BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Atmos Energy to Amend its Purchase Gas Adjustment (PGA) Schedule to Add a Demand Charge Savings and Pipeline Bypass Savings Component to the PGA	)))))	Docket No. 14-ATMG-230-TAR

AMENDED APPLICATION

Atmos Energy ("Atmos") files this Amended Application to amend its Purchased Gas Adjustment (PGA) Schedule to add a Demand Charge Savings and Pipeline Bypass Savings Component to the PGA. This Application is being filed pursuant to K.S.A. 66-117. In support of this Application, Atmos states as follows:

1. Atmos is a corporation organized and existing under the laws of the State of Texas and the Commonwealth of Virginia with its principal place of business located at Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Atmos currently operates as a natural gas public utility local distribution company in the State of Kansas pursuant to certificates of convenience and necessity issued by the Kansas Corporation Commission ("Commission" or "KCC"). Atmos' principal place of business in the State of Kansas is located at 25090 W. 110th Terr., Olathe, Kansas 66061.

2. Atmos provides retail natural gas service to approximately 128,502 customers in Kansas, including natural gas service to 106 communities in 32 counties.

3. Atmos provides natural gas service to a total of approximately three million customers in eight states.

4. In 1995, in response to the passage of the Federal Energy Regulatory Commission's ("FERC") Order 636, and the significant change in the natural gas industry with the unbundling of

interstate pipeline capacity costs and gas costs, this Commission issued an order approving a mechanism that allowed natural gas public utilities ("LDCs") in Kansas to amend their PGA tariffs so revenues associated with the LDCs' resale of interstate pipeline capacity could be shared on a 50/50 basis with their customers. **Docket No. 190,061-U, Order dated May 1, 1995, page 10, paragraph 13**. In approving this incentive mechanism the Commission made the following statements:

> The Commission believes that allowing an LDC to share in revenue will be more likely to induce prudent and efficient capacity release than the threat of regulatory investigation alone.
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> ***
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> The Commission's ultimate goal is to devise a gas cost incentive mechanism; perhaps a performance based mechanism, which addresses gas purchasing activities as a whole, rather than just the capacity resale decision.

Docket No. 190,061-U, Order dated May 1, 1995, pg. 10, paragraph 13; pg. 13, paragraph 18.

5. Over the past three years, Atmos has reduced upstream transportation costs in the PGA by approximately $3 million under this capacity release program. The savings generated by capacity release has declined steadily over the past several years from a peak in 2012 of $1.265 million in customer savings to $700,000 in 2013. The capacity release value has decreased over time primarily due to decreasing basis differentials from the Rockies to Midcontinent areas, shrinking seasonal storage spreads and a diluted secondary (capacity release) market on Southern Star Central Gas Pipeline ("Southern Star").

6. The recent and dramatic increase in shale gas production in the traditional production areas and more importantly in the traditional market areas is spawning a significant change in the natural gas industry. The natural gas market in the United States has dramatically changed since 2008 with the increase of shale gas production. This increase in gas supply has resulted in unprecedented price stability. The increase in shale gas production has changed the pipeline flow dynamics and some

pipelines have experienced decreased utilization as volumes have moved to new pipelines directly connected to the shale basins. Many interstate pipelines affected by the changing flow dynamics have responded by filing rate cases at FERC seeking to increase their fixed monthly demand charges to their captive firm customers. For example, Atmos currently receives about 80% of its upstream interstate pipeline transportation capacity requirements from Southern Star to meet a large number of its Kansas' customers' needs. Southern Star has recently filed a rate case at FERC for an estimated 47% rate increase. If this rate case is approved by FERC as filed, it would result in an estimated $6.2 million increase in demand charges (from the current $13.2 million to the proposed $19.4 million) to Atmos and its Kansas customers.[1]

7. The changing natural gas market conditions and pipeline rate cases have created a situation where LDC customers who prudently execute traditional supply practices by purchasing pipeline capacity at the maximum FERC tariff rate will face escalating cost increases. To counter these cost increases, Atmos seeks approval to make additional enhancements similar to the Commission's current capacity release mechanism which will directly incentivize Atmos to consider non-traditional supply practices to reduce pipeline demand charges. These enhancements would allow Atmos to potentially capture these non-traditional opportunities and restructure its natural gas supply contracts which could result in substantial savings to its customers. Atmos would not enter into supply or capacity arrangements that would jeopardize the security and reliability of supply.

