr. Chernick asserts that upgrade charges should not be assessed in either of two situations. First, upgrade charges should not be assessed if the net additional revenues of the installation are greater than the net revenues for a space-heating conversion using a similar service line. Second, upgrade charges should not be assessed if the new load serves a special need, such as a medical need, for a residential customer who would be unduly burdened by the charge.

[47, 48] The Commission finds that BGE should be permitted to assess charges for new gas line installations necessitated by customer additions of non-standard usage equipment such as outdoor swimming pool heating systems or electric generators. The Commission finds that treatment of such installations in the same manner as new service installations is appropriate. Otherwise, the residential customer class as a whole will bear the costs of gas service installations for non-standard applications, since such installations cannot be expected to yield revenues that recover the cost of the installation. The Commission is not persuaded that OPC's approach, which entails examining the quantity of gas used and the shape of the load in each customer-specific circumstance, will yield a sufficiently more accurate, much less cost-effective, determination of which installations should be subject to charges to justify the expense of the

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analysis.

The Commission further determines that OPC's proposal that BGE not charge residential customers for service upgrades for medically necessary equipment is not sufficiently developed at this time. The Commission requires more information on the nature of such equipment, the frequency of its installation, and whether service upgrades typically are necessary in order to allow its use. The Commission advises People's Counsel to explore these matters with the Company and advise the Commission if in fact such provisions are necessary and, if so, provide the Commission with a reasonable proposal for implementation.

H. Miscellaneous Issues

1. Use of BGE Gas by Schedule C Non-Standby and Interruptible Service Customers.

BGE notes that Schedule C Non-Standby and interruptible customers do not participate in BGE's Gas Commodity Service. Therefore, BGE says the price for BGE gas when used by these customers should recover the cost of purchasing that gas, as well as a modest disincentive for relying on BGE gas. Ms. Duhan notes that these minor changes reflect only an approximately $10,000 change in rates for these customers. Only MIG objected to these proposed changes. Based upon the record, the Commission finds that these modest changes are appropriate for this service for the reasons noted.

2. Simplifications, Clarifications and Reorganization

Ms. Duhan also presented simplifications, clarifications and reorganizations of all of the rate schedules in her Direct Testimony. She notes that these changes are proposed to become effective February 2006, concurrent with changes approved in Case No. 8950 Phase II. These changes are not contested and will be accepted by the Commission with a February 2006 implementation date.

3. Uncontested Tariff Revisions

In Appendix C to BGE's Initial Brief, the Company lists a number of uncontested tariff revisions. Inasmuch as there is no dispute that these are appropriate tariff revisions, they will be accepted.

VI. CONCLUSION

In conclusion, the Commission finds that the application of Baltimore Gas and Electric Company filed on April 25, 2005 seeking to increase gas base rates by $52.7 Million should be rejected. Instead, the Commission finds that a revenue increase of $35,645,000 will result in just

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and reasonable rates, and the Company may file amended schedules of rates and tariffs in accordance with the findings and decisions of this Order.

IT IS, THEREFORE, this 21st day of December, in the year Two Thousand Five, by the Public Service Commission of Maryland,

ORDERED: (1) That the application of Baltimore Gas and Electric Company for an increase of $52.7 Million in gas base rates is hereby denied;

(2) That the fair value of the Company's property used and useful in rendering service to the public is determined to be $791,907,000, and the Company's test year adjusted operating income is determined to be $46,384,000;

(3) That the just and reasonable rate of return for the Company is 8.49 percent, which when applied to the rate base determined in this proceeding and reflecting the operating income, results in a revenue deficiency of $35,645,000;

(4) That Baltimore Gas and Electric Company may file amended schedules of rates and tariffs in accordance with the findings of this Order, which shall result in an increase of not more than $35,645,000 in the gross annual revenues of the Company;

(5) That the Company and Staff shall comply with the directives of this Order with respect to future studies and reporting requirements;

(6) That the motions to correct transcript of Baltimore Gas and Electric Company and ISG Sparrows Point, LLC are granted;

(7) That the Motion to Strike the Alliance letter of October 28, 2005 is denied in accordance with the discussion in this Order.

(8) That all other pending motions not granted by action taken herein are denied.

Harold D. Williams
Karen A. Smith
Charles R. Boutin
Commissioners

APPENDIX 1

RATE BASE AND REVENUE REQUIREMENT
(000)
(07/31/05 Test Year)

[Graphic(s) below may extend beyond size of screen or contain distortions.]

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Unadjusted Rate Base	$793,665
Uncontested Adjustments	
Eliminate unamortized deferred conservation balance	66
Adjusted unamortized gains on real estate sales	(25)
Adjusted unamortized deferred environmental costs	(243)
Eliminate unamortized balance TVSERP asset	(154)
Contested Adjustments	
Effect on CWC of Operating Income Adjustments	(2,165)
Annualize allocation of common utility costs	3,507
Reflect CWC interest and dividends expense lag	(2,744)
Adjusted Rate Base	$791,907
X 8.49% ROR	8.49%
Operating Income Requirement	67,233
Adjusted Operating Income	46,384
Operating Income Deficiency	20,849
Conversion Factor	0.5849
REVENUE REQUIREMENT	$35,645,000

APPENDIX II

OPERATING INCOME
(000)
(07/31/05 Test Year)

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Unadjusted Operating Income	$51,210
Uncontested Adjustments	
Eliminate certain advertising, lobbying expenses	834
Eliminate return of conservation surcharge	5
Amortize gains on sale of real estate	35
Eliminate shareholder's portion of gas margin sharing	(5,871)
Eliminate shareholder's portion of compliance costs	3
Annualize amortization of deferred environmental costs	982
Annualize wage adjustments	(368)
Annualize increases in taxes other than income	(186)
Reflect Increase in Customer Deposits	(81)
Eliminate electric portion of maps and record costs	462
Eliminate TVSERP amortization	334
Eliminate Revenue from General Motors	(305)
Contested Adjustments	
Annualize AFC	21
Tax effect of pro forma interest	(927)
Annualize allocation of common utility costs	(2,206)
Annualize PSC assessment	47
Revise 2002 VSERP amortization	2395
ADJUSTED OPERATING INCOME	$46,384

DISSENTING OPINION

Schisler, Chairman, and Freifeld, Commissioner, dissenting.

[49-52] The rate increase authorized by the majority in this Order is $3,397,000 greater than is just and reasonable, as is clearly evident from the record in this proceeding. Contrary to sound judicial and regulatory precedents, the majority Order sets a new, flawed course for the

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Commission. In our view, this new course fails to reflect the consumer interest in an efficient capital structure. The majority's acceptance of the Company's actual capital structure for use in setting utility rates imposes unnecessary costs on customers; costs unrelated to the provision of utility service. Specifically, in this case the majority overlooks the function of lower cost short-term financing of variable capital requirements for an efficient public service company. In so doing, the majority unfairly burdens ratepayers with several million dollars in excess costs.

A major disputed issue in this proceeding is the ratemaking implications that flow from the absence of any short-term debt in Baltimore Gas and Electric Company's (BGE) actual capital structure during the test year. The Company urges the Commission to accept its actual capital structure for ratemaking purposes. [1] (27) However, People's Counsel, Staff, and Maryland Industrial Group each propose ratemaking adjustments that have the effect of imputing short-term debt as a part of the capital structure. The Commission's long-standing precedent with respect to the issue is a preference for "using the Company's actual capital structure or that structure projected to exist during the rate effective period absent clear evidence on the record that such a structure will be unnecessarily burdensome to ratepayers." [2] (28) In our view, the record reveals that the Company's actual capital structure is unnecessarily burdensome to ratepayers.

In determining that the actual capital structure utilized by BGE is unnecessarily burdensome to ratepayers, we hasten to add that we are not suggesting any imprudence or impropriety in the Company's actual capital structure. As will be discussed below, there may be entirely rational business reasons for the Company's choice of a capital structure that may, at the same time, create an unnecessary burden to ratepayers. The two concepts are not at all mutually exclusive. We emphasize this point at the outset because it appears that the polestar of the majority's decision not to review the reasonableness of BGE's actual capital structure for ratemaking purposes is the absence of allegations of imprudence on the record. We agree that the Company's selection of a capital structure is not imprudent, but that does not end the inquiry.

Short-term debt is considerably less expensive than long-term debt or common equity. In this proceeding, for example, the cost of common equity is determined to be 11%, and the cost of long-term debt is 6.3%. Expert testimony in this proceeding places the cost of short-term debt at 3.61% to 3.66%. A capital structure that includes no short-term debt imposes unnecessarily high financing costs on ratepayers. In theory, efficient firms should have a mixture of long-term and short-term financing instruments that rationally follow the relative variations in capital needs and financing costs over time. This minimizes the cost of capital, and also reflects a reasonable amount of risk. The record indicates that short-term debt is a normal requirement of the gas distribution business due to the seasonal variation in the need for capital associated with gas service. For example, the group of 14 comparable gas companies presented in this proceeding by both Drs. Avera (for the Company) and King (for People's Counsel) had capital structures containing as much as an 11% short-term debt component during the period 2002-2004. During 2002, 10 of the 14 companies maintained short-term debt; during 2003, 12 of the 14 companies maintained short-term debt; and during 2004, 13 of the 14 companies maintained short-term debt.

BGE is a wholly-owned subsidiary of the Constellation Energy Group (Constellation), a

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holding company with regulated and unregulated business affiliates in Maryland and elsewhere. The dispute here arises in the context of BGE's participation in a money pool run by Constellation for the use of Constellation's affiliated companies. Various entities within the corporate family both lend and borrow money from the money pool to support the capital needs of the individual companies. The money pool serves the commonwealth interests of Constellation and its affiliated companies. We assume this arrangement is in place because it is the most efficient means to raise a portion of the capital needs of the variety of companies in the Constellation family.

We are not critical of the money pool arrangement, and we are not critical of BGE's participation in it either as a borrower or a lender. The issue of concern from a ratemaking perspective is Constellation's reliance upon BGE as an overall net source of capital to the money pool, and the capital costs incurred by BGE in making funds available to the pool. [3] (29) For Constellation, the arrangement makes sense. BGE, as a relatively stable regulated utility with sound credit and substantial assets, has the ability to borrow funds from outside lending institutions at favorable interest rates that are lower than could be obtained by other BGE affiliates, engaged in competitive lines of business. Within reason, and we believe BGE's level of participation in the money pool has been so far reasonable, [4] (30) it appears a sensible choice for Constellation to utilize BGE as a low cost source of capital for the money pool.

BGE produces funds in excess of its needs for much of the year and makes that cash available for loans through the money pool to its affiliates. Constellation has an interest in seeing that the money pool utilizes least cost capital, and it may be that BGE is an attractive place to find it. However, in doing so, the money pool imposes extra costs on BGE that would not be borne by the Company if it were not affiliated with Constellation.

But for its relationship with Constellation, BGE's carrying of excess cash (at long-term rates) throughout most of the year would reflect an unduly conservative asset management strategy that would likely be considered imprudent. Yet it is not imprudent from the perspective of the corporate whole of Constellation. We are not setting rates for Constellation in this proceeding. We are setting rates for BGE. In doing so, the capital structure utilized for establishing BGE's cost of capital ought to reflect conditions appropriate for BGE. It is an inappropriate regulatory treatment to allow BGE to pass the extra burden placed upon it by its parent on to its ratepayers. These costs are incurred for the benefit of the parent, not BGE, and are a result of a capital borrowing strategy that results in excess cash on hand (carrying long-term rates) that is not used and useful in the provision of utility service. Accordingly, some regulatory device is necessary to unwind what would otherwise be a *de facto* subsidy from BGE ratepayers to Constellation and its unregulated affiliates.

It is entirely appropriate for BGE and Constellation to decide on the capital structure to be used in the consolidated operations. It is similarly appropriate for BGE to participate in Constellation's money pool because the arrangement makes sense from the overall corporate perspective. However, it is clear that BGE's approach to this issue, and involvement in the pool, imposes costs on its ratepayers, which would not occur if BGE were a stand alone gas company. The record indicates that BGE has raised capital at the relatively more expensive rates associated with long-term debt and common equity and has not taken advantage of the relatively less

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expensive short-term debt available to it. This may make sense from an overall holding company perspective, but it creates excess costs for the regulated company whose rates are being determined in this proceeding. The majority decision rendered herein passes on these higher costs to customers.

By virtue of the Commission's Order, BGE will be effectively raising higher cost capital at the higher weighted average cost of capital, recovering these costs from ratepayers, and lending excess funds to its parent at the lower short-term rates. BGE makes capital available to its parent at the considerably lower rates associated with short-term debt; the record indicates that borrowings from the pool occurred at rates as low as 1.5%. Again, this arrangement makes sense from the corporate perspective and BGE and Constellation are free to arrange their affairs in this way. However, the Commission's responsibility is to set just and reasonable rates for customers of BGE. Rates cannot be just and reasonable when BGE fails to avail itself of low cost short-term debt, yet makes excess funds available to its parent at precisely the types of rates which it forgoes on behalf of its customers.

Staff Witness Lee has proposed a ratemaking adjustment to the revenue requirement calculation that has the effect of including a modest short-term debt component in the capital structure. He and others noted in this regard that the capital structure proposed by BGE in this proceeding, in a departure from the prior case (and indeed from all prior cases of which the Commission is aware), no longer includes short-term debt.

Lee's methodology reduces rate base by an amount closely approximating the short-term assets reflected in BGE's books. Lee's methodology addresses the short-term debt concern without imputing short-term debt into a hypothetical capital structure for calculating the Company's weighted average cost of capital.

People's Counsel Witness King proposed a hypothetical capital structure for ratemaking purposes which includes a larger short-term debt component. King's methodology has the effect of reducing the weighted average cost of capital to reflect the inclusion of lower cost short-term debt in the capital structure. Both of these methods do essentially the same thing, and differ primarily in the amount of short-term debt to be imputed. If Lee's rate base and income adjustments are translated into a hypothetical capital structure, he imputes short-term debt at 4.1% of the capital structure of BGE, and reduces the common equity, preferred stock, and long-term debt components by proportionate amounts from the actual capital structure. King's methodology imputes 7.9% of short-term debt into BGE's capital structure.

We conclude that in order for rates to be just and reasonable the adjustment proposed by Staff Witness Lee must be made. Both methods are equally valid means of addressing this situation. Indeed, King's method is the more traditional approach. As was observed in a prior Commission case, in which short-term debt was imputed, there is some difficulty in determining the precise level to be included in the capital structure. [5] (31) Of the two proposals on the record, Lee's is the more conservative. Lee supported his choice of inputs based upon the actual short-term assets on the Company's books. His approach strikes a fair and valid balance, and is a reasonably precise way of analyzing the problem. Having reviewed the analyses of both Lee and King, and contrasting them to the arguments of the Company, we would employ Lee's adjustment in this case.

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The majority's acceptance of the Company's position on this issue will create costs for the ratepayers, which would not occur if BGE were a stand alone gas company. BGE will be raising more higher cost capital than is necessary for daily operations, with the added expense being the cost responsibility of ratepayers, and lending excess funds to other Constellation affiliates at lower short-term rates.

BGE asserts one substantive argument against imputation of short-term debt. In essence the Company argues that its decision to forgo use of short-term instruments was a reasonable exercise of management discretion, and that "[a]t this time, short-term debt is not necessarily cheaper than long-term debt, especially when taking interest rate risk and the flat yield curve into account." While the spread between short-term and long-term rates may have narrowed, it is clear that short-term rates remain below long-term rates. Moreover, while the Company's assertions may well support a conclusion that the portion of the capital structure represented by short-term debt should be less than it would be given larger spreads, it does not support a conclusion that a capital structure with no short-term debt is appropriate. Also, a review of utility rate cases conducted before this Commission over a lengthy time frame indicates that the approved capital structures for ratemaking almost universally include a short-term debt component, in a variety of interest rate environments. Finally, we note that through affiliate participation in the money pool, Con-
stellation employs short-term debt in the operation of its unregulated businesses. As a ratemaking matter, a regulatory treatment that acknowledges the proper function of short-term financing in the gas utility business operations would be appropriate for the benefit of BGE's customers also.

The judicial and regulatory precedents in support of the treatment noted above are quite overwhelming. First, with respect to adopting an alternative hypothetical capital structure, the oft-stated precedent of a general preference for an actual capital structure presupposes the Commission's authority to adopt an alternative, where appropriate. It states a preference for "using the Company's actual capital structure or that structure projected to exist during the rate effective period *absent clear evidence on the record that such a structure will be unnecessarily burdensome to ratepayers*." [6] (32) (emphasis added). Inasmuch as the record demonstrates the excess costs to the utility due to the absence of short-term debt as a part of its capital structure, we suggest our view of the matter is entirely in harmony with this precedent.

The authority of the Commission to utilize a hypothetical capital structure for ratemaking is settled law in Maryland, and is in accord with precedents throughout the country. In *C&P Telephone Co. of Maryland v. PSC (C&P)*, 230 Md. 395 (1962), the utility challenged the authority of the Commission to approve a tax adjustment in a rate case, which action effectively imputed a different capital structure than that which was used by the Company. This case is particularly on point here because C&P had arranged its actual capital structure, which C&P was seeking to have the Commission utilize for ratemaking, for the purpose of conferring a benefit on AT&T, C&P's parent company. C&P argued that the Commission's action invaded the prerogatives of corporate management, and that the Commission could only make such an adjustment on a finding of "abuse of discretion, bad faith or wastefulness." [7] (33) The Court explicitly rejected the Company's argument in upholding the Commission. The Court stated, "[t]he owners and managers of the Company have the right to determine what its debt-equity

ratio should be, but they may not always make the ratepayers foot the bill resulting from the choice." [8] (34)

What is unambiguous from the *C&P* Court's reasoning is that the Commission's authority did not turn on a finding of imprudence. In fact, the Court colorfully expresses support for the Commission's regulatory adjustment to balance consumers' interests with that of the Company.

In *Re Columbia Gas of Maryland, Inc. (Columbia Gas)*, 72 Md. PSC 575 (1981), the Commission applied the balancing test to impute short-term debt into the capital structure of Columbia Gas of Maryland, Inc. (Columbia). In that case, Columbia urged the Commission to accept the Company's projected capital structure for the rate effective period, which did not include short-term debt. Columbia was at the time a wholly owned subsidiary of Columbia Gas System, Inc., and received all of its financing from the parent company. The Commission justified its action on the basis "that short-term debt was a "permanent, although shifting feature, of the CGS [9] (35) capital structure." 72 Md. PSC at 590. Again, as in the *C & P* proceeding, the Commission's decision in *Columbia Gas* to adopt a hypothetical capital structure, and indeed to impute short-term debt into it, was not based upon a finding of imprudence.

The balancing analysis that is being jettisoned by the Commission today is remarkably similar to that followed by federal agencies, and a number of states as well. In *COMSAT v. FCC*, 611 F.2d 883 (1977)(D.C. Circuit), the Court upheld the FCC's authority to impute debt into the capital structure for ratemaking purposes. The Court noted in its decision that " * * * it is well settled in public utility law that it is no interference with this management prerogative for a regulatory commission to impute a hypothetical capital structure, * * *; for that is done merely in pursuance of the Commission's legitimate ratemaking authority." [10] (36) The Court went on to describe a balancing analysis remarkably similar to the approach now being abandoned in Maryland:

> Perhaps the ultimate authority for imputing debt when necessary to protect rate-payers from excessive capital charges is the Supreme Court's statement in *Hope Natural Gas*, that "The rate-making process under the Act, *i.e.*, the fixing of `just and reasonable' rates, involves a balancing of the investor and consumer interests." 320 U.S. at 603, 64 S.Ct. at 288. The equity investor's stake is made less secure as the company's debt rises, but the consumer rate-payer's burden is alleviated. It is these conflicting interests that the Commission is to reconcile. [11] (37)

At the time that *COMSAT* was decided in 1977, the Court noted that the practice of imputing a hypothetical amount of debt was commonplace among state public utility commissions, and the practice had been explicitly approved in twenty-two states and the District of Columbia. [12] (38)

In summary, we acknowledge that the actual capital structure of BGE may be appropriate from the vantage point of the consolidated operations of Constellation and BGE. However, the

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record reveals that while not imprudent, it unreasonably burdens utility ratepayers with excessive costs that are not used in the provision of utility service. As such, an adjustment to the Company's capital structure is in order to reflect consumers' interests. Ultimately, what is absent from today's majority Order is an appreciation of the balancing of investor and consumer interests that is a crucial part of the ratemaking process. The majority's decision today to accept the Company's position, notwithstanding record evidence of the excess cost to customers, is contrary to controlling Maryland precedent. For all these reasons, we respectfully dissent from the Commission's Order in this proceeding.

FOOTNOTES

[1] *Re Baltimore Gas and Electric Company*, 91 Md. PSC 240 (2000).

[2] PUC Article § 4-208 requires the filing of an independent audit opinion with applications for base rate changes by certain public service companies that provide gas or electric services and are subject to a cost allocation manual approved by the Commission.

[3] By Order No. 80245, issued on September 8, 2005, the Commission denied a request for rehearing of Order No. 80072 filed by BGE.

[4] By Order No. 80080, entered on July 6, 2005, the Commission denied requests for reconsideration of Order No. 80076. The Commission also established a procedural schedule in this matter by separate letter issued that same date. By Order No. 80392, issued November 15, 2005, the suspension period was extended for an additional 30 days.

[5] Robert Cooper, Manager of Energy of United States Gypsum Company, which company is a MIG member and also a joint party with MIG, pre-filed testimony but did not appear at the hearings, and therefore his testimony was not admitted into the record.

[6] Pre-filed testimony of Michael Gorman, a consultant and principal in Brubaker and Associates, Inc., was withdrawn prior to hearing by ISG and therefore not admitted into evidence.

[7] As previously noted, the Alliance filed a Motion to Dismiss the proceeding prior to the hearings, which resulted in the application being held in abeyance and setting of a new suspension period.

The Alliance also requested issuance of a subpoena prior to the hearing to compel BGE to present a representative from its independent auditors as a witness at the evidentiary hearings at BGE's expense. By Order No. 80208, issued on August 26, 2005, the Commission granted the Alliance request for issuance of the subpoena conditioned on the Alliance bearing responsibility for the reasonable fees, compensation, and expenses of the witness, which ruling was reaffirmed by Order No. 80259, issued on September 14, 2005, denying reconsideration of Order No. 80208.

[8] On October 11, 2005, BGE filed a Motion for Transcript Corrections. On October 24,

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2005, ISG also filed a Motion to Correct Transcript. As no party has indicated opposition to these Motions, they are hereby granted.

[9] The Electric Customer Choice and Competition Act of 1999, codified in Subtitle 5 of Title 7 of the PUC Article, provided for restructuring of the electric industry in Maryland (PUC Article, §§ 7-501, *et seq.*)

[10] The Company uses the "Modified Massachusetts Formula," which determines the ratio to distribute common regulated utility expenses to gas and electric and is influenced by each business' share of total utility direct labor, depreciation, amortization, and taxes, according to Mr. Castagnera.

[11] Mr. Castagnera contends the Company recovered approximately $116.6 million of $180.7 million total common expenses during the test period.

