FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

ARTICLE V

QUALITY

All natural gas tendered to Pipeline for Customer's account shall conform to the quality specifications set forth in Section 5 of Pipeline's General Terms and Conditions. Customer agrees that in the event Customer tenders for service hereunder and Pipeline agrees to accept natural gas which does not comply with Pipeline's quality specifications, as expressly provided for in Section 5 of Pipeline's General Terms and Conditions, Customer shall pay all costs associated with processing of such gas as necessary to comply with such quality specifications. Customer shall execute or cause its supplier to execute, if such supplier has retained processing rights to the gas delivered to Customer, the appropriate agreements prior to the commencement of service for the transportation and processing of any liquefiable hydrocarbons and any PVR quantities associated with the processing of gas received by Pipeline at the Point(s) of Receipt under such Customer's service agreement. In addition, subject to the execution of appropriate agreements, Pipeline is willing to transport liquids associated with the gas produced and tendered for transportation hereunder.

ARTICLE VI

ADDRESSES

Except as herein otherwise provided or as provided in the General Terms and Conditions of Pipeline's FERC Gas Tariff, any notice, request, demand, statement, bill or payment provided for in this Service Agreement, or any notice which any party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered, certified, or regular mail to the post office address of the parties hereto, as the case may be, as follows:

(a) Pipeline:

(b) Customer:

or such other address as either party shall designate by formal written notice.

ARTICLE VII

ASSIGNMENTS

Any Company which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of Customer, or of Pipeline, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this Service Agreement; and either Customer or Pipeline may assign or pledge this Service Agreement under the provisions of any mortgage, deed of trust, indenture, bank credit agreement, assignment, receivable sale, or similar instrument which it has executed or may execute hereafter; otherwise,

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

neither Customer nor Pipeline shall assign this Service Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other; provided further, however, that neither Customer nor Pipeline shall be released from its obligations hereunder without the consent of the other. In addition, Customer may assign its rights to capacity pursuant to Section 3.14 of the General Terms and Conditions. To the extent Customer so desires, when it releases capacity pursuant to Section 3.14 of the General Terms and Conditions, Customer may require privity between Customer and the Replacement Customer, as further provided in the applicable Capacity Release Umbrella Agreement.

ARTICLE VIII

INTERPRETATION

The interpretation and performance of this Service Agreement shall be in accordance with the laws of the State of _____ without recourse to the law governing conflict of laws.

This Service Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter, State and Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

ARTICLE IX

CANCELLATION OF PRIOR CONTRACT(S)

This Service Agreement supersedes and cancels, as of the effective date of this Service Agreement, the contract(s) between the parties hereto as described below:

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be signed by their respective Presidents, Vice Presidents or other duly authorized agents and their respective corporate seals to be hereto affixed and attested by their respective Secretaries or Assistant Secretaries, the day and year first above written.

TEXAS EASTERN TRANSMISSION CORPORATION

By _____

ATTEST:

_____

_____

By _____

ATTEST:

_____

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

EXHIBIT A, TRANSPORTATION PATHS
FOR BILLING PURPOSES, DATED _____,
TO THE SERVICE AGREEMENT UNDER RATE SCHEDULE FT-1
BETWEEN TEXAS EASTERN TRANSMISSION CORPORATION ("Pipeline")
AND _____ ("Customer"), DATED _____:

(1) Customer's firm Point(s) of Receipt:

Point of Receipt	Description	Maximum Daily Receipt Obligation (plus Applicable Shrinkage)	Measurement Responsibilities	Owner	Operator

(2) Customer shall have Pipeline's Master Receipt Point List ("MRPL"). Customer hereby agrees that Pipeline's MRPL as revised and published by Pipeline from time to time is incorporated herein by reference.

Customer hereby agrees to comply with the Receipt Pressure Obligation as set forth in Section 6 of Pipeline's General Terms and Conditions at such Point(s) of Receipt.

Transportation Path	Transportation Path Quantity

SIGNED FOR IDENTIFICATION

PIPELINE: _____

CUSTOMER: _____

SUPERSEDES EXHIBIT _ DATED: _____

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

EXHIBIT B, POINT(S) OF DELIVERY, DATED _____,
TO THE SERVICE AGREEMENT UNDER RATE SCHEDULE FT-1
BETWEEN TEXAS EASTERN TRANSMISSION CORPORATION ("Pipeline")
AND _____ ("Customer"), DATED _____:

Point of Delivery	Description	Maximum Daily Delivery	Delivery Pressure Obligation	Measurement Responsibilities	Owner	Operator

SIGNED FOR IDENTIFICATION:

PIPELINE: _____

CUSTOMER: _____

SUPERSEDES EXHIBIT B DATED _____

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

EXHIBIT C, ZONE BOUNDARY ENTRY QUANTITY
AND ZONE BOUNDARY EXIT QUANTITY, DATED _____,
TO THE SERVICE AGREEMENT UNDER RATE SCHEDULE FT-1
BETWEEN TEXAS EASTERN TRANSMISSION CORPORATION ("Pipeline")
AND _____ ("Customer"), DATED _____:

ZONE BOUNDARY ENTRY QUANTITY
Dth/D

TO

FROM	STX	ETX	WLA	ELA	M1-24	M1-30	M1-TXG	M1-TGC	M2-24	M2-30	M2-TXG	M2-TGC	M2	M3
STX														
ETX														
WLA														
ELA														
M1-24														
M1-30														
M1-TXG														
M1-TGC														
M2-24														
M2-30														
M2-TXG														
M2-TGC														
M2														
M3														

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

EXHIBIT C (Continued)

ZONE BOUNDARY EXIT QUANTITY
Dth/D

TO

FROM	STX	ETX	WLA	ELA	M1-24	M1-30	M1-TXG	M1-TGC	M2-24	M2-30	M2-TXG	M2-TGC	M2	M3
STX														
ETX														
WLA														
ELA														
M1-24														
M1-30														
M1-TXG														
M1-TGC														
M2-24														
M2-30														
M2-TXG														
M2-TGC														
M2														
M3														

SIGNED FOR IDENTIFICATION:

PIPELINE: _____

CUSTOMER: _____

SUPERSEDES EXHIBIT C DATED _____

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FT-1
(Continued)

EXHIBIT D, CRP™ ELECTION FORM
FOR CONTRACT NUMBER _____

DATED: _____

_____ ("Customer") hereby elects the Customized Reservation Patternþ option in accordance with Section 3.7 of Pipline's Rate Schedule FT-1 and hereby notifies Pipeline that it desires to be billed, and agrees to pay, the Reservation Charges elected from time to time on Pipeline's LINK® System for the period commencing November 1, __ through October 31, __.

Customer acknowledges that this election is alternative to the uniform monthly billing contemplated by the reservation charge rates for Rate Schedule FT-1 as set forth on Sheet Nos. 30, 32, 34, 34B and 34C as revised from time to time, and that by so electing it waives the applicability of such uniform billing for the affected months as elected on the LINK® System. Customer hereby indemnifies and holds Pipeline harmless from any claims of Customer, any person claiming through Customer and any Replacement Customer as to the service rights governed by the Service Agreement in any way related to rights to billing different from those elected on the LINK® System.

PIPELINE: _____

CUSTOMER: _____

SUPERCEDES EXHIBIT D DATED: _____

Original Sheet Nos. 727-730 are
being reserved for future use.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-2

This Service Agreement, made and entered into this ____ day of _____, ____, by and between TEXAS EASTERN TRANSMISSION CORPORATION, a Delaware Corporation (herein called "Pipeline") and _____ (herein called "Customer", whether one or more),

W I T N E S S E T H:

WHEREAS,

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the parties do covenant and agree as follows:

ARTICLE I

SCOPE OF AGREEMENT

Subject to the terms, conditions and limitations hereof and of Pipeline's Rate Schedule FTS-2, Pipeline agrees to deliver on a firm basis for Customer's account quantities of gas up to the following quantity:

Maximum Daily Quantity (MDQ) _____ dth

Pipeline shall receive for Customer's account, at the Customer Point(s), for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the Equitrans Point(s), such daily quantities tendered up to such Customer's MDQ.

Pipeline shall receive for Customer's account, at the Equitrans Point(s), for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the Customer Point(s), such daily quantities tendered up to such Customer's MDQ.

Pipeline shall not be obligated to, but may at its discretion, receive at any Point of Receipt on any day a quantity of gas in excess of the applicable Maximum Daily Receipt Obligation (MDRO), plus Applicable Shrinkage, but shall not receive in the aggregate at all Points of Receipt on any day a quantity of gas in excess of the applicable MDQ, plus Applicable Shrinkage, as specified in the executed service agreement. Pipeline shall not be obligated to, but may at its discretion, deliver at any Point of Delivery on any day a quantity of gas in excess of the applicable Maximum Daily Delivery Obligation (MDDO), but shall not deliver in the aggregate at all Points of Delivery on any day a quantity of gas in excess of the applicable MDQ, as specified in the executed service agreement.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-2
(Continued)

ARTICLE II

TERM OF AGREEMENT

This Service Agreement shall become effective on _____ and shall continue in force and effect until and including March 31, 2002 ("Primary Term") and shall continue thereafter unless terminated by either party at the end of the Primary Term or the end of any subsequent month by twelve (12) months prior written notice.

Customer hereby expressly acknowledges and agrees that, to the extent not utilized by Customer for transportation of gas for Customer's account, Pipeline has the sole right to utilize any pipeline capacity attributable to facilities constructed by Pipeline to provide service pursuant to this Service Agreement as part of Pipeline's overall general system capacity. To that end, Customer agrees not to instigate or cause to be instigated any action designed to alter or increase Customer's right to utilize the pipeline capacity attributable to facilities constructed by Pipeline to provide service pursuant to this Service Agreement. Upon termination of this Service Agreement, all rights of Customer to the transportation service provided by the facilities constructed and utilized to provide service hereunder shall terminate and the capacity provided by such facilities shall be available without limitation for Pipeline's use as Pipeline in its sole discretion deems desirable. If Customer elects to terminate this Service Agreement, then notwithstanding such termination Customer shall continue to pay the monthly charge provided under Section 3.2(A) of Rate Schedule FTS-2 until the earlier of (i) the date Pipeline recovers through said monthly charge the full original cost of the facilities attributable to the service which has been terminated, or (ii) the date Pipeline makes effective its next general rate filing and begins receiving recovery on an alternate basis, which may include systemwide recovery, of the costs of facilities attributable to the service which has been terminated. At such time Customer shall cease paying the monthly charge attributable to the terminated service. In addition, if and to the extent that Customer terminates this Service Agreement and the Federal Energy Regulatory Commission or any other Agency having jurisdiction over the premises ever determines that the facilities attributable to such service are not used or useful in providing natural gas service on Pipeline's system or otherwise precludes Pipeline from recovering the full original cost of such facilities then Customer shall reimburse Pipeline the remaining initial cost of said facilities not previously recovered by Pipeline through depreciation charges. Such reimbursement shall not be applicable if and to the extent that Pipeline elects to terminate this Service Agreement.

Any portions of this Service Agreement necessary to correct or cash-out imbalances under this Service Agreement as required by the General Terms and Conditions of Pipeline's FERC Gas Tariff, Volume No. 1, shall survive the other parts of this Service Agreement until such time as such balancing has been accomplished.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-2
(Continued)

ARTICLE III

RATE SCHEDULE

This Service Agreement in all respects shall be and remain subject to the applicable provisions of Rate Schedule FTS-2 and of the General Terms and Conditions of Pipeline's FERC Gas Tariff on file with the Federal Energy Regulatory Commission, all of which are by this reference made a part hereof.

Customer shall pay Pipeline, for all services rendered hereunder and for the availability of such service in the period stated, the applicable prices established under Pipeline's Rate Schedule FTS-2 as filed with the Federal Energy Regulatory Commission and as the same may be hereafter revised or changed.

Customer agrees that Pipeline shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Pipeline's Rate Schedule FTS-2, (b) Pipeline's Rate Schedule FTS-2, pursuant to which service hereunder is rendered provided, however, that the firm character of service shall not be subject to change hereunder, or (c) any provision of the General Terms and Conditions applicable to Rate Schedule FTS-2. Pipeline agrees that Customer may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Pipeline's existing FERC Gas Tariff as may be found necessary to assure that the provisions in (a), (b), or (c) above are just and reasonable.

ARTICLE IV

CUSTOMER POINT(S) AND EQUITRANS POINT(S)

Natural gas to be received by Pipeline or for Customer's account for service hereunder shall be received on the outlet side of the measuring station at or near the following designated Customer Point(s) or Equitrans Point(s), and natural gas to be delivered by Pipeline for Customer's account hereunder shall be delivered at the outlet side of the measuring stations at or near the following designated Equitrans Point(s) or Customer Point(s), in accordance with the Maximum Daily Receipt Obligation (MDRO) plus Applicable Shrinkage, Maximum Daily Delivery Obligation (MDDO), and receipt and delivery pressure obligations and measurement responsibilities indicated below for each:

Customer Point	Maximum Daily Obligation	Pressure Obligation	Measurement Responsibilities

Equitrans Point	Maximum Daily Obligation	Pressure Obligation	Measurement Responsibilities

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-2
(Continued)

ARTICLE V

QUALITY

All natural gas tendered to Pipeline for Customer's account shall conform to the quality specifications set forth in Section 5 of Pipeline's General Terms and Conditions. Customer agrees that in the event Customer tenders for service hereunder and Pipeline agrees to accept natural gas which does not comply with Pipeline's quality specifications, as expressly provided for in Section 5 of Pipeline's General Terms and Conditions, Customer shall pay all costs associated with processing of such gas as necessary to comply with such quality specifications.

ARTICLE VI

ADDRESSES

Except as herein otherwise provided or as provided in the General Terms and Conditions of Pipeline's FERC Gas Tariff, any notice, request, demand, statement, bill or payment provided for in this Service Agreement, or any notice which any party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered, certified, or regular mail to the post office address of the parties hereto, as the case may be, as follows:

(a) Pipeline:

(b) Customer:

or such other address as either party shall designate by formal written notice.

ARTICLE VII

ASSIGNMENTS

Any company which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of Customer, or of Pipeline, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this Service Agreement; and either Customer or Pipeline may assign or pledge this Service Agreement under the provisions of any mortgage, deed of trust, indenture, bank credit agreement, assignment, receivable sale, or similar instrument which it has executed or may execute hereafter; otherwise, neither Customer nor Pipeline shall assign this Service Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other; provided further, however, that neither Customer nor Pipeline shall be released from its obligations hereunder without the consent of the other.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-2
(Continued)

ARTICLE VIII

INTERPRETATION

The interpretation and performance of this Service Agreement shall be in accordance with the laws of the State of Texas without recourse to the law regarding conflict of laws.

This Service Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter, State and Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

ARTICLE IX

CANCELLATION OF PRIOR CONTRACT(S)

This Service Agreement supersedes and cancels, as of the effective date of this Service Agreement, the contract(s) between the parties hereto as described below:

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be signed by their respective Presidents, Vice Presidents or other duly authorized agents and their respective corporate seals to be hereto affixed and attested by their respective Secretaries or Assistant Secretaries, the day and year first above written.

TEXAS EASTERN TRANSMISSION CORPORATION

By _____

ATTEST:

_____

_____

By _____

ATTEST:

_____

Original Sheet Nos. 850-854 are
being reserved for future use.

NOTICE OF TERMINATION

RATE SCHEDULE X-106

Exchange Agreement with Transcontinental
Gas Pipe Line Corporation
Dated May 23, 1978

The following tariff sheets have been superseded:

Second Revised Sheet Nos. 855 and 857 through 862
First Revised Sheet Nos. 856 and 862A through 865
Original Sheet Nos. 866 and 867

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. CP95-641-000, issued 11/9/95, 73 FERC ¶ 62,098 (1995).

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-7

This Service Agreement, made and entered into this ____day of _____, ____, by and between TEXAS EASTERN TRANSMISSION CORPORATION, a Delaware Corporation (herein called "Pipeline") and _____ (herein called "Customer", whether one or more),

W I T N E S S E T H:

WHEREAS,

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the parties do covenant and agree as follows:

ARTICLE I

SCOPE OF AGREEMENT

Subject to the terms, conditions and limitations hereof and of Pipeline's Rate Schedule FTS-7, Pipeline agrees to deliver on a firm basis for Customer's account quantities of gas up to the following quantity:

Maximum Daily Quantity (MDQ) _____ dth

Pipeline shall receive for Customer's account, at the Customer Point(s), for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the CNG Point(s), such daily quantities tendered up to such Customer's MDQ.

Pipeline shall receive for Customer's account, at the CNG Point(s), for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the Customer Point(s), such daily quantities tendered up to such Customer's MDQ.