8. The first proposed enhancement is a Demand Charge Savings Component. Opportunities may exist on pipelines where supply could be sourced from non-traditional sources

[1]The Southern Star FERC rate case has been settled. The approximate annual increase to Atmos and its customers is $2.3 million, or an increase of about 18%.

while still providing firm and reliable service to Atmos customers. Under the Demand Charge Savings mechanism, Atmos would evaluate alternative methods of serving the Atmos markets with the ultimate goal of reducing upstream transportation charges. The proposed Demand Charge Savings Component to the PGA consists of three sub components:

a. Segmentation Savings

b. Pipeline Discount Savings

c. Delivered Service Savings

The second proposed enhancement is referred to as a Pipeline Bypass Savings Component to the PGA. Opportunities may exist to construct new interconnects with alternative pipelines and realize an overall cost savings by increasing capacity on pipelines with lower demand charges and reducing capacity on pipelines that are more expensive. These opportunities may exist going forward because of changing supply and transportation dynamics. However, such interconnects are capital intensive and the cost could limit opportunities. Atmos would need to evaluate alternative pipeline costs and to work with pipelines to negotiate new interconnect agreements and long term transportation contracts to cover the capital cost of new interconnects. In areas where this is possible new interconnects can provide gas supply savings, operational benefits, supply diversity and security. Further details of each of these enhancements are attached in the prefiled testimony of Sheri W. Rowe, Manager of Gas Supply and Services.

9. The savings from these demand charge reductions would be calculated by comparing traditional pipeline demand charges to the alternative pipeline cost. In its original Application, Atmos proposed that any savings would then be shared equally between Atmos and the customers consistent with how the approved capacity release incentive mechanism works. The customer's share of the

savings would flow directly through the PGA via reduced demand charges in the same manner as the approved capacity release mechanism does today. On February 21, 2014, Atmos met with the Commission Staff to discuss an alternative use of the savings generated by the capacity demand charge and pipeline bypass mechanisms. Instead of sharing the savings equally between customer and shareholders, 100% of the savings would be used by Atmos to fund certain qualified capital projects. Those projects would fall within the following categories: (1) capital projects to provide natural gas service to under-served areas, such as all electric subdivisions, areas served by propane, or areas where irrigation farmers do not have access to natural gas distribution service; (2) capital projects that would reduce gas supply costs, such as capital improvements to the Atmos owned storage facilities, capital improvements to access alternative pipeline or local natural gas supplies; and (3) other capital projects approved by the Commission. Mr. Kenneth M. Malter, in his testimony being filed with this Amended Application, explains how the savings would be used by Atmos to fund these capital projects.

10. Supply reliability will not be compromised by these mechanisms. The control of assets and supply decisions will remain with Atmos.

11. Atmos has implemented savings mechanisms in other states with success. Ms. Rowe discusses those programs in her prefiled testimony.

12. In support of its Amended Application for approval of enhancements to the PGA, Atmos has attached the testimony of Sheri W. Rowe and the testimony of Kenneth M. Malter.

13. Also attached to this Amended Application and incorporated herein by reference is a proposed red line and clean version of Atmos' PGA schedule, which sets forth the proposed Demand Charge Savings Component and Pipeline Bypass Savings Component of the PGA. Mr. Malter is sponsoring the proposed changes to Atmos' PGA schedule. The proposed changes to Atmos' PGA

schedule attached to this Amended Application replace the proposed PGA schedule that was attached to the original Application.

14. Pursuant to discussions with the Commission Staff, and pursuant to K.S.A. 66-117, Atmos agrees to extend the statutory deadline for the Commission's decision in this case from July 14, 2014, to October 14, 2014.

WHEREFORE, Atmos Energy respectfully requests that the Commission issue an order approving this Amended Application and the proposed amendments to its PGA schedule.

James G. Flaherty, #11177
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<u>VERIFICATION</u>

STATE OF KANSAS, COUNTY OF FRANKLIN, ss:

James G. Flaherty, of lawful age, being duly sworn upon oath, deposes and says that he is attorney for Atmos Energy that he has read the above and foregoing Amended Application, and the statements contained therein are true.