[12] In several preceding BGE rate cases Case No. 8487, Order No. 70476, 84 Md. PSC 145, 161 (1993); Case No. 8697, Order No. 72269, 86 Md. PSC 378, 384 (1995); Case No. 8725, Order No. 73405, 88 Md. PSC 47, 64 (1997); and Case No. 8829 (Proposed Order of Hearing Examiner), 91 Md. PSC 240, 264 (2000) the Commission utilized a five-year amortization period while allowing full recovery of VSERP costs.

[13] Statement of Financial Accounting Standards No. 71.

[14] Order No. 76260, 91 Md. PSC 240, 244 (2000).

[15] The average net charge-off rate constitutes the ratio of net write-offs to customer revenues, according to Mr. Effron.

[16] 91 Md. PSC 240, 267 (2000).

[17] *Re Baltimore Gas and Electric Company*, 74 Md. PSC 249, 277 (1983); *Re Potomac Electric Power Company*, 74 Md. PSC 70, 98 (1983); *Re Baltimore Gas and Electric Company*, 78 Md. PSC 129, 150 (1987).

[18] These results are labeled "bare bones" because BGE, as will be discussed shortly, also advocates adding a total of 65 basis points to the return on equity to cover flotation costs and good performance recognition.

[19] *See Re Washington Gas Light Company*, 94 Md. PSC 329 (2003).

[20] *See*, for example, *Re WGL, supra*, at 339.

[21] BGE Ex. 16 at 4.

[22] The NCP allocator is based on each sub-class's highest hourly demand during the winter (November-March) months. Each sub-class's contribution to the NCP is calculated by dividing that sub-class's maximum hourly demand during the winter months by the sum of every sub-class's maximum hourly demand. *See* BGE Ex. 16 at 7-9 for a more thorough description of the NCP allocator.

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[23] See *Re Baltimore Gas and Electric Company*, Case No. 8070, 81 Md. PSC 43 (1990).

[24] While Staff only recommended an increase to $12.50 per month, its own calculation of customer costs is approximately $13.00, using Staff's rate of return. (Staff Ex. 8 at 7).

[25] OPC Ex. 5 at 31.

[26] OPC Ex. 5 at 35.

Dissenting Opinion

[1] The actual capital structure is a matter of management prerogative. For ratemaking purposes, the Commission must establish an appropriate capital structure in the context of determining a fair weighted average cost of capital. A Commission determination of an alternative capital structure for ratemaking does not, in any way, invade the right of corporate management to structure itself as it deems appropriate.

[2] *Re Baltimore Gas and Electric Company*, Case No. 8278 (81 Md. PSC 534, 572 (1990)

[3] During the 18-month period from January 1, 2004 through June 30, 2005, BGE borrowed from the money pool for 26 days and loaned money to the pool for 521 days.

[4] By this we mean that it does not appear that BGE's levering itself on behalf of Constellation to the extent that it has in the past, has created undue risks that would impair BGE's overall financial health.

[5] *Re Columbia Gas of Maryland, Inc.*, 72 Md. PSC 575, 590 (1981).

[6] *Re Baltimore Gas and Electric Company*, Case No. 8278 (81 Md. PSC 534, 572 (1990)

[7] 230 Md. at 412.

[8] 230 Md. at 413.

[9] The capital structure of the parent, Columbia Gas Systems, Inc., was utilized as the basis for ratemaking in the case.

[10] 611 F.2d at 903.

[11] 611 F.2d at 904.

[12] Ibid.

EDITOR'S APPENDIX

Citations in Text

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[MD.] Re Baltimore Gas & E. Co., Case No. 9036, Order No. 80259, 96 Md PSC 232, Sept. 14, 2005. [U.S.Sup.Ct.] Bluefield Water Works & Improv. Co. v. West Virginia Pub. Service Commission, 262 U.S. 679, PUR1923D 11, 67 L.Ed. 1176, 43 S.Ct. 675 (1923). [U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281 (1944).

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Endnotes

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38 (Popup)

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Re Baltimore Gas and Electric Company

Case No. 8829
Order No. 76260
203 PUR4th 1

EXHIBIT
RUCD-18
ADMITTED

Maryland Public Service Commission
June 19, 2000

ORDER authorizing a natural gas local distribution company to increase its rates and charges by $6.433 million, reflecting an authorized rate of return on equity (ROE) of 11.05% and an overall rate of return of 8.6061%. The authorized ROE is based on the results of discounted cash flow and other estimation models and includes an upward adjustment of 25 basis points for flotation and a downward adjustment of 50 basis points for reduced risk associated with the operation of a weather normalization rate rider.

The costs of an incentive compensation plan are divided equally between ratepayers and shareholders. Commission explains that full recovery of incentive compensation costs from ratepayers would require a clear demonstration that the goals of the incentive plan benefit ratepayers and that the incentive plan is necessary to raise employees' overall compensation to the market rate.

Commission finds that contributions by the LDC to the Maryland Fuel Fund promote important universal service objectives and are appropriate expenses for rate-making purposes. However, inasmuch as the LDC treats its contribution as a dollar-for-dollar offset to its uncollectible expense, its promotional materials must be clarified to eliminate all references describing the contributions as charitable.

Commission assigns to regulated operations 50% of the profits from appliance repair services provided by an unregulated affiliate of the LDC.

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1. EXPENSES, § 105

[MD.] Incentive compensation — Partial disallowance — Sharing between ratepayers and

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shareholders — Prerequisites to full recovery — Natural gas local distribution company. p. 4.

2. REVENUES, § 12

[MD.] Nonutility business — Appliance repair service — Assignment of 50% of profits to regulated operations — Natural gas local distribution company. p. 5.

3. REVENUES, § 5

[MD.] Natural gas local distribution company — Nonutility business — Appliance repair service — Assignment of 50% of profits to regulated operations. p. 5.

4. EXPENSES, § 126

[MD.] Natural gas local distribution company — Electricity — Purchases from electric division — Combination utility. p. 6.

5. EXPENSES, § 49

[MD.] Postretirement benefits other than pensions — Inflation adjustment — Health care inflation rate — Natural gas local distribution company. p. 7.

6. EXPENSES, § 19

[MD.] Depreciation — Amortization adjustment — Correction of errors — Natural gas local distribution company. p. 7.

7. DEPRECIATION, § 24

[MD.] Calculation of annual depreciation — Factors affecting allowance — Amortization period for personal computers — Natural gas local distribution company. p. 7.

8. EXPENSES, § 20

[MD.] Environmental remediation — Amortization of deferred costs — Natural gas local distribution company. p. 8.

9. EXPENSES, § 125

[MD.] Natural gas local distribution company — Environmental remediation — Amortization of deferred costs. p. 8.

10. EXPENSES, § 125

[MD.] Natural gas local distribution company — Fuel fund credits — Shareholder contributions. p. 8.

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11. EXPENSES, § 46

[MD.] Charitable contributions — Maryland Fuel Fund — Natural gas local distribution company — Discussion. p. 8.

12. EXPENSES, § 118

[MD.] Uncollectibles — Offsets — Maryland Fuel Fund contributions — Natural gas local distribution company. p. 8.

13. RETURN, § 26.4

[MD.] Reasonableness — Cost of equity — Flotation adjustment — Risk adjustment for weather normalization — Natural gas local distribution company. p. 9.

14. RETURN, § 26.4

[MD.] Reasonableness — Cost of equity — Estimation methodologies — Discounted cash flow analysis — Risk adjustment — Natural gas local distribution company. p. 9.

15. RETURN, § 44

[MD.] Reasonableness — Factors considered — Risk — Weather normalization rider — Downward adjustment to cost of equity — Natural gas local distribution company. p. 9.

16. RETURN, § 26.2

[MD.] Reasonableness — Cost of short-term debt — Natural gas local distribution company. p. 10.

17. RATES, § 373

[MD.] Natural gas rate design — Allocation of increase — Minimization of subsidies — Reduction in class and sub-class disparities — Local distribution company. p. 10.

18. RATES, § 384

[MD.] Natural gas rate design — General service — Allocation of increase — Volumetric charge — Double rate increase on tail block — Local distribution company. p. 10.

19. RATES, § 386

[MD.] Natural gas rate design — Industrial customer — Assignment of gas main costs — Direct assignment proposal — Grounds for rejection — Local distribution company. p. 11.

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20. APPORTIONMENT, § 30

[MD.] Natural gas — Distribution costs — Gas mains — Direct assignment proposals — Grounds for rejection — Local distribution company. p. 11.

21. APPORTIONMENT, § 58

[MD.] Natural gas — Distribution costs — Gas mains — Direct assignment proposals — Grounds for rejection — Local distribution company. p. 11.

22. RATES, § 373

[MD.] Natural gas rate design — Cost assignment — Gas main costs — Direct assignment proposal — Grounds for rejection — Local distribution company. p. 11.

23. APPORTIONMENT, § 30

[MD.] Natural gas — Liquified natural gas and propane facilities — Cost functionalization and allocation — Assignment to firm customers — Local distribution company. p. 13.

24. APPORTIONMENT, § 58

[MD.] Natural gas — Liquified natural gas and propane facilities — Cost functionalization and allocation — Assignment to firm customers — Local distribution company. p. 13.

25. RATES, § 373

[MD.] Natural gas rate design — Cost assignment — Liquified natural gas and propane facilities — Assignment to firm customers — Local distribution company. p. 13.

26. RATES, § 384

[MD.] Natural gas rate design — Interruptible service — Usage penalty for failure to interrupt — Crediting of penalty revenues to firm customers — Local distribution company. p. 14.

27. REVENUES, — 5

[MD.] Natural gas — Interruptible service penalties — Credit to firm customers — Local distribution company. p. 14.

28. RATES, § 378

[MD.] Natural gas rate design — Fixed charges — Demand charge — Force majeure clauses — Local distribution company. p. 14.

29. RATES, § 378

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[MD.] Natural gas rate design — Customer charges — Movement toward costs — Avoiding rate shock — Local distribution company. p. 15.

30. RATES, § 385

[MD.] Natural gas rate design — Residential service — Customer charge — Movement toward costs — Avoiding rate shock — Local distribution company. p. 15.

31. RATES, § 384

[MD.] Natural gas rate design — Commercial service — Customer charge — Local distribution company. p. 15.

Before Ivey, Ligon, Brogan, Riley and Curran, III, commissioners.

BY THE COMMISSION:

I. BACKGROUND

On November 17, 1999, Baltimore Gas and Electric Company ("BGE" or "Company") filed an application with the Public Service Commission ("Commission") for authority to increase the Company's base rates for natural gas services. As part of this filing, the Company proposed changes in depreciation and amortization rates. The Company's application, if approved as filed, would increase gas rates by an average of 5.87 percent. The proposed rate increase was to become effective with service rendered on or after December 20, 1999. However, by Order No. 75794, issued November 24, 1999 the Commission suspended the proposed rates for 150 days and assigned this case to the Hearing Examiner Division to hold proceedings to determine the justness and reasonableness of the Company's proposed rates.

Initially, BGE requested a $36.3 million increase in its base rates for gas service to enable the Company to earn a 9.7 percent overall rate of return. On February 10, 2000, and thereafter on March 15, 2000, the Company reduced its request ultimately to $30.1 million. The Company proposed an across-the-board allocation of the rate increase, including increases to customer charges. A pre-hearing conference was held by the Hearing Examiner on December 14, 1999, at which time the Commission Staff ("Staff") and the Office of People's Counsel ("OPC") entered their appearances. Additionally, the following parties were granted leave to intervene: the Department of Defense/Federal Executive Agencies ("DOD"); the Building Owners and Managers Association of Metropolitan Baltimore, Inc. ("BOMA"); the Maryland Industrial Group/Millenium Inorganic Chemicals, Inc. ("MIG"); and Bethlehem Steel Corporation ("Bethlehem" or "Bethlehem Steel").

Testimony was filed by the parties and hearings were held in this case on January 11, 12, and 19, 2000, February 8-9, 2000, and March 13, 15, and 16, 2000. Hearings were also held in the

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evening in Annapolis, Baltimore and Bel Air, Maryland on February 22, 23 and 24, 2000 respectively to receive public comments in this matter. Initial Briefs were filed on March 31, 2000 and Reply Briefs were filed on April 1, 2000. (The Hearing Examiner, based upon an objection filed by Bethlehem Steel, struck Attachment 1 of BOMA's Initial Brief). On April 11, 2000, the Commission extended the suspension period for an additional 30 days.

On April 21, 2000, a Proposed Order of Hearing Examiner was issued in this proceeding. The Hearing Examiner determined that BGE's gas revenue requirement should be raised by $5.098 million based upon an overall rate of return of 8.71 percent. On April 27, 2000, BGE filed a Motion to Correct Errors, Seek Clarification and Request for Expedited Responses and Ruling. The Company's Motion detailed six issues requiring clarification or correction.[1(1)] Thereafter, on May 5, 2000, the Hearing Examiner issued an Order in response to the Motion resulting in an increase to the Company's gas rate base of $2.860 million. The corrected Order reflected BGE's investment in Home Products and Services ("HP&S/BGE Home") as well as an adjustment to net operating income of $1.102 million to reflect to accept for depreciation corrections. The Hearing Examiner determined that an increase in gas rates of $7.792 million was necessary in order to produce just and reasonable rates for BGE's gas service.

BGE, OPC, Staff, BOMA, MIG, DOD and Bethlehem Steel all filed appeals to the Proposed Order of Hearing Examiner on or before May 19, 2000. BGE appealed the Hearing Examiner's determinations regarding: the treatment of costs of BGE's Results Incentive Award Program; inclusion of HP&S/BGE Home revenues in BGE's revenue requirement; the appropriate rate of return; allocation of LNG and propane facilities; treatment of interdepartmental electric sales rates; and an adjustment for post-retirement and post-employment benefit expense.

Other parties raised the following issues. OPC appealed the Hearing Examiner's determinations regarding: unamortized deferred environmental costs; unrecognized correction of depreciation rate errors; the return on equity; and the treatment of fuel fund contributions. BOMA sought modification or reversal of the Hearing Examiner's decisions regarding: the commercial Customer Charge; the treatment of revenues collected under BGE's interruptible penalty structure; and the effect of Rider 8 on the return on equity. MIG appealed the Hearing Examiner's determinations regarding: the allocation of LNG and propane facilities costs to interruptible customers; the assignment of the cost of new service mains to all customers, including interruptible customers; the penalty structure for interruptible customers; and the force majeure clause. Bethlehem Steel appealed the Hearing Examiner's determinations regarding: direct assignment of the Manor Line; assignment of the cost of new service mains to non-firm customers; and assignment of the costs of LNG and propane facilities. DOD appealed the Hearing Examiner's determination regarding allocation of the Company's revenue requirement increase to the Schedule C volumetric charge. Finally, Staff challenged the Hearing Examiner's determinations regarding a separate depreciation proceeding, BGE's ongoing amortization of environmental costs, and the return on equity. Each of these parties filed reply memoranda.

II. APPEAL ISSUES

A. Cost of Service

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1. *Results Incentive Award Program*

[1] In its appeal of the Proposed Order of Hearing Examiner, BGE argued that the Hearing Examiner's disallowance of one-half of all costs of the Results Incentive Award Program ("RIA") was contrary to the evidence and contrary to Commission precedent. The Company argued that the RIA Program is part of its overall employee compensation package and not a bonus or additive to compensation.[2(2)] Rather, the Company asserted that the RIA program motivates employees to meet goals that benefit the Company, shareholders and ratepayers. According to BGE, the Hearing Examiner's decision is inconsistent with prior Commission treatment of other similar incentive plans.

BGE asserted that this represents "the single most important policy issue presented by this case."[3(3)] The Company stated that:

> The implications of this decision are enormous and will not only affect BGE Gas Division's ability to attract and retain personnel, it will also affect fundamental salary decisions by the management of BGE's Electric Transmission and Distribution Division and every other investor-owned utility in the State of Maryland, including gas, electric and telecommunications companies.[4(4)]

The Company argued that "[i]n conjunction with the employee's base salary, the RIA enables the employee to receive total compensation that is competitive in the marketplace, and ensures that the Company can attract highly qualified personnel.[5(5)] BGE argued that the RIA program places a portion of employee compensation at risk and that shareholders should not be penalized for utilizing such a program.

The Company argued further that:

> By declaring that an element of employee compensation is not fully recoverable from ratepayers, the Hearing Examiner's decision will hamper the Company's ability to balance the important goals of compensating employees in a manner that is competitive with other employers and providing employees with an incentive to perform efficiently.[6(6)]

Staff argued, however, that nothing in the record supports BGE's contention that RIA is part of employees' base salary that is at risk.[7(7)] Staff believed that these awards are in addition to employees' base salary. Further, Staff commented that when it requested a description of the goals and objectives that would result in an RIA award, the Company was less than forthcoming in providing acceptable responses.[8(8)] Staff therefore concluded that there was a lack of "\&... a clear showing that the objectives that resulted in receiving these awards had in fact been beneficial to ratepayers."[9(9)]

On the one hand, according to the Company, the RIA is intended to "show gain for the

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Company, its customer and shareholders" by placing an employee's overall compensation "at risk." Under this scenario, the RIA might be used by the Company in providing competitive wages for its employees and could be appropriately charged solely to ratepayers. Moreover, the Company correctly noted that RIA costs have been included as operating expenses in previous rate cases.

On the other hand, RIA was not a contested matter in those previous rate cases. Furthermore, the evidence does not support the Company's position in this case. Company Witness Hasselbarth's testimony contained only one example of an RIA: that of an employee closing the Company's books early for the Board of Directors' Meeting. While this example may show a benefit to the shareholders, it fails to demonstrate a direct benefit to the ratepayers. Finally, the record showed that salaries were adjusted by the Company to "competitive levels" in 1998. The RIA predates that increase, and there is no evidence, based on Company-offered studies, that wages, without the RIA, are not competitive.

Therefore, we uphold the Hearing Examiner's reasoned decision in this regard. On the existing record, we find that the costs should be divided equally between ratepayers and shareholders. In the future, if the Company seeks full recovery of RIA costs from ratepayers, the Company must clearly demonstrate that the goals employees are expected to achieve would clearly benefit ratepayers and that the award would be necessary to raise employees' overall compensation to the market rate.

2. *Inclusion of HP&S Revenues in BGE's Revenue Requirement*

[2, 3] BGE appealed the Hearing Examiner's above the line assignment of 50 percent of the profits from the appliance repair service provided by HP&S. The Hearing Examiner's treatment of this matter is a continuation from the Commission's ruling in Case No. 8697.

BGE argued, that in Case No. 8697, the Commission justified its decision by citing a lack of evidence to support a change in policy and the difficulty in quantifying benefits received by HP&S/BGE Home. According to BGE, the development and use of the Company's Cost Allocation Manual ("CAM"), that provides accounting recognition for use and exchange of resources between the Company and its affiliate, should be viewed as having satisfactorily resolved this issue. BGE argued that HP&S/BGE Home is an independent, unregulated company that utilizes and pays for services from BGE in accordance with the CAM.

OPC, on the other hand, argued that a strong nexus exists between BGE and HP&S/BGE Home that warrants continued assignment of profits to the Company. As proof, OPC emphasized that HP&S/BGE Home uses the Company's bill for billing customers. The Company argued that the Hearing Examiner improperly relied on OPC's contention that HP&S/BGE Home's use of BGE's bill represents a strong connection to BGE. In response, OPC asserted that the fact the Company has filed a CAM does not, in and of itself, diminish the connection between the Company and its affiliate.[10(10)]

The Commission adopts the Hearing Examiner's determination on this matter. As noted in the Proposed Order, the difficulty observed by the Commission in Case No. 8697, remains with regard to quantifying HP&S/BGE Home's profits that should be treated above-the-line. The

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Commission is persuaded by OPC's arguments that the continued use of BGE's bill by HP&S/BGE Home maintains a strong connection that clearly benefits HP&S/BGE Home. The Hearing Examiner's finding that the Company's general telephone number leads callers to a "BGE Home" option, is also compelling support for his decision.

Although it was expected that the Company's cost allocation manual process might sufficiently eliminate cross-subsidization in the future, such appears to not be the case at present. Therefore, the Commission continues to find that above-the-line assignment of 50 percent of the profits from the appliance repair service is appropriate.

3. *Interdepartmental Sales Rates*

[4] BGE stated that it proposed to replace its interdepartmental sales rates for electricity with current tariff prices in compliance with Order No. 72269 in Case No. 8697. This would increase the Gas Division's expenses. Virtually, all other parties argued this would create a windfall (due to capped rates) for the Electric Division. Thereafter, the Company modified its proposal to recognize only a $501,689 adjustment to eliminate the "windfall." On July 1, 2000, electric power purchases will become market-based transactions. BGE argued that the Hearing Examiner erred in rejecting this adjustment because the Company will be denied the opportunity to recover a known and appropriate expense.

In deciding this issue, the Hearing Examiner noted that BGE estimated that the increase in expense to be recovered by the Gas Division through use of tariff rates is $1.05 million. He stated that BGE appears to have read into Order No. 72269 in Case No. 8697 a non-existent requirement for arms-length pricing by BGE's electric division to its gas division, something it did not pursue immediately after issuance of the Order in 1995. Also, according to the Hearing Examiner, the Company has not thought through the implications for electric ratepayers. Moreover, Staff argued that the record includes the Company's admission that it has no demand meters in place to accurately measure electric demand, no plans to install such meters, and no plans to bid out the Gas Division's electricity requirements in the future.

The Commission agrees with the Hearing Examiner's conclusion that BGE failed to produce sufficient evidence to warrant its proposed adjustment. Thus, the Hearing Examiner's decision on this matter is affirmed.

4. *Adjustment for Post Retirement and Employment Expenses*

[5] BGE argued that the Hearing Examiner erred by using Staff's 4.5 percent health care inflation rate rather than the Company's proposed 7.5 percent rate.[11(11)] According to the Company, the Hearing Examiner adopted Staff's adjustment based on the arguments made by Staff in its Initial Brief and that there was no record evidence to support Staff's adjustment. According to the Company, its proposed 7.5 percent rate is based on surveys by three national benefits and actuarial consulting firms.[12(12)]

Staff challenged the Company's assertion that the basis for its adjustment was first introduced

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in its initial brief. According to Staff, the adjustment was in fact based on record evidence, *i.e.*, the testimony of Staff Witness Allen. Staff Witness Allen showed that the historical and projected health care inflation rate trend ranged from 3.55 percent in 1996 to 4.52 percent in 2005.[13(13)] He also noted that the 7.5 percent rate proposed by the Company in this case is contradicted by BGE's own published estimate of 6.0 percent in its 1999 Annual Report to Shareholders.

The Commission finds that the Hearing Examiner's reliance on Staff's position on this issue is appropriate. The rate that Staff assigned is sufficient to accommodate the Company's historic rate of growth. The Commission believes that acceptance of the Company's position would unnecessarily inflate BGE's health care cost recovery.