Pipeline shall not be obligated to, but may at its discretion, receive at any Point of Receipt on any day a quantity of gas in excess of the applicable Maximum Daily Receipt Obligation (MDRO), plus Applicable Shrinkage, but shall not receive in the aggregate at all Points of Receipt on any day a quantity of gas in excess of the applicable MDQ, plus Applicable Shrinkage, as specified in the executed service agreement. Pipeline shall not be obligated to, but may at its discretion, deliver at any Point of Delivery on any day a quantity of gas in excess of the applicable Maximum Daily Delivery Obligation (MDDO), but shall not deliver in the aggregate at all Points of Delivery on any day a quantity of gas in excess of the applicable MDQ, as specified in the executed service agreement.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-7
(Continued)

ARTICLE II

TERM OF AGREEMENT

This Service Agreement shall become effective on _____ and shall continue in force for a primary term of _____ years; and from year to year thereafter unless terminated by either party upon twenty-four months' prior written notice. Subject to Section 22 of Pipeline's General Terms and Conditions and without prejudice to such rights, this Service Agreement may be terminated at any time by Pipeline in the event Customer fails to pay part or all of the amount of any bill for service hereunder and such failure continues for thirty (30) days after payment is due; provided, Pipeline gives thirty (30) days prior written notice to Customer of such termination and provided further such termination shall not be effective if, prior to the date of termination, Customer either pays such outstanding bill or furnishes a good and sufficient surety bond guaranteeing payment to Pipeline of such outstanding bill. Notwithstanding the foregoing, service shall not be terminated unless and until Pipeline has received abandonment authority pursuant to Section 7 of the Natural Gas Act. Customer shall have the right to oppose Pipeline's application to the Federal Energy Regulatory Commission, or any successor agency, for such abandonment authority. For the 120 days following termination of this Service Agreement, Pipeline shall utilize its best efforts to provide Customer with such additional interruptible transportation service, to be provided pursuant to Rate Schedule IT-1 or successor of Rate Schedule IT-1, as is necessary for Customer to withdraw and receive delivery of all gas remaining in storage pursuant to CNG's Rate Schedule GSS.

Any portions of this Service Agreement necessary to correct or cash-out imbalances under this Service Agreement as required by the General Terms and Conditions of Pipeline's FERC Gas Tariff, Volume No. 1, shall survive the other parts of this Service Agreement until such time as such balancing has been accomplished.

ARTICLE III

RATE SCHEDULE

This Service Agreement in all respects shall be and remain subject to the applicable provisions of Rate Schedule FTS-7 and of the General Terms and Conditions of Pipeline's FERC Gas Tariff on file with the Federal Energy Regulatory Commission, all of which are by this reference made a part hereof.

Customer shall pay Pipeline for, all services rendered hereunder and for the availability of such service in the period stated, the applicable prices established under Pipeline's Rate Schedule FTS-7 as filed with the Federal Energy Regulatory Commission and as the same may be hereafter revised or changed.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-7
(Continued)

Pipeline shall have the right from time to time, by the filing of a revised rate schedule, to increase or decrease the rates, to change the form of the applicable rate schedule and to take such other and further action with respect thereto without further consent by Customer and such changes in rates and other changes shall become the Rate Schedule and Terms and Conditions under which the gas shall be transported hereunder. Customer shall have the right to oppose any of the foregoing and to request reduction in rates to the extent that Customer is legally permitted to do so under the Natural Gas Act.

ARTICLE IV

CUSTOMER POINT(S) AND CNG POINT(S)

Natural gas to be received by Pipeline for Customer's account for service hereunder shall be received on the outlet side of the measuring station at or near the following designated Customer Point(s) or CNG Point(s), and natural gas to be delivered by Pipeline for Customer's account hereunder shall be delivered at the outlet side of the measuring stations at or near the following designated CNG Point(s) or Customer Point(s), in accordance with the Maximum Daily Receipt Obligation (MDRO) plus Applicable Shrinkage, Maximum Daily Delivery Obligation (MDDO), receipt and delivery pressure obligations and measurement responsibilities indicated below for each:

Customer Point	Maximum Daily Obligation	Pressure Obligation	Measurement Responsibilities

CNG Point	Maximum Daily Obligation	Pressure Obligation	Measurement Responsibilities

provided, however, receipt of gas by Pipeline for Customer's account at Customer Point(s) shall be accomplished solely by the displacement of gas quantities otherwise deliverable to Customer by Pipeline pursuant to other contractual arrangements between Pipeline and Customer, and which quantities shall be billed by Pipeline and paid by Customer as if such deliveries in fact occurred pursuant to the relevant contractual arrangements.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-7
(Continued)

ARTICLE V

QUALITY

All natural gas tendered to Pipeline for Customer's account shall conform to the quality specifications set forth in Section 5 of Pipeline's General Terms and Conditions. Customer agrees that in the event Customer tenders for service hereunder and Pipeline agrees to accept natural gas which does not comply with Pipeline's quality specifications, as expressly provided for in Section 5 of Pipeline's General Terms and Conditions, Customer shall pay all costs associated with processing of such gas as necessary to comply with such quality specifications.

ARTICLE VI

ADDRESSES

Except as herein otherwise provided or as provided in the General Terms and Conditions of Pipeline's FERC Gas Tariff, any notice, request, demand, statement, bill or payment provided for in this Service Agreement, or any notice which any party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered, certified, or regular mail to the post office address of the parties hereto, as the case may be, as follows:

(a) Pipeline:

(b) Customer:

or such other address as either party shall designate by formal written notice.

ARTICLE VII

ASSIGNMENTS

Any Company which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of Customer, or of Pipeline, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this Service Agreement; and either Customer or Pipeline may assign or pledge this Service Agreement under the provisions of any mortgage, deed of trust, indenture, bank credit agreement, assignment, receivable sale, or similar instrument which it has executed or may execute hereafter; otherwise, neither Customer nor Pipeline shall assign this Service Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other; provided further, however, that neither Customer nor Pipeline shall be released from its obligations hereunder without the consent of the other.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-7
(Continued)

ARTICLE VIII

INTERPRETATION

The interpretation and performance of this Service Agreement shall be in accordance with the laws of the State of Texas without recourse to the law governing conflict of laws.

This Service Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter, State and Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

ARTICLE IX

CANCELLATION OF PRIOR CONTRACT(S)

This Service Agreement supersedes and cancels, as of the effective date of this Service Agreement, the contract(s) between the parties hereto as described below:

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be signed by their respective Presidents, Vice Presidents or other duly authorized agents and their respective corporate seals to be hereto affixed and attested by their respective Secretaries or Assistant Secretaries, the day and year first above written.

TEXAS EASTERN TRANSMISSION CORPORATION

By _____

ATTEST:

_____

_____

By _____

ATTEST:

_____

Original Sheet Nos. 880-884 are
being reserved for future use.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-8

This Service Agreement, made and entered into this ____day of _____, ____, by and between TEXAS EASTERN TRANSMISSION CORPORATION, a Delaware Corporation (herein called "Pipeline") and _____ (herein called "Customer", whether one or more),

W I T N E S S E T H:

WHEREAS,

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the parties do covenant and agree as follows:

ARTICLE I

SCOPE OF AGREEMENT

Subject to the terms, conditions and limitations hereof and of Pipeline's Rate Schedule FTS-8, Pipeline agrees to deliver on a firm basis for Customer's account quantities of gas up to the following quantity:

Maximum Daily Quantity (MDQ) _____ dth

Pipeline shall receive for Customer's account, at the Customer Point(s), for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the CNG Point(s), such daily quantities tendered up to such Customer's MDQ.

Pipeline shall receive for Customer's account, at the CNG Point(s), for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the Customer Point(s), such daily quantities tendered up to such Customer's MDQ.

Pipeline shall not be obligated to, but may at its discretion, receive at any Point of Receipt on any day a quantity of gas in excess of the applicable Maximum Daily Receipt Obligation (MDRO), plus Applicable Shrinkage, but shall not receive in the aggregate at all Points of Receipt on any day a quantity of gas in excess of the applicable MDQ, plus Applicable Shrinkage, as specified in the executed service agreement. Pipeline shall not be obligated to, but may at its discretion, deliver at any Point of Delivery on any day a quantity of gas in excess of the applicable Maximum Daily Delivery Obligation (MDDO), but shall not deliver in the aggregate at all Points of Delivery on any day a quantity of gas in excess of the applicable MDQ, as specified in the executed service agreement.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-8
(Continued)

ARTICLE II

TERM OF AGREEMENT

This Service Agreement shall become effective on _____ and shall continue in force for a primary term of _____ years; and from year to year thereafter unless terminated by either party upon twenty-four months' prior written notice. Subject to Section 22 of Pipeline's General Terms and Conditions and without prejudice to such rights, this Service Agreement may be terminated at any time by Pipeline in the event Customer fails to pay part or all of the amount of any bill for service hereunder and such failure continues for thirty (30) days after payment is due; provided, Pipeline gives thirty (30) days prior written notice to Customer of such termination and provided further such termination shall not be effective if, prior to the date of termination, Customer either pays such outstanding bill or furnishes a good and sufficient surety bond guaranteeing payment to Pipeline of such outstanding bill. Notwithstanding the foregoing, service shall not be terminated unless and until Pipeline has received abandonment authority pursuant to Section 7 of the Natural Gas Act. Customer shall have the right to oppose Pipeline's application to the Federal Energy Regulatory Commission, or any successor agency, for such abandonment authority. For the 120 days following termination of this Service Agreement, Pipeline shall utilize its best efforts to provide Customer with such additional interruptible transportation service, to be provided pursuant to Rate Schedule IT-1 or successor of Rate Schedule IT-1, as is necessary for Customer to withdraw and receive delivery of all gas remaining in storage pursuant to CNG's Rate Schedule GSS.

Any portions of this Service Agreement necessary to correct or cash-out imbalances under this Service Agreement as required by the General Terms and Conditions of Pipeline's FERC Gas Tariff, Volume No. 1, shall survive the other parts of this Service Agreement until such time as such balancing has been accomplished.

ARTICLE III

RATE SCHEDULE

This Service Agreement in all respects shall be and remain subject to the applicable provisions of Rate Schedule FTS-8 and of the General Terms and Conditions of Pipeline's FERC Gas Tariff on file with the Federal Energy Regulatory Commission, all of which are by this reference made a part hereof.

Customer shall pay Pipeline for, all services rendered hereunder and for the availability of such service in the period stated, the applicable prices established under Pipeline's Rate Schedule FTS-8 as filed with the Federal Energy Regulatory Commission and as the same may be hereafter revised or changed.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-8
(Continued)

Pipeline shall have the right from time to time, by the filing of a revised rate schedule, to increase or decrease the rates, to change the form of the applicable rate schedule and to take such other and further action with respect thereto without further consent by Customer and such changes in rates and other changes shall become the Rate Schedule and Terms and Conditions under which the gas shall be transported hereunder. Customer shall have the right to oppose any of the foregoing and to request reduction in rates to the extent that Customer is legally permitted to do so under the Natural Gas Act.

ARTICLE IV

CUSTOMER POINT(S) AND CNG POINT(S)

Natural gas to be received by Pipeline for Customer's account for service hereunder shall be received on the outlet side of the measuring station at or near the following designated Customer Point(s) or CNG Point(s), and natural gas to be delivered by Pipeline for Customer's account hereunder shall be delivered at the outlet side of the measuring stations at or near the following designated CNG Point(s) or Customer Point(s), in accordance with the Maximum Daily Receipt Obligation (MDRO) plus Applicable Shrinkage, Maximum Daily Delivery Obligation (MDDO), receipt and delivery pressure obligations and measurement responsibilities indicated below for each:

Customer Point	Maximum Daily Obligation	Pressure Obligation	Measurement Responsibilities

CNG Point	Maximum Daily Obligation	Pressure Obligation	Measurement Responsibilities

provided, however, receipt of gas by Pipeline for Customer's account at Customer Point(s) shall be accomplished solely by the displacement of gas quantities otherwise deliverable to Customer by Pipeline pursuant to other contractual arrangements between Pipeline and Customer, and which quantities shall be billed by Pipeline and paid by Customer as if such deliveries in fact occurred pursuant to the relevant contractual arrangements.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-8
(Continued)

ARTICLE V

QUALITY

All natural gas tendered to Pipeline for Customer's account shall conform to the quality specifications set forth in Section 5 of Pipeline's General Terms and Conditions. Customer agrees that in the event Customer tenders for service hereunder and Pipeline agrees to accept natural gas which does not comply with Pipeline's quality specifications, as expressly provided for in Section 5 of Pipeline's General Terms and Conditions, Customer shall pay all costs associated with processing of such gas as necessary to comply with such quality specifications.

ARTICLE VI

ADDRESSES

Except as herein otherwise provided or as provided in the General Terms and Conditions of Pipeline's FERC Gas Tariff, any notice, request, demand, statement, bill or payment provided for in this Service Agreement, or any notice which any party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered, certified, or regular mail to the post office address of the parties hereto, as the case may be, as follows:

(a) Pipeline:

(b) Customer:

or such other address as either party shall designate by formal written notice.

ARTICLE VII

ASSIGNMENTS

Any Company which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of Customer, or of Pipeline, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this Service Agreement; and either Customer or Pipeline may assign or pledge this Service Agreement under the provisions of any mortgage, deed of trust, indenture, bank credit agreement, assignment, receivable sale, or similar instrument which it has executed or may execute hereafter; otherwise, neither Customer nor Pipeline shall assign this Service Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other; provided further, however, that neither Customer nor Pipeline shall be released from its obligations hereunder without the consent of the other.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE FTS-8
(Continued)

ARTICLE VIII

INTERPRETATION

The interpretation and performance of this Service Agreement shall be in accordance with the laws of the State of Texas without recourse to the law governing conflict of laws.

This Service Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter, State and Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

ARTICLE IX

CANCELLATION OF PRIOR CONTRACT(S)

This Service Agreement supersedes and cancels, as of the effective date of this Service Agreement, the contract(s) between the parties hereto as described below:

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be signed by their respective Presidents, Vice Presidents or other duly authorized agents and their respective corporate seals to be hereto affixed and attested by their respective Secretaries or Assistant Secretaries, the day and year first above written.

TEXAS EASTERN TRANSMISSION CORPORATION

By _____

ATTEST:

_____

_____

By _____

ATTEST:

_____

Original Sheet Nos. 890-894 are
being reserved for future use.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE CTS

This Service Agreement, made and entered into this _____ day of _____, ____, by and between TEXAS EASTERN TRANSMISSION CORPORATION, a Delaware Corporation (herein called "Pipeline"), and COLUMBIA GAS TRANSMISSION CORPORATION (herein called "Customer"),

W I T N E S S E T H:

WHEREAS,

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the parties do covenant and agree as follows:

ARTICLE I

SCOPE OF AGREEMENT

Subject to the terms, conditions and limitations hereof and of Pipeline's Rate Schedule CTS, Pipeline agrees to deliver on a firm basis for Customer's account quantities of natural gas up to the following quantity:

Maximum Daily Quantity (MDQ) _____ dth

Pipeline shall receive for Customer's account, at the Point(s) of Receipt, for transportation hereunder daily quantities of gas up to Customer's MDQ, plus Applicable Shrinkage. Pipeline shall transport and deliver for Customer's account, at the Point(s) of Delivery, such daily quantities tendered up to such Customer's MDQ.

Pipeline shall not be obligated to, but may at its discretion, receive at any Point of Receipt on any day a quantity of gas in excess of the applicable Maximum Daily Receipt Obligation (MDRO), plus Applicable Shrinkage, but shall not receive in the aggregate at all Points of Receipt on any day a quantity of gas in excess of the applicable MDQ, plus Applicable Shrinkage, as specified in the executed service agreement. Pipeline shall not be obligated to, but may at its discretion, deliver at any Point of Delivery on any day a quantity of gas in excess of the applicable Maximum Daily Delivery Obligation (MDDO), but shall not deliver in the aggregate at all Points of Delivery on any day a quantity of gas in excess of the applicable MDQ, as specified in the executed service agreement.

ARTICLE II

TERM OF AGREEMENT

This Service Agreement shall become effective on the in-service date hereunder and shall continue in force and effect until and including October 31, 2010, unless this Service Agreement is terminated earlier as

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE SS

This Service Agreement, made and entered into this ___ day of _____ ___, by and between TEXAS EASTERN TRANSMISSION CORPORATION, a Delaware Corporation (herein called "Pipeline") and _____ (herein called "Customer", whether one or more),

W I T N E S S E T H :

WHEREAS,

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the parties do covenant and agree as follows:

ARTICLE I

SCOPE OF AGREEMENT

Subject to the terms, conditions and limitations here of and of Pipeline's Rate Schedule SS, Pipeline agrees to provide firm service for Customer under Rate Schedule SS and to store for Customer quantities of natural gas up to the following quantity:

Maximum Storage Quantity (MSQ)_____ dth

Pipeline agrees to withdraw from storage for Customer, at Customer's request, quantities of gas up to Customer's Maximum Daily Quantity (MDQ) of _____ dekatherms, from Customer's Storage Inventory up to Customer's MSQ, plus Applicable Shrinkage, and deliver for Customer's account such quantities.