James G. Flaherty

SUBSCRIBED AND SWORN to before me this 24th day of April, 2014.

NOTARY PUBLIC - State of Kansas
RONDA ROSSMAN
My Appt. Exp. 5/25/2014

Notary Public

Appointment/Commission Expires:

CERTIFICATE OF SERVICE

I hereby certify that a copy of the above and foregoing was mailed, postage prepaid, this 24th day of April, 2014, addressed to:

Niki Christopher
Citizens' Utility Ratepayer Board
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Topeka, KS 66604

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James G. Flaherty

SCHEDULE V - PURCHASED GAS ADJUSTMENT (PGA)

SECTION 1 - PURCHASED GAS COST ADJUSTMENT PROCEDURE

A. RATE SCHEDULES COVERED

All of the Company's sales rate schedules shall be subject to a purchased gas cost adjustment:

Description Combined Kansas Rate Division and Southwest Kansas Rate Division

Firm Sales Service including: Residential, Commercial, Public Authority, School, Irrigation Engine, Agricultural Service, and Small Industrial. 910, 915, 920, 930, 940, 960, 965 Interruptible Sales Service including: School, Small Industrial, Large Industrial, and Economic Development. 955, 960

B. COMPUTATION FORMULA

1. The Company's rates for gas service are subject to adjustment for change in the average cost of gas from all sources of supply purchased. At the end of the twelve-month period ending August, the Company will project the average cost of gas for the twelve months ending August 31 of the following year. If at any time during this twelve month period the Company experiences a change or changes in supplier rates or in sources of supply, the cumulative effect of which change or

changes is to produce an increase or decrease in the new projected effective rate for purchased gas from all suppliers of at least $.010 per Ccf, then an adjusted average rate shall be determined. The annual cost of gas projection and any revised projections throughout the year will be computed using the following formula:

$$\frac{P + E + S}{V} = \text{Adjustment}$$

Where:

P = The estimated total dollar cost of purchased gas to be sold calculated by summing the products of the most recent unit cost of purchased gas from each supplier and the estimated unit purchases from each supplier for the twelve month period ending August 31. In the event that changes in the rates paid for purchased gas will take place within the current twelve month period ending August 31, as specified by contract provisions currently in effect, the estimated average unit cost of purchased gas from each supplier for the current twelve month period ending August 31, may be used in the calculation in place of the most recent unit cost.

E = Estimated net cost (positive or negative) arising from exchange gas transactions that are expected to occur during the twelve month period ending August 31 (Account 806), not including storage gas transactions.

S = Estimated cost of stored gas to be withdrawn from storage (Account 808) and sold.

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V = The estimated sales volume in Ccf for the twelve month period ending August 31. (If the actual sales volume reflects a line loss factor greater than the limit value, restatement of sales volume, based on the limit value for line loss, shall be required.)

Volumes sold under Rate Schedule 955, and 960 shall not be billed the demand costs, or its equivalent, contained in the PGA computed in accordance with the above-stated formula, but shall be billed the remaining costs contained in the PGA formula. In addition to the PGA less demand costs, or its equivalent, Rate Schedule 955 and 960 shall also have applied to the volumes sold the sum of the Southern Star Central Gas Pipeline, Inc.'s maximum ITS-P and ITS-M commodity rates, adjusted for fuel reimbursement percentages, as set forth in Southern Star Central Gas Pipeline, Inc.'s tariff on file with the Federal Energy Regulatory Commission.

C. COMPUTATION PERIOD

The computation period shall be the subsequent twelve month period ending August 31.

D. COMPUTATION FREQUENCY

The computation shall be made annually or each time a change or changes occur in supplier rates or sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new effective rate paid for purchased gas by at least $.010/Ccf.

E. COSTS INCLUDED

The formula includes only costs which are properly included in FERC Accounts 800, 801, 802, 803, 804, 858, applicable to Kansas; 805, 806, 808, and 809.

F. SETTLEMENT PROVISIONS

Subsequent to the effective date of this clause, the Company shall maintain a continuing monthly comparison of the actual (as billed) cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by applying to the volumes sold during said month the purchased gas cost adjustments calculated pursuant to these purchased gas cost adjustment provisions. For each twelve month period ended August 31, the differences of the comparisons described above including any balance or credit for the previous year shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs.