5. *Depreciation*

[6, 7] BGE proposed new depreciation rates for the Company's gas and common plant. As a result, the Company proposed an increase in depreciation expense from $31,557,000 to $34,800,000 for the rate effective period. Staff objected to the Hearing Examiner's consideration of depreciation in the case at all. Staff also argued that the matter was compounded by the Hearing Examiner's decision to decrease the Company's amortization period for personal computers.[14(14)]

According to Staff, the present eight-year amortization period represents the period over which the Company's personal computers
would have been used had BGE not decided to retire them early.[15(15)] Staff contended that, during the proceedings, BGE failed to explain why it expended funds for personal computers in 1998 when the Company "expected to initiate a personal computer leasing program [on] January 1, 1999."[16(16)]

OPC also appealed the Hearing Examiner's treatment of depreciation. According to OPC, the Company's depreciation study was fraught with errors, some of which the Company acknowledged. According to OPC, the Company acknowledged errors that, when accounted for, reduced the Company's revenue requirement by $975,000.[17(17)] OPC asserted that evidence of these errors could lead to the logical conclusion that depreciation expense is overstated due to other accounts having inappropriate methodologies or accounting errors.[18(18)] OPC argued that "without adjusting [the Company's] present depreciation accrual rate to remedy [BGE's] errors, the error[s] will be carried on in the Company's rates indefinitely until a new depreciation study by BGE is performed and reviewed."[19(19)]

The Hearing Examiner declined to adopt the Company's depreciation rates stating that "\&... there is no convincing rationale or need at this time for changing BGE's overall depreciation schedule or requiring the Company to begin an expensive and time-consuming depreciation study."[20(20)] The Commission concurs and adopts the Hearing Examiner's determination of this issue. As determined by the Hearing Examiner, the Company's depreciation rates for gas and common plant shall remain unchanged, except for the computer amortization adjustment and corrections for errors.

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The Hearing Examiner adopted a reduced amortization period for the Gas Division's personal computers. He noted that the five-year amortization period being adopted had been proposed by OPC in the Company's previous rate case. That conclusion was not challenged by OPC. Based on the Company's planned change over to a personal computer leasing program and proposals in the Company's previous rate case to apply a five-year amortization period to this equipment, the Commission finds the Hearing Examiner's determination reasonable.

6. *Environmental Costs*

[8, 9] In Case No. 8697, the Commission allowed BGE to change its amortization of deferred environmental costs prospectively.[21(21)] In the instant case, BGE is seeking to recover all environmental clean-up costs incurred in the rate effective period in Case No. 8697. The Hearing Examiner noted that BGE reduced test year operating income by $386,000 consistent with amortization of clean-up costs prior to November 1995.

According to the Hearing Examiner, Case No. 8697 "clearly indicates that amortization of known and measurable Spring Garden environmental clean-up costs is appropriate."[22(22)] In response to Case No. 8697, the Company reversed the $5,246,824 of environmental expenses previously amortized over a different time period and began amortizing those costs over 10 years.

Staff argued that the Hearing Examiner erred in adopting BGE's approach to adjusting test year rate base and operating income for environmental clean-up costs incurred from November 1, 1995 through May 31, 2000. Staff proposed rate base and operating income adjustments to remove post-October 1995 clean-up costs from the test year. According to Staff, accepted accounting practices require post-October 1995 costs to be expensed as incurred. Staff also argued that to permit BGE to amortize them when it unilaterally chose to defer these costs, since no regulatory asset was created, constitutes retroactive ratemaking.

OPC argued that BGE's proposal to reflect the unamortized deferred environmental cost in rates should be rejected as retroactive ratemaking. In addition, OPC argued that the Company's failure to follow proper accounting methods resulted in an understatement in the accumulated amortization of environmental costs.

The Commission adopts the Hearing Examiner's decision on this matter. The Commission finds that the Company's environmental clean-up costs are known and reasonable and in conformance with Commission policy. As noted by the parties, this issue was addressed in Case No. 8697, which allowed environmental clean-up costs. However, as recommended by DOD, such costs were limited to those incurred up to the date of the issuance of the Commission's Order in Case No. 8697, but the Company was not denied the opportunity to recover amortized environmental costs in future rate cases. The Hearing Examiner's finding on this issue is therefore affirmed.

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7. *Fuel Fund Contributions*

[10-12] OPC asserted that the Hearing Examiner's reasoning regarding the treatment of Fuel Fund contributions is internally inconsistent and should be overturned on appeal. Both Staff and OPC argued that the Company's fuel fund "credits" are charitable donations and relied on the Company's fliers to support this proposition. OPC asserts that the Hearing Examiner determined that these fuel fund contributions are charitable contributions and as such should be excluded from cost-of-service. The Hearing Examiner noted that BGE granted $1 million in fuel fund credits to the Maryland Fuel Fund in 1999 to match money contributed by others (generally ratepayers). Since fuel fund credits reduce the arrearages of low-income customers, BGE treats Fuel Fund credits as an off-set against the Company's uncollectible balance.

In the Proposed Order, the Hearing Examiner stated that BGE's Fuel Fund contributions appear essentially to be a voluntary relinquishment of the right to receive payments, *i.e.*, charitable contributions.[23(23)] However, the Hearing Examiner resolved the matter by requiring BGE to clarify its public references to and solicitations regarding the Fuel Fund rather than disallowing the expenses."[24(24)]

The Commission agrees with the Hearing Examiner that the Company's contributions to the Fuel Fund, in whatever form, promote important universal service objectives and are appropriate Company expenses. It appears, however, that the Company's treatment of these funds is not truly charitable. Instead, the Company's contribution is a dollar for dollar offset of its uncollectible expense. Since uncol- lectibles is an above-the-line expense, the Company treats its fuel fund contribution likewise as an above-the-line expense.

There does appear to be an inconsistency between the Company's treatment of these amounts and the representations made in Fuel Fund solicitations and fliers. In order to avoid misleading consumers, the Company may contribute shareholder funds as a match for customer contributions to the Fuel Fund. Under that scenario, the Company's existing promotion of the program would be appropriate. However, if the Company declines to contribute shareholder funds to the program, its promotional material must be clarified to eliminate all references describing the Company's contribution as charitable.

B. Rate of Return

1. *Return on Equity*

[13-15] In this case, the Hearing Examiner adopted an 8.71 percent overall rate of return for the Company's gas operations based on an 11.3 percent rate of return on equity ("ROE"). BGE argued that the Hearing Examiner's determinations are at odds with the reality of current financial markets.[25(25)] The Company advocated a 12.75 percent ROE and an overall rate of return of 9.70 percent.

Staff argued that the 11.3 percent ROE authorized by the Hearing Examiner is excessive because it fails to adequately compensate ratepayers for BGE's reduced risk resulting from

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operation of Rider 8. Staff recommended a 100 basis point reduction to 10.3 percent. Staff stated that "Rider 8 acts as a guarantee that the Company will receive 100 percent of the portion of its revenue requirement, constituting the vast majority of revenues, allocated to firm service customers."[26(26)] Staff noted, however, that the Hearing Examiner properly recognized that Rider 8 undermines any justification for an attrition adjustment, as proposed by BGE. Nonetheless, according to Staff, after the Hearing Examiner recognized that Rider 8 provides substantial benefits to BGE, he failed to incorporate any real recognition of this value in his ROE determination.

OPC also criticized the Hearing Examiner's return on equity determination. Like Staff, OPC argued that Rider 8 should have had a greater downward impact on the Hearing Examiner's determination. OPC submitted that the Company's return on equity should not be more than 10.75 percent. OPC argued that while the Proposed Order has an extensive discussion of the parties' positions, it "is devoid of any methodology or reasoning justifying the selection of 11.3 percent as the appropriate return-on-equity."[27(27)] In his return on equity analysis, OPC witness Hill included an additional 25 basis points for flotation costs. However, OPC argued that floatation costs are offset by the effect of Rider 8 benefits to BGE.

BOMA was also among the parties that argued that Rider 8 guarantees the Company recovery of its revenue requirement.[28(28)] BOMA noted that, while recognizing Rider 8, the Hearing Examiner failed to quantify an appropriate reduction in risk.

By contrast, the Company complained that the Hearing Examiner should not have considered Rider 8 at all in calculating the ROE. According to BGE, the principal effect of Rider 8 is to smooth out revenue effects that would otherwise occur due to changes in weather.[29(29)] BGE argued that the Hearing Examiner reduced the ROE by an unspecified amount due to Rider 8 and that contrary to the record, the Hearing Examiner concluded that Rider 8 gives BGE a guarantee of earning its return. The Hearing Examiner stated in the Proposed Order that he agreed with the parties that BGE's ROE must recognize some increased level of security due to Rider 8, but he rejected Staff's 100 basis point reduction as unjustified. The Hearing Examiner concluded:

> In an attempt to balance the greater security BGE receives from Rider 8 against the Company's revenue needs, I shall assign the Company's common equity a rate of 11.30 percent. The rate of return approved herein reflects the stabilizing effect of Rider 8 without the need to "objectify" the effect of Rider 8 through an additional downward adjustment.[30(30)]

BGE also challenged the Hearing Examiner's ROE determination as "[c]ontrary to clear and longstanding Commission precedent for failing to adjust ROE for flotation costs."[31(31)]

Based on a review of the record in this case, the Commission determines that the appropriate return on equity for BGE at this time is 11.05 percent. This rate will allow the Company to attract the capital necessary for its operations and will allow a fair and reasonable return to investors.

As noted by the Hearing Examiner, the Commission has expressed in the past a preference

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for the use of discounted cash flow ("DCF") analyses to predict the level of return that investors require on their equity investments. However, the Commission recognizes that other methodologies, including comparable earnings, risk premium, and capital asset pricing models, and their results were presented in this proceeding. The Commission finds that the DCF results of each of the parties is within a range of reasonableness. Staff's DCF calculation based on an analysis of seven comparable companies produced an 11.3 percent ROE.[32(32)] OPC developed a DCF-based ROE of 10.50 percent to 11 percent, plus a 25 basis point adjustment for flotation costs, and recommended the lower amount of 10.75 percent. BGE proposed an ROE of 12.75 percent although its unadjusted DCF ROE was 11.17.[33(33)] The Commission finds Staff's unadjusted DCF result, albeit at the high end of the range, is reasonable.

The Commission also agrees with BGE, OPC and BOMA that a flotation adjustment is necessary. OPC proposed a flotation adjustment of the magnitude of 25 basis points. BGE appeared to embrace this adjustment in its Notice of Appeal.[34(34)] This increases the return on equity to 11.55 percent.

The Commission agrees with Staff, OPC and BOMA that Rider 8 operates to reduce the Company's risk and therefore should be considered in determining the Company's return on equity. Based on the arguments of the parties, the Commission believes a 50 basis point downward adjustment is appropriate. As a result, the return on equity determination in this case is 11.05 percent.

2. *Short-Term Debt*

[16] BGE noted that the Hearing Examiner used a cost for short-term debt of 4.77 percent. According to the Company, its short-term debt rate is 5.34 percent. OPC, Staff, DOD, and MIG all used BGE's actual cost rate in September of 1999, which was 5.34 percent. The Commission finds that the Company is correct and that the appropriate cost of short-term debt is 5.34 percent.

C. Cost Allocation and Rate Design

[17, 18] BGE proposed an across-the-board allocation of any rate increase to firm and interruptible customers. BGE's rate design method is based on the principle that rate classes and sub-classes should provide BGE a return as close to the overall return as possible. According to the Hearing Examiner, no party objected to the Company's allocation to firm customers. For interruptible classes, however, BGE proposed a two-step allocation. First, an increase of $243,735 for auto-interruptible service ("AIS") customers and a decrease of $503,476 in revenue from Bethlehem Steel. The Hearing Examiner stated that these adjustments were designed to bring the return of AIS and Bethlehem Steel closer to the Gas Division's overall rate of return.[35(35)] The second step was to raise the tail-block of Schedule C of the GS class by twice the percentage of the initial-block.

1. *Schedule C — Volumetric Charge*

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In the Proposed Order, the Hearing Examiner adopted BGE's proposal to impose double the rate increase on the tail-block relative to the initial-rate block of Schedule C of the General Service ("GS") class. According to the Proposed Order, BGE justified this by noting that its adjusted 1998 cost of service study shows that Schedule C returns only 75 percent of the return assigned to other sub-classes of the GS class.[36(36)] According to the Hearing Examiner, BGE is attempting to drive both class and sub-class rates of return toward unity in its proposed rate design.[37(37)] DOD appealed the finding of the Hearing Examiner and argued that BGE's proposal should be rejected. According to DOD, to the extent any rate increase is necessary, it should be apportioned based upon an equal percentage rate increase for both volumetric blocks of Schedule C of the GS class.[38(38)]

It is the Commission's policy to reduce class and sub-class rate design disparities, when appropriate. This minimizes or avoids any class having to subsidize the rates of another. Therefore, the Commission will affirm the Hearing Examiner's decision on this matter.

2. *Direct Assignment of Manor Line*

[19-22] Although BGE proposed to decrease Bethlehem Steel's cost responsibility for any rate increase, Bethlehem Steel nonetheless argued that at least $2 million of any rate increase should be shifted away from Bethlehem Steel to other rate classes. Bethlehem Steel's methodology for doing this would be to receive direct allocation of the cost of the Manor Line gas main rather than bearing a share of BGE's overall system costs. Alternatively, Bethlehem Steel proposed the allocation of costs for only those mains that are of sufficient size and pressure to provide service to Bethlehem Steel.

Bethlehem Steel asserted that the direct assignment of the Manor Line was first proposed in Case No. 8697. In that case, BGE testified that Bethlehem Steel is served from the Manor Line and sought to directly assign the reconstruction cost of the Manor Line to Bethlehem Steel. Bethlehem Steel did a cost analysis based on the actual cost of the Manor Line and concluded that with adjustments, the analysis purported to show that Bethlehem Steel is paying rates that are $4.3 million in excess of the cost to serve Bethlehem Steel. Although BGE proposed to decrease Bethlehem Steel's cost responsibility, Bethlehem Steel nonetheless argued that at least $2 million of any revenue increase should be shifted away from Bethlehem Steel to other rate classes.

Bethlehem Steel argued that while the Hearing Examiner concluded that the effect of this proposal on the rates of other classes was unclear, Bethlehem Steel testified that the effect on other customer classes was minor. For these reasons, Bethlehem Steel asserted that the Commission should require BGE to allocate costs to Bethlehem Steel based on a direct allocation of Manor Line costs and reduce Bethlehem Steel's rates by at least $2 million in this case.

As an alternative cost of service approach, Bethlehem Steel advocated allocating only the costs for large mains to Bethlehem Steel. Bethlehem Steel stated that this can be accomplished in

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three ways, by allocating to Bethlehem Steel only its appropriate share of BGE's: 1) Over High Pressure System; or 2) transmission system (which contains the Over High Pressure System); or 3) mains above 12" in diameter constructed of steel (*i.e.*, only 30 percent of BGE's investment in pipes). Based on an analysis of this data, Bethlehem Steel concluded that it is paying rates approximately $4.1 million higher than cost.[39(39)] Bethlehem Steel noted that most of BGE's gas mains are too small to serve Bethlehem Steel. Bethlehem Steel argued that BGE should be directed to allocate to Bethlehem Steel only the cost of mains that are of sufficient size and pressure to provide service to Bethlehem Steel. By analogy, just as BGE does not allocate its production and storage costs to Bethlehem Steel because these facilities are not used by the Sparrows Point Plant, methods that allocate small low pressure pipes to Bethlehem Steel are erroneous.

According to BGE testimony in Case No. 8697, Bethlehem Steel takes 96 percent of its gas by way of the Manor Line and this direct supply is unique on BGE's otherwise fully integrated distribution system. In this case, BGE supported this Cost of Service treatment for Bethlehem Steel, but asserts that current replacement cost, less system average depreciation, is the appropriate amount to use for a direct assignment of the Manor Line.[40(40)] BGE, however, advocated that the Commission examine this proposal in a separate Cost of Service proceeding.

Staff argued that the Manor Line was not developed exclusively to serve Bethlehem Steel, rather it is part of the Company's integrated distribution system and serves many other customers.[41(41)] OPC noted that this issue was resolved by the Commission, against Bethlehem Steel, in Case No. 8697.[42(42)]

BOMA noted Company Witness DeWitt's testimony on this matter, *i.e.*, that the Manor Line serves purposes other than providing service to Bethlehem Steel. The taps on the Manor Line serve the Company's general distribution load and assist the Company in providing interruptible service.[43(43)] BOMA also noted that although Bethlehem Steel is an interruptible customer, " \&... it has not been interrupted for four years."[44(44)] Consequently, according to BOMA, Bethlehem Steel actually enjoys "exponentially lower rates than the firm customers it believes should absorb [the cost of its proposed rate reduction]"[45(45)]

In response to Bethlehem Steel's cost allocation proposal, MIG pointed out that the Manor Line main was constructed in the mid-1950s and has been part of the Company's integrated rate base ever since.[46(46)] MIG also noted that prior to Case No. 8697, no effort had been made by Bethlehem Steel to seek direct assignment.[47(47)]

The Commission adopts the Hearing Examiner's decision on this matter. Although the discussion of this matter apparently consumed a great deal of time during the proceedings, the Hearing Examiner's finding is simple and accurate, is based on the record, and reflects the Commission's long-standing recognition of the Company's gas distribution system as an integrated system.

According to the Hearing Examiner:

> 1) the [Manor Line] was not specifically built for Bethlehem Steel; 2) other customers are served by the line; 3) the line was constructed to serve as an integrated part of BGE's

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distribution system; 4) direct responsibility for maintenance or replacement costs are not assigned to Bethlehem Steel; 5) Bethlehem Steel has no control over the line; and 6) Bethlehem Steel has no long-term commitment to pay the cost of the line if it leaves the system.[48(48)]

The Hearing Examiner concluded that Bethlehem Steel has raised significant, but not new issues. The Commission believes that these issues should be considered after a full investigation of the facts and of the implication of any proposed changes.

3. *Direct Assignment of New Service Mains*

In its initial proposal, BGE requested authority to assign $47.3 million in costs associated with investment in new service mains (in 1997 and 1998) to residential and GS customers only. The Hearing Examiner denied the Company's request and assigned these costs to all customer classes.[49(49)] BGE did not appeal the Hearing Examiner's decision. MIG, however, did.[50(50)]

According to MIG, BGE's proposal to directly assign these costs to firm service customers comports with generally accepted cost allocation principles and long-standing precedent.[51(51)] MIG emphasized that BGE's Witness DeWitt testified that "a direct assignment methodology produces a better link between cost and cost causation in those instances where the investment can be specifically identified with a specific customer.[52(52)] " Staff, OPC and BOMA opposed the Company's proposal and MIG's endorsement of it.

In addition to its argument that BGE's distribution system is an integrated one, where costs and benefits should generally be allocated to all customer classes, Staff argued that direct assignment is generally appropriate for a "lateral extension" dedicated to the service of a specific customer rather than expansion of the system as a whole.[53(53)]

BOMA emphasized that "it is an undisputed fact that BGE operates its distribution system as an integrated whole and that, consistent with that theory, these costs should be shared by all customer classes to ensure that each receives both the benefits of fully depreciated investment and the higher cost of new construction."[54(54)]

OPC also opposed MIG's and Bethlehem Steel's support for direct assignment of new main costs.[55(55)] OPC argued, however, that there is no need for the Commission to resolve the issue in this case. According to OPC, the Commission should merely leave the issue open for resolution in future proceedings.[56(56)] As noted above, BOMA opposed the BGE direct assignment of new main costs to firm and GS customers on evidentiary grounds. BOMA disagreed with OPC's assertion that a Commission conclusion on this issue is not needed in this case.[57(57)]

On this point, the Hearing Examiner is affirmed. BGE's proposal to assign all of the costs of its new service mains to firm customers only defies the fundamental notion that its gas system is an integrated system that in almost every aspect serves both firm and interruptible customers alike. Moreover, the Commission agrees with Staff and BOMA that the cost of new mains should be shared by all customer classes to ensure that each receives the benefits and burdens of

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these investments.

4. *Allocation of LNG and Propane Facilities*

[23-25] BGE proposed to classify liquefied natural gas ("LNG") and propane peak-shaving facilities as production and storage facilities and to assign their cost recovery solely to firm customers. The Company proposed to functionalize LNG and propane peak shaving facilities as production and storage related, and to allocate the costs on a class contribution to peak day.[58(58)] MIG and Bethlehem Steel supported BGE's position. BOMA opposed it.

The Hearing Examiner denied BGE's request to recover all LNG and propane costs from firm customers, and instead determined that both firm and interruptible customers should bear the cost of the Company's LNG and propane plant. Further, he determined that the interruptible class should bear costs proportionate to its use of those facilities.[59(59)]

In response, BGE argued that the Hearing Examiner essentially misinterpreted the record, specifically its witnesses' testimony. On some days when interruptible customers delivered their own gas, BGE simultaneously made the economic decision on behalf of firm service sales to substitute LNG or propane for more expensive pipeline supply. BGE stated that LNG and propane peak-shaving facilities provide no benefit to interruptible customers. BGE submitted that operating LNG and propane facilities for the economic benefit of firm customers cannot be used as the basis for allocating costs to interruptible customers.

MIG argued that LNG and propane facilities have two functions: (1) to augment BGE's ability to meet distribution design day capacity needs of firm service customers; and (2) to allow BGE to provide an economic benefit to firm service customers by using these facilities to supply system load when the cost of natural gas is higher. Also, interruptible service and AIS customers must install alternate fuel capability and must use it during periods of interruption. BGE functionalizes these facilities as production and storage related and allocates them to firm customers. MIG asserted that BOMA "unjustifiably relied on a BGE data response to draw incorrect inferences that caused the Hearing Examiner to mistakenly believe interruptible service customers use LNG and propane facilities."[60(60)] MIG argued that the use of LNG and propane facilities on certain cold days was solely to give firm customers an economic benefit. "The fact that BGE was delivering customer owned `transportation gas' at the same time is a coincidence without significance."[61(61)]

The Commission agrees that interruptible customers should not bear part of the cost of LNG and propane facilities. As BGE stated, its proposal to functionalize LNG and propane facilities as production and storage related and allocate by peak day is reasonable and equitable, and should be continued. Therefore, no part of these costs should be allocated to interruptible customers.

The Commission notes that in reaching his decision to assign a portion of cost to interruptible customers, the Hearing Examiner relied on the Company's admission that in fact interruptible customers have indeed used the LNG and propane facilities on "very cold days."[62(62)] While this testimony is not dispositive of this issue, it does raise serious concerns regarding the Company's adherence to gas facilities' design and use policies and practices, and

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the economic considerations used in formulating interruptible customer rates. Thus, although the Commission declines to apportion LNG and propane facilities costs to interruptible customers at this time, the Commission, hereby, directs Staff to fully investigate the historic and recent use of the Company's LNG and propane facilities by firm and interruptible customers. Further, Staff shall investigate the economic dispatch of these facilities as discussed by the Company. Staff shall report its findings, along with appropriate recommendations, to the Commission on or before October 1, 2000.