ARTICLE II

TERM OF AGREEMENT

The term of this Service Agreement shall commence on _____ and shall continue in force and effect until _____ and _____ to _____ thereafter unless this Service Agreement is terminated as hereinafter provided. This Service Agreement may be terminated by either Pipeline or Customer upon _____ [at least two (2) years for long-term service agreements; mutually agreeable for short-term service agreements] prior written notice to the other specifying a termination date of any _____ occurring on or after the expiration of the primary term. Subject to Section 22 of Pipeline's General Terms and Conditions and without prejudice to such rights, this Service Agreement may be terminated at any time by Pipeline in the event Customer fails to pay part or all of the amount of any bill for service hereunder and such failure continues for thirty (30) days after payment is due; provided, Pipeline gives thirty (30) days prior written notice to Customer of such termination and provided further such termination shall not be effective if, prior to the date of termination, Customer either pays such outstanding bill or furnishes a good and sufficient surety bond guaranteeing payment to Pipeline of such outstanding bill.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE SS
(Continued)

In the event there is gas in storage for Customer's account on April 30 of the year of termination of this Service Agreement, this Service Agreement shall continue in force and effect for the sole purpose of withdrawal and delivery of said gas to Customer for an additional one-hundred and twenty (120) days.

ARTICLE III

RATE SCHEDULE

This Service Agreement in all respects shall be and remain subject to the applicable provisions of Rate Schedule SS and of the General Terms and Conditions of Pipeline's FERC Gas Tariff on file with the Federal Energy Regulatory Commission, all of which are by this reference made a part hereof.

Customer shall pay Pipeline, for all services rendered hereunder and for the availability of such service in the period stated, the applicable prices established under Pipeline's Rate Schedule SS as filed with the Federal Energy Regulatory Commission and as same may hereafter be legally amended or superseded.

Customer agrees that Pipeline shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Pipeline's Rate Schedule SS, (b) Pipeline's Rate Schedule SS, pursuant to which service hereunder is rendered or (c) any provision of the General Terms and Conditions applicable to Rate Schedule SS. Notwithstanding the foregoing, Customer does not agree that Pipeline shall have the unilateral right without the consent of Customer subsequent to the execution of this Agreement and Pipeline shall not have the right during the effectiveness of the service agreement to make any filings pursuant to Section 4 of the Natural Gas Act to change the MSQ and MDQ specified in Article I, to change the term of the service agreement as specified in Article II, to change Point(s) of Receipt specified in Article IV, to change the Point(s) of Delivery specified in Article IV, or to change the firm character of the service hereunder. Pipeline agrees that Customer may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Pipeline's existing FERC Gas Tariff as may be found necessary to assure that the provisions in (a), (b), or (c) above are just and reasonable.

ARTICLE IV

POINT(S) OF RECEIPT AND POINT(S) OF DELIVERY

The natural gas received by Pipeline for Customer's account for storage injection pursuant to this Service Agreement shall be those quantities scheduled for delivery pursuant to service agreements between Pipeline and Customer under Rate Schedules CDS, FT-1, IT-1 or PTI which specify as a Point of Delivery the "SS Storage Point". For purposes of billing of Usage Charges under Rate Schedules CDS, FT-1, IT-1 or PTI

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE SS
(Continued)

deliveries under Rate Schedules CDS, FT-1, IT-1 or PTI for injection into storage shall be deemed to have been delivered 60% in Market Zone 2 and 40% in Market Zone 3.

The Point(s) of Delivery at which Pipeline shall deliver gas shall be specified in Exhibit A of the executed service agreement.

Exhibit A is hereby incorporated as part of this Service Agreement for all intents and purposes as if fully copied and set forth herein at length.

ARTICLE V

QUALITY

All natural gas tendered to Pipeline for Customer's account shall conform to the quality specifications set forth in Section 5 of Pipeline's General Terms and Conditions. Customer agrees that in the event Customer tenders for service hereunder and Pipeline agrees to accept natural gas which does not comply with Pipeline's quality specifications, as expressly provided for in Section 5 of Pipeline's General Terms and Conditions, Customer shall pay all costs associated with processing of such gas as necessary to comply with such quality specifications.

ARTICLE VI

ADDRESSES

Except as herein otherwise provided or as provided in the General Terms and Conditions of Pipeline's FERC Gas Tariff, any notice, request, demand, statement, bill or payment provided for in this Service Agreement, or any notice which any party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered, certified, or regular mail to the post office address of the parties hereto, as the case may be, as follows:

(a) Pipeline:

(b) Customer:

or such other address as either party shall designate by formal written notice.

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE SS
(Continued)

ARTICLE VII

ASSIGNMENTS

Any Company which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of Customer, or of Pipeline, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this Service Agreement; and either Customer or Pipeline may assign or pledge this Service Agreement under the provisions of any mortgage, deed of trust, indenture, bank credit agreement, assignment, receivable sale, or similar instrument which it has executed or may execute hereafter; otherwise, neither Customer nor Pipeline shall assign this Service Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other; provided further, however, that neither Customer nor Pipeline shall be released from its obligations hereunder without the consent of the other.

ARTICLE VIII

INTERPRETATION

The interpretation and performance of this Service Agreement shall be in accordance with the laws of the State of Texas without recourse to the law regarding the conflict of laws.

This Service Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter, either State or Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

ARTICLE IX

CANCELLATION OF PRIOR CONTRACT(S)

This Service Agreement supersedes and cancels, as of the effective date of this Service Agreement, the contract(s) between the parties hereto as described below:

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE SS
(Continued)

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be signed by their respective Presidents, Vice Presidents or other duly authorized agents and their respective corporate seals to be hereto affixed and attested by their respective Secretaries or Assistant Secretaries, the day and year first above written.

TEXAS EASTERN TRANSMISSION CORPORATION

By _____

ATTEST:

_____

_____

By _____

ATTEST:

_____

FORM OF SERVICE AGREEMENT
FOR RATE SCHEDULE SS
(Continued)

EXHIBIT A, POINT(S) OF DELIVERY, DATED _____,
TO THE SERVICE AGREEMENT UNDER RATE SCHEDULE SS
BETWEEN TEXAS EASTERN TRANSMISSION CORPORATION ("Pipeline")
AND _____ ("Customer"), DATED _____:

Point of Delivery	Description	Maximum Daily Delivery Obligation	Delivery Pressure Obligation	Measurement Responsibilities	Owner	Operator

SIGNED FOR IDENTIFICATION:

PIPELINE: _____

CUSTOMER: _____

SUPERSEDES EXHIBIT A DATED _____

ANR Pipeline

04-May-00

ANR PIPELINE COMPANY
FIRM STORAGE AND TRANSPORTATION SERVICE

PHILADELPHIA GAS WORKS
SEASONAL UNRATCHED SERVICE
APRIL 2000 THRU MARCH 2001

STORAGE AND TRANSPORTATION DATA

Days of Service	137	Days
Injection Period	7	Months
Withdrawal Period	5	Months
Injection Rate	200	Days
Maximum Storage Quantity	1,894,299	Dth
Maximum Daily Injection Quantity	9,471	Dth per Day
Maximum Daily Withdrawal Quantity	13,827	Dth per Day
MDQ at Delivery Point	13,665	Dth per Day
Fuel - Storage to Market	1.17	Percent
Fuel - Storage	0.99	Percent

Firm Storage Rates - FSS K# 31800 Exp. 03/31/2013

Reservation Charges	Rate	Months	MDQ Volume	Cost
- Deliverability (04/00-03/01)	$2.6000 / month / dth	12	13,827	$431,402
- Capacity (04/00-03/01)	$0.4000 / dth	12	1,894,299	$757,720
Commodity Charges				
- Injection (04/00-10/00)	$0.0126 / dth	7	1,894,299	$23,868
- Withdrawal (11/00-03/01)	$0.0126 / dth	5	1,894,299	$23,868
		Total		$1,236,858

Firm Transportation Rates - FTS-1 K# 12850 Exp. 03/31/2013

Reservation Charges	Rate	Months	MDQ Volume	Cost
- Injection (04/00-10/00)	$6.0000 / month / dth	7	9,566	$401,759
- Withdrawal (11/00-03/01)	$2.5900 / month / dth	5	13,665	$176,962
Commodity Charges				
- Injection (04/00-10/00)	$0.0095 / dth	7	1,913,240	$18,176
- Withdrawal (11/00-03/01)	$0.0095 / dth	5	1,872,105	$17,785
		Total		$614,682
			Grand Total	$1,851,540
			Total Unit Rate	$0.9890

Notes: 1. Rates per applicable approved FERC filings.
2. Rate cap = $0.989 inclusive of B/B (if applicable) and Dakota, however, Dakota is waived; Exclusive of Transition costs, ACA, GRI and Fuel.
3. Overrun at Commodity rate.
4. Secondary routes and release of Capacity at maximum Tariff rates for Transport K# 12850.

RATE SCHEDULE FTS-1
MATRIX OF BASE TARIFF TRANSMISSION RATES BY ROUTE
EXCLUSIVE OF ADDITIONAL CHARGES OR SURCHARGES

RECEIVED FROM \ DELIVERED TO		SOUTHEAST			SOUTHWEST			
		S.E. Area (SE)	Southern Segment (ML-2)	Central Segment (ML-3)	S.W. Area (SW)	Southern Segment (ML-5)	Central Segment (ML-6)	NORTHERN Segment (ML-7)
SOUTHEAST AREA (SE)	- Res	$1.6860	$8.7020	$9.7730	$15.0070	$13.0960	$12.1260	$10.9680
	- Cmd	0.0019	0.0059	0.0070	0.0138	0.0105	0.0095	0.0084
	- MIN	0.0019	0.0059	0.0070	0.0138	0.0105	0.0095	0.0084
	- Ovrn	0.0574	0.2922	0.3285	0.5075	0.4413	0.4084	0.3692
SE - Southern (ML-2)	- Res	$8.7020	$7.0160	$8.0870	$13.3210	$11.4100	$10.4400	$9.2820
	- Cmd	0.0059	0.0040	0.0051	0.0119	0.0086	0.0076	0.0065
	- MIN	0.0059	0.0040	0.0051	0.0119	0.0086	0.0076	0.0065
	- Ovrn	0.2922	0.2348	0.2711	0.4501	0.3839	0.3510	0.3118
SE - Central (ML-3)	- Res	$9.7730	$8.0870	$6.2560	$11.4900	$9.5790	$8.6090	$7.4510
	- Cmd	0.0070	0.0051	0.0034	0.0102	0.0069	0.0059	0.0048
	- MIN	0.0070	0.0051	0.0034	0.0102	0.0069	0.0059	0.0048
	- Ovrn	0.3285	0.2711	0.2092	0.3882	0.3220	0.2891	0.2499
SOUTHWEST AREA (SW)	- Res	$15.0070	$13.3210	$11.4900	$1.9110	$8.0660	$9.2240	$10.4190
	- Cmd	0.0138	0.0119	0.0102	0.0033	0.0066	0.0077	0.0091
	- MIN	0.0138	0.0119	0.0102	0.0033	0.0066	0.0077	0.0091
	- Ovrn	0.5075	0.4501	0.3882	0.0662	0.2719	0.3111	0.3518
SW - Southern (ML-5)	- Res	$13.0960	$11.4100	$9.5790	$8.0660	$6.1550	$7.3130	$8.5080
	- Cmd	0.0105	0.0086	0.0069	0.0066	0.0033	0.0044	0.0058
	- MIN	0.0105	0.0086	0.0069	0.0066	0.0033	0.0044	0.0058
	- Ovrn	0.4413	0.3839	0.3220	0.2719	0.2058	0.2450	0.2857
SW - Central (ML-6)	- Res	$12.1260	$10.4400	$8.6090	$9.2240	$7.3130	$6.3430	$7.5380
	- Cmd	0.0095	0.0076	0.0059	0.0077	0.0044	0.0034	0.0048
	- MIN	0.0095	0.0076	0.0059	0.0077	0.0044	0.0034	0.0048
	- Ovrn	0.4084	0.3510	0.2891	0.3111	0.2450	0.2121	0.2528
NORTHERN (ML-7)	- Res	$10.9680	$9.2820	$7.4510	$10.4190	$8.5080	$7.5380	$6.3800
	- Cmd	0.0084	0.0065	0.0048	0.0091	0.0058	0.0048	0.0037
	- MIN	0.0084	0.0065	0.0048	0.0091	0.0058	0.0048	0.0037
	- Ovrn	0.3692	0.3118	0.2499	0.3518	0.2857	0.2528	0.2136

General Note: All rates shown combine area and segment rates for each route, utilizing the transmission rates set forth on Sheet No. 12 and represent maximum rates unless designated as minimum firm service rates (MIN).

STATEMENT OF RATES FOR
STORAGE OF NATURAL GAS

	Maximum Rate per Dth	Minimum Rate per Dth
RATE SCHEDULE FSS		
With Ratchets and Seasonal Entitlements		
1. Reservation Rate		
a. Deliverability Rate	$ 1.98	$ 0
b. Capacity Rate	$ .3891	$ 0
2. Commodity Rate Injection/Withdrawal	$ 0.0031	$ 0.0031
3. Overrun Service Rate	1/	$ 0.0031
With Ratchets and Annual Entitlements		
1. Reservation Rate		
a. Deliverability Rate	$ 2.46	$ 0
b. Capacity Rate	$ .3891	$ 0
2. Commodity Rate Injection/Withdrawal	$ 0.0031	$ 0.0031
3. Overrun Service Rate	1/	$ 0.0031
Without Ratchets and Seasonal Entitlements		
1. Reservation Rate		
a. Deliverability Rate	$ 2.47	$ 0
b. Capacity Rate	$ .3891	$ 0
2. Commodity Rate Injection/Withdrawal	$ 0.0031	$ 0.0031
3. Overrun Service Rate	1/	$ 0.0031
Without Ratchets and Annual Entitlements		
1. Reservation Rate		
a. Deliverability Rate	$ 2.95	$ 0
b. Capacity Rate	$ .3891	$ 0
2. Commodity Rate Injection/Withdrawal	$ 0.0031	$ 0.0031
3. Overrun Service Rate	1/	$ 0.0031
RATE SCHEDULE DDS		
1. Storage Commodity Rate	$ .0823	$ 0.0031

1/ 100% Load Factor Rate. See Section 3.5 of Rate Schedule FSS.

(RP)

ANR PIPELINE COMPANY
TRANSPORTER'S USE (%)

1. For all transmission transportation services in Volume Nos. 1 and 2:

(PERCENTAGE)

	TO:	SOUTHEAST			SOUTHWEST			
FROM:		S.E. AREA (SE)	SOUTHERN SEGMENT (ML-2)	CENTRAL SEGMENT (ML-3)	S.W. AREA (SW)	SOUTHERN SEGMENT (ML-5)	CENTRAL SEGMENT (ML-6)	NORTHERN SEGMENT (ML-7)
SOUTHEAST AREA (SE)		1.3	2.7	3.8	2.0	2.9	4.4	4.4
S.E. SOUTHERN SEGMENT (ML-2)		--	2.3	3.4	1.6	2.5	4.0	4.0
S.E. CENTRAL SEGMENT (ML-3)		--	--	2.0	--	1.1	2.6	2.6
SOUTHWEST AREA (SW)		2.6	4.0	5.1	2.1	3.0	4.5	5.1
S.W. SOUTHERN SEGMENT (ML-5)		1.4	2.8	3.9	--	1.8	3.3	3.9
S.W. CENTRAL SEGMENT (ML-6)		--	1.9	3.0	--	--	2.4	3.0
NORTHERN SEGMENT (ML-7)		--	--	1.5	--	--	1.5	1.5

NOTES: (a) There will be no charge for Transporter's Use on Backhauls.

(b) The areas and segments listed above are defined in Section 1 of the General Terms and Conditions of this Tariff, and are illustrated on the system map on Sheet No. 4.

2. For Rate Schedules FSS and IDS storage services, Transporter's Use (%): 1.3%

3. In the case of any Shipper that purchases Gas from a Pooler, the provisions of Rate Schedules PTS-1, PTS-2 and PTS-3 shall be applicable.

(RP)

RATE SCHEDULE FTS-1
Firm Transportation Service

1. AVAILABILITY

This Rate Schedule is available to any person, corporation, partnership or any other party (hereinafter referred to as "Shipper") for the transportation of Gas by Transporter, subject to the following limitations:

(a) Transporter has determined that it has sufficient available and uncommitted capacity to perform service requested by Shipper; and

(b) Shipper and Transporter have executed an Agreement under this Rate Schedule, or conformed an existing Agreement to be consistent with this Rate Schedule.

2. APPLICABILITY AND CHARACTER OF SERVICE

(a) This Rate Schedule shall apply to all transportation service rendered by Transporter for Shipper pursuant to the executed Agreement under this Rate Schedule.

(b) Transportation service under this Rate Schedule shall consist of: (1) the receipt of Gas on behalf of Shipper, (2) the transportation of Gas, and (3) the Tender of Gas for delivery by Transporter to Shipper, or for Shipper's account.

(c) Transportation service rendered under this Rate Schedule shall be firm, up to the Primary Route MDQs specified in the executed Agreement.

3. CHARGES

Each Month Shipper shall pay to Transporter the following charges:

3.1 Reservation Charges.

(a) For each Dekatherm of MDQ, the applicable Reservation Rate(s), as stated on Sheet No. 7, for each Pooling Area or Mainline Segment (together, "Rate Segment(s)") traversed by the Primary Route designated for such MDQ.