An “Actual Cost Adjustment” (ACA) shall be computed by dividing the cumulative balance of under-recovered or over-recovered costs by the volume of total sales during the twelve month period ending on that date. This adjustment shall be rounded to the nearest $.0001 per Ccf and applied to sales billed on or after the first day of the month following the month in which the adjustment has been approved by the Commission. The “Actual Cost Adjustments” shall remain in effect until superseded by subsequent “Actual Cost Adjustments” calculated according to this provision.

The Gas Cost portion of uncollectible accounts is recoverable through the ACA. The cumulative balance of over-recovered or under-recovered costs shall include the Gas Cost portion of uncollectible PGA customer accounts billed under this Schedule during the preceding Computation Year and which remain unpaid. The uncollectible amounts included in the annual ACA computation shall not contain interest or collection fees or charges. This sub-component of the ACA will be a separate line item on Sheet 1 of the Purchased Gas Adjustment.

G. CAPACITY RELEASE/DEMAND CHARGE SAVINGS/PIPELINE BYPASS SAVINGS

1. CAPACITY RELEASE

The Company shall forecast, on a monthly basis, the capacity release credits expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Capacity Release Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Capacity Release Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Capacity Release Balance, that is, a cumulative balance of under or over distributed credits. An Accumulated Capacity Release Factor will be calculated annually by dividing the accumulated balance of under or over distributed credits by the volume of actual sales during the twelve month period ending August 31. The Accumulated Capacity Release Factor will be added to the Monthly Capacity Release Factor to equal the Total Capacity Release Factor. The Accumulated Capacity Release Balance will be adjusted by the monthly capacity release under/over disbursements.

2. DEMAND CHARGE SAVINGS

The Company shall calculate a Monthly Demand Charge Savings Factor (applicable to its Kansas jurisdiction) by dividing the actual monthly demand charge savings amount by estimated monthly sales volumes. The funds generated by the Total Demand Charge Savings Factor shall be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects (as defined below) approved by the Commission. The Company shall maintain a continuing monthly comparison of the actual Demand Charge Savings and the Demand Charge Savings collected by the monthly factor. The differences of the comparisons described above shall be accumulated to produce an Accumulated Demand Charge Savings Balance, that is, a cumulative balance of under or over collected demand charge savings. An Accumulated Demand Charge Savings Factor will be calculated annually by dividing the accumulated balance of under or over demand charge savings by the volume of actual sales during the twelve month period ending August 31. The funds collected through the Accumulated Demand Charge Savings Factor shall also be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects. For purposes of this Schedule, a Qualified Capital Project shall include (1) capital projects to provide natural gas service to under-served areas; (2) capital projects that would reduce gas supply costs; and (3) other capital projects approved by the Commission. Before the Company would be allowed to use funds generated by Demand Charge Savings to fund a Qualified Capital Project, it will be required to file an application with the Commission seeking approval of the specific capital project(s) and the use of funds generated by Demand Charge Savings to fund the capital project(s).

3. PIPELINE BYPASS SAVINGS

The Company shall calculate a Monthly Pipeline Bypass Savings Factor (applicable to its Kansas jurisdiction) by dividing the actual monthly pipeline bypass savings amount by estimated monthly sales volumes. The funds generated by the Total Pipeline Bypass Savings Factor shall be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects (as defined below) approved by the Commission. The Company shall maintain a continuing monthly comparison of the actual Pipeline Bypass Savings and the Pipeline Bypass Savings collected by the monthly factor. The differences of the comparisons described above shall be accumulated to produce an Accumulated Pipeline Bypass Savings Balance, that is, a cumulative balance of under or over collected pipeline bypass savings. An Accumulated Pipeline Bypass Savings Factor will be calculated annually by dividing the accumulated balance of under or over pipeline bypass savings by the volume of actual sales during the twelve month period ending August 31. The funds collected through the Accumulated Pipeline Bypass Savings Factor shall also be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects. For purposes of this Schedule, a Qualified Capital Project shall include (1) capital projects to provide natural gas service to under-served areas; (2) capital projects that would reduce gas supply costs; and (3) other capital projects approved by the Commission. Before the Company would be allowed to use funds generated by Pipeline Bypass Savings to fund a Qualified Capital Project, it will be required to file an application with the Commission seeking approval of the specific capital(s) project and the use of funds generated by Pipeline Bypass Savings to fund the capital project(s).