5. *Interruptible Service Penalties*

[26, 27] BGE's filing proposed to implement an unauthorized usage penalty on interruptible customers who fail to interrupt their gas service when told to do so. Under existing tariffs, interruptible service customers pay a penalty if they fail to interrupt as required. MIG argued that BGE failed to show that the existing penalty is not an adequate deterrent, and that BGE's proposed new penalties — 2.4 times the standard demand charge for every dth of billing demand during the ensuing 12 months — are disproportionate to the infraction being penalized. The Hearing Examiner agreed that there has to be proportionality for penalties. Therefore, the Proposed Order permits the Company's requested penalty, with a two-step modification in an attempt to distinguish between small and large usage during times of interruption and whether the infraction is intentional or accidental. MIG argued that even this is not justifiable. MIG concluded that BGE has failed to satisfy the requisite statutory burden for changing the existing penalty.

BOMA noted that interruptible customers pay distribution rates substantially below the rates for firm service customers in exchange for their exposure to interruption. Over the last two years, interruptible customers have not been interrupted. The purpose of the penalty is to ensure that interruption will occur when required. BOMA supported penalties and recommended that penalty revenues be credited back to firm customers because they are the ones harmed by any failure to interrupt.[63(63)] BOMA asserted that the Hearing Examiner did not address this part of the issue. Therefore, BOMA requested that the Commission direct that penalty revenues be credited to firm customers, rather than unjustly enriching shareholders.

The Commission finds that, under present circumstances, the Hearing Examiner's resolution of this issue is appropriate. The Commission further agrees that the parties may wish to explore this issue to a greater extent outside of this rate case. If appropriate, the Commission would be receptive to proposed tariff changes that reflect a consensus among the parties as to a more appropriate interruptible customer penalty structure. With regard to BOMA's suggestion that penalty revenues be credited to firm customers, the Commission finds that such revenues should be credited to firm customers in accordance with existing procedures. The Company acknowledged that it will apply any dollars collected from this penalty to all firm service customers.[64(64)]

6. *Force Majeure*

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[28] BGE's demand charge is a non-volumetric fixed charge that customers are obligated to pay for 12 months, which is unaffected by change in demand or consumption. The demand charge for interruptible service customers is based "on the maximum winter day measured demand during the latest twelve-month period."[65(65)] MIG asserted that since the demand on a single winter day will determine the customer's charge for the next 12 months, a force majeure clause is required for BGE's demand charge. MIG further argued that unresolved disputes would be submitted to the Commission, and that a force majeure clause would permit interruptible service customers to seek relief from extraordinary conditions beyond their control. MIG stated that the Hearing Examiner clearly recognized the propriety of a force majeure clause. According to MIG, the Commission should either order an appropriate force majeure clause, have the Hearing Examiner hold a hearing on this issue, or place the matter on the Administrative Hearing docket. The Hearing Examiner determined that parties may use force majeure clauses to which they agree, but declined to impose MIG's proposed language, noting that it places no limits on the reasons for a challenge to BGE's demand charge.

The Commission finds that the record, with regard to this matter, is sparse. Although the concerns raised by MIG may have merit, the Commission declines to develop actual terms based on the existing record. Therefore, the Hearing Examiner's decision on this issue is affirmed.

7. *Customer Charges*

[29-31] BGE initially proposed an increase in the residential customer charge from $12.00 to $13.00 and an increase in the Schedule C commercial customer charge from $25 to $29. In the Proposed Order, the Hearing Examiner approved an increase in the residential customer charge to $12.17, based on the proportion of the increase in revenue requirement he approved. No finding was made with regard to the commercial customer charge.

BOMA, which represents a significant number of commercial customers, argued that the Schedule C customer charge should reflect the same percentage increase compared to BGE's proposal as the authorized revenue increase bears to BGE's request.[66(66)] In the Hearing Examiner's Response to Motions to Correct, he determined that the commercial customer charge should also increase in proportion to the amount of approved revenue requirement increase.

The Hearing Examiner's determinations with regard to the residential and commercial customer charge issues are rejected. There is no basis in the record for according the proportionality adopted in the Proposed Order.

Rather, in recognition of the Company's need to move rates closer to costs and a desire to avoid rate shock, the Commission adopts the following gradual adjustments:

a. *Residential Customer Charge*

The Commission approves an increase in the residential customer charge by $0.25. This represents a reasonable increase along the continuum sought by the Company and recognizes the magnitude and frequency of customer charge increases in the recent past.

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b. *Commercial Customer Charge*

The Commission approves an increase in the commercial customer charge by $2.00. Again, this amount recognizes the magnitude and frequency of customer charge increases that have been adopted in the past.

IT IS, THEREFORE, this 19th day of June, in the year Two Thousand, by the Public Service Commission of Maryland,

ORDERED: (1) That the Proposed Order of Hearing Examiner is affirmed, except as modified herein;

(2) That Company's test year net operating income is determined to be $58,330,000 on a rate base of $721,980,000;

(3) That the Company's revenue requirement is $6,433,000 based on an overall rate of return of 8.6061 percent;

(4) That Baltimore Gas and Electric Company shall file with the Commission amended schedules with rates consistent with this Order.

APPENDIX A

CASE NO. 8829
BALTIMORE GAS AND ELECTRIC COMPANY
FOR THE TWELVE MONTHS ENDED
DECEMBER 31, 1999
(Thousands of Dollars)

REVENUE REQUIREMENT

[Graphic(s) below may extend beyond size of screen or contain distortions.]

Adjusted Rate Base	$721,980
Rate of Return	8.6061%
Required Operating income	62,134
Adjusted Operating Income	58,330
Operating Income Deficiency	3,804
Conversion Factor	0.5914
Revenue Requirement	$6,433

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[Graphic(s) below may extend beyond size of screen or contain distortions.]

Rate of Return	Capitalization Ratio	Cost Rate	Weighted Cost
Long-Term Debt	46.24%	6.58%	3.0426%
Short-Term Debt	1.00%	5.34%	0.0534%
TOPrS	3.64%	7.40%	0.2694%
Preferred Stock	4.64%	7.02%	0.3257%
Common Equity	44.48%	11.05%	4.9150%
	100.00%		8.6061%

FOOTNOTES

[1]Staff filed an Answer to the Company's Motion on May 1, 2000. OPC filed an Answer on May 3, 2000.

[2]BGE Memorandum on Appeal at 2.

[3]*Id.*

[4]*Id.*

[5]*Id.* at 3 *citing* Tr. at 1576.

[6]BGE Memorandum on appeal at 5.

[7]Staff Reply Memorandum on Appeal at 3.

[8]*Id.* at 4.

[9]*Id.* at 3.

[10]OPC Reply Memorandum at 5.

[11]BGE Memorandum on Appeal at 13.

[12]BGE Memorandum on Appeal at 14.

[13]Staff Reply Memorandum at 7.

[14]Staff Memorandum on Appeal at 5-6.

[15]*See* Proposed Order at 34.

[16]Staff Memorandum on Appeal at 7.

[17]OPC Memorandum on Appeal at 6-7.

[18]*Id.*

[19]*Id.* at 8-9.

[20]Proposed Order at 36.

[21]BGE sought to recover environmental clean-up costs due to contamination from oil

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containing PCBs and coal tar at Spring Gardens due to prior natural gas manufacturing.

[22]Proposed Order at 9.

[23]*Id.* at 27.

[24]*Id.* at 28.

[25]BGE Memorandum on Appeal at 8.

[26]Staff Memorandum on Appeal at 9.

[27]OPC Memorandum on Appeal p. 9

[28]BOMA Memorandum on Appeal at 12-13.

[29]BGE Memorandum on Appeal at 10, 7, 10.

[30]Proposed Order at 46.

[31]BGE Memorandum on Appeal at 9.

[32]Staff's recommendation of 10.3 percent reflected a 100 basis point adjustment for Rider 8.

[33]BGE Exh. 2 at 30. The Commission does not agree that market/book differences necessarily lead to a "misspecified" cost of equity when the DCF methodology is used.

[34]*See* BGE Memorandum on Appeal at 9.

[35]Proposed Order at 48.

[36]Proposed Order at 49.

[37]*Id.*

[38]DOD Memorandum of Appeal at 11.

[39]Bethlehem Steel Memorandum on Appeal at 7.

[40]*Id.* at 7, citing BGE Ex. 16 at 7.

[41]Staff Reply Memorandum on Appeal at 11-12.

[42]OPC Reply Memorandum on Appeal at 11.

[43]*See* Tr. at 1345-46.

[44]BOMA Reply Memorandum on Appeal at 12.

[45]*Id.*

[46]MIG Reply Memorandum on Appeal at 6.

[47]*Id.* As noted above, BGE does not *per se* oppose direct assignment of Manor Line costs to Bethlehem Steel. However, the Company argued that cost recovery, on a direct assignment basis, should be based on replacement cost rather than on original cost accounting.

[48]Proposed Order at 57-58, *citing* BOMA's Initial Brief at 8; 86 Md P.S.C. 389, 421 (1995).

[49]*Id.* at 60.

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[50]Bethlehem Steel also supported the Company's new mains direct assignment proposal.

[51]MIG Memorandum on Appeal at 7.

[52]*Id.* MIG argued that the $47.3 million investment in new mains can be matched directly to residential and general service class growth and thus the requisite linkage between costs and cost causation exists.

[53]Staff Reply Memorandum at 12, *citing* Tr. at 1407-1408.

[54]BOMA Reply Memorandum on Appeal at 6, citing Staff Ex. 19 at 5-7.

[55]OPC Reply Memorandum on Appeal at 8-10.

[56]*Id.* OPC asserted that this specific cost allocation detail has no bearing on the results of the present case.

[57]*See* BOMA Reply Memorandum on Appeal at 7.

[58]BGE Memorandum on Appeal at 11

[59]Proposed Order at 61.

[60]MIG Memorandum on Appeal at 4.

[61]*Id.*

[62]Proposed Order at 55.

[63]BOMA stated that FERC has adopted this principle.

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Endnotes

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

EXHIBIT
AIC - 1
ADMITTED

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.

DOCKET NO. G-01551A-07-0504

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

Direct Testimony of

Daniel G. Hansen, Ph.D.

on Behalf of

Arizona Investment Council

April 11, 2008

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1. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Daniel G. Hansen. My business address is 4610 University Avenue, Suite 700, Madison, Wisconsin 53705.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am a Vice President at Laurits R. Christensen Associates, Inc. I received a Ph.D. in Economics from Michigan State University in 1997, at which time I joined Laurits R. Christensen Associates, Inc. I have worked primarily with the energy industry during my 11 years of consulting. In 2005, I conducted independent evaluations of Northwest Natural Gas's decoupling and weather normalization mechanisms in Oregon, as required by that Commission's Orders approving the mechanisms. Last year, I provided testimony on behalf of the Utah Division of Public Utilities regarding Questar Gas Company's decoupling mechanism. On behalf of Environment Northeast (a non-profit environmental organization), I provided testimony regarding a decoupling mechanism proposed by Connecticut Light & Power and also served on a panel before the Massachusetts Department of Public Utilities to discuss the merits of decoupling mechanisms (Docket 07-50). My resume is attached as AIC Exhibit No. __ (DGH-1).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Arizona Investment Council ("AIC") has retained Christensen Associates Energy Consulting, LLC, a subsidiary of Laurits R. Christensen Associates, Inc., to provide testimony regarding the Revenue Decoupling Adjustment Provision ("RDAP") and the

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Weather Normalization Adjustment Provision ("WNAP") proposed by Southwest Gas Corporation ("Southwest Gas" or "the Company"). The aspects of these mechanisms that this testimony will address are:

- How RDAP addresses utility incentives to promote conservation and energy efficiency without significantly altering the customer-level incentive to conserve;
- Other benefits associated with RDAP;
- How WNAP reduces risk for both the utility and its customers; and
- How a combination of RDAP and WNAP can be particularly effective.

2. THE REVENUE DECOUPLING ADJUSTMENT PROVISION

Q. WHAT IS THE PURPOSE OF A DECOUPLING MECHANISM?

A. Decoupling mechanisms are primarily intended to reduce or eliminate a utility's disincentive to promote conservation and energy efficiency. For this reason, environmental organizations such as the Natural Resources Defense Council[1] and Environment Northeast support decoupling. At the same time, decoupling mechanisms reduce the variability of utility non-gas revenues. In the case of Southwest Gas's proposed RDAP, the Company would recover a fixed amount of non-gas revenues per customer served.

[1] "Joint Statement of the American Gas Association and the Natural Resources Defense Council", July 2004.

Q. PLEASE DESCRIBE THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY THAT EXISTS UNDER ITS CURRENT NON-GAS RATES.

A. The disincentive is created because traditional rate designs require the utility to recover the majority of its non-gas costs, which are largely fixed costs, through volumetric rates. A reduction in sales leads to a reduction in non-gas revenues, but does not lead to a matching reduction in non-gas, i.e., primarily fixed, costs. Therefore, under its current non-gas rates, the Company's realized rate of return is tied to sales levels. Lower sales levels lead to a lower rate of return and higher sales levels lead to a higher rate of return. This traditional design leads to a game of chance as to whether customer usage patterns and weather patterns will actually allow the utility to recover its fixed costs, which do not fluctuate with those weather or usage patterns.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVENUE DECOUPLING ADJUSTMENT PROVISION.

A. The RDAP is a standard revenue per customer decoupling mechanism in which the Company's allowed monthly non-gas revenues are equal to the number of customers in the billing month multiplied by the allowed margin per customer in that month. The *allowed* non-gas revenue is compared to the *actual* non-gas revenue billed and the difference is entered into the RDAP Balancing Account ("RDAP BA"). An over-recovery of non-gas revenue (i.e., when actual non-gas revenue exceeds allowed non-gas revenue) produces a credit in the RDAP BA, reducing the non-gas rate in the following year. An under-recovery of non-gas revenue (i.e., when actual non-gas revenue is less

than allowed non-gas revenue) produces a debit in the RDAP BA, increasing the non-gas rate in the following year.

Q. HOW DOES RDAP ADDRESS THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?

A. RDAP removes the link between the Company's sales and revenues. Under RDAP, Southwest Gas recovers the level of revenue per customer approved for the RDAP tariff, regardless of the level of sales per customer. Therefore, when RDAP is in place, the Company's realized rate of return is not adversely affected by the success of conservation or energy efficiency programs.

Q. HAS THE REVENUE PER CUSTOMER RDAP DESIGN PROPOSED BY SOUTHWEST GAS BEEN USED IN OTHER JURISDICTIONS?

A. Yes, the revenue per customer design is the most common form of decoupling that I have observed. The per-customer concept has been used by Vectren Energy in Indiana and Ohio; Cascade Natural Gas in Washington and Oregon; Piedmont Natural Gas in North Carolina; Baltimore Gas & Electric in Maryland; New Jersey Natural Gas; Washington Gas in Maryland; South Jersey Gas; Questar Gas in Utah; and Northwest Natural Gas in Oregon. Although there are differences between these decoupling mechanisms, they all tie the level of non-gas revenues to the number of customers in the current month or year.

Q. HOW DOES DECOUPLING AFFECT THE RATEPAYERS' INCENTIVE TO ENGAGE IN CONSERVATION OR ENERGY EFFICIENCY?

A. Decoupling has essentially no effect on an individual ratepayer's incentive to conserve energy and may actually increase the customer-level incentive to conserve. To see this, consider what happens to a residential customer's bill when they conserve energy with and without decoupling. Suppose a G-5 customer would typically consume 35 therms in January, but is assessing the benefits (under current rates) of reducing usage to 30 therms. Whether decoupling is present or not, the reduction in usage would reduce the customer's January non-gas bill by $2.71 (= $0.542 per therm x 5-therm reduction). With a decoupling mechanism in place, the $2.71 bill reduction goes into the RDAP BA to be recovered in the following year. However, this $2.71 will be paid by *all* G-5 customers in the following year, so that the bills for the conserving customer will be essentially unchanged by the presence of decoupling.

Q. DOES THE EXAMPLE ABOVE STILL WORK IF MORE THAN ONE RATEPAYER AT A TIME CONSERVES ENERGY?

A. Yes. The only thing that a ratepayer can control is whether he or she engages in conservation or energy efficiency activities. Because the "true-up" of non-gas revenue through the decoupling mechanism is almost entirely paid by other ratepayers, the individual-level incentive to conserve is not affected. If many or most of the ratepayers also decide to conserve energy, decoupling could lead to an increase in rates in the following year. However, that higher rate only *increases* the customer-level incentive to engage in long-term conservation and energy efficiency activities.

Q. IT SEEMS COUNTER-INTUITIVE THAT DECOUPLING COULD INCREASE THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE. COULD YOU PLEASE EXPLAIN THIS IN MORE DETAIL?

A. Yes. Consider an example in which a conservation program causes 20% of the customers to reduce usage by 20% each, which would lead to a 4% decrease in total usage (= 0.2 x -0.2). Assume that this leads to a reduction in non-gas revenue of 4% (it will actually be less than that because some non-gas revenue comes from the fixed monthly charge). All of the customers, including the 20% who conserve and the 80% who do not, will pay the standard tariff rates in the current year. In the following year, the non-gas rate increases by approximately 4% for all customers. This rate increase actually *increases* an individual customer's incentive to conserve in the following year.

While it may seem counter-intuitive that decoupling increases the customer-level incentive to conserve, consider the decision-making process for one customer. Suppose that this customer knows that (1) the conservation program is in place, (2) it will likely lead others to reduce their usage levels and (3) therefore the program will cause an increase in the non-gas rate in the following year. The customer in this example will pay the higher rate in the following year regardless of whether he or she chooses to conserve. Therefore, the customer will evaluate the benefits of conserving energy by considering the full non-gas rate in the current year and a higher non-gas rate in the following year (due to the effects of the conservation program combined with the decoupling mechanism). This *increases* the incentive (relative to current rates in the absence of decoupling) to engage in long-term conservation activities, such as investing in a more efficient furnace.

Q. AIC IS INTERESTED IN IMPROVING THE ABILITY OF SOUTHWEST GAS AND ALL ARIZONA UTILITIES TO RAISE CAPITAL AT REASONABLE RATES TO MEET THE INFRASTRUCTURE NEEDS OF ARIZONA'S RAPID GROWTH. DO REVENUE DECOUPLING MECHANISMS ASSIST IN THAT GOAL AS WELL?

A. Yes. Decoupling reduces the variability in a utility's non-gas revenues and ensures that a fixed amount of non-gas revenue per customer is recovered as customers are added to the system. By making the level of non-gas revenue more predictable over time, decoupling is likely to improve an investor's view of Southwest Gas as an investment opportunity and, therefore, improve the Company's ability to attract capital at a reasonable rate. As Mr. Montgomery wrote in his direct testimony, the Company has not been able to earn its authorized rate of return since the last rate case, which has been a consistent trend for a decade or more. (Montgomery at p. 5.) In the absence of decoupling, the ongoing problems that the Company has had in achieving its allowed rate of return may be exacerbated by, among other things, the expansion of Demand-Side Management programs and the prospect of a national carbon tax. This would further endanger Southwest Gas's ability to compete for capital, which would be detrimental to the interests of both the Company and its ratepayers, unless the RDAP is approved.

Q. DOES DECOUPLING LEAD TO ANY OTHER POSITIVE OUTCOMES?

A. Yes. By providing increased stability in non-gas revenues, decoupling will, in all likelihood, reduce the frequency of rate cases. A reduction in the frequency of rate cases reduces costs for the Company, its customers and the regulator.

3. THE WEATHER NORMALIZATION ADJUSTMENT PROVISION

Q. WHAT IS THE PURPOSE OF A WEATHER NORMALIZATION MECHANISM?

A. Weather normalization mechanisms reduce the variability in non-gas revenue for the utility and reduce the variability of non-gas bills for ratepayers. Because of the use of natural gas for space heating, weather is a significant driver of fluctuations in natural gas usage from month-to-month and year-to-year. When non-gas costs are recovered through volumetric rates, weather fluctuations lead to significant variability in customer payments for, and utility receipt of, non-gas revenue. A weather adjustment mechanism adjusts non-gas revenue to reflect revenues that would have been collected under normal weather conditions.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT PROVISION ("WNAP").

A. WNAP calculates customer-specific bill adjustments based on normal weather conditions, actual weather conditions and the customer's usage levels across months. It does so by first adjusting actual (metered) volumes to normal weather conditions. The volume adjustment is then used to calculate a bill adjustment, accounting for the effect of the block rates.

Q. HOW ARE WEATHER CONDITIONS MEASURED?

A. Weather conditions are measured in heating degree days ("HDDs"), which is calculated for each day (and then summed up across days within a billing month). This variable is intended to reflect the use of space heating appliances (none when the average temperature is above 65 degrees and increasing linearly below 65 degrees).

Q. HAS THE WNAP DESIGN BEEN USED IN OTHER JURISDICTIONS?

A. Yes. Weather normalization mechanisms have been implemented for at least 41 utilities in 20 different states.[2] Specifically, the WNAP design suggested by Southwest Gas is identical to the Weather Normalization Adjustment used by Questar Gas in Utah.

Q. WOULD YOU EXPECT THE WNAP TO BE EFFECTIVE IN REDUCING THE VARIABILITY OF THE COMPANY'S NON-GAS REVENUES AND THE RATEPAYER'S NON-GAS BILLS?

A. Yes. When winter temperatures are below normal, natural gas consumption increases, causing the Company to over-recover its non-gas revenues. This over-recovery comes at the expense of the ratepayers, who receive higher than normal bills in colder than normal months. The opposite outcome occurs in a winter month that is warmer than normal. That is, in a warm winter month, the utility will under-recover its non-gas revenues, while customers will pay bills that are lower than expected. WNAP reduces the variability of non-gas bills and revenue by removing the effects of changes in weather

[2] Daniel G. Hansen and Steven D. Braithwait, "A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," Oregon Public Utility Commission Docket UG-152, October 2005, pp. 10-11.

conditions on customer usage levels, i.e., increasing non-gas revenue (and bills) in mild winter months and decreasing non-gas revenue (and bills) in cold winter months.

Q. WHY ARE THE ADJUSTMENTS MADE USING CUSTOMER-SPECIFIC DATA?

A. Because some customers are more weather sensitive than others. For example, a customer who only uses natural gas for cooking will not tend to change usage levels in response to changes in weather conditions. WNAP accounts for the differences across customers by calculating customer-specific bill adjustments based on each customer's usage levels in winter and summer months, using billing data from the summer months to determine the amount of usage that is not weather-sensitive.

Q. DOES WNAP SHIFT RISK FROM THE COMPANY TO ITS RATEPAYERS?

A. No. Both the Company and its ratepayers are exposed to risk caused by fluctuating weather conditions. Because a specific weather outcome (e.g., a cold winter month) benefits one party at the expense of the other, the weather risk can be offset for both of the parties through a weather adjustment mechanism. WNAP will reduce the variability of the non-gas portion of the bill for customers and reduce the variability of non-gas revenues for the Company.

4. HOW RDAP AND WNAP COMPLEMENT ONE ANOTHER

Q. IS IT A GOOD IDEA TO HAVE BOTH A DECOUPLING MECHANISM AND A WEATHER ADJUSTMENT MECHANISM?

A. Yes. By itself, the RDAP will adjust rates to account for fluctuations in non-gas revenues due to any source, including weather. However, the rate will not adjust until the following year. Therefore, RDAP alone does not address the month-to-month weather risk to which ratepayers are exposed. For example, in a cold winter month, customers' overall bills (including gas costs) will be higher than expected. The RDAP will refund a portion of the high bill through a reduction in the non-gas rate, but this rate decrease will not take effect until the following year.