RATE SCHEDULE FTS-1
Firm Transportation Service
(Continued)

(b) If, in any Month, Shipper nominates quantities at Secondary Receipt Points or Secondary Delivery Points, and all of such Secondary Points are within Rate Segment(s) for which capacity is reserved pursuant to Section 3.1(a), above, no Reservation Charges associated with the use of additional Rate Segment(s) shall be applicable.

(c) If, in any Month, Shipper nominates quantities at Secondary Receipt Point(s) or Secondary Delivery Point(s) that are outside of Rate Segment(s) or portion(s) thereof, for which capacity is reserved pursuant to Section 3.1(a), above, Shipper shall pay on a pro rata basis for each Day of such nomination the applicable Reservation Rate(s), as stated on Sheet Nos. 7 and/or 68G, that Transporter otherwise would charge for transportation to or from those additional Rate Segment(s) or portion(s) thereof.

(d) If Transporter fails to Tender Gas for redelivery at the Delivery Point(s) for the account of a Shipper during any Day, due to the Transporter's scheduling of necessary maintenance and repair of pipeline facilities, necessary maintenance and repair of compression facilities, and/or facility outages for tie-in of new facilities, the quantity of Gas that Shipper has nominated, or makes available to Transporter on such Day, or Shipper's MDQ, whichever is less, then subject to the provisions of the General Terms and Conditions, the portion of the monthly bill of such Shipper which is attributable to the Reservation Charges shall be reduced by an amount equal to the combined Reservation Rates divided by 30.4, and multiplied by the difference between such quantity of Gas nominated or made available for delivery by Shipper, whichever is less, up to the MDQ, and the quantity actually delivered by Transporter for the account of Shipper during such Day.

(RP)

RATE SCHEDULE FTS-1
Firm Transportation Service
(Continued)

(e) If, at the commencement or termination of the Agreement, service is provided for only a portion of a Service Month, any applicable Reservation Charges shall be prorated for the number of Days that service is provided.

3.2 Commodity Charges

(a) A Commodity Rate, as stated on Sheet No. 7 and, if applicable, Sheet No. 68G, shall be paid for each Dekatherm of Gas Delivered Hereunder to or on behalf of Shipper for each Nomination Route during the Month.

(b) Other Applicable Charges or Surcharges. All applicable reservation and volumetric charges or surcharges, including but not limited to those charges under Sections 24 through 29 of the General Terms and Conditions, for each Dekatherm of MDQ, or Gas Delivered Hereunder, as applicable. Such charges or surcharges are shown on Sheet Nos. 17 and 18.

3.3 Daily Scheduling Penalties. Only Shippers identified in Section 14.1(a)(3)(iii) may be subject to daily scheduling penalties, and only on each Dekatherm of the quantities of variance set forth therein that exceeds the Swing Percentage. The rate for any such daily scheduling penalty per Dekatherm shall be the highest applicable Rate Schedule ITS Maximum Rate to that Delivery Point.

3.4 Authorized Overrun Service. Transporter may authorize Shipper to take hereunder daily overrun quantities of Gas to the extent that, in the sole judgment of Transporter, the delivery capacity of Transporter's Pipeline System will permit such delivery without jeopardizing the ability of Transporter to meet all of its other firm service delivery obligations. The term "Authorized Daily Overrun Quantity" shall mean the quantity of Gas which is authorized and delivered by Transporter during any one Day in excess of any of Shipper's Primary Route MDQs. Any request for Authorized Daily Overrun Quantity Gas must be made by Shipper at least twenty-four (24) hours prior to the beginning of the Day to which such request relates. Transporter may waive part or all of such advance notice requirement if, in its judgment, operating conditions

(RP)

RATE SCHEDULE FTS-1
Firm Transportation Service
(Continued)

permit such waiver. In addition to other applicable charges, Shipper shall pay a commodity charge for each Dekatherm of Authorized Daily Overrun Quantity equal to (a) the applicable maximum Reservation Rates divided by 30.4, plus (b) in the case of utilization of any Secondary Receipt or Delivery Points, the applicable incremental maximum Reservation Rate(s) set forth in Section 3.1(c), above, divided by 30.4.

(RP)

RATE SCHEDULE FTS-1
Firm Transportation Service
(Continued)

3.5 Unauthorized Overrun Service.

(a) Each Dekatherm of Gas Delivered Hereunder to Shipper pursuant to Section 14 of the General Terms and Conditions of this Second Revised Volume No. 1 FERC Gas Tariff on any Day, which is in excess of any of Shipper's Primary Route MDQs, which has not been authorized under Section 3.4 of this Rate Schedule, shall be considered as "Unauthorized Daily Overrun Quantity" and shall be subject to a penalty rate equal to the greater of ten dollars ($10.00) or two times the Spot Price Index for the Service Month, as defined in Section 16 of the General Terms and Conditions, in addition to all the charges set forth in Section 3.4 above.

(b) Each Dekatherm of Gas Delivered Hereunder to Shipper as an Unauthorized Daily Overrun Quantity at any time after Transporter has issued an express order to Shipper to cease and desist shall be subject to a penalty rate equal to twelve (12) times the sum of the applicable maximum Reservation Rates under this Rate Schedule, in addition to all of the charges set forth in Sections 3.4 and 3.5(a), above.

3.6 Fuel Reimbursement. Shipper shall furnish at Receipt Point(s) the Gas for Transporter's Use utilizing the applicable Transporter's Use (%) set forth on Sheet No. 19 and, if applicable, Sheet No. 68H.

3.7 Third Party Charges. Shipper shall be responsible for delivering all Gas to Transporter's system, and shall be free to contract with Third Party(s) to achieve such result. If Shipper requests, and Transporter agrees, that Transporter

RATE SCHEDULE FTS-1
Firm Transportation Service
(Continued)

shall, for service to Shipper, use transportation service which Transporter has contracted for with Third Party(s) for Shipper on or after November 1, 1989, Shipper shall pay Transporter an amount equal to the charges Transporter is obligated to pay to Third Party(s) for transportation or other services attributable to performance of Service on behalf of Shipper under this Rate Schedule. Such charges include, but are not limited to, compression fuel charges, compression fees, Gas handling fees, measurement fees, processing fees, facility rents, or charges that Transporter pays to a Third Party for Transportation of Shipper's Gas, including Third Party's filing and regulatory fees. Such charges, as they may be from time to time, shall be set forth as separate items on billings rendered to Shipper.

3.8 Rate Changes. Subject to any limitations agreed to by Shipper and Transporter, Transporter may from time to time and at any time selectively adjust any or all of the rates charged to any individual Shipper for any and all of the transportation routes for which a Maximum Rate and Minimum Rate are stated on Sheet No. 7 of this Second Revised Volume No. 1 FERC Gas Tariff or a superseding Tariff; provided, however, that such adjusted rate(s) shall not exceed the applicable Maximum Rate(s), nor shall they be less than the Minimum Rate(s), set forth on such sheets. Transporter shall have the right to charge the Maximum Rate at any time as a condition for new service, or for continuation of service under an existing Agreement, or pursuant to Sections 4.1(b) and 4.2(b) of the General Terms and Conditions. Transporter shall make all information filings required by the Commission's regulations with respect to any charges at less than the Maximum Rate.

3.9 Cashout of Monthly Imbalances. Transporter or Shipper, as the case may be, shall be responsible for payment of the Cashout amount(s) provided for in Section 15 of the General Terms and Conditions.

RATE SCHEDULE FTS-1
Firm Transportation Service
(Continued)

4. SMALL SHIPPER SERVICE OPTION

Any Shipper that meets all of the eligibility requirements set forth in Sections 1(a), (c), (e) and (f) of Rate Schedule STS shall not be subject to Sections 3.1 and 3.2(a), but shall be charged the one-part rate set forth on Sheet No. 6, applicable to each Nomination Route for each Dekatherm of Gas Delivered hereunder including applicable charges and surcharges. In addition, any such Shipper shall be charged for each Dekatherm of authorized overrun service pursuant to Section 3.4 hereunder the applicable rate set forth on Sheet No. 6, plus all applicable charges and surcharges.

5. COMMISSION AND OTHER REGULATORY FEES

Shipper shall reimburse Transporter directly for any separately stated fees required by the Commission or any other federal or any state regulatory body which are related to service provided under this Rate Schedule.

6. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions of this Second Revised Volume No. 1 FERC Gas Tariff are hereby specifically incorporated herein and made a part of this Rate Schedule.

RATE SCHEDULE FSS
FIRM STORAGE SERVICE

1. AVAILABILITY

This Rate Schedule is available to any person, corporation, partnership or any other party (hereinafter referred to as "Shipper") for the purchase of storage service from Transporter, subject to the following limitations:

(a) Transporter has determined that it has sufficient available and uncommitted storage capacity to perform service requested by Shipper; and

(b) Shipper and Transporter have executed an Agreement under this Rate Schedule, or conformed an existing Agreement to be consistent with this Rate Schedule.

2. APPLICABILITY

(a) This Rate Schedule shall apply to all storage service which is rendered by Transporter for Shipper pursuant to an executed Agreement under this Rate Schedule.

(b) If a Shipper contracts for storage service hereunder, Shipper shall arrange for Transportation of the Gas to be stored to and from the Point of Injection/Withdrawal, by appropriate agreement with Transporter pursuant to Transporter's Rate Schedules ETS, FTS-1, FTS-2 or ITS.

(c) Storage service rendered by Transporter under this Rate Schedule shall consist of:

(1) The receipt during the Injection Period of Gas on behalf of Shipper at the Point of Injection/Withdrawal up to the Maximum Storage Quantity at daily rates up to (i) the Maximum Daily Injection Quantity plus (ii) any NNE (as defined in Rate Schedule NNS) of such Shipper;

(2) The storage of Gas in quantities not to exceed the Maximum Storage Quantity; and

(3) The tender during the Withdrawal Period of Gas for delivery by Transporter to Shipper at the Point of Injection/Withdrawal at daily rates up to the Maximum

RATE SCHEDULE FSS
FIRM STORAGE SERVICE
(Continued)

Daily Withdrawal Quantity, provided that the quantities delivered in the Winter Period cannot exceed the Maximum Storage Quantity.

(d) If Shipper has renewed its service hereunder, for the next succeeding Storage Contract Year, Shipper shall be required to reduce its Working Storage Gas to twenty percent (20%) of the Maximum Storage Quantity by the end of the Winter Period.

(e) Storage service under this Rate Schedule shall be firm during the Withdrawal Period, up to the Maximum Daily Withdrawal Quantity and shall be firm during the Injection Period up to the quantities specified in Section 2(c)(1) of this Rate Schedule. The Maximum Storage Quantity, the Base Maximum Daily Injection Quantity, and the Base Maximum Daily Withdrawal Quantity shall be specified in the executed Agreement.

(f) Injection Period shall mean the Summer Period, and Withdrawal Period shall mean the Winter Period, respectively, except for Shippers electing service pursuant to Section 6.2, below.

3. CHARGES

Each Month Shipper shall pay to Transporter the following charges:

3.1 Reservation Charges.

(a) The applicable FSS Deliverability Reservation Rate, as stated on Sheet No. 10, shall be paid each Month for each Dekatherm of Shipper's Base Maximum Daily Withdrawal Quantity; plus

(b) A FSS Capacity Reservation Rate, as stated on Sheet No. 10, shall be paid each Month for each Dekatherm of Shipper's Maximum Storage Quantity divided by twelve (12).

(c) If Transporter fails to Tender Gas for delivery at the Point of Injection/Withdrawal for the account of a Shipper during any Day, due to the Transporter's scheduling of necessary maintenance and repair of pipeline facilities,

RATE SCHEDULE FSS
FIRM STORAGE SERVICE
(Continued)

necessary maintenance and repair of compression facilities, and/or facility outages for tie-in of new facilities, the quantity of Gas that Shipper has nominated for, or makes available to Transporter on such Day, or Shipper's Maximum Daily Injection Quantity or Maximum Daily Withdrawal Quantity, as applicable, whichever is less, then subject to the provisions of the General Terms and Conditions, the portion of the Monthly bill of such Shipper which is attributable to the Reservation Charges shall be reduced by an amount equal to the product of (1)(i) the combined Reservation Charge multiplied by (ii) twelve (12) divided by (iii) the Maximum Storage Quantity and (2) the difference between such quantity of Gas nominated or made available for withdrawal, whichever is less, up to the Maximum Daily Withdrawal Quantity, as applicable, and the quantity actually withdrawn by Transporter for the account of Shipper during such Day.

3.2 Commodity Charges. An Injection/Withdrawal Commodity Rate, as stated on Sheet No. 10, shall be paid each Month by Shipper for each Dekatherm of Gas Tendered to or by Transporter at the Point of Injection/Withdrawal during the Service Month, excluding quantities delivered pursuant to Section 3.4 of this Rate Schedule.

3.3 Other Applicable Charges or Surcharges. All applicable reservation and volumetric charges or surcharges, including but not limited to those charges under Sections 24 through 29 of the General Terms and Conditions, for each Dekatherm of Gas Delivered Hereunder. Such charges or surcharges are shown on Sheet Nos. 17 and 18. Such surcharges shall not be applicable if paid on related transportation service.

3.4 Storage Overrun Service. Shipper may request Transporter to inject quantities of Gas for Shipper on any Day during the Injection Period in excess of the quantities specified in Section 2(c)(1) of this Rate Schedule or to withdraw quantities of Gas for Shipper on any Day during the Withdrawal Period in excess of Shipper's Maximum Daily Withdrawal Quantity. Shipper may also request Transporter to inject quantities of Gas for Shipper on any Day

RATE SCHEDULE FSS
FIRM STORAGE SERVICE
(Continued)

during the Withdrawal Period or withdraw quantities of Gas for Shipper on any Day during the Injection Period. Shipper may request Transporter to accept deliveries of quantities of Gas in excess of the Maximum Storage Quantity during any Injection Period and Shipper may request Transporter to redeliver quantities of Gas in excess of the Maximum Storage Quantity during any Withdrawal Period provided, however, that at no time may Shipper's Working Storage Gas exceed Shipper's Maximum Storage Quantity. Transporter may do so on an interruptible basis if it can do so without adverse effect on Transporter's operations or its ability to meet all of its other firm service obligations.

3.5 Overrun Service Charge. An Overrun Service Rate shall be paid for each Dekatherm of Gas which is injected or withdrawn on behalf of Shipper during the Month pursuant to Section 3.4 of this Rate Schedule unless such overrun service, with Transporter's concurrence, is makeup of quantities of Gas that Transporter previously failed to inject into storage or withdraw from storage. The Rate Schedule FSS Overrun Service Rate shall be the one hundred percent (100%) load factor rate which is the sum of (a) the product of (1) the Deliverability Reservation Rate, (2) twelve (12), and (3) the Base Maximum Daily Withdrawal Quantity divided by the Maximum Storage Quantity, (b) the Capacity Reservation Rate, and (c) the Injection/Withdrawal Commodity Rate.

3.6 Fuel Reimbursement. Shipper shall furnish at the Point(s) of Injection/Withdrawal, for each Dekatherm injected, the Transporter's Use utilizing the Rate Schedule FSS Transporter's Use (%) set forth on Sheet No. 19.

3.7 Cycling Fuel Charge. If a Shipper has renewed its Agreement for the next Storage Contract Year under this Rate Schedule, or any successor Rate Schedule, and fails to reduce its Working

RATE SCHEDULE FSS
FIRM STORAGE SERVICE
(Continued)

Storage Gas to twenty percent (20%) or less of its Maximum Storage Quantity by the end of the Winter Period, then Transporter shall reduce the Working Storage Gas for Cycling Fuel.

3.8 If a Shipper has not renewed its Agreement for the next Storage Contract Year, and fails to withdraw all of its Working Storage Gas by the end of the Winter Period, then such Shipper shall be deemed to have executed the necessary Agreements under Rate Schedules DDS and ITS for the further disposition of such remaining Working Storage Gas.

3.9 Rate Changes. Subject to any limitations agreed to by Shipper and Transporter, Transporter may from time to time and at any time selectively adjust any or all of the rates charged to any individual Shipper for which a Maximum Rate and Minimum Rate are stated on Sheet No. 10 of this Tariff or a superseding Tariff; provided, however, that such adjusted rate(s) shall not exceed the applicable Maximum Rate(s), nor shall they be less than the Minimum Rate(s), set forth on such sheet. Transporter shall have the right to charge the Maximum Rate at any time as a condition for new service, or for continuation of service under an existing Agreement. Transporter shall make all information filings required by the Commission's regulations with respect to any charges at less than the Maximum Rate.

4. COMMISSION AND OTHER REGULATORY FEES

Shipper shall reimburse Transporter directly for any separately stated fees required by the Commission or any other federal or any state regulatory body which are related to service provided under this Rate Schedule.

5. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions of this Second Revised Volume No. 1 FERC Gas Tariff are hereby specifically incorporated herein and made a part of this Rate Schedule.