H. OVERRUN PENALTIES

Overrun penalties applicable to the Company's Kansas jurisdiction shall be separately accumulated and shall be administered in compliance with the provisions contained in the Commission Order in Docket No. 190,061-U. The Company shall maintain a continuing monthly comparison of the actual penalties received (applicable to its Kansas jurisdiction) and the amount recovered from its customers. The differences of the comparisons described above shall be accumulated to produce an Accumulated Penalty Balance, that is, a cumulative balance of under or over recovered penalties. An Accumulated Penalty Recovery Factor will be calculated annually by dividing the accumulated balance of under or over recovered penalties by the volume of actual sales during the twelve month period ending August 31. The Accumulated Penalty Recovery Factor will be applied to the Purchased Gas Cost Factor each month. The Accumulated Penalty Balance will be adjusted by the monthly penalty under/over recovery.

I. REPORTING REQUIREMENTS

The Company shall submit to the Commission purchased gas cost filings at least 15 days before the filing is to be effective. Purchased gas cost filings and cost adjustment reports shall use the format prescribed by the Commission.

J. LINE LOSS LIMITATIONS

The Company shall compute one actual line loss for the entire State of Kansas. In the event that the actual line loss (unaccounted for gas) statistic for the computation period exceeds the line loss limit of 4%, the Company will compute the purchased gas adjustment using the limit value rather than the actual operating statistic value.

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SECTION 2 - PURCHASED GAS COST REFUND ADJUSTMENT PROCEDURE

A. REFUND PROVISION

1. For the purpose hereof, unless the Kansas Corporation Commission shall otherwise order, refunds or a balance in the refund account in excess of $.002 per Ccf for purchased gas from all suppliers (including interest from the suppliers) in a rate area received by Company from charges paid for natural gas resold to its customers, shall be refunded to such customers as a reduction in the Purchased Gas Adjustment. Within ninety (90) days of the receipt of a refund in excess of $.002 per Ccf for purchased gas from any supplier or the balance of the refund account reaching the equivalent of $.002 per Ccf for purchased gas from all suppliers, the Company shall file with the Commission and propose to make effective, the appropriate Purchased Gas Adjustment reflecting the decrease and an associated statement showing the computation of the refund adjustment.

2. The refund adjustment per Ccf shall be determined by dividing the appropriate refund amount by the estimated Ccf sales to the rate area as shown on Line 6, Sheet KCC Form PGA 1. The amount of the unit refund adjustment shall be computed to the nearest $.00001 per Ccf.

3. The length of the refund period shall generally be twelve (12) months, except that each refund period may be lengthened or shortened by the Company to avoid a refund materially above or below the refundable amount.

4. After the refunding period is completed, the difference between the refund(s) received from the Company's suppliers and the amount refunded to the respective rate area customers shall be determined and said difference retained in the refund account until such time as a subsequent refund is received from such suppliers.

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The balance in said refund account shall be added to any subsequent refund before computing a new refund adjustment.

5. In the event any refund received from the Company's supplier is less than the equivalent of $.002 per Ccf for purchased gas for a rate area, said refund shall be credited to the refund account. The credit balance in said account, exclusive of those amounts which have been included in the calculation of refunds then in progress, shall be accumulated to the equivalent of $.002 per Ccf for purchased gas before commencing a subsequent refund as hereinabove provided.

SECTION 3 - PURCHASED GAS COST SURCHARGES

A. GAS HEDGE PROGRAM

The Company shall operate its Gas Hedge Program pursuant to the relevant order in Docket No. 05-ATMG-617-HED. Costs and revenues associated with any purchase or sale of straight call options, and other alternative risk management strategies, such as call spreads, the net balance of which shall not exceed approved annual budget amount. The estimated net balance shall be recovered as a separate cost component during the months of April through October each year from all PGA customers except irrigation. Any over or under recovery, and any of the allowed budget amount not used by the Company over the course of the Hedge Program year, shall be reflected in the Company's next ACA filing. Costs and revenues generated from the settlement of all financial derivatives shall be flowed back as a separate component during the months of November through March to all PGA customers except irrigation. This settlement component shall be a volumetric charge or credit that is calculated each month from November to March by dividing the monthly estimated hedge payoff amount by the sales volume projected to occur during that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation of the settlement component. No settlement component will be added if it is less than $.002 per Ccf, rather the amount will be accumulated until the component results in a rate more than $.002 per Ccf.