In contrast, the WNAP will adjust the *current* bill for the effect of weather on the non-gas portion of bills. Therefore, under WNAP, ratepayers will receive immediate relief from the effects of a cold winter month.

In addition, because weather tends to be the largest driver of usage fluctuations, the fact that WNAP adjusts current non-gas revenues for the effects of weather reduces the size of the RDAP deferrals. That is, if RDAP and WNAP are both in place, RDAP deferrals will tend to be smaller (in absolute value) because the effect of weather on non-gas revenues is removed.

Q. PLEASE DESCRIBE HOW WNAP IS IMPROVED BY THE PRESENCE OF RDAP.

A. A key issue when establishing a weather adjustment mechanism is in defining normal weather conditions. For example, if the level of "normal" heating degree days is set too high, the weather adjustment mechanism will consistently work as though the winter is milder than average, leading to customer surcharges on average. However, if RDAP is present in addition to WNAP, the decoupling deferrals will correct any errors that occur because of an incorrect definition of normal weather. Continuing this example in which "normal" heating degree days are set too high and the WNAP will over-charge customers on average, the increase in non-gas revenues due to the WNAP bill adjustments is completely offset by the matching customer refund that is created in the RDAP BA.

It is difficult to determine the timeframe that should be used to define normal weather conditions (e.g., the previous 10, 20 or 30 years) and reasonable people can disagree on the issue. The fact that RDAP automatically adjusts non-gas revenues to account for any errors that may exist in the definition of normal weather used in WNAP is, therefore, a convenient and desirable attribute that effectively eliminates the need to debate the definition of normal weather conditions.

5. <u>RECOMMENDATIONS</u>

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING RDAP AND WNAP?

A. I recommend that the Commission approve both RDAP and WNAP. RDAP removes a disincentive that Southwest Gas faces in supporting conservation and energy efficiency programs. Importantly, it does so in a way that does not reduce the customer-level

incentives to engage in conservation and energy efficiency activities. Also, decoupling will likely reduce the frequency of rate cases by providing an automatic adjustment to allowed revenues based on the observed change in the number of customers served and by reducing the financial effects associated with changes in customer usage levels over time. In addition, by improving the stability of non-gas revenues, decoupling will, all else equal, improve Southwest Gas's ability to obtain capital at reasonable rates.

WNAP is appropriate because it reduces weather-induced risk for both the Company and its ratepayers. It accounts for the fact that customers differ in their weather sensitivity and provides customers with immediate bill relief in colder-than-normal winter months.

WNAP and RDAP function particularly well in combination. That is, WNAP reduces the size of RDAP deferrals (reducing the size of the annual rate changes due to RDAP), while RDAP eliminates the potential for errors in WNAP bill adjustments due to an incorrect normal weather definition that could otherwise skew WNAP payments toward either the Company or its ratepayers.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

18762-6/1807516

DGH-1

Daniel G. Hansen

RESUME

March 2008

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Academic Background:

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006-present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999-2005
Economist, Laurits R. Christensen Associates, Inc., 1997-1999
Research Assistant to David Neumark, 1995-1997
Instructor, School of Management, University of Michigan-Flint, spring 1996: MBA Business Economics

Academic Honors:

Trinity Presidential Scholarship, Trinity University, 1987-1991
American Express Scholarship, 1987-1991

Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

Major Projects:

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

Professional Papers:

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33-38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37-49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

Testimony and Reports before Regulatory Agencies:

Otter Tail Power Company, Docket No. E-017/GR-07-1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Connecticut Light & Power Company, Docket No. 07-07-01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05-057-T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

EXHIBIT
AIC-2
ADMITTED

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.

DOCKET NO. G-01551A-07-0504

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Rejoinder Testimony of

Daniel G. Hansen, Ph.D.

on Behalf of

Arizona Investment Council

June 9, 2008

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1 **1. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND ADDRESS.**

3 A. My name is Daniel G. Hansen. My business address is 4610 University Avenue,

4 Suite 700, Madison, Wisconsin 53705.

5

6 **Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS DOCKET ON**

7 **APRIL 11, 2008?**

8 A. Yes, I did.

9

10 **Q. WHAT IS THE PURPOSE OF THIS REJOINDER TESTIMONY?**

11 A. Its primary purpose is to respond to the arguments raised in opposition to the Revenue

12 Decoupling Adjustment Provision ("RDAP") and the Weather Normalization Adjustment

13 Provision ("WNAP") (1) in the direct testimony of RUCO witness Mr. Rigsby, as well as

14 the surrebuttal testimony of Ms. Diaz Cortez which adopts Mr. Rigsby's direct testimony

15 and (2) in the direct testimony of Mr. Radigan filed March 28, 2008 and his surrebuttal

16 testimony. I will also summarize the key reasons why the RDAP and WNAP should be

17 approved by this Commission and provide the Commission information on revenue

18 decoupling pilot programs I evaluated that were instituted and are still in effect in the

19 states of Utah and Oregon.

20

21 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

22 A. Section 2 reviews the reasons that RDAP and WNAP should be approved; Section 3

23 provides support for the pilot programs proposed by Southwest Gas Company

24

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("Southwest Gas" or "the Company"); Section 4 responds to arguments by Mr. Radigan, Mr. Rigsby, and Ms. Diaz Cortez; and Section 5 provides my recommendations.

2. KEY REASONS WHY RDAP AND WNAP SHOULD BE APPROVED

Q. WHAT ARE THE BENEFITS OF RDAP?

A. As explained in my direct testimony, RDAP has the following key benefits:

1. RDAP eliminates the Company's disincentive to support conservation and energy efficiency due to regulatory lag (pp. 3-4);
2. RDAP preserves, and potentially increases, the customer-level incentive to conserve that exists in standard rates (pp. 5-6);
3. RDAP improves the Company's ability to attract capital at reasonable rates by providing improved stability in revenues (p. 7); and
4. RDAP may reduce the frequency of rate cases (p. 7).

Q. WHAT ARE THE BENEFITS OF WNAP?

A. As I discussed at pages 8-10 of my direct testimony, WNAP reduces weather risk for both the Company and its ratepayers. This is possible, because when weather makes one party better off, the other party is worse off. Therefore, because WNAP reduces the weather-induced variability of Company revenues, it also reduces the weather-induced variability of customer bills. Because WNAP includes ratepayer-specific bill adjustments and affects bills in the current month, it is effective in reducing weather risk for individual ratepayers. I will discuss this issue further in my response to the Staff and RUCO testimony.

Q. DO RDAP AND WNAP WORK WELL IN COMBINATION?

A. Yes. As I discussed at pages 11-12 of my direct testimony, RDAP and WNAP work particularly well together. WNAP helps to reduce the size of the RDAP deferrals, which improves rate stability over time. RDAP eliminates concern regarding the definition of normal weather used in WNAP, so that weather adjustments will not be skewed toward either the Company or its ratepayers over time.

3. <u>PILOT PROGRAM PROPOSAL</u>

Q. AT PAGES 23-25 OF HIS REBUTTAL TESTIMONY, MR. CONGDON SUGGESTS THAT THE COMMISSION AUTHORIZE RDAP AND WNAP ON A PILOT BASIS. MR. SCHLEGEL SUPPORTS THAT CONCEPT IN HIS SURREBUTTAL TESTIMONY. DO YOU HAVE EXPERIENCE WITH SUCH PILOT PROGRAMS IN OTHER STATES?

A. Yes, I provided evaluations of both revenue decoupling and weather adjustment pilot programs in Oregon and provided testimony on behalf of the Utah Division of Public Utilities regarding a revenue decoupling mechanism in that state.

Q. PLEASE DESCRIBE THE OREGON <u>DECOUPLING</u> PILOT PROGRAM.

A. In Order No. 02-634, the Oregon Public Utility Commission approved a three-year decoupling pilot program for Northwest Natural Gas beginning on October 1, 2002. The Order also required an independent review by March 21, 2005 to determine whether the

mechanism should be continued beyond its initial termination date of September 30, 2005. Dr. Steven Braithwait and I conducted the independent review.

The review was quite extensive and included assessments of the effect of decoupling on:

- Utility and ratepayer incentives;
- Utility and ratepayer risk;
- Utility financial outcomes;
- Utility behavior, including marketing efforts, energy efficiency program performance, an analysis of new customer connections and corporate culture and organization;
- Service quality;
- Connections practices; and
- Utility finances (e.g., bond ratings).

In addition, we interviewed other interested parties to obtain their views on the mechanism and its effect on the utility's behavior. At the conclusion of the review, we recommended the continued use of decoupling.

The Oregon Commission accepted our recommendation and extended the pilot an additional four years. The decoupling pilot was recently extended again and is currently set to expire on October 31, 2012.

Q. PLEASE DESCRIBE THE OREGON WEATHER ADJUSTMENT MECHANISM PILOT PROGRAM.

A. In Order No. 03-057, the Oregon Public Utility Commission approved a five-year weather adjustment mechanism ("WARM") pilot program for Northwest Natural Gas beginning on September 1, 2003. The Order required "a report on the functioning of WARM, including any proposed refinements to the program"[1] by September 30, 2005. Dr. Steven Braithwait and I also prepared that report.

The review included:

- An assessment of the effect of WARM on utility and ratepayer incentives;
- An assessment of the effect of WARM on utility and ratepayer risk;
- A review of weather normalization programs used in the United States;
- Analyses and simulations of program outcomes; and
- An examination of service quality issues.

The report recommended the continued use of a weather adjustment mechanism. The pilot program was recently extended to October 31, 2012. This date was selected so that the pilot program periods for the decoupling and weather adjustment mechanisms would match, allowing for a future joint examination of the programs.

Q. PLEASE DESCRIBE THE UTAH DECOUPLING PILOT PROGRAM.

A. The Public Service Commission of Utah approved a three-year decoupling pilot program (called the Conservation Enabling Tariff, or "CET") for Questar Gas Company to begin

[1] Page 3, Appendix C to Oregon Public Utility Commission Order No. 03-507.

on November 1, 2006. The Order required a one-year review of the program to provide parties with the opportunity to recommend modifications to, or the termination of, the decoupling mechanism. I provided testimony on behalf of the Utah Division of Public Utilities and recommended the continuation of the pilot program.

The Commission agreed: "We view the remaining two years of the Pilot Period as an opportunity to gain more experience and gather more information by which we may evaluate the benefits and detriments of the CET."[2]

Q. DO YOU RECOMMEND THE USE OF THE PILOT PROGRAM MODEL FOR SOUTHWEST GAS?

A. Yes. Pilot programs provide regulators and other parties the opportunity to observe how a mechanism functions without the risk of incurring any long-term adverse effects they suspect might come to pass. In addition, they provide the opportunity to fine tune the mechanism in response to real-world experience. While I believe that RDAP and WNAP are well-designed programs that will outlive a pilot program period, the use of a pilot may provide information that allows for the mechanisms to be improved.

[2] November 5, 2007 Order in Docket No. 05-057-T01, p. 13.

4. <u>RESPONSE TO MR. RADIGAN, MR. RIGSBY AND MS. DIAZ CORTEZ</u>

Q. BOTH THE RUCO AND STAFF WITNESSES STATE THAT WNAP SHIFTS WEATHER RISK FROM SHAREHOLDERS TO RATEPAYERS.[3] DO YOU AGREE?

A. No. They make this claim repeatedly and without any support or justification. It seems to be based on a view that risk is a zero sum game, so that if risk is reduced for one party, it must be increased for another. A simple example shows that this is not the case.

Suppose that weather in a winter month can only be one of two things: mild, in which case the customer pays $20 in non-gas costs; or cold, in which case the customer pays $30 in non-gas costs. In this example, the allowed non-gas revenue is $25. In a mild winter month, the utility undercollects by $5 (= $20 – $25), while the customer underpays by $5. In a cold winter month, the utility overcollects by $5 (= $25 – $20), while the customer overpays by $5.

It would be easy to design WNAP if the world worked this way. In a mild winter month, the customer's non-gas bill is increased by $5, and in a cold winter month the customer's non-gas bill is decreased by $5. After the "WNAP" adjustment is made, the utility collects $25 and the customer pays $25 no matter what happens with the weather.

Prior to the adjustment, both the utility and the customer faced weather risk. After the adjustment, neither the utility nor the customer face weather risk. This demonstrates that a weather adjustment mechanism reduces risk for <u>both</u> the utility and the ratepayers.

[3] Rigsby Direct, p. 7; Diaz Cortez Surrebuttal, p. 9; and Radigan Surrebuttal, pp.4 and 10.

Q. THAT WAS A VERY SIMPLE EXAMPLE. DOES IT ACTUALLY DEMONSTRATE HOW WNAP WOULD WORK?

A. Yes, the example contains all of the basic features of volumetric non-gas rates and WNAP: weather conditions that make one party better off make the other party worse off and a mechanism that makes customer-specific adjustments to the non-gas portion of the bill. The details of WNAP are more complicated because of the need to accommodate a broader range of weather conditions and customers.

WNAP reduces weather risk for both the Company and its ratepayers. The Company will experience reduced variability of non-gas revenues and customers will experience reduced variability in the non-gas portion of their bills. Another customer advantage is the WNAP adjustments affect the *current* bill, so that relief from the effects of a cold winter month are provided immediately. Also, the WNAP adjustments are based on customer-specific data, so that the size of the adjustment is appropriate given each customer's weather sensitivity.

Q. MS. DIAZ CORTEZ CLAIMS THAT UNDER RDAP "THE PRICE MESSAGE AS IT RELATES TO INCENTING CONSERVATION IS DILUTED SO THAT THE CUSTOMER WILL NOT SEE AS COMPELLING OF A CONSERVATION PRICE MESSAGE UNDER THE PROPOSED RDAP AS THEY OTHERWISE WOULD ABSENT THE RDAP."[4] DO YOU AGREE?

A. No. Ms. Diaz Cortez appears to be confusing the effect of RDAP on *all* customers with the effect of RDAP on the incentives for *any one* customer. That is, when customers

[4] Diaz Cortez Surrebuttal, p. 6.

conserve under RDAP, the applicable customer group as a whole will "repay" the Company for the associated reduction in non-gas revenue. Therefore, it may appear that RDAP reduces the customers' incentive to engage in conservation by the amount of the non-gas rate.

However, that's not the case. Any *one* customer who conserves energy promptly receives the full reduction and corresponding conservation signal in non-gas revenue on his or her current bill. It's only in the next year that customer "repays" an imperceptibly small portion of it through the RDAP deferral. This means that the customer-level incentive to conserve is essentially unchanged by the presence of RDAP.

Q. HAVE OTHER GROUPS RECOGNIZED THAT DECOUPLING DOES NOT SIGNIFICANTLY ALTER THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE?

A. Yes. The Natural Resources Defense Council ("NRDC") supports using decoupling to sever the link between sales and revenues, but does not support the use of high fixed charges. In their article, "Breaking the Consumption Habit", which appeared in The Electricity Journal in December 2001, the NRDC concludes that high fixed charges should not be used as a substitute for decoupling because "We should not make a bad situation worse by reducing customers' rewards for using less electricity, which is precisely what would happen if we raised their fixed charges and cut their usage-based distribution charges by a corresponding amount." While this article was written from the electricity perspective, the same argument applies to the natural gas industry. That's evidenced by the NRDC's support for natural gas decoupling mechanisms in their joint

statement with the AGA. (This joint statement has been included as Exhibit A to Mr. Miller's direct testimony.)

Q. CAN RDAP *INCREASE* THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE?

A. Yes. For example, suppose that a customer anticipates that other customers will conserve—perhaps because of the introduction of a new DSM program. Based on this, the customer expects a rate increase in the following year through the RDAP deferral. The expectation of the higher rate will increase the benefits the customer perceives in engaging in conservation and energy efficiency. That example is described in greater detail on page 6 of my direct testimony.

Q. IS IT FAIR FOR RDAP TO REQUIRE THE CUSTOMER GROUP AS A WHOLE TO PAY FOR THE REDUCTIONS IN NON-GAS REVENUES FROM CONSERVING CUSTOMERS?

A. I believe that it is. For example, it is no different from the use of regulatory surcharges collected from all customers to fund DSM programs. Like RDAP deferrals, these rates are paid by all ratepayers, but the direct benefits of the DSM programs are limited to participating customers. However, there are indirect benefits—potentially associated with environmental improvements or reductions in commodity costs—that are shared with all customers.

Q. MS. DIAZ CORTEZ TESTIFIED THAT "THE RDAP WOULD ONLY ADJUST BILLING DETERMINANTS FOR THERMS LOST TO CONSERVATION AND IGNORE ANY GAINS IN BILLING DETERMINANTS DUE TO GROWTH."[5] DO YOU AGREE?

A. No. This statement indicates that Ms. Diaz Cortez may not understand how RDAP works. First, RDAP does not "adjust billing determinants." Rather, it causes revenue to be added to or subtracted from a deferral account because of differences between allowed and actual use per customer. The total deferrals for the year—positive or negative—are then converted into a rate adjustment for the following year.

Second, RDAP does not adjust only for "therms lost to conservation." RDAP will add to or subtract from the deferral account whenever there is a difference between allowed and actual use per customer, regardless of the cause of that difference.

Third, RDAP will not "ignore any gains in billing determinants due to growth" if the growth is associated with increases in use per customer. It is true that RDAP will not create a deferral when average-sized customers are added to the system. That is, if customers are added, but use per customer does not change, the RDAP won't do anything. This allows the Company to recover additional non-gas revenue to cover costs associated with serving the added customers, which also occurs under standard rates. Alternatively, if *existing* customers increase usage relative to the approved levels, RDAP will cause rates to go down in the following year.

[5] Diaz Cortez Surrebuttal, p. 4.

Her misconceptions regarding how RDAP works appear to be the source of her view that RDAP "truly is biased."[6] In fact, RDAP rate adjustments can lead to either rate increases or rate decreases. However, if RDAP is successful in increasing the level of conservation and energy efficiency, the deferrals will tend to lead to rate increases. I don't believe that such rate increases should be viewed as a bias, because, as I've pointed out, customers would also benefit from the increased conservation and energy efficiency activity.

Q. TO SUPPORT HIS ARGUMENTS AGAINST RDAP, MR. RADIGAN CITED THE MAINE EXPERIENCE WITH DECOUPLING, AS DESCRIBED IN A NARUC DECOUPLING FAQ DOCUMENT.[7] DID HE OMIT ANY RELEVANT INFORMATION FROM THAT DOCUMENT?

A. Yes. NARUC included a box on page 8 of the FAQ document that decribes Maine's decoupling experience. Not included in Mr. Radigan's reference was this important conclusion:

> It should be noted that <u>while decoupling is often cited as the culprit here, in fact the economic downturn was the problem</u>. Traditional regulation would have eventually yielded rate changes through a traditional rate case and the resulting price increases would have reflected the same economic circumstances. (Emphasis added.)

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[6] <u>Ibid</u>., p. 5.
[7] Radigan Direct, pp. 8-9.

As the quote indicates, NARUC does not believe that Maine's experience with decoupling revealed any fundamental problem with the mechanism itself.

Q. MR. RADIGAN ARGUES THAT "THERE HAS BEEN NO SHOWING IN THIS CASE THAT A LACK OF REVENUE DECOUPLING IS A MAJOR OBSTACLE TO ENERGY EFFICIENCY."[8] DO YOU HAVE ANY SUCH EVIDENCE TO GIVE THE COMMISSION?

A. Yes. The Order associated with the Questar Gas Company ("QGC") decoupling proceeding contained the following summary of the views of Utah Clean Energy and Southwest Energy Efficiency Project ("UCE/SWEEP"):

> UCE/SWEEP argue removing financial disincentives and aligning the interests of the utility with that of the consumer are critical for advancing natural gas energy efficiency. In UCE/SWEEP's view, since the CET (the decoupling mechanism) has removed such disincentives, Questar has undergone a transformation in its interest and actions with respect to DSM. In addition, to date, UCE/SWEEP claim the CET has not adversely affected rates and QGC has moved from having no DSM programs to aggressively implementing DSM.[9] (Parenthetical comment added.)

[8] Radigan Surrebuttal, p. 9.
[9] Public Service Commission of Utah Order for Docket No. 05-057-T01, p. 9.

The findings of the Commission supported this view: "All parties express satisfaction with Questar Gas's initial effort to begin offering customer energy efficiency programs and we concur the effort is a positive change from prior inaction."[10]

In addition, as part of my independent evaluation of decoupling in Oregon, I interviewed a number of interested third parties to obtain their views regarding the utility's performance under decoupling. These included Ralph Cavanagh of the NRDC; Margie Harris, Executive Director for the Energy Trust of Oregon (which administers the majority of the DSM programs in Oregon); and Bob Jenks, Executive Director of the Citizens' Utility Board. The report summarized these interviews as follows:[11]

> The input that we received from these individuals consistently indicated that NW Natural is sincere in its commitment to promote conservation efforts, specifically in the form of high-efficiency furnaces... Taken together, we believe that the views expressed to us indicate that NW Natural takes its commitment to promoting energy efficiency seriously.

The experience to date in both Oregon and Utah provides two examples in which the utilities' efforts in pursuing conservation and energy efficiency have been positively influenced by the introduction of decoupling.

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[10] Ibid., p. 10.

[11] "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural", March 2005, pp. 47-48.

Q. IS IT REASONABLE TO APPLY THE EXPERIENCE IN OREGON AND UTAH TO SOUTHWEST GAS?

A. Yes. All three of the utilities face (or faced) the same disincentive to promote conservation and energy efficiency in the absence of decoupling. Specifically, because fixed non-gas costs are recovered through volumetric rates, each utility is (or was) made worse off when customers conserve energy. Decoupling removes this disincentive by breaking the link between usage and non-gas revenues.

Q. MR. RADIGAN QUESTIONS WHETHER USE PER CUSTOMER WILL CONTINUE TO DECLINE.[12] DO YOU HAVE AN OPINION ON THIS ISSUE?

A. I find Mr. Radigan's views on this matter to be contradictory. On the one hand, he questions whether use per customer will continue to decline. On the other hand, he argues that RDAP is unfair because "ratepayers generally don't like clauses that are designed to automatically increase their bills."[13] However, RDAP will only *increase* customer bills *if use per customer continues to go down*. In fact, if use per customer were to reverse its historical pattern and instead increases, RDAP will automatically *reduce* ratepayers' bills.

RDAP produces balanced results. RDAP mitigates the financial losses associated with further reductions in use per customer that may occur. If those reductions do not occur, Mr. Radigan should have no problem with the fact that RDAP will not lead to rate increases.

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[12] Radigan Surrebuttal, p. 7.
[13] Radigan Direct, p. 5.

Therefore, I don't believe that the approval of RDAP should be based on whether one expects use per customer to continue to decline (in the absence of increased conservation and energy efficiency efforts induced by decoupling). The utility's disincentive to support conservation and energy efficiency is removed by RDAP regardless of what happens to use per customer.