RATE SCHEDULE FSS
FIRM STORAGE SERVICE
(Continued)

6. ENHANCED SERVICE FEATURES

6.1 Elimination of Storage Ratchets. Shippers that had an Agreement under Transporter's previously effective Rate Schedule FSS in effect prior to November 1, 1991, and that had utilized their services prior to April 1, 1993, and, subject to available capacity, other Rate Schedule FSS Shippers, may elect to have the Maximum Daily Injection Quantity and the Maximum Daily Withdrawal Quantity equal to the Base Maximum Daily Injection Quantity and Base Maximum Daily Withdrawal Quantity, respectively. The maximum reservation rate for Rate Schedule FSS service pursuant to such an election shall be stated on Sheet No. 10, and denoted as Rate Schedule FSS service without Storage Ratchets.

6.2 Annual Storage Service. Subject to the determination in Section 1(a), above, Rate Schedule FSS Shippers may elect annual injections and withdrawals from storage. The maximum reservation rate for Rate Schedule FSS service pursuant to such an election shall be stated on Sheet No. 10, and denoted as Rate Schedule FSS service with Annual Entitlements. The Injection Period and Withdrawal Period under such an election shall be one (1) consecutive twelve (12) Month period of April 1 through March 31.

6.3 Injections and Withdrawals of Gas. Shippers electing Annual Storage Service pursuant to Section 6.2, above, shall during the Injection Period and the Withdrawal Period be permitted to inject and withdraw, respectively, quantities of Gas up to 1.42 times the Maximum Storage Quantity ("MSQ"). The storage of Gas in excess of MSQ, or the injection or the withdrawal of Gas in excess of 1.42 times MSQ, as the case may be, shall be permitted only on a best efforts, overrun basis. For the purposes of determining the applicable limits on injections and withdrawals pursuant to this provision, quantities allocated as Designated Storage Account activity pursuant to the provisions of Rate Schedule NNS shall not be included in the calculations of a Shipper's accumulated injections and withdrawals of Gas.

Dominion

CNG Transmission Corporation
FERC Gas Tariff
Second Revised Volume No. 1

Twenty-Fourth Revised Sheet No. 35
Superseding
Sub.Twenty-Third Revised Sheet No. 35

RATES APPLICABLE TO RATE SCHEDULES IN FERC GAS TARIFF, VOLUME NO. 1

Rate Schedule	Rate Component	Base Tariff Rate [1]	TCRA [8]	GRI Adj.	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)
GSS [2], [5], [6]						
	Storage Demand - Acct. 858/EPCA	0.1078	(0.0209)	-	-	0.0869
	Storage Demand - Other	1.7504	-	-	-	1.7504
	Total Storage Demand	1.8582	(0.0209)	-	-	1.8373
	Storage Capacity	0.0137	-	-	-	0.0137
	Injection Charge - Acct. 858/EPCA	0.0046	0.0089	-	-	0.0135
	Injection Charge - Other	0.0154	-	-	-	0.0154
	Total Injection Charge	0.0200	0.0089	-	-	0.0289
	Withdrawal Charge	0.0154	0.0102	-	0.0022	0.0278
	GSS-TE Surcharge - Acct. 858 [4]	0.0111	(0.0113)	-	-	(0.0002)
	Dem. Charge Adj. - Acct. 858/EPCA	1.2936	(0.2508)	-	-	1.0428
	Demand Charge Adj. Oth	21.0048	-	-	-	21.0048
	Total Demand Charge Adj.	22.2984	(0.2508)	-	-	22.0476
	Excess Deliveries from					
	Cust. Bal. - Acct. 858/EPCA	0.0238	0.0055	-	-	0.0293
	- Other	0.5991	-	-	0.0022	0.6013
	Excess Deliveries Total	0.6229	0.0055	-	0.0022	0.6306
GSS II [3], [5], [7]						
	Storage Demand - Acct. 858/EPCA	0.0605	(0.0122)	-	-	0.0483
	Storage Demand - Other	3.3774	-	-	-	3.3774
	Total Storage Demand	3.4379	(0.0122)	-	-	3.4257
	Storage Capacity	0.0317	-	-	-	0.0317
	Injection Charge - Acct. 858/EPCA	0.0023	0.0043	-	-	0.0066
	Injection Charge - Other	0.0208	-	-	-	0.0208
	Total Injection Charge	0.0231	0.0043	-	-	0.0274
	Withdrawal Charge	0.0208	0.0050	-	0.0022	0.0280
	Dem. Charge Adj. - Acct. 858/EPCA	0.7260	(0.1464)	-	-	0.5796
	Demand Charge Adj. - Other	40.5288	-	-	-	40.5288
	Total Demand Charge Adj.	41.2548	(0.1464)	-	-	41.1084
	Excess Deliveries from					
	Cust. Bal. - Acct. 858/EPCA	0.0132	(0.0010)	-	-	0.0122
	- Other	0.9354	-	-	0.0022	0.9376
	Excess Deliveries Total	0.9486	(0.0010)	-	0.0022	0.9498
ISS [2], [5]						
	ISS Capacity - Acct. 858/EPCA	0.0036	(0.0008)	-	-	0.0028
	ISS Capacity - Other	0.0712	-	-	-	0.0712
	Total ISS Capacity	0.0748	(0.0008)	-	-	0.0740
	Injection Charge - Acct. 858/EPCA	0.0046	0.0089	-	-	0.0135
	Injection Charge - Other	0.0154	-	-	-	0.0154
	Total Injection Charge	0.0200	0.0089	-	-	0.0289
	Withdrawal Charge	0.0154	0.0102	-	0.0022	0.0278
	Authorized Overrun/from					
	Cust. Bal. - Acct. 858/EPCA	0.0238	0.0055	-	-	0.0293
	- Other	0.5991	-	-	0.0022	0.6013
	AuthOvr/fromCustBal Total	0.6229	0.0055	-	0.0022	0.6306
	Excess Injection Charge					
	- Acct. 858 EPCA	0.0046	0.0089	-	-	0.0135
	Excess Injection Charge	0.2135	-	-	-	0.2135
	Total Excess Injection Charge	0.2181	0.0089	-	-	0.2270

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.78%.
[3] Storage Service Fuel Retention Percentage is 1.95%.
[4] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[5] All rates reflect $ per Dt.
[6] Daily Capacity Release Rate for GSS per Dt $0.6028
[7] Daily Capacity Release Rate for GSS II per Dt $0.9218
[8] Includes current 858/EPCA adjustment to base rate + TCRA surcharges (858, electric, fuel over/under) from previous TCRA period.

Issued by: Bruce C.Klink, Vice President
Issued on: January 24, 2000
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP00-15, Issued December 21, 1999

Effective: February 1, 2000

Dominion Transmission,Inc
FERC Gas Tariff
Second Revised Volume No. 1

Sub. 24th Revised Sheet No. 35
Superseding
2nd Sub.Twenty-Third Rev. Sheet No. 35

RATES APPLICABLE TO RATE SCHEDULES IN FERC GAS TARIFF, VOLUME NO. 1

Rate Schedule	Rate Component	Base Tariff Rate [1]	TCRA [8]	GRI Adj.	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)
GSS [2], [5], [6]						
	Storage Demand - Acct. 858/EPCA	0.1078	(0.0209)	-	-	0.0869
	Storage Demand - Other	1.7504	-	-	-	1.7504
	Total Storage Demand	1.8582	(0.0209)	-	-	1.8373
	Storage Capacity	0.0137	-	-	-	0.0137
	Injection Charge - Acct. 858/EPCA	0.0046	0.0046	-	-	0.0092
	Injection Charge - Other	0.0154	-	-	-	0.0154
	Total Injection Charge	0.0200	0.0046	-	-	0.0246
	Withdrawal Charge	0.0154	0.0059	-	0.0022	0.0235
	GSS-TE Surcharge - Acct. 858 [4]	0.0111	(0.0113)	-	-	(0.0002)
	Dem. Charge Adj. - Acct. 858/EPCA	1.2936	(0.2508)	-	-	1.0428
	Demand Charge Adj. Oth	21.0048	-	-	-	21.0048
	Total Demand Charge Adj.	22.2984	(0.2508)	-	-	22.0476
	Excess Deliveries from					
	Cust. Bal. - Acct. 858/EPCA	0.0238	0.0012	-	-	0.0250
	- Other	0.5991	-	-	0.0022	0.6013
	Excess Deliveries Total	0.6229	0.0012	-	0.0022	0.6263
GSS II [3], [5], [7]						
	Storage Demand - Acct. 858/EPCA	0.0605	(0.0122)	-	-	0.0483
	Storage Demand - Other	3.3774	-	-	-	3.3774
	Total Storage Demand	3.4379	(0.0122)	-	-	3.4257
	Storage Capacity	0.0317	-	-	-	0.0317
	Injection Charge - Acct. 858/EPCA	0.0023	0.0022	-	-	0.0045
	Injection Charge - Other	0.0208	-	-	-	0.0208
	Total Injection Charge	0.0231	0.0022	-	-	0.0253
	Withdrawal Charge	0.0208	0.0029	-	0.0022	0.0259
	Dem. Charge Adj. - Acct. 858/EPCA	0.7260	(0.1464)	-	-	0.5796
	Demand Charge Adj. - Other	40.5288	-	-	-	40.5288
	Total Demand Charge Adj.	41.2548	(0.1464)	-	-	41.1084
	Excess Deliveries from					
	Cust. Bal. - Acct. 858/EPCA	0.0132	(0.0031)	-	-	0.0101
	- Other	0.9354	-	-	0.0022	0.9376
	Excess Deliveries Total	0.9486	(0.0031)	-	0.0022	0.9477
ISS [2], [5]						
	ISS Capacity - Acct. 858/EPCA	0.0036	(0.0008)	-	-	0.0028
	ISS Capacity - Other	0.0712	-	-	-	0.0712
	Total ISS Capacity	0.0748	(0.0008)	-	-	0.0740
	Injection Charge - Acct. 858/EPCA	0.0046	0.0046	-	-	0.0092
	Injection Charge - Other	0.0154	-	-	-	0.0154
	Total Injection Charge	0.0200	0.0046	-	-	0.0246
	Withdrawal Charge	0.0154	0.0059	-	0.0022	0.0235
	Authorized Overrun/from					
	Cust. Bal. - Acct. 858/EPCA	0.0238	0.0012	-	-	0.0250
	- Other	0.5991	-	-	0.0022	0.6013
	AuthOvr/fromCustBal Total	0.6229	0.0012	-	0.0022	0.6263
	Excess Injection Charge					
	- Acct. 858 EPCA	0.0046	0.0046	-	-	0.0092
	Excess Injection Charge	0.2135	-	-	-	0.2135
	Total Excess Injection Charge	0.2181	0.0046	-	-	0.2227

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.78%.
[3] Storage Service Fuel Retention Percentage is 1.95%.
[4] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[5] All rates reflect ¢ per Dt.
[6] Daily Capacity Release Rate for GSS per Dt $0.6028
[7] Daily Capacity Release Rate for GSS II per Dt $0.9218
[8] Includes current 858/EPCA adjustment to base rate + TCRA surcharges (858, electric, fuel over/under) from previous TCRA period.

Issued by: Bruce C.Klink, Vice President
Issued on: June 22, 2000
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. TM00-22-001, Issued June 16, 2000

Effective: February 1, 2000

RATES APPLICABLE TO RATE SCHEDULES IN FERC GAS TARIFF, VOLUME NO. 1

Rate Schedule	Rate Component	Base Tariff Rate [1]	TCRA [8]	GRI Adj.	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)
GSS [2], [5], [6]						
---	Storage Demand - Acct. 858/EPCA	0.1012	(0.0038)	-	-	0.0974
	Storage Demand - Other	1.7680	-	-	-	1.7680
	Total Storage Demand	1.8692	(0.0038)	-	-	1.8654
	Storage Capacity	0.0140	-	-	-	0.0140
	Injection Charge - Acct. 858/EPCA	0.0046	0.0319	-	-	0.0365
	Injection Charge - Other	0.0154	-	-	-	0.0154
	Total Injection Charge	0.0200	0.0319	-	-	0.0519
	Withdrawal Charge	0.0154	0.0304	-	0.0022	0.0480
	GSS-TE Surcharge - Acct. 858 [4]	0.0111	(0.0099)	-	-	0.0012
	Dem. Charge Adj. - Acct. 858/EPCA	1.2144	(0.0456)	-	-	1.1688
	Demand Charge Adj. Oth	21.2160	-	-	-	21.2160
	Total Demand Charge Adj.	22.4304	(0.0456)	-	-	22.3848
	Excess Deliveries from					
	Cust. Bal. - Acct. 858/EPCA	0.0222	0.0296	-	-	0.0518
	- Other	0.6055	-	-	0.0022	0.6077
	Excess Deliveries Total	0.6277	0.0296	-	0.0022	0.6595
GSS II [3], [5], [7]						
------	Storage Demand - Acct. 858/EPCA	0.0605	(0.0025)	-	-	0.0580
	Storage Demand - Other	3.3774	-	-	-	3.3774
	Total Storage Demand	3.4379	(0.0025)	-	-	3.4354
	Storage Capacity	0.0317	-	-	-	0.0317
	Injection Charge - Acct. 858/EPCA	0.0023	0.0172	-	-	0.0195
	Injection Charge - Other	0.0208	-	-	-	0.0208
	Total Injection Charge	0.0231	0.0172	-	-	0.0403
	Withdrawal Charge	0.0208	0.0157	-	0.0022	0.0387
	Dem. Charge Adj. - Acct. 858/EPCA	0.7260	(0.0300)	-	-	0.6960
	Demand Charge Adj. - Other	40.5288	-	-	-	40.5288
	Total Demand Charge Adj.	41.2548	(0.0300)	-	-	41.2248
	Excess Deliveries from					
	Cust. Bal. - Acct. 858/EPCA	0.0132	0.0111	-	-	0.0243
	- Other	0.9354	-	-	0.0022	0.9376
	Excess Deliveries Total	0.9486	0.0111	-	0.0022	0.9619
ISS [2], [5]						
------	ISS Capacity - Acct. 858/EPCA	0.0034	(0.0002)	-	-	0.0032
	ISS Capacity - Other	0.0721	-	-	-	0.0721
	Total ISS Capacity	0.0755	(0.0002)	-	-	0.0753
	Injection Charge - Acct. 858/EPCA	0.0046	0.0319	-	-	0.0365
	Injection Charge - Other	0.0154	-	-	-	0.0154
	Total Injection Charge	0.0200	0.0319	-	-	0.0519
	Withdrawal Charge	0.0154	0.0304	-	0.0022	0.0480
	Authorized Overrun/from					
	Cust. Bal. - Acct. 858/EPCA	0.0222	0.0296	-	-	0.0518
	- Other	0.6055	-	-	0.0022	0.6077
	AuthOvr/fromCustBal Total	0.6277	0.0296	-	0.0022	0.6595
	Excess Injection Charge					
	- Acct. 858 EPCA	0.0046	0.0319	-	-	0.0365
	Excess Injection Charge	0.2176	-	-	-	0.2176
	Total Excess Injection Charge	0.2222	0.0319	-	-	0.2541

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.78%.
[3] Storage Service Fuel Retention Percentage is 1.95%.
[4] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[5] All rates reflect $ per Dt.
[6] Daily Capacity Release Rate for GSS per Dt $0.6115
[7] Daily Capacity Release Rate for GSS II per Dt $0.9232
[8] Includes current 858/EPCA adjustment to base rate + TCRA surcharges (858, electric, fuel over/under) from previous TCRA period.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

1. AVAILABILITY

1.1 This Rate Schedule is available to any person ("Customer") for the purchase of natural gas storage service from CNG Transmission Corporation ("Pipeline"), where Pipeline has obtained case-specific Commission authorization pursuant to Section 7(c) of the Natural Gas Act to serve Customer under this Rate Schedule or its predecessor, Rate Schedule GSS; and subsequent to January 6, 1998, also where

A. Customer has requested service under this Rate Schedule pursuant to Section 11A of the General Terms an Conditions of this Tariff. And,

B. After review and acceptance of such request by Pipeline, Pipeline and Customer have entered into a Service Agreement that conforms to the form of Service Agreement for Section 7(c) storage service contained in this Tariff, in which Pipeline agrees to receive and redeliver stated quantities of gas to Customer at specified Delivery Point(s) at which facilities of Pipeline and Customer connect or at which gas is received and redelivered for the account of Customer. All necessary transportation services will be the sole responsibility of Customer unless otherwise agreed by Pipeline. And,

C. Customer is willing and able to pay the maximum rates hereunder, or such other rate to which Pipeline and Customer mutually agree in accordance with the General Terms and Conditions of this Tariff.

1.2 This Rate Schedule will be made available for new or expanded service only when, in Pipeline's judgment, it has capability to render such service after meeting its other obligations. Pipeline is not required to provide any requested service for which it does not have available capability, or that would require Pipeline to file an application with the Commission, or that would require Pipeline to construct or acquire any new facilities.