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SCHEDULE V - PURCHASED GAS ADJUSTMENT (PGA)

SECTION 1 - PURCHASED GAS COST ADJUSTMENT PROCEDURE

A. RATE SCHEDULES COVERED

All of the Company's sales rate schedules shall be subject to a purchased gas cost adjustment:

Description Combined Kansas Rate Division and Southwest Kansas Rate Division

Firm Sales Service including: Residential, Commercial, Public Authority, School, Irrigation Engine, Agricultural Service, and Small Industrial. 910, 915, 920, 930, 940, 960, 965 Interruptible Sales Service including: School, Small Industrial, Large Industrial, and Economic Development. 955, 960

B. COMPUTATION FORMULA

1. The Company's rates for gas service are subject to adjustment for change in the average cost of gas from all sources of supply purchased. At the end of the twelve-month period ending August, the Company will project the average cost of gas for the twelve months ending August 31 of the following year. If at any time during this twelve month period the Company experiences a change or changes in supplier rates or in sources of supply, the cumulative effect of which change or

changes is to produce an increase or decrease in the new projected effective rate for purchased gas from all suppliers of at least $.010 per Ccf, then an adjusted average rate shall be determined. The annual cost of gas projection and any revised projections throughout the year will be computed using the following formula:

$$\frac{P + E + S}{V} = \text{Adjustment}$$

Where:

P = The estimated total dollar cost of purchased gas to be sold calculated by summing the products of the most recent unit cost of purchased gas from each supplier and the estimated unit purchases from each supplier for the twelve month period ending August 31. In the event that changes in the rates paid for purchased gas will take place within the current twelve month period ending August 31, as specified by contract provisions currently in effect, the estimated average unit cost of purchased gas from each supplier for the current twelve month period ending August 31, may be used in the calculation in place of the most recent unit cost.

E = Estimated net cost (positive or negative) arising from exchange gas transactions that are expected to occur during the twelve month period ending August 31 (Account 806), not including storage gas transactions.

S = Estimated cost of stored gas to be withdrawn from storage (Account 808) and sold.

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V = The estimated sales volume in Ccf for the twelve month period ending August 31. (If the actual sales volume reflects a line loss factor greater than the limit value, restatement of sales volume, based on the limit value for line loss, shall be required.)

Volumes sold under Rate Schedule 955, and 960 shall not be billed the demand costs, or its equivalent, contained in the PGA computed in accordance with the above-stated formula, but shall be billed the remaining costs contained in the PGA formula. In addition to the PGA less demand costs, or its equivalent, Rate Schedule 955 and 960 shall also have applied to the volumes sold the sum of the Southern Star Central Gas Pipeline, Inc.'s maximum ITS-P and ITS-M commodity rates, adjusted for fuel reimbursement percentages, as set forth in Southern Star Central Gas Pipeline, Inc.'s tariff on file with the Federal Energy Regulatory Commission.

C. COMPUTATION PERIOD

The computation period shall be the subsequent twelve month period ending August 31.

D. COMPUTATION FREQUENCY

The computation shall be made annually or each time a change or changes occur in supplier rates or sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new effective rate paid for purchased gas by at least $.010/Ccf.

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E. COSTS INCLUDED

The formula includes only costs which are properly included in FERC Accounts 800, 801, 802, 803, 804, 858, applicable to Kansas; 805, 806, 808, and 809.

F. SETTLEMENT PROVISIONS

Subsequent to the effective date of this clause, the Company shall maintain a continuing monthly comparison of the actual (as billed) cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by applying to the volumes sold during said month the purchased gas cost adjustments calculated pursuant to these purchased gas cost adjustment provisions. For each twelve month period ended August 31, the differences of the comparisons described above including any balance or credit for the previous year shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs.

An "Actual Cost Adjustment" (ACA) shall be computed by dividing the cumulative balance of under-recovered or over-recovered costs by the volume of total sales during the twelve month period ending on that date. This adjustment shall be rounded to the nearest $.0001 per Ccf and applied to sales billed on or after the first day of the month following the month in which the adjustment has been approved by the Commission. The "Actual Cost Adjustments" shall remain in effect until superseded by subsequent "Actual Cost Adjustments" calculated according to this provision.