Q. MR. RADIGAN ALSO QUESTIONS WHETHER RDAP WILL REDUCE THE FREQUENCY OF RATE CASES.[14] DO YOU HAVE AN OPINION ON THIS ISSUE?

A. Yes. As stated in my direct testimony, I believe that RDAP will, all else equal, reduce the frequency of rate cases. I am not alone in this view. Attachment 3 to Mr. Rigsby's direct testimony contains a presentation on decoupling by Dr. Dismukes of LSU. Slide 2 of this presentation lists the arguments in favor of revenue decoupling, which include "Reduces regulatory costs and the need for frequent rate cases." Correspondingly, slide 17 of his presentation lists some alternatives to revenue decoupling. The last alternative stated is "More frequent rate cases: traditional approach at correcting rates that get out of balance." Obviously, Dr. Dismukes expects that decoupling will tend to reduce the frequency of rate cases. Having opposed Dr. Dismukes in the Questar Gas Utah proceeding, I can tell you that he does not support decoupling. While he and I disagree on many issues regarding decoupling, we do agree on the effect decoupling will have on the frequency of rate cases.

[14] Radigan Direct, p. 5.

5. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the ACC approve RDAP and WNAP. The ACC may wish to consider approving them on a pilot basis, which is a method that has been used effectively elsewhere.

My experience in Utah and Oregon indicates that decoupling is effective in altering utility behavior with respect to conservation and energy efficiency. In addition, WNAP offers an opportunity to reduce risk for both the Company and its ratepayers.

Staff and RUCO have offered no compelling arguments against RDAP and WNAP. Several of their objections are based on misconceptions, including:

- A false belief that RDAP will reduce the customer-level incentive to conserve. In fact, RDAP may even increase the customer-level incentive to conserve.
- A false belief that WNAP will shift risk from the Company to its ratepayers. In fact, WNAP reduces weather risk for both the Company and its ratepayers.
- A false belief that RDAP is biased because it only adjusts for therms lost to conservation, but ignores gains due to growth. In fact, RDAP adjusts non-gas revenues for *any* change in use per customer, regardless of the cause.

Finally, RDAP and WNAP are fair. They only recover non-gas revenues that have been reviewed and approved in a rate case. Any rate increases that occur through RDAP because of enhanced conservation or energy efficiency are no different from, for example, the charges commonly used to fund DSM programs.

1 **Q. DOES THIS COMPLETE YOUR REJOINDER TESTIMONY?**

2 A. Yes.

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MEMORANDUM

TO: Chairman Mike Gleason
Commissioner William A. Mundell
Commissioner Jeff Hatch-Miller
Commissioner Kristen K. Mayes
Commissioner Gary Pierce

FROM: Robert G. Gray
Executive Consultant
Utilities Division

THRU: Ernest G. Johnson
Director
Utilities Division

DATE: June 6, 2008

RE: STAFF REPORT FOR SEMSTREAM ARIZONA PROPANE ISSUES RELATED TO THE COMMISSION'S MARCH 18, 2008 TOWN HALL MEETING IN PAYSON, ARIZONA

Attached is the Staff Report on various issues related to propane service in Payson, Arizona by Semstream Arizona Propane ("Semstream"). The Commission previously held a town hall meeting in Payson, Arizona on March 18, 2008, where various issues were discussed with the public and Semstream officials.

EGJ:RGG:tdp

Attachment: Original and Ten Copies

CC: Brian McNeil
Ken Rozen
Adam Stafford
Amber Brown
Brad Morton
John LeSueur
Janice Alward
Terri Ford

EXHIBIT
MAYES-1
ADMITTED

STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

SEMSTREAM ARIZONA PROPANE

JUNE 6, 2008

Introduction

Semstream Arizona Propane ("Semstream" or "Company") serves approximately 7,900 propane customers in Payson, Pine, and Strawberry, Arizona and nearby areas, with sales of approximately 4,000,000 therms annually. According to an April 2007 Energy West press release, approximately 2,300 customers are also served in rural areas near these communities by the unregulated side of the Company. Semstream also provides propane service in Page, Arizona to approximately 1,300 customers.

Utility propane service in Payson ("Payson Division") began in 1968 when the Commission granted a Certificate of Convenience and Necessity ("CC&N") to Broken Bow Gas Company in Decision No. 39518 (June 17, 1968). On January 13, 1993, the Commission approved the transfer of Broken Bow Gas Company's CC&N to Great Falls Gas Company in Decision No. 58151. In 1997 Great Falls Gas Company changed its name to Energy West Inc. Semstream acquired the Payson Division from Energy West, Inc., receiving Commission approval of the transaction in Decision No. 69394 (March 22, 2007). The Commission order approving the acquisition contained a variety of provisions, including retention of existing rates and charges and the purchased gas adjustor ("PGA") surcharge, maintenance of adequate staffing in Arizona, continued compliance with Commission orders, and other matters. No rates or charges were changed as a result of the acquisition of the Payson Division in 2007. Semstream does not operate any propane distribution systems outside of Arizona.

This report is organized into a series of sections, with each section discussing a specific issue that was identified at the town hall or other discussions. The questions/topics that are discussed in this report are listed below:

1. Structure of the bill – consumer complaints

2. Structure of the Company – relationship between the parent company and the subsidiary, parent company's buying power

3. Report on why the Company had a 39/45 day billing period and whether a Commission rule has been violated.

4. What the Company is doing to be better prepared for next winter? How can customers be made more aware of changing costs, for example, costs now or this past winter versus what costs might be heading into next winter?

5. Whether the Company has procured reasonably priced propane on the wholesale market.

6. Status of the surcharge and adjustor mechanism. When will the surcharge be lifted?

7. What other alternatives exist for utility service to Payson? UNS Gas, Southwest Gas, and other options.

8. What options to propane service from Semstream does a customer have in Payson, particularly for winter heating?

1. Structure of the bill – consumer complaints

At the town hall in Payson and in other contacts, customers have indicated that they find the current bill difficult to understand, leading to efforts to adjust the bill presentation to make it clearer and easier to understand. Staff has had several discussions with Semstream on this matter. Semstream has indicated it is currently devising a new bill format and that it will provide Staff with a draft of this new bill format for comment sometime in May 2008. Items under consideration include showing a graph of the monthly usage for the previous year, grouping of line items in a more understandable manner, showing the usage volume in gallons for easier comparison to propane competitors, and other changes. Staff and the Company have also discussed possibly putting additional information explaining Semstream's bill on the back of the customer bill. Staff anticipates working with the Company in the coming months to have an improved bill format finalized this summer.

Another question that arose was how the reading on the meter is converted to the number of therms the customer is billed. This conversion involves a number of calculations and it would be very difficult to reflect these calculations on the customer bill. However, other Arizona gas utilities, including Southwest Gas and UNS Gas, have an explanation of this conversion process in their tariff, so it is available for review if people wish to do so. Staff has suggested to Semstream that it consider making a tariff filing with the Commission so that the conversion process from meter reading to billing therms is explicitly identified in its tariff. This is similar to what UNS Gas did several years ago, when UNS Gas received Commission approval of tariff language explaining its conversion calculations. Semstream was receptive to this suggestion and indicated it will move toward making such a tariff filing in the future.

2. Structure of the Company – relationship between the parent company and the subsidiary, parent company's buying power

Semstream's two distribution companies, in Payson and Page, are the only propane distribution companies owned by SemGroup, the parent company over all the various affiliates. SemGroup is over 7 groupings of companies. One of these seven groupings is Semstream LLC. The Payson and Page Divisions are within the Semstream LLC group. Within SemGroup, the other functions of most interest are the trading floor function, where propane is traded on the propane market, and the part of SemGroup that sells propane to the Arizona divisions. Both the trading floor and the propane sales functions are within Semstream LLC, the same grouping that the Arizona divisions are in. Attachment one is an organization chart for SemGroup.

An important consideration for the Payson Division is that some of the propane supplies are purchased from an affiliated company within the Semstream LLC group. When such

affiliated transactions take place, Staff believes a greater level of scrutiny is required. The order approving Semstream's acquisition of the Payson Division includes a condition requiring Semstream to provide additional documentation in its monthly PGA reports, indicating any purchases Semstream makes from an affiliate. This documentation also shows Semstream's other purchases, providing an on-going opportunity to compare Semstream's affiliate and non-affiliate purchases. The pricing of purchases from affiliated and non-affiliated suppliers is discussed further under question five below which deals with Semstream's propane acquisitions.

Regarding the trading floor operations, the Company has indicated to Staff that its trading floor operation trades an average of approximately 50,000 barrels of propane a day, representing 3-5 percent of the overall daily national demand for propane of roughly 1.1 million barrels. A barrel of propane is equal to 42 gallons of propane.

A number of federal agencies play various roles related to the propane market. The Commodity Futures Trading Commission ("CFTC") oversees propane futures and options markets. The Department of Justice's Antitrust Division enforces antitrust laws in the propane market. Attached to this document as Attachment Two is a listing of federal agencies involved in the propane market contained in a recent General Accounting Office report.

As a general premise, Staff does not believe that Semstream's level of involvement in the propane market would appear to represent a likely scenario for market manipulation of national propane prices. For comparison purposes, the CFTC's recently settled a case involving charges of market manipulation and attempted manipulation against BP Products North America Inc. ("BP"), with BP paying a total of $303 million to settle the case. In this case the CFTC alleged that BP controlled 88 percent of TET propane supplies in February 2004. Texas Eastern Pipeline ("TET") propane is propane that is deliverable at the Texas Eastern Petroleum Products Company ("TEPPCO") storage facility at Mont Belvieu, Texas or elsewhere on the TEPPCO pipeline system which runs from Texas to Midwest and Northeastern markets. Attachment Three is the press release issued by the CFTC on October 25, 2007, in this case.

Data showing Semstream's share of propane trading within Southwestern propane markets is not readily available. However, Staff believes that on-going monitoring of the prices paid by the Payson Division to affiliated and non-affiliated suppliers, in conjunction with the ability to compare prices paid by the Payson Division to pricing data around the country that is published by the Energy Information Administration, provides some ability to assess whether purchases for the Payson Division are out of line with national pricing trends or whether the Payson Division was favoring affiliated suppliers over non-affiliated suppliers. Additionally, when Semstream completes construction of the propane terminal in Winslow, Arizona, the ability to move propane between Arizona and eastern markets via rail lines will be increased and it would be reasonable to expect that Arizona propane supplies and pricing would be more closely linked to the larger eastern markets.

3. Report on why the Company had a 39/45 day billing period and whether a Commission rule has been violated.

In late December 2007 and January 2008, the Payson Division experienced difficulties in its meter reading operations, resulting in customers seeing longer than usual billing periods, in certain cases in excess of 40 days.

Several Commission rules relate to this issue. According to Rule 14-2-309.A.7, "meters shall be read monthly on as close to the same day as practical." Further, according to Rule 14-2-310.A.1, "Each utility shall bill monthly for services rendered. Meter readings shall be scheduled for periods of not less than 25 days or more than 35 days." This section of the Commission's rules also discusses a utility issuing estimated bills if it is unable to read a meter on the scheduled meter read date. Allowable reasons for estimating bills include severe weather conditions and inaccessibility of the meter. Normal billing cycles each month range from 26 to 32 days, with the average being in 28 or 29 days.

Staff's understanding is that at the time Semstream had two full time meter readers and one part time meter reader. During the period where the meters were read later than usual, one of the full time meter readers was unavailable for an extended period of time due to surgery, and that the other two meter readers were unavailable for shorter periods of time due to illnesses. Semstream also cited that this period included the Christmas and New Year's holidays and that the days these holidays fell on contributed to the meter reading difficulties. Additionally, there was severe weather that made meter reading more difficult. The Company also indicated that it cross-trains additional employees on meter reading to be available to help with meter reading if they were needed. The Company indicated to Staff that it has upgraded the part time meter reading position to be a full time meter reader, and that it now monitors the status of billing cycles on a daily basis and makes note of when holidays occur in planning its meter reading activities.

In some circumstances a longer billing period might not be noticed by customers or might have a relatively small impact on customer bills. However, Semstream's meter reading difficulties happened during the peak of the winter heating season, at a time when usage was relatively high due to cold weather, and with propane prices rising. Any one of these factors by itself may not have led to the size of bill increases customers experienced this past December and January. But in combination all of these factors combined to impact customer bills to a greater extent.

Regarding the question of whether Semstream violated the Commission's rules on meter reading and the length of billing cycles, Staff believes that the Company did violate the rules. Certainly a billing cycle of 40 days or more is well beyond the 35 day limit in R-14-2-310.A.1., and Semstream did not issue estimated bills as it could have considered doing under Commission rules. Semstream has indicated to Staff that it considered estimating bills, but it is the practice of the Company to ensure that it visits each meter every month to visually inspect it and therefore Semstream did not estimate bills. Staff believes the changes Semstream has made since January

to increase personnel assigned to and trained for meter reading, as well as efforts to more closely monitor the on-going status of billing periods, significantly lessen the chance of this problem recurring. Further, the Company does not have a history of having billing cycle problems in the Payson Division and the uncommon confluence of events discussed above, including surgery, illness, and bad weather, make it relatively unlikely that this would be a chronic problem in the Payson Division, even absent the steps the Company has taken since January. Also, it is Staff's understanding that Semstream has worked with customers who have had difficulties paying their bills due to the longer billing cycle and other issues. Given these mitigating circumstances and the fact that this is the first problem of this nature Semstream has had, Staff does not believe that a penalty or other sanction against the Company is warranted at this time. Other utilities[1] have experienced similar incidences because of billing software problems or other factors, and those utilities have not been sanctioned by the Commission, due to the isolated nature of the occurrence. However, if this becomes a recurring problem, Staff believes it would be reasonable for the Commission to give strong consideration to taking action against the Company, subject to the specific facts of any future event.

4. What the Company is doing to be better prepared for next winter? How can customers be made more aware of changing costs, for example costs now or this past winter versus what costs might be heading into next winter?

In discussions with Staff, Semstream has indicated that it is taking a variety of actions to be better prepared for next winter, both in terms of working with its customers and in procuring propane supplies.

Semstream offers, and plans to offer, a number of programs to help its customers manage their propane bills. For low income assistance, Semstream directs customers to the Community Action Program in Payson. Semstream also has indicated it plans to implement a low income discount tariff similar to tariffs offered by a number of other Arizona utilities. Semstream has indicated the program would be open to customers up to 150 percent of federal poverty guidelines and would provide a discount of up to $15 per month from November through March. Staff and the Company are currently discussing the appropriate way to implement this tariff.

Semstream also currently offers a levelized billing option, termed the Even Billing Plan. Customers sign up for the program in the April – May period. Semstream may adjust the customer's monthly bill amount in December if the differential between the actual paid amount and the owed amount is too great, but only does so after contacting the customer and discussing the situation with the customer. Semstream indicated it has not had any complaints from customers about its Even Billing Plan. Semstream has also indicated that it is committed to working with any customers who may have difficulty paying their Semstream bills on time.

[1] Arizona Public Service Company, Tucson Electric Power, UNS Gas & Electric, Southwest Gas Corp. and Global-Santa Cruz Water

Semstream will also have a Share the Warmth program in place which will provide an opportunity for Semstream customers to donate money to help other customers who qualify for low income assistance or who are in crisis. This program would be administered by an independent local agency. Semstream has committed to contribute $5,000 of initial funding for the Share the Warmth program in Payson (and an additional $2,000 for the Page Division). This program would be similar to Southwest Gas' Energy Share program, where the funds are administered by the Salvation Army.

Semstream is also in the process of implementing its ECARE online program. This will provide customers the ability to view various account information, such as usage history, online. Semstream's customers will also have the opportunity to pay their bills online, and the Company has indicated to Staff that it does not intend to charge customers any fee to pay their bills online. Semstream plans to have its online system operational and available to customers before September 2008.

Regarding Semstream's propane procurement activities, the biggest development is Semstream's on-going efforts to build a new propane terminal in Winslow, Arizona. Semstream has indicated that its ability to access the Adamana and Bumstead propane storage facilities in Arizona is in question, as both facilities have been sold to new owners. Semstream has indicated that the new owners have increased fees and may even limit or eliminate access to those facilities by other entities such as Semstream. The Adamana storage facility, located near the Petrified Forest National Park along Interstate 40 in northern Arizona, was sold by FerrellGas to Enterprise Products Partners L.P. in 2005. The Bumstead storage facility, a series of three salt dome storage caverns located on the west side of Phoenix, was sold by AmeriGas Propane L.P. to Plains All American Pipeline L.P. ("Plains") in July 2007. Uncertainty regarding the cost and availability of these facilities for Semstream emphasizes the importance of the construction of the propane terminal in Williams, Arizona. Semstream has indicated at this time that it expects it will still be able to store propane at the Adamana facility, but that the Bumstead facility is now closed to outside parties storing propane there, and that the only supply option at Bumstead will be to buy propane supplies from Plains, the facility owner.

Given these developments, Semstream's construction of a propane terminal in Winslow is timely. Semstream has indicated it expects to receive approval of the facility on June 2, 2008, and plans to have it in operation by the fall of 2008. The facility would receive rail cars and would have a storage capacity of 60,000 gallons. Propane would be received at Winslow and would then be delivered via truck to the Payson Division. Within the greater Semstream Corporation, it has significant rail assets, and would have the opportunity to bring in propane supplies from a variety of supply points to the east that Semstream would have found difficult if not impossible to access prior to this facility's construction. The ability to buy and/or store propane at points to the east will assist Semstream in adjusting to the more limited storage opportunities and higher costs at the two Arizona propane storage facilities. Staff believes that the Williams facility should provide Semstream with a greater variety of supply options, enhancing supply reliability and possibly providing opportunities to reduce propane costs.

Semstream is also looking into the possibility of using other hedging tools, such as possibly financial tools, to manage its propane supplies and try to reduce price volatility in the future. The Company has indicated it plans to meet with Staff in the near term future to provide a further explanation of its interest in pursuing other hedging tools. The Payson Division has traditionally used storage as a way of hedging its winter heating season propane supplies to a significant extent. Careful use of other hedging tools may allow Semstream to more effectively hedge its propane supplies in the future.

Another topic of interest has been the need for Semstream to communicate with customers regarding changes in rates and expectations of what may happen in the future with propane prices. This interest is especially great regarding prices and expectations going into upcoming winter heating seasons. Staff believes that Semstream has opportunities to more effectively communicate with its customers, and Semstream has expressed a willingness to work with the Commission to get pertinent information to its customers on a timely basis. Semstream plans to more actively communicate with its customers regarding changing propane prices, the connection between propane prices and oil prices, and other matters which will help inform customers as they make decisions in the future. Semstream will send out a bill stuffer in the fall that will provide a variety of information to customers on Semstream's expectations for the winter heating season and changes in propane markets, recognizing that there is always a good deal of uncertainty regarding future commodity cost levels. Semstream will provide a draft of this bill stuffer to Staff to review. Semstream can also use outside resources to help provide information to its customers, possibly in coordination with its new web services discussed above. For example, the United States Department of Energy's Energy Information Administration has a good explanatory document entitled "Propane Prices, What Consumers Should Know", with the following link: http://www.eia.doe.gov/bookshelf/brochures/propane/index.html
Semstream could provide a link to this brochure on its website and/or on its bill stuffer.

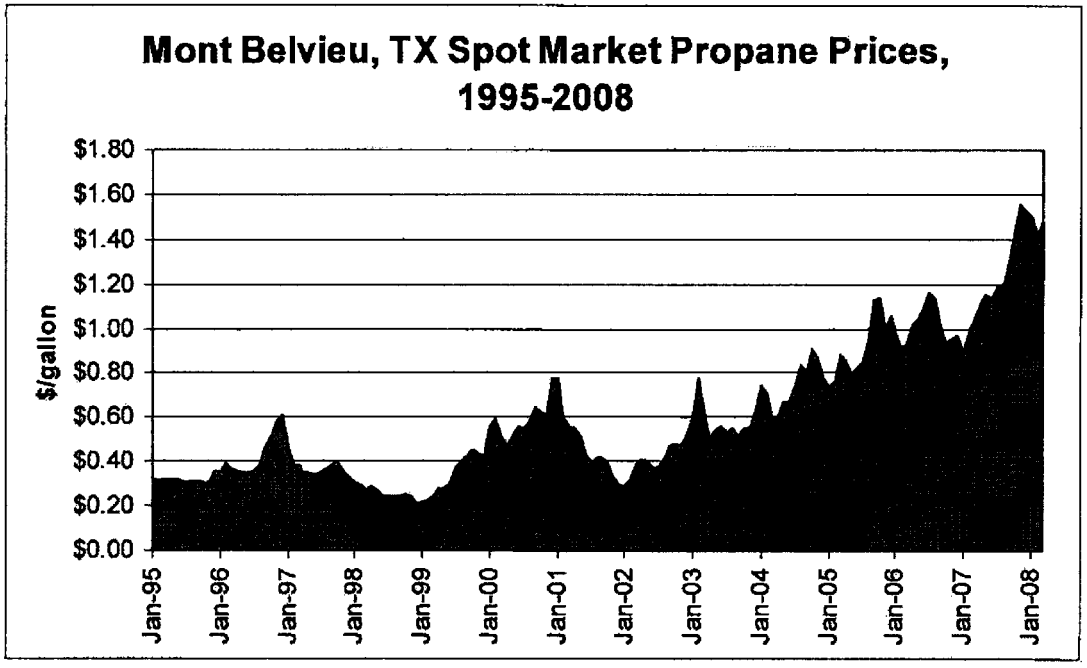
5. Whether the Company has procured reasonably priced propane on the wholesale market.