2. APPLICABILITY AND CHARACTER OF SERVICE

This Rate Schedule shall apply to storage service rendered by Pipeline to Customer under the service agreement executed for service hereunder. Service rendered under this Rate Schedule, within the limitations described in Sections 7 and 8 below, shall be firm and shall not be subject to curtailment, interruption, or discontinuance except as provided herein or in the General Terms and Conditions of this Tariff.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

3. STORAGE DEMAND AND CAPACITY

The executed Service Agreement shall specify the Storage Demand and the Storage Capacity, as defined in the General Terms and Conditions of this Tariff. For those Service Agreements executed prior to April 1, 1978 where the Storage Capacity and Storage Demand is expressed in Mcf, the Storage Capacity and Storage Demand in Dt for billing hereunder shall be determined based upon an average heating value of 1028 Btu.

4. RATE

The applicable rates and charges under this Rate Schedule shall include all applicable rates and charges set forth at the currently effective Sheet Nos. 32-99 of this Tariff, and these rates and charges are incorporated herein by reference.

5. MONTHLY BILL

5.1 For natural gas storage service under this Rate Schedule, Customer shall pay Pipeline each month the following:

A. A Storage Demand Charge. A charge per month per Dt of Storage Demand.

B. A Storage Capacity Charge. A charge per month per Dt of Storage Capacity.

C. An Injection Charge. A charge per Dt for all gas injected during the billing month.

D. A Withdrawal Charge. A charge per Dt for all gas withdrawn during the billing month.

E. A "From Customer's Balance" Charge. A charge per Dt for all gas withdrawn for Customer under Section 9 of this Rate Schedule, during the billing month.

F. Any Applicable Penalties. For excess daily injection overruns, injections in excess of Storage Capacity, and excess withdrawals, as required by Section 35.3 of the General Terms and Conditions.

G. A GSS-TETCO Charge. A charge per Dt for all gas withdrawn during the billing month. This charge shall apply only to service rendered under this Rate Schedule to former customers of Texas Eastern Transmission Corporation under Texas Eastern's Rate Schedule(s) SS-2 and/or SS-3.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

H. Any other applicable rates, charges, and penalties as set forth in the General Terms and Conditions of this Tariff.

5.2 Fuel Retention. Pipeline will retain the percentage of gas received for injection as set forth on Sheet No. 35 as the Storage Service Fuel Retention Percentage.

5.3 In the event Customer has failed to meet the minimum turnover requirements of Section 8.7 below, Pipeline shall retain the quantity of gas required by Section 35.3.D of the General Terms and Conditions.

5.4 Notwithstanding the provisions of Sections 5.1-5.3, for any Day during the Summer Period that a Customer gives Pipeline both (a) notice under Section 7 of this Rate Schedule for injections into storage, and (b) notice under Section 8 of this Rate Schedule for withdrawals from storage, to the extent that quantities tendered for injection and the quantities requested to be withdrawn are equal and such quantities are redelivered by Pipeline at the same injection/withdrawal point for subsequent transportation, the injection withdrawal charges in Section 5.1 above shall not apply. Instead, there shall be a Usage Charge of $0.01 per dekatherm times the quantity of gas tendered for injection plus $0.01 per dekatherm times the quantity of gas requested for withdrawal. To the extent that such quantities tendered for injection and requested for withdrawal are not equal, the injection/withdrawal charges reflected on the currently effective Sheet No. 35 shall apply to the net difference.

5.5 Notwithstanding the general provision of Sections 4 and 5.1, above, if Pipeline and Customer mutually agree to negotiated rates for service hereunder, such negotiated rates shall apply in lieu of the otherwise applicable charges identified in Sections 5.1.A through 5.1.E and/or 5.1.G of this Rate Schedule.

6. MINIMUM MONTHLY BILL

Unless Pipeline and Customer agree otherwise as provided in Section 5.5, above, the minimum monthly bill shall be the sum of the Storage Demand Charge and the Storage Capacity Charge, and any other applicable charges as set forth in the General Terms and Conditions of Pipeline's Tariff.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

7. INJECTIONS INTO STORAGE

7.1 Receipt Points. The executed Service Agreement shall specify the Receipt Point(s) for quantities tendered by Customer to Pipeline for storage injection. Such Receipt Points will be deemed to be Primary Receipt Points, as defined in the General Terms and Conditions of this Tariff, for quantities tendered up to the Daily Injection Entitlement described in Section 7.4.A. of this Rate Schedule.

7.2 General Procedure. For any Day when Customer desires Pipeline to store gas for its account under this Rate Schedule, it shall nominate to Pipeline in accordance with the General Terms and Conditions of this Tariff, specifying the quantity of gas it desires to have injected into storage on such Day. When Customer's nominations are confirmed and scheduled as required by this Tariff, Pipeline shall inject into storage for Customer's account on such Day, the quantity of gas so nominated, subject to the limitations set forth below in this Section 7.

7.3 Notice Required. The notice given by Customer to Pipeline for injections on any Day shall be at least eight hours. Pipeline may waive any part of the eight hours notice upon request if in Pipeline's judgment, operating conditions permit such waiver.

7.4 Summer Period Injections.

A. Daily Injection Entitlement. Unless provided otherwise in Customer's Service Agreement, during any Summer Period, the quantity of gas which Customer shall be entitled to tender to Pipeline for injection into storage on any one Day is one- one hundred eightieth (1/180th) of Customer's Storage Capacity whenever Customer's Storage Gas Balance is less than or equal to one half of Customer's Storage Capacity, and one-two hundred fourteenth (1/214th) of Customer's Storage Capacity whenever Customer's Storage Gas Balance is greater than one half of Customer's Storage Capacity. These limitations upon daily injection entitlement are subject to the tolerance levels set forth in Section 35.3.A of the General Terms and Conditions.

GSS RATE SCHEDULE
General Storage Service, Section 7(c)

Sheet No. 153A
is reserved for future use.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

B. Additional Injections. Any Customer may nominate to Pipeline under Section 7.2 above quantities for injection that are in addition to Customer's daily injection entitlements, as set forth in Section 7.4.A. Additional storage injections shall include gas injected into storage under Rate Schedule FTNN, to the extent such injections exceed Customer's daily entitlements. Pipeline shall endeavor to inject on any one Day, as much of Customer's storage nominations for such Day as operating conditions will permit. If the total of all nominations for storage injection for such Day together with Pipeline's injections into storage under Rate Schedule FTNN exceed the total quantity which Pipeline can inject or cause to be injected into storage on such Day, then the nominations for additional injections on such Day shall be allocated pro rata at each storage injection Receipt Point, based upon Customer's actual confirmed nomination to tender gas for injection at that Receipt Point.

C. Maximum Daily Injection Quantity. The maximum daily injection quantity for Customer shall be the sum of Customer's daily injection entitlement as set forth in Section 7.4.A. above, plus any additional injection quantities that Pipeline has agreed to accept pursuant to Section 7.4.B. above.

7.5 Winter Period Injections.

A. Unless provided otherwise in Customer's Service Agreement, during the Winter Period, Customer may tender to Pipeline quantities up to one two- hundred fourteenth (1/214th) of Customer's Storage Capacity for injection into storage, unless Pipeline has issued an operational flow order in accordance with Section 11B of the General Terms and Conditions, governing Winter Period injections. This limitation upon daily injections is subject to the tolerance levels set forth in Section 35.3.A of the General Terms and Conditions.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

B. While such operational flow order is in effect:

1. From time to time, Pipeline may post, on its Electronic Bulletin Board ("EBB"), Receipt Points where Customer may tender quantities for injection and any conditions applicable to injection through such Receipt Points.

2. Pipeline may limit or refuse to accept injections not tendered in accordance with the operational flow order and EBB notice, unless Pipeline has expressly agreed in the executed Service Agreement to accept specific quantities at specified points on a firm basis during the Winter Period.

3. Pipeline will continue to inject gas for balancing purposes under FTNN, but Customer's Storage Gas Balance will not be credited with such quantities for the purposes of establishing Customer's daily entitlement to withdraw gas, as set forth in Section 8 of this Rate Schedule, until March 31 of the Winter Period in which the operational flow order is in effect, unless the gas is received by Pipeline at the Receipt Points specified in the EBB notice.

7.6 Pipeline shall be obligated to inject gas into storage for Customer's account only when Customer's Storage Gas Balance is less than Customer's Storage Capacity.

GSS RATE SCHEDULE
General Storage Service, Section 7(c)

8. WITHDRAWALS FROM STORAGE

8.1 Delivery Points. Each executed Service Agreement shall specify the Delivery Points for all gas withdrawn from storage.

A. If Customer does not require firm transportation by Pipeline from Pipeline's storage pools, or if Pipeline requires that deliveries be made to Customer at points distant from Pipeline's storage pools for operational reasons, the Delivery Point(s) shall be the point(s) of interconnection between Pipeline's facilities and Customer's or Customer's Transporter's facilities, as specified in the Service Agreement.

B. If Customer's Service Agreement specifies a single Receipt Point for injection quantities and Customer requires delivery of all withdrawal quantities at that same point, then the Delivery Point shall be the same as the Receipt Point.

C. If Customer requires transportation by Pipeline from Pipeline's storage pools then the Delivery Point(s) shall be those point(s) specified in the Service Agreement.

D. Such Delivery Point(s) will be deemed to be Primary Delivery Points, within the meaning set forth in the General Terms and Conditions of this Tariff.

8.2 General Procedure. For any Day when Customer desires the delivery of gas stored for Customer's account under this Rate Schedule, Customer shall nominate to Pipeline in accordance with the General Terms and Conditions of this Tariff the quantity of gas under this Rate Schedule during such Day. Upon any necessary confirmation, Pipeline shall thereupon deliver to Customer at the Delivery Points the quantity of gas so nominated, subject to each of the limitations set forth below in this Section 8.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

8.3 Notice Required. Except as provided in Section 9 of Rate Schedule FTNN, the notice given by Customer to Pipeline for withdrawals on any Day shall be at least eight hours. Pipeline may waive any part of the eight hours' notice upon request if, in Pipeline's judgment, operating conditions permit such waiver.

8.4 Reduction in Customer's Daily Entitlement.

A. To the extent not otherwise provided in Customer's Service Agreement, if at the end of any Day Customer's Storage Gas Balance is less than or equal to 35 percent, but greater than 16 percent of Customer's Storage Capacity, then Pipeline's obligation to make deliveries to Customer shall be reduced by 8 percent of such Customer's Storage Demand. If Customer's Storage Gas Balance at the end of any Day is less than or equal to 16 percent, but greater than 10 percent of Customer's Storage Capacity, then Pipeline's obligation to make deliveries to Customer shall be reduced by 30 percent of such Customer's Storage Demand. If Customer's Storage Gas Balance at the end of any Day is less than or equal to 10 percent of Customer's Storage Capacity, then Pipeline's obligation to make deliveries to Customer shall be reduced by 37 percent of such Customer's Storage Demand.

B. If Customer's Storage Demand is equal to or less than one-one hundred fortieth (1/140th) of Customer's Storage Capacity, or if the Service Agreement provides that Pipeline has the right to interrupt the storage service, then the reductions in daily entitlement specified in Section 8.4.A. above shall not apply.

C. Transfers of storage inventory in accordance with Section 34 of the General Terms and Conditions shall be treated as a reduction in the Storage Gas Balance of the Transferring Customer, and an increase in the Storage Gas Balance of the Receiving Customer.

GSS RATE SCHEDULE
General Storage Service , Section 7(c)

8.5 Minimum Storage Gas Balance and Additional Reduction in Customer's Daily Entitlement.

A. Each Customer must maintain a Storage Gas Balance equal to or greater than the following percentages of Storage Capacity on each Day during the following Winter Period months:

December	35%
January	35%
February	15%

B. If Customer does not maintain the required Storage Gas Balance then, commencing on such Day and continuing until Customer's Storage Gas Balance is at the level required under Section 8.5.A., Pipeline's obligation to make deliveries to Customer shall be reduced by 10 percent of the lesser of (1) Customer's Storage Demand or (2) Pipeline's obligation to deliver as established pursuant to Section 8.4 above.

8.6 Limitations on Withdrawals. During any calendar month, Pipeline shall not be obligated to deliver a daily average in excess of the following: (1) more than 70 percent of the Customer's daily entitlement described under Section 8.4, if Customer's Storage Demand is equal to or greater than one-sixtieth (1/60th) of Customer's Storage Capacity, or (2) more than 87.5 percent of the Customer's daily entitlement described under Section 8.4, if Customer's Storage Demand is less than one-sixtieth (1/60th) of Customer's Storage Capacity. Pipeline may issue an operational flow order to limit storage withdrawals, in accordance with Section 11B of the General Terms and Conditions of this Tariff. The limitations under this Section 8.6 shall not apply to transfers of storage inventory in accordance with Section 34 of the General Terms and Conditions.

8.7 Minimum Turnover. By April 15 of any year, Customer's total withdrawals from storage since the beginning of the preceding, just completed, Winter Period must be equal to or greater than the amount by which Customer's Storage Gas Balance as of November 1 of the preceding calendar year exceeds 35 percent of Customer's Storage Capacity. If Customer has failed to withdraw such quantities, then Customer will be subject to the penalties of Section 35.3.D of the General Terms and Conditions.

GSS RATE SCHEDULE
General Storage Service, Section 7(c)

9. DELIVERIES OF STORAGE GAS IN EXCESS OF ENTITLEMENT

9.1 From Customer's Balance. Customer may request Pipeline to deliver gas to Customer on any Day in addition to the quantity that Customer is entitled to withdraw, as established pursuant to Section 8 of this Rate Schedule, and Pipeline will make such delivery if such gas is available from Customer's Storage Gas Balance, unless Pipeline issues an OFO pursuant to Section 11B.3.E. of the General Terms and Conditions because, in Pipeline's sole judgment, such delivery cannot be made without adverse effect upon deliveries to other Customers or to Pipeline's other operations.

9.2 For all quantities of gas delivered under the provisions of this Section, unless Pipeline and Customer agree otherwise, Customer shall pay Pipeline at the rate per Dt set forth at the currently effective Sheet No. 35 of this Tariff for Excess Deliveries from Customer's Balance.

10. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions of this Tariff, and any revisions thereof that may be proposed and made effective from time to time hereafter, to the extent not inconsistent with the provisions of this Rate Schedule, shall apply to and are made a part of this Rate Schedule.

Equitrans

TRANSPORTATION RATES (Rates per Dth)

	Base Tariff Rates	ACA Adj	Total Rates
RATE SCHEDULE NOFT:			
Winter			
Reservation Charge	$8.3395	-	$8.3395
Usage	$0.0092	$0.0022	$0.0114
Authorized Overrun			
Maximum	$0.2853	$0.0022	$0.2875
Minimum	$0.0092	$0.0022	$0.0114
Max. Capacity Rel. Vol. Charge /1	$0.2853	$0.0022	$0.2875
Base			
Reservation Charge	$7.5857	-	$7.5857
Usage	$0.0079	$0.0022	$0.0101
Authorized Overrun			
Maximum	$0.2560	$0.0022	$0.2582
Minimum	$0.0079	$0.0022	$0.0101
Max. Capacity Rel. Vol. Charge /1	$0.2560	$0.0022	$0.2582
RATE SCHEDULE FTS:			
Winter			
Reservation Charge			
Maximum	$5.7625	-	$5.7625
Minimum	$0.0000	-	$0.0000
Authorized Overrun			
Maximum	$0.2000	$0.0022	$0.2022
Minimum	$0.0092	$0.0022	$0.0114
Max. Capacity Rel. Vol. Charge /1	$0.2000	$0.0022	$0.2022
Usage			
Maximum	$0.0092	$0.0022	$0.0114
Minimum	$0.0092	$0.0022	$0.0114
Base			
Reservation Charge			
Maximum	$5.0087	-	$5.0087
Minimum	$0.0000	-	$0.0000
Authorized Overrun			
Maximum	$0.1717	$0.0022	$0.1739
Minimum	$0.0079	$0.0022	$0.0101
Max. Capacity Rel. Vol. Charge /1	$0.1717	$0.0022	$0.1739
Usage			
Maximum	$0.0079	$0.0022	$0.0101
Minimum	$0.0079	$0.0022	$0.0101

Pursuant to Section 28 of the General Terms and Conditions:	
GRI Demand Surcharge to applicable high load factor customers	$0.2000
GRI Demand Surcharge to applicable low load factor customers	$0.1230
GRI Commodity Surcharge to applicable customers	$0.0072

GRI Demand and Commodity Surcharges may be discounted to a minimum surcharge of zero.