The Gas Cost portion of uncollectible accounts is recoverable through the ACA. The cumulative balance of over-recovered or under-recovered costs shall include the Gas Cost portion of uncollectible PGA customer accounts billed under this Schedule during the preceding Computation Year and which remain unpaid. The uncollectible amounts included in the annual ACA computation shall not contain interest or collection fees or charges. This sub-component of the ACA will be a separate line item on Sheet 1 of the Purchased Gas Adjustment.

G. CAPACITY RELEASE/DEMAND CHARGE SAVINGS/PIPELINE BYPASS SAVINGS

1. CAPACITY RELEASE

The Company shall forecast, on a monthly basis, the capacity release credits expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Capacity Release Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Capacity Release Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Capacity Release Balance, that is, a cumulative balance of under or over distributed credits. An Accumulated Capacity Release Factor will be calculated annually by dividing the accumulated balance of under or over distributed credits by the volume of actual sales during the twelve month period ending August 31. The Accumulated Capacity Release Factor will be added to the Monthly Capacity Release Factor to equal the Total Capacity Release Factor. The Accumulated Capacity Release Balance will be adjusted by the monthly capacity release under/over disbursements.

2. DEMAND CHARGE SAVINGS

The Company shall calculate a Monthly Demand Charge Savings Factor (applicable to its Kansas jurisdiction) by dividing the actual monthly demand charge savings amount by estimated monthly sales volumes. The funds generated by the Total Demand Charge Savings Factor shall be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects (as defined below) approved by the Commission. The Company shall maintain a continuing monthly comparison of the actual Demand Charge Savings and the Demand Charge Savings collected by the monthly factor. The differences of the comparisons described above shall be accumulated to produce an Accumulated Demand Charge Savings Balance, that is, a cumulative balance of under or over collected demand charge savings. An Accumulated Demand Charge Savings Factor will be calculated annually by dividing the accumulated balance of under or over demand charge savings by the volume of actual sales during the twelve month period ending August 31. The funds collected through the Accumulated Demand Charge Savings Factor shall also be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects. For purposes of this Schedule, a Qualified Capital Project shall include (1) capital projects to provide natural gas service to under-served areas; (2) capital projects that would reduce gas supply costs; and (3) other capital projects approved by the Commission. Before the Company would be allowed to use funds generated by Demand Charge Savings to fund a Qualified Capital Project, it will be required to file an application with the Commission seeking approval of the specific capital project(s) and the use of funds generated by Demand Charge Savings to fund the capital project(s).

3. PIPELINE BYPASS SAVINGS

The Company shall calculate a Monthly Pipeline Bypass Savings Factor (applicable to its Kansas jurisdiction) by dividing the actual monthly pipeline bypass savings amount by estimated monthly sales volumes. The funds generated by the Total Pipeline Bypass Savings Factor shall be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects (as defined below) approved by the Commission. The Company shall maintain a continuing monthly comparison of the actual Pipeline Bypass Savings and the Pipeline Bypass Savings collected by the monthly factor. The differences of the comparisons described above shall be accumulated to produce an Accumulated Pipeline Bypass Savings Balance, that is, a cumulative balance of under or over collected pipeline bypass savings. An Accumulated Pipeline Bypass Savings Factor will be calculated annually by dividing the accumulated balance of under or over pipeline bypass savings by the volume of actual sales during the twelve month period ending August 31. The funds collected through the Accumulated Pipeline Bypass Savings Factor shall also be retained by the Company in a deferred account until it is used by the Company to fund Qualified Capital Projects. For purposes of this Schedule, a Qualified Capital Project shall include (1) capital projects to provide natural gas service to under-served areas; (2) capital projects that would reduce gas supply costs; and (3) other capital projects approved by the Commission. Before the Company would be allowed to use funds generated by Pipeline Bypass Savings to fund a Qualified Capital Project, it will be required to file an application with the Commission seeking approval of the specific capital(s) project and the use of funds generated by Pipeline Bypass Savings to fund the capital project(s).