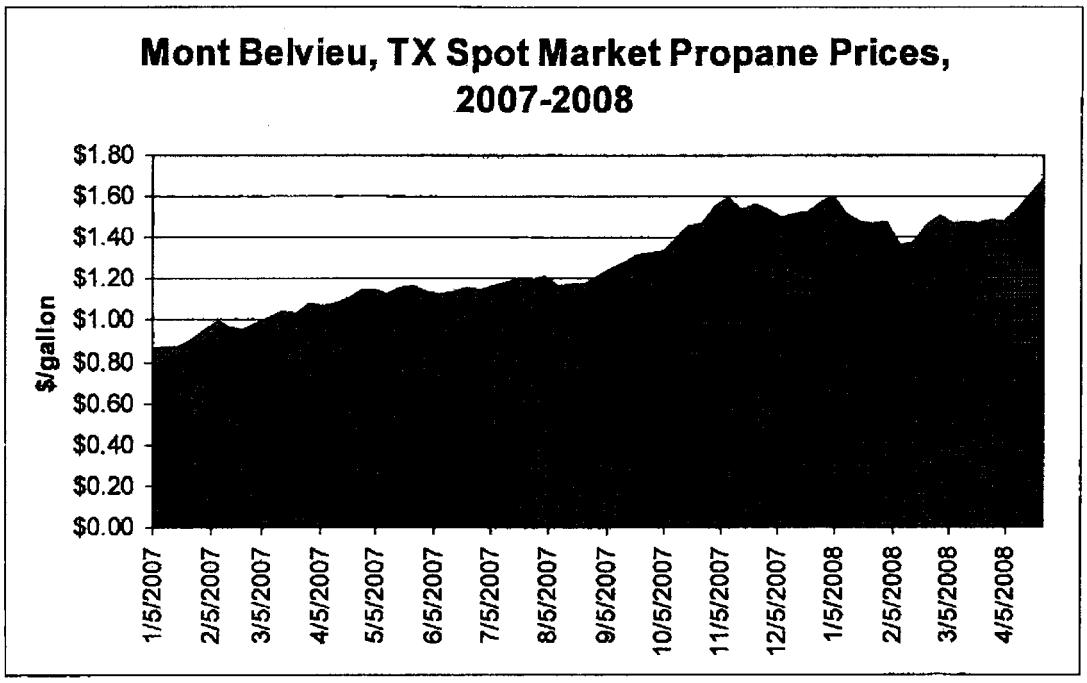
A comprehensive analysis of Semstream's propane purchasing practices would be a significant undertaking. While Semstream is a relatively small company in comparison to Arizona's large natural gas LDCs, a procurement review of Semstream's propane purchasing activities would likely take a number of months. Staff is not aware of the last time a procurement review has been conducted for the Payson Division. Typically to date, if a procurement review is conducted, it is done within the context of a general rate proceeding. For the Payson Division, its last rate case was decided in 1997, and a review of that proceeding indicates that a procurement review was not conducted. Other than the 1996-1997 rate proceeding, it appears that the Payson Division's next most recent rate proceeding was decided in 1981. Procurement reviews can be conducted outside of a general rate proceeding, and over the years there has been some discussion at the Commission about possibly conducting procurement reviews on a regular basis outside of rate proceedings, particularly when utilities do not have rate proceedings for a substantial period of time. Semstream has indicated to Staff that

it may file a rate case with the Commission in 2009, using 2008 as the test year. While the nature of this rate case is tentative at this time, Staff believes that this rate case would provide an opportunity to conduct a procurement review of the Payson Division. If Semstream were to decide to not file a rate case with the Commission in 2009, further consideration could be given at that time regarding whether a procurement review would be undertaken outside a rate proceeding.

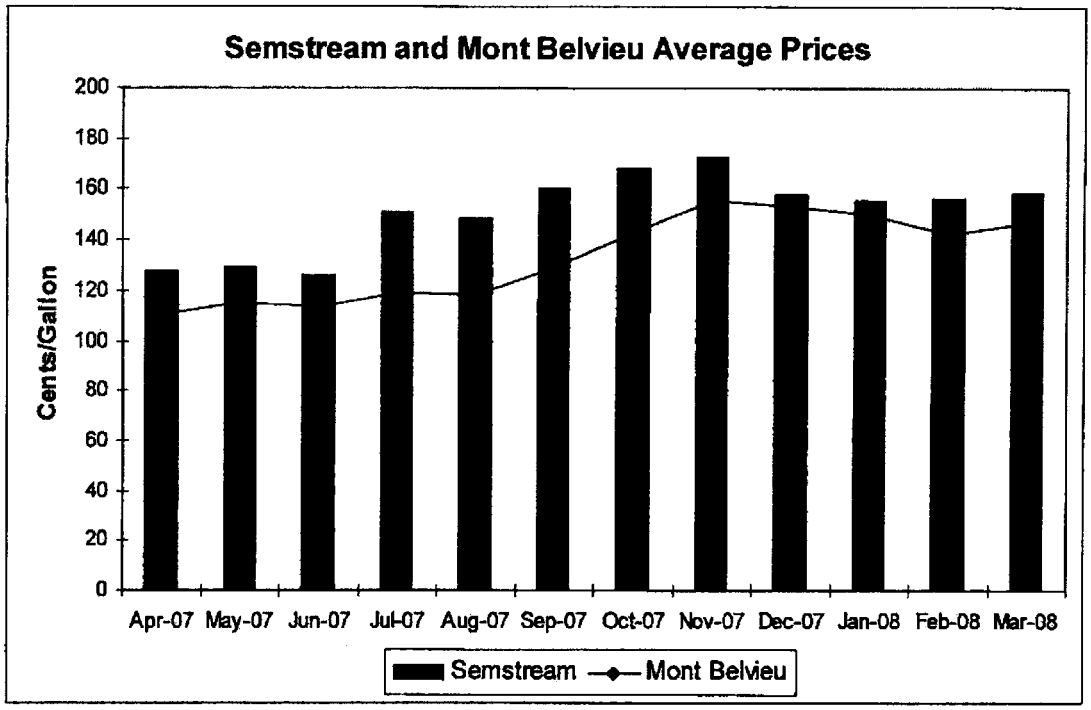
For the purpose of this report, a high level review of Semstream's propane purchasing activities has been conducted, using readily available information from Semstream's monthly PGA reports and other sources. A full blown procurement review would look at Semstream's procurement activities in significantly greater detail. As a threshold matter, Staff's review focuses on the time period beginning in April 2007, as the Commission approved Semstream's acquisition of the Payson Division from Energy West in late March 2007.

The two graphs below show spot market propane prices at the Mont Belvieu, Texas pricing hub in past years. Arizona does not have a pricing point to which purchasing is directly tied to. Mont Belvieu provides a reasonable price comparison point, recognizing that costs in Arizona will likely be a bit higher due to the lack of a pipeline infrastructure to transport propane, resulting in supplies being trucked to their final destinations in Payson and elsewhere.





Due to the significant volumes Semstream typically puts into storage in the summer, Semstream's cost of propane during a given heating season month reflects a combination of the cost of propane put into storage during a prior period (including storage fees) and the cost of propane supplies purchased on the spot market during the given month being considered. Semstream's use of storage has traditionally provided the Company with a significant hedging tool that is not available to Arizona's natural gas companies such as Southwest Gas and UNS Gas. At the town hall meeting and in other discussions, Semstream indicated that its ability to buy propane last summer and put it into storage prior to the fall and winter price increases enabled Semstream to have lower overall propane costs this past winter heating season than if it had relied solely on spot market purchases. The chart below compares the monthly average cost per gallon for Semstream with the monthly average spot market price per gallon at Mont Belview, Texas. The Semstream price includes the transportation cost (which generally ranges from $0.08 to $0.15 per gallon) and a smaller additional fee for the Propane Education and Research Council ("PERC").



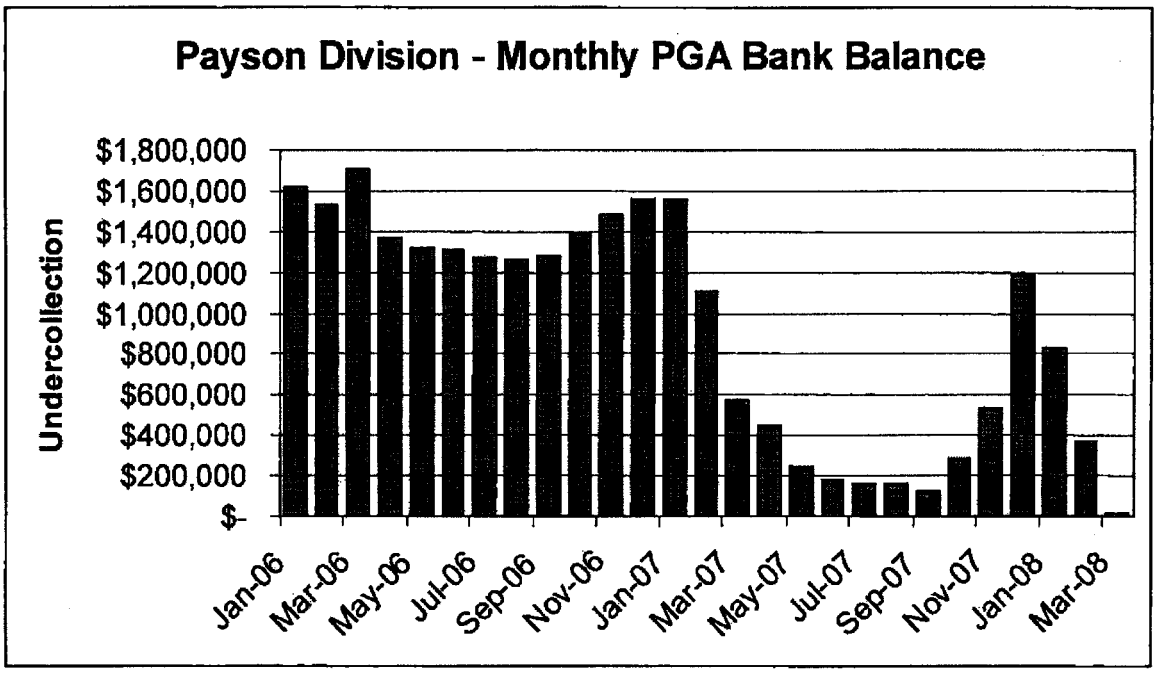
A review of the chart above indicates that in the last year Semstream's total cost for propane has generally been higher than the Mont Belvieu prices, but the size of the differential would seem to roughly match the transportation costs for delivering propane to the Payson Division. Given the higher transport costs to deliver propane to the Payson Division in comparison to Mont Belvieu, as well as the limited supply options available for the Payson Division to purchase propane from at the current time, Staff believes that at a high level, Semstream's propane prices seem reasonable in light of broader market prices.

As noted in the discussion of Question Number Two above, Semstream purchases a portion of its propane supplies from an affiliate within Semstream LLC, a situation that calls for additional scrutiny by the Commission. The additional information contained in the monthly PGA report allows Staff to compare the prices paid to the Semstream affiliate to prices paid to non-affiliated suppliers. A surface level review of the monthly prices paid to affiliated and non-affiliated suppliers does not show any clear pattern of affiliated prices being higher or lower than non-affiliated suppliers. For example, Conoco's Wingate refinery in New Mexico is a non-affiliated supplier from which Semstream at times buys propane from. In various months, Wingate's prices are higher, lower, or very similar to the prices paid to Semstream. A complicating factor to this level of analysis is that the Semstream supplies are coming from the Adamana and Bumstead storage facilities, so the prices paid for at least some portion of those supplies may have been established during an earlier time period. But with the information available from the PGA reports, Staff does not have any reason to believe that Semstream is

suppliers differently than non-affiliated suppliers. A full procurement review would provide additional opportunities to analyze this and other purchasing questions.

6. Status of the surcharge and adjustor mechanism. When will the surcharge be lifted?

Semstream's purchased gas adjustor mechanism functions in a similar manner to the PGA mechanisms used by a number of other gas utilities in Arizona, using a 12-month rolling average, a $0.16 per therm band on the monthly PGA rate, and a trigger on the PGA bank balance of $120,000. Semstream's most recent general rate proceeding concluded on August 29, 1997, when the Commission issued Decision No. 60383. The acquisition of the Payson Division by Semstream from Energy West did not change the PGA mechanism or the existing PGA surcharge in any way. As of the end of March, 2008, Semstream's monthly PGA report shows an undercollected bank balance of $16,239. The chart below shows the changes in Semstream's PGA bank balance over time.



The PGA bank balance has declined significantly from a high of $1,187,856 at the end of December 2007. Given the relatively low bank balance in the summer of 2007 and the current low bank balance, customers in the 2007-2008 heating season ended up paying roughly the same amount of money overall as Semstream paid for propane supplies during the period.

The current PGA surcharge of $0.55 per therm was approved in Decision No. 68814 (June 29, 2006) for implementation beginning with the July 2006 billing cycle. It was approved until such time as the PGA bank balance reached zero, or the Commission ordered otherwise. The $0.55 per therm PGA surcharge replaced a previously existing $0.1525 per therm PGA surcharge. Finding of Fact No. 9 in this order notes that Energy West projected that absent the surcharge, its projected PGA bank balance undercollection would approach $3,000,000 by the end of 2007. Because the level of the PGA bank balance is unpredictable over time, there is no way of knowing with certainty when the $0.55 per therm PGA surcharge will end. Semstream's end of March 2008 bank balance showed an undercollection of $16,239. Semstream has recently communicated to Staff that its' projected bank balance at the end of April 2008 will be overcollected by approximately $247,000. Therefore Semstream has told Staff that the $0.55 per therm PGA surcharge will not be on May bills, due to its expiration upon the bank balance level reaching zero. While the elimination of the surcharge at this point would immediately reduce customers' bills in the coming months, the propane cost recovery level in Semstream's rates, absent the surcharge, may be insufficient to recover the on-going commodity costs the Company is incurring under current market conditions. In such a situation, it is very possible that Semstream could come before the Commission this coming fall or winter to implement a new PGA surcharge.

In recent rate proceedings involving natural gas utilities, the Commission has revisited the size of the band on the monthly PGA rate, as well as the trigger level for the PGA bank balance. Staff believes that these issues would be ripe for consideration the next time Semstream comes before the Commission for a rate proceeding.

7. What other alternatives exist for utility service to Payson? UNS Gas, Southwest Gas, and other options.

Given the very high price of propane and the likelihood that propane will remain an expensive fuel for home heating and other uses, one matter for possible consideration is whether some other utility service option would be possible for Payson. With natural gas prices current roughly half of what propane costs, extension of natural gas service to Payson by one of Arizona's natural gas local distribution companies is one potential option to provide some relief to propane users in Payson.

Semstream indicated that at the time Great Falls Gas Company purchased the Payson Division from Broken Bow, that Great Falls considered the possibility of extending natural gas service to Payson. Semstream indicated that its understanding is that Great Falls found that the volume of sales available in Payson did not justify the cost of building the infrastructure necessary to bring natural gas to Payson. One complication was that the system would have needed to be run at a very high pressure, possibly 800 pounds per square inch ("psi"), due to the significant length of the line that would run to Payson from Camp Verde or another distant location. This pressure level is higher than most end users require, even for power plant operations. To provide this level of pressure would have led to additional costs. Another

difficulty that was identified was that the Payson Division has a number of satellite systems serving small groupings of customers that are too distant from the underground system to economically interconnect. These satellite systems can be served with propane service via truck delivery with little difficulty, a delivery mechanism that would not work nearly as well for natural gas. If natural gas service were to reach Payson, it is not clear how customers of these satellite systems would continue to receive service from the Payson Division.

However, extension of natural gas service to Payson faces a number of significant obstacles. Staff has held high level discussions with UNS Gas and Southwest Gas, two natural gas utilities that could potentially extend service to Payson from their existing service territories.

UNS Gas indicated to Staff that its closest facilities to Payson are in Camp Verde. Extension of service to Payson would involve construction of a 54 mile pipeline, with an initial estimate from UNS Gas of a cost of approximately $60 million (roughly $170 to $200 per foot). This amount does not include any additional costs to tie into the local distribution system in the Payson area.

For Southwest Gas, its closest facilities are in Fountain Hills, resulting in a 53 mile pipeline extension if it were to extend service to Payson. Southwest indicated an initial cost estimate would be over $50 million. Southwest believes that if the costs of such an extension were paid specifically by customers in the Payson area, that rates in Payson would be significantly higher than Southwest's general Arizona tariffs. Southwest did indicate that rate treatment would be a significant issue in determining the economics of the project. If the costs of the extension were given rolled-in treatment, spreading them over all Southwest's customers, Southwest believes that such an increase for all Arizona customers would be a single-digit percentage increase.

If an effort were made to tie directly into the nearest interstate pipeline, this would be El Paso's Maricopa Lateral which roughly tracks the I-17 highway coming down from Flagstaff and is approximately 50 miles west of Payson. Southwest Gas indicated it believed an extension connecting directly to El Paso's system would cost upwards of $50 million.

Beyond the significant cost of extending a pipe to Payson, a number of other issues would need to be addressed. Any line would run through significant amounts of rugged territory such as national forest land and possible national wilderness land, raising possible environmental issues and construction challenges. For UNS, the entire route would traverse national forest land and possibly national wilderness land. There is an Arizona Public Service Company ("APS") transmission line that runs roughly from Camp Verde to Payson, so that route would be one possibility. Another possibility would be to try to have such a line follow the 260 and 87 Highways at least for portions of the way to Payson. For Southwest Gas, there are several APS transmission lines running from the Cholla generating station through the Payson vicinity and down into the Phoenix area, providing one possible existing right-of-way to explore. Without further investigation, Staff does not know whether any space exists in the APS right-of-way. Another possibility would be for the route to run along Highway 87 from Fountain Hills to

Payson. Other possible land issues for Southwest Gas could be the McDowell Mountain Regional Park and the For McDowell Indian Reservation, which skirt Fountain Hills on the north and east. Between the land status and the rugged geology to be crossed, finding a route for a natural gas line extension to Payson would be a challenging endeavor.

Another possible cost issue for a UNS Gas or Southwest Gas expansion would be whether their backbone pipeline systems, which currently deliver gas to Camp Verde and Fountain Hills, have spare capacity to serve the additional load Payson represents. The distribution lines serving Camp Verde and Fountain Hills are at the end of their respective distribution systems and may not have the spare capacity to also be able to handle throughput for potential new demand in Payson. Thus, it seems likely that some amount of additional facilities would need to be added so that the upstream distribution system would be able to handle the additional throughput to which an extension to Payson would lead.

If a way were found to extend a natural gas line to Payson, another issue to be addressed is that Semstream currently holds a Certificate of Convenience and Necessity to serve Payson and surrounding areas and owns the propane distribution system in the Payson area. Semstream paid approximately $15 million to acquire the Payson Division from Energy West in 2006. It is unclear how the extension of a natural gas distribution line by UNS Gas or Southwest Gas for natural gas service in Payson would be made compatible with Semstream's ownership of and investment in the Payson Division. Possibilities would include the acquisition of the Payson Division by UNS Gas or Southwest Gas, or some other arrangement between Semstream and the natural gas LDC.

On a general note, Staff has observed over time that major gas line extensions in Arizona are often the result of the natural gas demand by a large end user, who serves as a sort of "anchor tenant" to give critical mass to demand for the line extension. Staff is not aware of what, if any, large commercial or industrial entities may exist in the Payson area that could serve as an anchor tenant, but if such an end user were identified, it could significantly improve the economics of getting a natural gas pipeline built to Payson.

A historic experience of note is the major buildout program Citizens Utilities ("Citizens"), now UNS Gas, undertook in the 1990s to upgrade the distribution system and extend natural gas service to a number of new communities in northern Arizona. Citizens Utilities' buildout program was ordered as part of Citizens' acquisition of the Arizona natural gas distribution system assets of Southern Union Gas Company and reflect significant concerns at the time regarding the safety and maintenance of the Southern Union system. Citizens Utilities' buildout program has a long and complex history, with the program costing significantly more and taking significantly longer to build than was initially projected. The program provided for customers in communities where natural gas service was extended to, to pay a 50 percent bill adder for a number of years to contribute toward the costs of extending service. Given delays in construction, lower than expected penetration levels, and other factors, these new customers' contributions to the cost of the extensions was less than expected. In combination with higher than expected costs, Citizens' existing customer base ended up paying higher rates to help pay

for the buildout program, resulting in some level of cross-subsidization between existing and new customers. Given the likely high cost of extending a natural gas pipeline to Payson, the Commission would need to carefully balance the various interests of both new customers in Payson and existing natural gas utility customers as it considers cost recovery, ratemaking treatment, and other issues.

Another possible option would be to truck liquid natural gas ("LNG) into Payson and the regasify it for distribution via the existing distribution system. As with any option bringing natural gas into Payson, there would likely be some costs to adjust the local distribution system to distribute natural gas rather than propane. However, the larger barrier to bringing LNG to Payson would be the significant investment in liquefaction and regasification facilities. The cost of such LNG would be noticeably higher than natural gas delivered through a normal pipeline system, but if the price differential between propane and natural gas was large enough over a sustained period, such a system could be a possibility.

8. What options to propane service from Semstream does a customer have in Payson, particularly for winter heating?

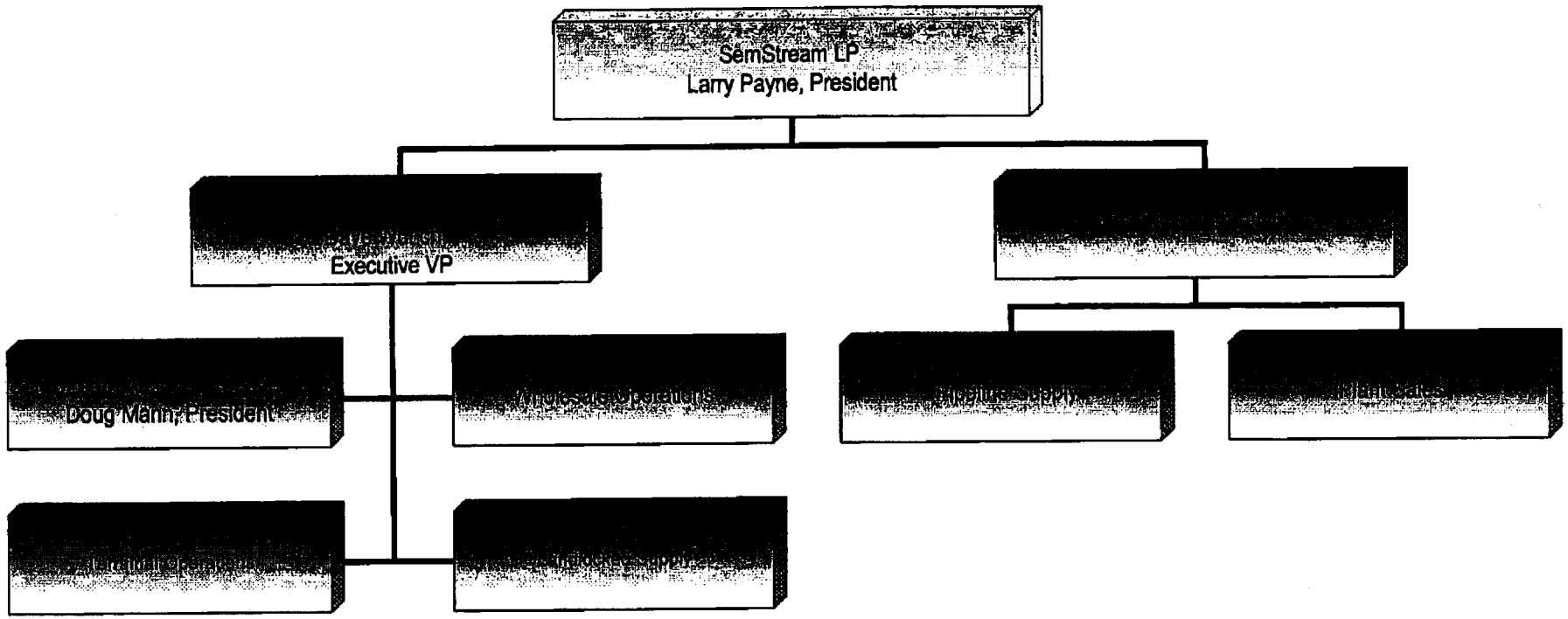
Semstream customers in Payson have limited options for heating their homes in the winter. For propane service, they can choose between Semstream and unregulated competitors who could place a propane tank on a customer's premises. But in a marketplace where wholesale propane prices are rising significantly, switching between different suppliers of propane suppliers may provide limited opportunity to seek relief from the higher propane prices all propane providers would be subject to, recognizing that some price differentiation takes place among Semstream and other propane suppliers.