/1 The maximum rate ceiling does not apply to capacity release transactions of less than one year until September 30, 2002

TRANSPORTATION RATES (Rates per Dth)

	Base Tariff Rates	ACA Adj	Total Rates
RATE SCHEDULE NOFT:			
Winter			
Reservation Charge	$8.3395	-	$8.3395
Usage	$0.0092	$0.0022	$0.0114
Authorized Overrun			
Maximum	$0.2853	$0.0022	$0.2875
Minimum	$0.0092	$0.0022	$0.0114
Max. Capacity Rel. Vol. Charge /1	$0.2853	$0.0022	$0.2875
Base			
Reservation Charge	$7.5857	-	$7.5857
Usage	$0.0079	$0.0022	$0.0101
Authorized Overrun			
Maximum	$0.2560	$0.0022	$0.2582
Minimum	$0.0079	$0.0022	$0.0101
Max. Capacity Rel. Vol. Charge /1	$0.2560	$0.0022	$0.2582
RATE SCHEDULE FTS:			
Winter			
Reservation Charge			
Maximum	$5.7625 ✓	-	$5.7625
Minimum	$0.0000	-	$0.0000
Authorized Overrun			
Maximum	$0.2000	$0.0022	$0.2022
Minimum	$0.0092	$0.0022	$0.0114
Max. Capacity Rel. Vol. Charge /1	$0.2000	$0.0022	$0.2022
Usage			
Maximum	$0.0092	$0.0022	$0.0114
Minimum	$0.0092	$0.0022	$0.0114
Base			
Reservation Charge			
Maximum	$5.0087	-	$5.0087
Minimum	$0.0000	-	$0.0000
Authorized Overrun			
Maximum	$0.1717	$0.0022	$0.1739
Minimum	$0.0079	$0.0022	$0.0101
Max. Capacity Rel. Vol. Charge /1	$0.1717	$0.0022	$0.1739
Usage			
Maximum	$0.0079	$0.0022	$0.0101
Minimum	$0.0079	$0.0022	$0.0101

Pursuant to Section 28 of the General Terms and Conditions:

GRI Demand Surcharge to applicable high load factor customers	$0.0900
GRI Demand Surcharge to applicable low load factor customers	$0.0550
GRI Commodity Surcharge to applicable customers	$0.0070

GRI Demand and Commodity Surcharges may be discounted to a minimum surcharge of zero.

/1 The maximum rate ceiling does not apply to capacity release transactions of less than one year until September 30, 2002

TRANSPORTATION RATES (Rates per Dth)

	Base Tariff Rates	ACA Adj	Total Rates
RATE SCHEDULE ITS:			
Winter			
Usage			
Maximum	$0.2000	$0.0022	$0.2022
Minimum	$0.0092	$0.0022	$0.0114
Base			
Usage			
Maximum	$0.1717	$0.0022	$0.1739
Minimum	$0.0079	$0.0022	$0.0101
Gathering Rate 1/			
Interruptible			
Maximum	$0.3000	-	$0.3000
Minimum	$0.0092	-	$0.0092
Firm			
Reservation			
Maximum	$8.8451	-	$8.8451
Minimum	*$0.0000*	-	*$0.0000*
Usage	$0.0092	-	$0.0092
Products Extraction Rate 2/	$0.1000	$0.0000	$0.1000
Products Extraction Underrecovery Surcharge 3/	$0.0067	$0.0000	$0.0067

GRI Commodity Surcharge to applicable customers, pursuant to Section 28 of the General Terms and Conditions. $0.0070

GRI Commodity Surcharge may be discounted to a minimum surcharge of zero.

1/ Applicable when Customer's transportation gas is received or delivered at any point on Equitrans' gathering facilities.

2/ Applicable when Customer's gas is delivered to the West Union or Copley Processing plants or other processing points on the Equitrans' system in order to meet pipeline quality standards, unless the Customer has entered into a separate agreement with processor pursuant to Section 32.1 or Customer processes his own gas pursuant to Section 32.5.

3/ *Surcharge to recover prior period revenue shortfall related to products extraction during the period January 1, 1999 through October 31, 1999.*

STORAGE SERVICE RATES (Rates per Dth)

	Base Tariff Rates	ACA Adj	Total Rates
RATE SCHEDULE SS-3:			
Demand Charge	$1.3887	-	$1.3887
Storage Space Charge	$0.0265	-	$0.0265
Injection Charge	$0.0089	-	$0.0089
Withdrawal Charge	$0.0089	-	$0.0089
Storage Overrun Charge			
Maximum	$0.2725	-	$0.2725
Minimum	$0.0089	-	$0.0089
RATE SCHEDULE STS-1:			
Reservation Charge	$7.0070	-	$7.0070
Base Reservation Charge	$6.2532	-	$6.2532
Authorized Overrun	$0.2124	-	$0.2124
Usage	$0.0079	$0.0022	$0.0101

GRI Demand Surcharge to applicable high load factor customers, pursuant to Section 28 of the General Terms and Conditions.	$0.2300
GRI Demand Surcharge to applicable low load factor customers, pursuant to Section 28 of the General Terms and Conditions.	$0.1420
GRI Commodity Surcharge to applicable customers, pursuant to Section 28 of the General Terms and Conditions.	$0.0075

GRI Demand and Commodity Surcharges may be discounted to a minimum surcharge of zero.

STORAGE SERVICE RATES (Rates per Dth)

	Base Tariff Rates	ACA Adj	Total Rates
RATE SCHEDULE SS-3:			
Demand Charge 4498 52500	$1.3887	-	$1.3887
Storage Space Charge	$0.0265	-	$0.0265
Injection Charge	$0.0089	-	$0.0089 injection chg w/o charge
Withdrawal Charge	$0.0089	-	$0.0089
Storage Overrun Charge			
Maximum	$0.2725	-	$0.2725
Minimum	$0.0089 ✓	-	$0.0089
RATE SCHEDULE STS-1:			
Winter			
Reservation Charge	$5.7625	-	$5.7625 VOL 3460
Base (SUMMER)			
Reservation Charge	$5.0087	-	$5.0087 VOL 2492
Authorized Overrun	$0.1717	-	$0.1717
Usage (Commodity)	$0.0079	$0.0022	$0.0101

GRI Demand Surcharge to applicable high load factor customers, pursuant to Section 28 of the General Terms and Conditions.	$0.2000
GRI Demand Surcharge to applicable low load factor customers, pursuant to Section 28 of the General Terms and Conditions.	$0.1230
GRI Commodity Surcharge to applicable customers, pursuant to Section 28 of the General Terms and Conditions.	$0.0072

GRI Demand and Commodity Surcharges may be discounted to a minimum surcharge of zero.

STORAGE SERVICE RATES (Rates per Dth)

	Base Tariff Rates	ACA Adj	Total Rates
RATE SCHEDULE SS-3:			
Demand Charge 4,998	$1.3887	-	$1.3887
Storage Space Charge 522,000	$0.0265	-	$0.0265
Injection Charge	$0.0089	-	$0.0089
Withdrawal Charge	$0.0089	-	$0.0089
Storage Overrun Charge			
Maximum	$0.2725	-	$0.2725
Minimum	$0.0089	-	$0.0089
RATE SCHEDULE STS-1:			
Winter			
Reservation Charge (SUMMER)	$5.7625	-	$5.7625
Base		2442 VOLUME	
Reservation Charge	$5.0087		$5.0087
Authorized Overrun	$0.1717	-	$0.1717
Usage (COMMODITY) TRANS	$0.0079	$0.0022	$0.0101

GRI Demand Surcharge to applicable high load factor customers, pursuant to Section 28 of the General Terms and Conditions.	$0.0900
GRI Demand Surcharge to applicable low load factor customers, pursuant to Section 28 of the General Terms and Conditions.	$0.0550
GRI Commodity Surcharge to applicable customers, pursuant to Section 28 of the General Terms and Conditions.	$0.0070

GRI Demand and Commodity Surcharges may be discounted to a minimum surcharge of zero.

ACA CHARGE - STORAGE

RETAINAGE FACTORS

	Retainage Factors	
Transportation Retainage Factor 1/	2.75%	.9725
Gathering Retainage Factor 2/	5.00%	
Storage Loss Retainage Factor 3/	0.49%	.9951

1/ Percentage is applied to receipt quantities on Rate Schedules NOFT, FTS, STS-1 and ITS.

2/ Percentage is applied to receipt or delivery points located on Equitrans' gathering facilities under Rate Schedules APS, NOFT, FTS and ITS.

3/ Percentage is applied to storage injections on Rate Schedues SS-3, 10SS, 30SS, 60SS, 115SS, INSS and LPS.

RATE SCHEDULE SS-3
WINTER STORAGE SERVICE

1. AVAILABILITY

This Rate Schedule is available to any party (hereinafter called "Customer") contracting for Firm Storage Service with Equitrans, Inc. (hereinafter called "Equitrans") where Customer has executed a storage service agreement for service under this rate schedule, and has separately entered into a service agreement with Equitrans for Firm Transportation Service under one of Equitrans' Firm Transportation Rate Schedules prior to the effective date of Equitrans' Order No. 636 restructuring.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 This Rate Schedule shall apply to all storage service rendered under an executed storage service agreement providing for a Total Annual Storage Quantity (TASQ), Maximum Daily Injection Quantity (MDIQ), and Maximum Daily Withdrawal Quantity (MDWQ).

2.2 This Rate Schedule shall apply to the injection on a daily basis of up to 1/200th of Customer's TASQ into storage, storage on a daily basis of Customer's gas, and withdrawal on a daily basis of up to 1/115th of the Customers TASQ. Storage injections and on a daily basis storage withdrawals under this Rate Schedule are permitted on any day during the year.

2.3 Service provided hereunder shall be considered firm, and shall not be subject to curtailment or interruption except as caused by force majeure or as otherwise provided in the General Terms and Conditions of Equitrans' FERC Gas Tariff.

2.4 Storage service under this Rate Schedule is offered on an aggregate basis and is not tied to any individual storage reservoir on the Equitrans system.

3. RATE

3.1 The applicable rates for storage service hereunder are set forth on Sheet No. 8 of this Tariff. The Customer shall pay Equitrans each month for service rendered based on the following charges:

(A) Storage Demand — The charge per Dth multiplied by the MDWQ specified in the Storage Service Agreement.

RATE SCHEDULE SS-3
WINTER STORAGE SERVICE

1. AVAILABILITY

This Rate Schedule is available to any party (hereinafter called "Customer") contracting for Firm Storage Service with Equitrans, L.P. (hereinafter called "Equitrans") where Customer has executed a storage service agreement for service under this rate schedule, and has separately entered into a Service Agreement with Equitrans for Firm Transportation Service under one of Equitrans' Firm Transportation Rate Schedules prior to the effective date of Equitrans' Order No. 636 restructuring.

2. *APPLICABILITY AND CHARACTER OF SERVICE*

2.1 This Rate Schedule shall apply to all storage service rendered under an executed Storage Service Agreement providing for a Total Annual Storage Quantity (TASQ), Maximum Daily Injection Quantity (MDIQ), and Maximum Daily Withdrawal Quantity (MDWQ).

2.2 This Rate Schedule shall apply to the injection on a daily basis of up to 1/200th of Customer's TASQ into storage, storage on a daily basis of Customer's gas, and withdrawal on a daily basis of up to 1/115th of the Customers TASQ. Storage injections and on a daily basis storage withdrawals under this Rate Schedule are permitted on any day during the year.

2.3 Service provided hereunder shall be considered firm, and shall not be subject to curtailment or interruption except as caused by force majeure or as otherwise provided in the General Terms and Conditions of Equitrans' FERC Gas Tariff.

2.4 Storage service under this Rate Schedule is offered on an aggregate basis and is not tied to any individual storage reservoir on the Equitrans system.

3. RATE

3.1 The applicable rates for storage service hereunder are set forth on Sheet No. 10 of this Tariff. The Customer shall pay Equitrans each month for service rendered based on the following charges:

(A) Storage Demand — The charge per Dth multiplied by the MDWQ specified in the Storage Service Agreement.

RATE SCHEDULE SS-3
WINTER STORAGE SERVICE (Continued)

(B)	Storage Space	The charge per Dth multiplied by the TASQ specified in the Storage Service Agreement.
(C)	Storage Injection	The charge per Dth multiplied by the quantity of gas injected for the month.
(D)	Storage Withdrawal	The charge per Dth multiplied by the quantity of gas withdrawn for the month.
(E)	Storage Overrun	The charge per Dth multiplied by the quantity of gas withdrawn during the month in excess of the Customer's MDWQ.

3.2 Customer shall deliver to Equitrans, for injection into storage, the quantity of gas specified for storage loss associated with this Rate Schedule. The quantity of gas retained by Equitrans for storage loss shall be equal to the quantity of gas designated for injection into Equitrans' storage facilities for Customer's account multiplied by the storage loss retention factor set forth on Sheet No. 11 of this Tariff. The quantity of gas retained by Equitrans for storage loss shall not be available for withdrawal by the Customer.

4. MINIMUM BILL

The minimum bill for service hereunder shall be equal to the monthly storage demand charge plus the monthly storage space charge.

5. *STORAGE INJECTIONS*

5.1 Generally, Equitrans will inject gas into storage on behalf of Customer during the period from the beginning of the gas day on April 1 through the end of the gas day on October 31 ("the injection period"). However, Customers under this Rate Schedule are entitled to inject gas into storage on a firm basis on any day during the year.

5.2 The maximum injection quantity of gas which Equitrans is obligated on any day to inject into storage for any Customer under this Rate Schedule shall be the MDIQ specified in the applicable storage service agreement, which shall be calculated as 1/200th of the Customer's TASQ. If operating conditions permit

RATE SCHEDULE SS-3
WINTER STORAGE SERVICE (Continued)

storage for any Customer under this Rate Schedule shall be the MDWQ specified in the applicable storage service agreement, which shall be calculated as 1/115th of the Customer's TASQ. In no event will Customer be permitted to withdraw gas in excess of its current storage quantity.

6.3 Withdrawal of gas from storage on behalf of the Customer will be permitted during the withdrawal period according to a sliding scale described as follows:

Percentage of Quantity in Storage to TASQ	Available Withdrawal Quantity
100% - 17%	110% of MDWQ
Below 17%	100% of MDWQ

In no event shall Equitrans be obligated to provide any storage service for which capacity is not available or which would require the expansion, construction or acquisition of facilities.

6.4 Scheduling of Withdrawals shall be provided by Customer to Equitrans in accordance with Section 8 of the General Terms and Conditions of Equitrans' FERC Gas Tariff.

6.5 Customer is required to withdraw seventy-five percent (75%) of its TASQ under this Rate Schedule on or before the last day of the withdrawal period. In the event that 75% of Customer's gas is not withdrawn from storage by the end of the withdrawal cycle, Equitrans may direct the withdrawal of the gas remaining in storage in excess of the specified level on an expedited schedule determined by Equitrans. In the event that Equitrans schedules the withdrawal of the gas remaining in storage, Equitrans shall assess a scheduling penalty of $0.25/Dth for the remaining gas in storage in addition to the required storage withdrawal charge.

6.6 Equitrans is authorized to withdraw any portion of the 25% of a Customer's TASQ remaining in storage after the conclusion of the withdrawal period for operational purposes, subject to the requirement that Equitrans reinject an equivalent quantity of gas for the Customer's account prior to the first day of the next withdrawal period.

RATE SCHEDULE SS-3
WINTER STORAGE SERVICE (Continued)

storage for any Customer under this Rate Schedule shall be the MDWQ specified in the applicable storage service agreement, which shall be calculated as 1/115th of the Customer's TASQ. In no event will Customer be permitted to withdraw gas in excess of its current storage quantity.

6.3 Withdrawal of gas from storage on behalf of the Customer will be permitted during the withdrawal period according to a sliding scale described as follows:

Percentage of Quantity in Storage to TASQ	Available Withdrawal Quantity
100% - 17%	110% of MDWQ
Below 17%	100% of MDWQ

In no event shall Equitrans be obligated to provide any storage service for which capacity is not available or which would require the expansion, construction or acquisition of facilities.

6.4 Scheduling of Withdrawals shall be provided by Customer to Equitrans in accordance with Section 8 of the General Terms and Conditions of Equitrans' FERC Gas Tariff.

6.5 Customer is required to withdraw seventy-five percent (75%) of its TASQ under this Rate Schedule on or before the last day of the withdrawal period. In the event that 75% of Customer's gas is not withdrawn from storage by the end of the withdrawal cycle, Equitrans may direct the withdrawal of the gas remaining in storage in excess of the specified level on an expedited schedule determined by Equitrans. In the event that Equitrans schedules the withdrawal of the gas remaining in storage, Equitrans shall assess a scheduling penalty of $0.25/Dth for the remaining gas in storage in addition to the required storage withdrawal charge.

6.6 Equitrans is authorized to withdraw any portion of the 25% of a Customer's TASQ remaining in storage after the conclusion of the withdrawal period for operational purposes, subject to the requirement that Equitrans reinject an equivalent quantity of gas for the Customer's account prior to the first day of the next withdrawal period.

RATE SCHEDULE SS-3
WINTER STORAGE SERVICE (Continued)

7. STORAGE OVERRUN SERVICE

Upon request of the Customer, Equitrans may, at its reasonable discretion, withdraw natural gas in excess of the Customer's MDWQ specified in the executed Storage Service Agreement. At no time may the Customer inject or withdraw a quantity in excess of its TASQ. All requests for Storage Overrun Service shall receive a priority in the first-come/first-served queue that is equal to any requests for interruptible storage service under Rate Schedule INSS. The rate for storage overrun service is set forth on Sheet No. 10 of this Tariff.