H. OVERRUN PENALTIES

Overrun penalties applicable to the Company's Kansas jurisdiction shall be separately accumulated and shall be administered in compliance with the provisions contained in the Commission Order in Docket No. 190,061-U. The Company shall maintain a continuing monthly comparison of the actual penalties received (applicable to its Kansas jurisdiction) and the amount recovered from its customers. The differences of the comparisons described above shall be accumulated to produce an Accumulated Penalty Balance, that is, a cumulative balance of under or over recovered penalties. An Accumulated Penalty Recovery Factor will be calculated annually by dividing the accumulated balance of under or over recovered penalties by the volume of actual sales during the twelve month period ending August 31. The Accumulated Penalty Recovery Factor will be applied to the Purchased Gas Cost Factor each month. The Accumulated Penalty Balance will be adjusted by the monthly penalty under/over recovery.

I. REPORTING REQUIREMENTS

The Company shall submit to the Commission purchased gas cost filings at least 15 days before the filing is to be effective. Purchased gas cost filings and cost adjustment reports shall use the format prescribed by the Commission.

J. LINE LOSS LIMITATIONS

The Company shall compute one actual line loss for the entire State of Kansas. In the event that the actual line loss (unaccounted for gas) statistic for the computation period exceeds the line loss limit of 4%, the Company will compute the purchased gas adjustment using the limit value rather than the actual operating statistic value.

SECTION 2 - PURCHASED GAS COST REFUND ADJUSTMENT PROCEDURE

A. REFUND PROVISION

1. For the purpose hereof, unless the Kansas Corporation Commission shall otherwise order, refunds or a balance in the refund account in excess of $.002 per Ccf for purchased gas from all suppliers (including interest from the suppliers) in a rate area received by Company from charges paid for natural gas resold to its customers, shall be refunded to such customers as a reduction in the Purchased Gas Adjustment. Within ninety (90) days of the receipt of a refund in excess of $.002 per Ccf for purchased gas from any supplier or the balance of the refund account reaching the equivalent of $.002 per Ccf for purchased gas from all suppliers, the Company shall file with the Commission and propose to make effective, the appropriate Purchased Gas Adjustment reflecting the decrease and an associated statement showing the computation of the refund adjustment.

2. The refund adjustment per Ccf shall be determined by dividing the appropriate refund amount by the estimated Ccf sales to the rate area as shown on Line 6, Sheet KCC Form PGA 1. The amount of the unit refund adjustment shall be computed to the nearest $.00001 per Ccf.

3. The length of the refund period shall generally be twelve (12) months, except that each refund period may be lengthened or shortened by the Company to avoid a refund materially above or below the refundable amount.

4. After the refunding period is completed, the difference between the refund(s) received from the Company's suppliers and the amount refunded to the respective rate area customers shall be determined and said difference retained in the refund account until such time as a subsequent refund is received from such suppliers.

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The balance in said refund account shall be added to any subsequent refund before computing a new refund adjustment.

5. In the event any refund received from the Company's supplier is less than the equivalent of $.002 per Ccf for purchased gas for a rate area, said refund shall be credited to the refund account. The credit balance in said account, exclusive of those amounts which have been included in the calculation of refunds then in progress, shall be accumulated to the equivalent of $.002 per Ccf for purchased gas before commencing a subsequent refund as hereinabove provided.

SECTION 3 - PURCHASED GAS COST SURCHARGES

A. GAS HEDGE PROGRAM

The Company shall operate its Gas Hedge Program pursuant to the relevant order in Docket No. 05-ATMG-617-HED. Costs and revenues associated with any purchase or sale of straight call options, and other alternative risk management strategies, such as call spreads, the net balance of which shall not exceed approved annual budget amount. The estimated net balance shall be recovered as a separate cost component during the months of April through October each year from all PGA customers except irrigation. Any over or under recovery, and any of the allowed budget amount not used by the Company over the course of the Hedge Program year, shall be reflected in the Company's next ACA filing. Costs and revenues generated from the settlement of all financial derivatives shall be flowed back as a separate component during the months of November through March to all PGA customers except irrigation. This settlement component shall be a volumetric charge or credit that is calculated each month from November to March by dividing the monthly estimated hedge payoff amount by the sales volume projected to occur during that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation of the settlement component. No settlement component will be added if it is less than $.002 per Ccf, rather the amount will be accumulated until the component results in a rate more than $.002 per Ccf.

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