Apart from taking a non-utility approach to home heating, via something like wood or pellets, in Payson the other option is to use electricity to heat homes. APS provides electric service in Payson, and while APS has seen rising costs and has increased rates in recent years, such increases have not approached the size of increases seen in the propane market. It is difficult to make a broad assessment of how electric heating compares to propane heating, given the variety of factors to be considered, including customer usage patterns and levels, expectations for future propane and electricity prices, the type of electric heating to be used, and the cost of retrofitting a given residence or business to use electric heating instead of propane. But given the current level of propane prices, a switch to some form of electric heating could potentially reduce customers' bills in certain circumstances. A worrying aspect of customers switching to electric heating from using a direct fuel source is that generally use of electricity for heating is a more energy intensive activity than burning a fuel such as natural gas or propane directly. To the extent more energy is used through the entire fuel cycle to heat a home with electricity, this would represent a growth in overall energy consumption and a movement away from efforts to encourage energy conservation, reduce air emissions, address climate change issues, etc. A further avenue for customers to explore would be participation in various APS demand-side management programs. APS has significantly expanded its demand-side

management activities in recent years, and customers in Payson might have opportunities to lower their overall utility costs, including possibly lowering propane costs, by participating in one or more APS demand-side management programs.

Attachment One – SemGroup Organization Chart

SemStream LP



Attachment Two – Federal Agencies Involved in the Regulation of Propane

Table 2: Federal Agencies and Their Respective Roles within the Propane Market

Agency	Role in Propane Market
Department of Energy (DOE)	DOE's role in the propane market is part of its overall role in fostering a secure and reliable energy system that is environmentally and economically sustainable. The Secretary of Energy has an oversight role regarding the Propane Education and Research Council's (PERC) activities and programs.
DOE's Energy Information Administration (EIA)	EIA serves as the lead federal authority for energy information to meet the needs of Congress, the federal government, industry, and the public for policy making, efficient markets, and public understanding. As part of this larger role, EIA collects and disseminates data on propane prices and supply.
Federal Energy Regulatory Commission (FERC)	FERC is an independent agency responsible for ensuring "just and reasonable rates" for interstate transportation of propane through pipelines.
Department of Commerce	Commerce has a role in the propane market as part of its overall goal to encourage, serve, and promote the nation's international trade, economic growth, and technological advancement. Commerce is required to monitor and report on the effects of PERC's programs on propane markets.
Department of Justice	The Antitrust Division of the Department of Justice enforces federal antitrust laws in the propane market as part of its overall role in promoting and maintaining competitive markets.
Federal Trade Commission (FTC)	FTC enforces laws that prohibit business practices that are anticompetitive, deceptive, or unfair to consumers and promotes informed consumer choice and public understanding of the competitive process.
Securities and Exchange Commission (SEC)	As part of SEC's role in securities markets, its overall role is providing protection for investors to ensure that they are fair and honest and, when necessary, to provide the means to enforce securities laws through sanctions.
Commodity Futures Trading Commission (CFTC)	CFTC is responsible for overseeing the nation's energy commodity futures and options markets, including propane futures and options markets.
U.S. Department of Transportation (DOT)	Three DOT entities deal with safety issues regarding different modes of transporting propane: the Federal Motor Carrier Safety Administration (preventing commercial motor vehicle-related fatalities and injuries); the Federal Railroad Administration (promoting safe and environmentally sound rail transportation); and the Research and Special Programs Administration (ensuring the safe transportation of packaged hazardous materials by all modes and the safe transportation of natural gas, petroleum, and other gas and liquid hazardous materials by pipeline). DOT grants waivers for motor carrier drivers during emergencies. State governors can petition DOT for these waivers or grant waivers themselves.

Source: GAO presentation.

Attachment Three – Commodity Futures Trading Commission Press Release on Settlement with BP Products North America Regarding Charges of Manipulation and Attempted Manipulation of the Propane Market

Release: 5405-07
For Release: October 25, 2007

BP Agrees to Pay a Total of $303 Million in Sanctions to Settle Charges of Manipulation and Attempted Manipulation in the Propane Market

Washington, DC – The U.S. Commodity Futures Trading Commission (CFTC) today announced the entry of a consent order by the Honorable Ruben Castillo of the Northern District of Illinois (Order) settling charges brought against **BP Products North America Inc. (BP)**, a corporate entity based in Warrenville Illinois, for manipulating and attempting to manipulate the price of TET propane in February 2004, for cornering the market for TET propane in February 2004, and for attempting to manipulate the price of TET propane in April 2003. The CFTC commenced this civil action against BP on June 28, 2006 (see Commodity Futures Trading Commission v. BP Products North America, Inc., 1:06-cv-03503 (N.D. Ill.) and CFTC Press Release 5193-06, June 28, 2006).

"This case demonstrates that the CFTC will aggressively combat manipulation in the nation's energy markets. Disrupting the energy markets hurts American consumers, and traders who engage in such misconduct face serious consequences. This announcement marks the largest manipulation settlement in CFTC history and requires the return of approximately $53 million to victims of the company's misconduct," said CFTC Acting Chairman Walt Lukken. "BP engaged in a massive manipulation – the magnitude of this settlement reflects that the Commission will not tolerate trading abuses in our open and competitive markets."

In a related filing, the Criminal Division, Fraud Section of the United States Department of Justice (DOJ) also announced the simultaneous filing of an information and entry into a deferred prosecution agreement with BP America Inc. based upon the same underlying conduct.

The October 25, 2007 CFTC consent order requires that BP pay a $125 million civil monetary penalty to the CFTC, establish a compliance and ethics program, and install a monitor to oversee BP's trading activities in the commodities markets. The consent order also recognizes the payment of approximately $53 million by BP into a restitution fund for victims.

The DOJ deferred prosecution agreement requires BP America to pay a $100 million criminal penalty, plus $25 million into a consumer fraud fund, as well as payments to the restitution fund and installment of the monitor as noted above.

Accordingly, the total monetary sanction that BP is required to pay to resolve the civil and criminal aspects of the unlawful conduct in the TET propane market is approximately $303 million.

The TET propane market refers to propane that is deliverable at the TEPPCO storage facility in Mont Belvieu, Texas or anywhere within the TEPPCO pipeline system. The TEPPCO pipeline runs from Mont Belvieu, Texas up through Ohio, into New York, Pennsylvania and Illinois. The TEPPCO pipeline is the only pipeline that transports propane from Mont Belvieu to the Northeast and Midwest regions of the United States.

"Although this case was difficult, our professional staff used strategic techniques during thousands of hours of investigation to uncover BP's misconduct. They effectively rooted out evidence of the defendant's intentions. This settlement shows that BP has decided to take positive steps to rectify the situation and provide relief to those who were impacted by BP's misdeeds," said Gregory Mocek, CFTC's Director of Enforcement.

The Order finds that in February 2004, BP employees sought to, and did, corner the TET propane market for the purpose of dictating prices to other market participants in order to obtain a significant trading profit. The Order finds that by engaging in this conduct, BP employees violated the Commodity Exchange Act's prohibitions against manipulating the price of a commodity and cornering a commodity market. The Order finds that BP employees attempted to manipulate the price of TET propane in April 2003 by engaging in similar conduct.

The CFTC would like to thank the Department of Justice and U.S. Postal Inspection Service for their cooperative enforcement assistance in this matter.

The following CFTC Enforcement Division staff are responsible for the case: Joseph Konizeski, Deputy Director Joan Manley, Judy Lee, Charlotte Ohlmiller, and Associate Director Paul Hayeck.

Last Updated: October 25, 2007

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	Docket No. G-01551A-07-0504

Direct Testimony of

Jeff Schlegel

on behalf of

Southwest Energy Efficiency Project (SWEEP)

March 28, 2007

EXHIBIT
SWEEP-1

Direct Testimony of Jeff Schlegel, SWEEP/NRDC
Docket No. G-01551A-07-0504

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Increased DSM Programs and Funding	3
Financial Disincentive to Natural Gas Utility Support of Energy Efficiency	4
Fixed Charges	6
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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Please describe the Southwest Energy Efficiency Project (SWEEP).

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection in the six states of Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. SWEEP works on state energy legislation, analysis of energy efficiency opportunities and potential, expansion of state and utility energy efficiency programs as well as the design of these programs, building energy codes and appliance standards, and voluntary partnerships with the private sector to advance energy efficiency. SWEEP is collaborating with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded primarily by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. I am the Arizona Representative for SWEEP.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency and clean energy resources. I consult for public groups and government agencies, and I have been working in the field for over 20 years. In addition to my responsibilities with SWEEP, I am working or have worked extensively in many of the states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, New Jersey, Vermont, and Wisconsin. In 1997, I received the Outstanding Achievement Award from the International Energy Program Evaluation Conference. I have testified before the Arizona Corporation Commission in many proceedings.

Q. What is the purpose of your testimony?

A. In my testimony I will discuss the public interest in increasing natural gas energy efficiency, summarize the performance of gas energy efficiency programs in other

states, propose an increase in funding for the Demand Side Management (DSM) programs of Southwest Gas, discuss the financial disincentive to natural gas utility support of energy efficiency, discuss decoupling mechanisms, and oppose higher fixed charges for Southwest Gas customers.

The Public Interest in Increasing Natural Gas Energy Efficiency

Q. What is the public interest in increasing natural gas energy efficiency?

A. Natural gas DSM energy efficiency programs are in the public interest. Increasing gas energy efficiency will provide significant and cost-effective benefits for Southwest Gas customers, the natural gas and electric utility systems, the economy, and the environment. Increasing natural gas energy efficiency will save consumers and businesses money through lower energy bills, resulting in lower total costs for customers. Natural gas energy efficiency programs will help mitigate fuel price increases and reduce customer vulnerability and exposure to natural gas price volatility. Increasing natural gas energy efficiency will also diversify energy resources, reduce air pollution and carbon emissions, and create jobs and improve the economy. Natural gas energy efficiency is a reliable energy resource that costs less than other resources for meeting the energy needs of customers in the Southwest Gas service territory.

There are many opportunities for cost-effective natural gas energy efficiency in the Southwest Gas service territory in Arizona, as evidenced by the programs Southwest Gas has implemented to date and the gas DSM programs in other states.

The Experience of Natural Gas DSM Programs in Other States

Q. What is the experience with natural gas DSM programs in other states?

A. Numerous gas utilities are implementing cost-effective DSM programs to help customers reduce their gas consumption and gas bills. One example is Questar Gas Company in Utah.

Questar began implementing gas DSM programs in Utah in 2007. The first year budget for Questar's programs was $7.0 million. These programs included free home energy audits, rebates for residential efficiency measures including insulation and high efficiency heating equipment, incentives for construction of Energy Star new homes, a contribution to the state's low-income weatherization program, and consumer education efforts. Questar's DSM programs are cost-effective and were very successful in attracting participation and achieving the first year goals. As a result, Questar proposed expanding the programs in 2008 and proposed adding new programs for promoting more efficient gas use in the commercial sector and in multi-family housing. Questar's total gas DSM budget for 2008, which was approved in full by the Utah Public Service Commission, is $10.5 million. This is equivalent to

over 1% of Questar's total revenues and about $12.70 per customer. For reference, Questar serves a total of about 825,000 full service gas customers, fewer than the 945,000 gas customers Southwest Gas serves in Arizona (Southwest Gas, Schedule E-7). Other states where gas utilities are spending well over 1% of total revenues on energy efficiency programs include California, Iowa, and Wisconsin.

Increased DSM Programs and Funding

Q. Does SWEEP support the current Southwest Gas DSM programs?

A. Yes. SWEEP supports the natural gas DSM programs proposed in the prior rate case, as modified and approved by the Commission. As Staff analysis has shown, the Commission-approved programs are cost-effective and they are providing value and net benefits to customers. Southwest Gas expects 2008 DSM spending to be about $2.9 million, which is part of the ramp up to full implementation of the programs, most of which were approved by the Commission in 2007. The 2009 DSM spending is expected to be at the $4.4 million funding level approved by the Commission in the prior rate case.

Q. Does SWEEP propose any revisions or increases to the DSM program efforts and funding for the Southwest Gas territory?

A. Yes. SWEEP proposes that funding for the DSM portfolio of programs should be increased, to at least $12 million annually, to better address the cost-effective opportunities throughout the Southwest Gas service territory. Additional DSM funding is necessary to capture energy efficiency opportunities and to assist more customers in reducing their energy bills.

Q. How does the level of DSM effort and funding you propose for Southwest Gas compare to total revenues and DSM spending per customer?

A. The SWEEP-proposed DSM program portfolio funding level of at least $12 million is equivalent to 1.2% of total revenues and $12.70 per customer, similar to the level of effort for Questar.[1] The current Commission-approved DSM program funding of $4.4 million is equivalent to about 0.4% of total revenues and $4.70 per customer.[2]

SWEEP recommends that the additional funding be used to expand existing programs to reach more customers. Also, additional cost-effective DSM programs could be considered for future years, and should be implemented if approved by the Commission in the future.

[1] $12 million of DSM program portfolio funding divided by $996.4 million of test year total revenues, per Southwest Gas Schedule E-6.
[2] $4.4 million of DSM program portfolio funding divided by $996.4 million of test year total revenues, per Southwest Gas Schedule E-6.

Q. Should the collaborative DSM working group review any program revisions or proposals for new programs?

A. Significant program revisions and proposals for new programs should be reviewed by the collaborative DSM working group. Southwest Gas should be able to expand existing, approved programs without *requiring* review by the collaborative working group, though SWEEP recommends that Southwest Gas consult the working group for ideas on how to reach more customers with the DSM programs.

Financial Disincentive to Natural Gas Utility Support of Energy Efficiency

Q. Does Southwest Gas experience a financial disincentive to its support of energy efficiency efforts when its customers respond and become more energy efficient?

A. Yes. Traditional utility regulation links the utility's financial health to the volume of natural gas sold, resulting in a financial disincentive to invest in energy efficiency and other demand-side resources that reduce natural gas sales. For Southwest Gas, energy savings by customers (which are beneficial for customers) result in lower revenues for the company and threaten recovery of utility fixed costs. In general, this financial disincentive can reduce utility support and enthusiasm for cost-effective resources such as energy efficiency programs that minimize the long-term cost of providing service. It also could impede potentially crucial utility support for energy-efficiency standards, building energy codes, and other policies that serve societal interests and reduce energy use without requiring any direct utility investment.

The financial disincentive is particularly strong for natural gas utilities that have experienced an overall trend of declining gas usage per customer, which is the situation for Southwest Gas.

Q. When should this financial disincentive be addressed?

A. SWEEP believes that the issue of the financial disincentive to natural gas utility support of energy efficiency should be addressed in Arizona in a timely manner, in this proceeding. We believe this will be necessary if Arizona wants to fully tap the potential for its lowest cost natural gas resource – cost-effective energy efficiency improvements for customers.

Q. Should a decoupling mechanism for Southwest Gas be implemented to remove the financial disincentive and encourage Southwest Gas to support additional increases in energy efficiency?

A. Yes. SWEEP supports decoupling mechanisms to address issues related to energy efficiency, i.e., when such mechanisms would be effective in substantially increasing customer energy efficiency and reducing the financial disincentive to gas utility support of increased energy efficiency. SWEEP is not in favor of decoupling solely or primarily as a mechanism for the utility to recover authorized fixed costs. Therefore, in SWEEP's view the implementation of decoupling is premised on substantial increases in customer energy efficiency, for which the decoupling mechanism would reduce the financial disincentive to the utility of such increased energy efficiency.

Q. Do you support any of the decoupling mechanisms proposed by Southwest Gas?

A. Yes. SWEEP supports the intent and design of the Revenue Decoupling Adjustment Provision (RDAP) proposed by Southwest Gas. This decoupling mechanism, if approved and implemented, would be effective in meeting the objectives set forth by SWEEP above. It is also similar to the decoupling mechanism approved in Utah for Questar Gas. SWEEP has a few outstanding questions on the specific design and operation of the RDAP mechanism, which SWEEP is addressing through discovery.

Q. Are there other actions that could be taken to ease the transition to the RDAP decoupling mechanism?

A. Yes. SWEEP suggests that the implementation of the RDAP decoupling mechanism could be a three-year pilot, with evaluation and review at the end of the pilot prior to full implementation. Also, to help reduce or address the concerns of other parties, an initial maximum cap could be placed on any revenue or refund from any differences between actual and authorized non-gas revenue, if such a cap would reduce some of the uncertainty regarding the effects of the mechanism.

Q. Is your proposal for increased DSM funding conditioned on approval of the RDAP decoupling mechanism?

A. No. SWEEP recommends the increase in DSM funding with or without approval of a decoupling mechanism. Increasing natural gas energy efficiency will provide significant and cost-effective benefits for Southwest Gas customers, the natural gas and electric utility systems, the economy, and the environment

Fixed Charges

Q. Should the Commission approve higher fixed charges for Southwest Gas?

A. No. SWEEP opposes higher fixed charges for natural gas customers because higher fixed charges would mute and reduce the price signal customers would receive when they reduce energy use and become more energy efficient, and therefore would reduce the power they have over their own energy bills.

Conclusion

Q. Does that conclude your direct testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	Docket No. G-01551A-07-0504

Surrebuttal Testimony of

Jeff Schlegel

on behalf of

Southwest Energy Efficiency Project (SWEEP)

May 27, 2008

EXHIBIT
SWEEP-2

Surrebuttal Testimony of Jeff Schlegel, SWEEP
Docket No. G-01551A-07-0504

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. Have you presented other testimony in this proceeding?

A. Yes. I prepared direct testimony on behalf of the Southwest Energy Efficiency Project (SWEEP), filed March 28, 2008.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony I will respond to the rebuttal testimony of Southwest Gas, particularly the rebuttal testimony of witnesses Congdon and Miller.

Q. What are SWEEP's primary positions set forth in your direct testimony?

A. SWEEP's primary positions are:

1. Cost-effective DSM programs should continue to ramp up and expand, substantially and expeditiously, to serve Southwest Gas customers, so that more customers can reduce their natural gas costs and mitigate the effects of any rate increase through increased energy efficiency.

2. The financial interest of Southwest Gas should be aligned more with the public interest and ratepayer interest by removing financial disincentives to utility support of energy efficiency (and the resulting reductions in customer costs).

Cost-Effective DSM Programs and Funding

Q. In its rebuttal testimony, Southwest Gas proposed to "remove the determination of the level of DSM program spending from Southwest's general rate case process and allow the level of spending to be established annually or bi-annually by Commission order based on recommendations from the previously established Southwest DSM Collaborative." Does SWEEP support this approach?

A. Not entirely. SWEEP supports the involvement of the DSM collaborative and the input and recommendations of collaborative members. However, SWEEP recommends the following process, which is more responsive to customer needs and

the increasing level of customer interest in the DSM programs, while retaining Commission review and approval of any proposed new programs.

First, for Commission-approved DSM programs, the spending levels are set initially as part of the Commission review and approval process. For these Commission-approved programs, the spending levels should be able to increase in between rate cases in response to program success and customer participation. Since the programs are cost-effective (i.e., by definition, lower cost than any other resources to meet customer energy needs), if customer interest and participation in the DSM programs are driving spending to be higher than estimated and set initially, the program spending should be increased and the increased spending should be recovered through the DSM adjustor. The Commission should be notified of the DSM program spending increase, though the spending increase should not require Commission pre-approval or other action by the Commission.[1] Any delay in increasing DSM spending to meet customer needs would result in waiting lists and dissatisfied customers, as well as higher total costs for customers.

Second, Southwest Gas and/or DSM collaborative members should be able to propose new DSM programs in between rate cases. New programs should be reviewed by Staff and approved by the Commission prior to implementation, consistent with current practice. New programs should include an estimated spending level in the program description. Once approved by the Commission, spending for new DSM programs should be recovered through the DSM adjustor.

Third, the Commission should set the overall direction for DSM in rate cases, as it has been doing, or alternatively in resource planning proceedings in which the Commission is considering and comparing the attributes, costs, and benefits of future resources.

As part of the above process, the collaborative DSM working group should review and provide input for any significant program revisions and proposals for new programs.

Q. Considering the process you recommend above, the rebuttal testimony of Southwest Gas, and the testimony of other parties, have you changed the recommendations in your direct testimony regarding DSM spending?

A. No. SWEEP continues to recommend a significant increase in DSM efforts to provide benefits to Southwest Gas customers and mitigate the effects of any rate increase. As noted above, the Commission should set the overall direction for DSM in rate cases. Specifically, SWEEP continues to recommend that funding for the DSM portfolio of programs should be increased, to at least $12 million annually, equivalent to about 1.2% of total revenues and $12.70 per customer. The current

[1] The Commission continues to have the authority and ability to initiate any DSM program revisions or spending adjustments it feels are appropriate, and Staff could provide any such recommendations to the Commission on its own initiative.

Commission-approved DSM program funding of $4.4 million is equivalent to about 0.4% of total revenues and $4.70 per customer.[2] SWEEP recommends that the Commission set this level as the target for DSM spending in 2010, with a ramp up in 2009.

SWEEP recommends that the additional funding be used to expand existing programs to reach more customers. Also, additional cost-effective DSM programs could be considered for future years, and should be implemented if approved by the Commission in the future.

Q. Does SWEEP support the current Southwest Gas DSM programs? Is SWEEP concerned about the rate of ramp up of the programs?

A. SWEEP supports the cost-effective natural gas DSM programs proposed in the prior rate case, as modified and approved by the Commission. However, SWEEP is concerned that the ramp up of the DSM programs is moving too slowly. Southwest Gas expects 2008 DSM spending to be about $2.9 million, which is part of the ramp up to full implementation of the programs, most of which were approved by the Commission in 2007. The 2009 DSM spending is expected to be at the $4.4 million funding level approved by the Commission in the prior rate case. SWEEP recommends that the DSM program ramp up be accelerated during 2008 and 2009.

Financial Disincentive to Natural Gas Utility Support of Energy Efficiency

Q. Are there actions that could be taken to pilot the decoupling mechanisms?

A. Yes. SWEEP supports the implementation of both decoupling mechanisms, RDAP and WNAP, as a three-year pilot, with annual tracking during the pilot, and with evaluation and review at the end of the pilot – similar to the proposal in my direct testimony and consistent with the Southwest Gas rebuttal testimony (Congdon, p. 22). Also, to help reduce or address the concerns of other parties, an initial maximum cap could be placed on any revenue or refund from any differences between actual and authorized non-gas revenue, to reduce some of the uncertainty regarding the effects of the mechanism during the pilot.

SWEEP suggests that the experience of pilot implementation will do more to resolve the differences among parties than continued debate in this or subsequent rate cases.

[2] $4.4 million of DSM program portfolio funding divided by $996.4 million of test year total revenues, per Southwest Gas Schedule E-6.

Higher Basic Service Charges

Q. Should the Commission approve higher basic service charges for Southwest Gas, as proposed by Southwest Gas, Staff, and RUCO?

A. No. SWEEP opposes higher basic service charges for natural gas customers because higher basic service charges would mute and reduce the price signal customers would receive when they reduce energy use and become more energy efficient.

Conclusion

Q. Does that conclude your surrebuttal testimony?

A. Yes.