8. TITLE TO GAS IN STORAGE

Title to gas stored on behalf of the Customer under this Rate Schedule will remain with the Customer.

9. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions of Equitrans' FERC Gas Tariff are applicable to this Rate Schedule where not inconsistent with the provisions contained herein.

RATE SCHEDULE STS-1
Transportation Service

1. AVAILABILITY

This Rate Schedule is available to any party (hereinafter called "Customer"), which has entered into a firm gas Transportation Agreement with Equitrans, L.P. (hereinafter called "Equitrans"), for transportation service under this Rate Schedule and has separately entered into a Service Agreement with Equitrans for firm contract storage service under Equitrans' Rate Schedule SS-3 prior to the effective date of Equitrans Order 636 Restructuring.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 This Rate Schedule shall apply to all natural gas transported by Equitrans for Customer pursuant to the executed Transportation Service Agreement providing for a Maximum Daily Quantity (MDQ).

2.2 Transportation service hereunder shall be firm, subject to the provisions of the exectued Transportation Service Agreement and to the General Terms and Conditions incorporated herein by reference and shall not be subject to curtailment or interruption except as caused by force majeure or otherwise provided in the General Terms and Conditions of Equitrans' FERC Gas Tariff.

2.3 Transportation service hereunder shall consist of the acceptance by Equitrans of natural gas tendered by Customers for transportation at the Receipt Points specified in the executed Transportation Service Agreement for delivery into storage, and the redelivery of such gas from storage, after retention of the transportation retainage percentage set forth on Sheet No. 11 of this Tariff, at the delivery points specified in the Customer's service agreement.

2.4 If Customer desires transportation of natural gas under this Rate Schedule, Customer will nominate service in accordance with Section 8 of the General Terms and Conditions of Equitrans' Tariff. Equitrans shall schedule receipt and deliveries in accordance with Customers' nominations.

2.5 Equitrans shall only be obligated to deliver to Customer thermally equivalent quantities to those received, less applicable retainage for fuel, loss, and unaccounted for, and less any thermal reduction resulting from processing gas in order to meet Equitrans' applicable quality standards.

RATE SCHEDULE STS-1
Transportation Service (Continued)

3. RATE

Unless otherwise mutually agreed to in accordance with Section 30 of the General Terms and Conditions, the charge for natural gas transportation service rendered during each monthly billing period shall be the sum of the applicable amounts specified below:

3.1 Reservation Charge - An amount determined as follows:

(a) Winter Demand - For the period November 1 through March 31, the Winter Monthly Reservation Charge multiplied by the Billing Demand as defined in the General Terms and Conditions, or

(b) Base Demand - For the period April 1 through October 31, the Base Monthly Reservation Charge multiplied by the Billing Demand defined in the General Terms and Conditions.

3.2 Usage Charge - An amount determined as the product of:

(a) The quantity of natural gas in Dth injected into storage; times

(b) The rate per Dth set forth from time to time on Sheet No. 10 of this Tariff, or superseding Tariff;

3.3 Surcharge - Customer shall pay all surcharges specified in the General Terms and Conditions or which otherwise may be applicable to service under this Rate Schedule as may be set forth from time to time on Sheet No. 10 of this Tariff.

4. MINIMUM MONTHLY BILL

The Reservation Charge for the month.

5. TRANSPORTATION CONTRACT DEMAND

A Customer's Transportation Contract Demand shall be the MDQ of gas which Equitrans shall be obligated to deliver to Customer (or for Customer's account) at the Delivery Point(s) under this Rate Schedule. The MDQ shall be specified on Exhibit A of the executed Transportation Service Agreement.

6. AUTHORIZED OVERRUN TRANSPORTATION

Upon request of Customer, Equitrans, at its reasonable discretion, may receive, transport and deliver natural gas in excess of Customer's

RATE SCHEDULE STS-1
Transportation Service (Continued)

MDQ specified in the executed Transportation Service Agreement. Said overrun service will have a priority equal to interruptible transportation service.

If Equitrans elects to transport said excess gas, Customer shall pay Equitrans for each Dth of excess gas scheduled for delivery by Equitrans to storage for Customer's account during the month, an authorized overrun rate equal to the 100% load factor of the Rate Schedule STS-1 rate, as such rate is in effect and reflected from time to time on Sheet No. 10 of this Tariff, or superseding Tariff.

7. GENERAL TERMS AND CONDITIONS

Except as otherwise indicated in this Rate Schedule or by the executed Transportation Service Agreement, all of the General Terms and Conditions contained in this Tariff, including (from and after their effective date) any future modifications, additions, or deletions to said General Terms and Conditions are applicable to transportation service rendered under

Docket No. R-01XXX
Item 53.64 (c)(3)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(3) A complete listing of sources of gas supply transportation or storage and their costs, including shut-in and curtailed sources of supply, both inside and outside this Commonwealth considered by or offered to the utility but not chosen for use during the past 12 months, which 12-month period shall end 2 months prior to the date of the tariff filing, and the reasons why the gas supply, transportation or storage was not selected for use as a part of the utility's supply mix. A similar listing of gas sources, transportation or storage and associated projected costs offered or considered but not chosen to meet supply for the next 20 months, along with reasons for nonselection.

Response:

All historic sources of supply, transportation and storage volumes and costs are identified in Item 53.64(c)(1), Schedules 1 and 3.

All forecasted sources of supply, transportation and storage volumes and costs are identified in Item 53.64(c)(1), Schedules 2 and 4.

See the attached Schedule 1 for a listing of PGW's current spot supply contracts.

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

APRIL 2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 2.8250	PGW GATE	4,844	04/01/00	04/30/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 2.8100	PGW GATE	4,235	04/01/00	04/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 2.8200	PGW GATE	921	04/01/00	04/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	6,455	$ 2.8200	PGW GATE	6,000	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	ELA	6,000	$ 2.2800	PGW GATE	5,560	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	ELA	3,638	$ 2.2850	PGW GATE	3,382	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	ELA	5,000	$ 2.3000	PGW GATE	4,648	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	STX	10,000	$ 2.2600	ANR-LEB.	9,296	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	ELA	575	$ 2.2850	ANR-LEB.	540	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	ELA	2,862	$ 2.2850	KEY-CRAYNE	2,687	04/01/00	04/30/00
Firm	Tetco-800232	Accepted	ELA	4,000	$ 2.2700	CNG-OAKFORD	3,755	04/01/00	04/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 2.8000	PGW GATE	1,700	04/01/00	04/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 2.2850	PGW GATE	2,500	04/01/00	04/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 2.8550	PGW GATE	5,800	04/01/00	04/30/00
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 3.0973	CITY GATE	55,212	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 2.3575	CITY GATE	9,528	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	20,000	$ 2.3425	CITY GATE	19,056	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 2.3590	CITY GATE	9,528	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 2.3800	CITY GATE	9,528	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 2.3850	CITY GATE	9,528	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 2.3400	CITY GATE	9,528	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 65	20,000	$ 2.3850	CITY GATE	19,056	04/01/00	04/30/00
Firm	TGPL-.3691	Accepted	STA 85	2,090	$ 2.9075	CITY GATE	2,001	04/01/00	04/30/00
Spot	TGPL-.3691	Accepted	STA 45	3,150	$ 2.8650	CITY GATE	2,987	04/01/00	04/03/00
Spot	TGPL-.3691	Accepted	STA 30	10,887	$ 2.8200	CITY GATE	10,096	04/01/00	04/03/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 2.8100	CITY GATE	5,000	04/01/00	04/03/00
Spot	TGPL-.3691	Accepted	STA45	8,438	$ 2.8650	CITY GATE	8,001	04/01/00	04/03/00
Spot	TGPL-.3691	Accepted	STA45	9,984	$ 2.8650	CITY GATE	9,467	04/01/00	04/03/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 2.8800	CITY GATE	5,000	04/01/00	04/03/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 2.8400	CITY GATE	5,000	04/04/00	04/04/00
Spot	TGPL-.3691	Accepted	STA 45	3,150	$ 2.9200	CITY GATE	2,987	04/04/00	04/04/00
Spot	TGPL- 3691	Accepted	STA45	8,438	$ 2.9000	CITY GATE	8,438	04/04/00	04/04/00
Spot	TGPL-.3691	Accepted	STA45	9,984	$ 2.9000	CITY GATE	9,467	04/04/00	04/04/00
Spot	TGPL-.3691	Accepted	STA45	4,644	$ 2.9000	CITY GATE	4,403	04/04/00	04/04/00
Spot	TGPL-.3691	Accepted	STA 45	2,637	$ 2.8600	CITY GATE	2,500	04/05/00	04/05/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 2.8500	CITY GATE	15,000	04/05/00	04/05/00
Spot	TGPL-.3691	Accepted	STA45	10,546	$ 2.8600	CITY GATE	10,000	04/05/00	04/05/00
Spot	TGPL-.3691	Accepted	STA 65	7,872	$ 2.8750	CITY GATE	7,500	04/05/00	04/05/00
Spot	TGPL-.3691	Accepted	STA 65	5,248	$ 2.8800	CITY GATE	5,000	04/05/00	04/05/00
Spot	TGPL-.3691	Accepted	STA 30	10,585	$ 2.8500	CITY GATE	10,000	04/06/00	04/06/00
Spot	TGPL-.3691	Accepted	STA 45	7,910	$ 2.8500	CITY GATE	7,500	04/06/00	04/06/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 2.8800	CITY GATE	15,000	04/06/00	04/06/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 2.8500	CITY GATE	5,000	04/06/00	04/06/00
Spot	TGPL-.3691	Accepted	STA 65	5,248	$ 2.8800	CITY GATE	5,000	04/06/00	04/06/00
Spot	TGPL-.3691	Accepted	STA 65	5,248	$ 2.9200	CITY GATE	5,000	04/06/00	04/06/00
Spot	TGPL-.3691	Accepted	STA 45	10,546	$ 2.9150	CITY GATE	10,000	04/07/00	04/07/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 2.8800	CITY GATE	15,000	04/07/00	04/07/00
Spot	TGPL-.3691	Accepted	STA45	2,637	$ 2.9000	CITY GATE	2,500	04/07/00	04/07/00
Spot	TGPL-.3691	Accepted	STA 65	5,248	$ 2.9300	CITY GATE	5,000	04/07/00	04/07/00
Spot	TGPL-.3691	Accepted	STA 65	2,624	$ 2.9200	CITY GATE	2,500	04/07/00	04/07/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 2.9450	CITY GATE	15,000	04/08/00	04/10/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 2.9750	CITY GATE	15,000	04/11/00	04/11/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 2.9750	CITY GATE	5,000	04/11/00	04/11/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 2.9600	CITY GATE	15,000	04/12/00	04/12/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 2.9600	CITY GATE	5,000	04/12/00	04/12/00
Spot	TGPL- 3691	Accepted	STA45	15,819	$ 2.9650	CITY GATE	15,000	04/13/00	04/13/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 2.9650	CITY GATE	5,000	04/13/00	04/13/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.0300	CITY GATE	15,000	04/14/00	04/14/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.0300	CITY GATE	5,000	04/14/00	04/14/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.0350	CITY GATE	15,000	04/15/00	04/17/00
Spot	TGPL-.3691	Accepted	STA45	10,546	$ 3.0350	CITY GATE	10,000	04/15/00	04/17/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

APRIL 2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.1050	CITY GATE	15,000	04/18/00	04/18/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.1250	CITY GATE	15,000	04/19/00	04/19/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.1100	CITY GATE	15,000	04/20/00	04/20/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.0550	CITY GATE	15,000	04/21/00	04/24/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.1000	CITY GATE	15,000	04/25/00	04/25/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 3.0900	CITY GATE	5,000	04/26/00	04/26/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.1400	CITY GATE	15,000	04/26/00	04/26/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.1400	CITY GATE	5,000	04/26/00	04/26/00
Spot	TGPL-.3691	Accepted	STA30	9,500	$ 3.0550	CITY GATE	8,975	04/27/00	04/27/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.1000	CITY GATE	15,000	04/27/00	04/27/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.1000	CITY GATE	5,000	04/27/00	04/27/00
Spot	TGPL-.3691	Accepted	STA30	6,000	$ 2.9850	CITY GATE	5,666	04/28/00	04/28/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.0400	CITY GATE	15,000	04/28/00	04/28/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.0400	CITY GATE	5,000	04/28/00	04/28/00
Spot	TGPL-.3691	Accepted	STA30	1,000	$ 3.0000	CITY GATE	945	04/29/00	04/30/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 3.0650	CITY GATE	15,000	04/29/00	04/30/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.0650	CITY GATE	5,000	04/29/00	04/30/00
Spot	Tetco-800232	Accepted	STX	4,346	$ 2.7800	CITY GATE	4,000	04/01/00	04/03/00
Spot	Tetco-800232	Accepted	ETX	6,455	$ 2.8100	CITY GATE	6,000	04/01/00	04/03/00
Spot	Tetco-800232	Accepted	STX	4,346	$ 2.7850	CITY GATE	4,000	04/04/00	04/04/00
Spot	Tetco-800232	Accepted	ETX	6,455	$ 2.8100	CITY GATE	6,000	04/04/00	04/04/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.7850	CITY GATE	5,000	04/05/00	04/05/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.7900	CITY GATE	5,000	04/05/00	04/05/00
Spot	Tetco-800232	Accepted	STX	4,346	$ 2.7300	CITY GATE	4,000	04/05/00	04/05/00
Spot	Tetco-800232	Accepted	STX	10,866	$ 2.7400	CITY GATE	10,000	04/05/00	04/05/00
Spot	Tetco-800232	Accepted	ETX	6,455	$ 2.7900	CITY GATE	6,000	04/05/00	04/05/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.8000	CITY GATE	5,000	04/06/00	04/06/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.7900	CITY GATE	5,000	04/06/00	04/06/00
Spot	Tetco-800232	Accepted	STX	4,346	$ 2.7900	CITY GATE	4,000	04/06/00	04/06/00
Spot	Tetco-800232	Accepted	STX	10,866	$ 2.7900	CITY GATE	10,000	04/06/00	04/06/00
Spot	Tetco-800232	Accepted	ETX	6,455	$ 2.8200	CITY GATE	6,000	04/06/00	04/06/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.8450	CITY GATE	5,000	04/07/00	04/07/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.8300	CITY GATE	5,000	04/07/00	04/07/00
Spot	Tetco-800232	Accepted	STX	4,346	$ 2.7950	CITY GATE	4,000	04/07/00	04/07/00
Spot	Tetco-800232	Accepted	ETX	6,455	$ 2.8450	CITY GATE	6,000	04/07/00	04/07/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.9050	CITY GATE	5,000	04/08/00	04/10/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.9000	CITY GATE	5,000	04/08/00	04/10/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.9350	CITY GATE	5,000	04/11/00	04/11/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.9300	CITY GATE	5,000	04/11/00	04/11/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.9150	CITY GATE	5,000	04/12/00	04/13/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.9050	CITY GATE	5,000	04/12/00	04/12/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.9000	CITY GATE	5,000	04/13/00	04/13/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.9900	CITY GATE	5,000	04/14/00	04/14/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.9750	CITY GATE	5,000	04/14/00	04/14/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 2.9750	CITY GATE	5,000	04/15/00	04/17/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 2.9650	CITY GATE	5,000	04/15/00	04/17/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 3.0550	CITY GATE	5,000	04/18/00	04/18/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 3.0350	CITY GATE	5,000	04/18/00	04/18/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 3.0700	CITY GATE	5,000	04/19/00	04/19/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 3.0700	CITY GATE	5,000	04/19/00	04/19/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 3.0100	CITY GATE	5,000	04/21/00	04/24/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 3.0000	CITY GATE	5,000	04/21/00	04/24/00
Spot	Tetco-800232	Accepted	WLA	10,791	$ 3.0600	CITY GATE	10,000	04/25/00	04/25/00
Spot	Tetco-800232	Accepted	WLA	10,791	$ 3.1000	CITY GATE	10,000	04/26/00	04/26/00
Spot	Tetco-800232	Accepted	WLA	10,791	$ 3.0750	CITY GATE	10,000	04/27/00	04/27/00
Spot	Tetco-800232	Accepted	WLA	10,791	$ 3.0150	CITY GATE	10,000	04/28/00	04/29/00
Spot	Tetco-800232	Accepted	WLA	10,791	$ 3.0350	CITY GATE	10,000	04/30/00	04/30/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

MAY-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 2.9800	PGW GATE	4,844	05/01/00	05/31/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 3.0100	PGW GATE	4,235	05/01/00	05/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 3.0200	PGW GATE	921	05/01/00	05/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	6,455	$ 3.0200	PGW GATE	6,000	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	WLA	6,000	$ 2.2400	PGW GATE	5,560	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	ELA	6,563	$ 2.2450	PGW GATE	6,100	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	ELA	5,000	$ 2.2475	PGW GATE	4,648	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	ETX	4,000	$ 2.2350	PGW GATE	3,718	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	ELA	5,000	$ 2.2950	PGW GATE	4,788	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	STX	10,000	$ 2.2250	ANR-LEB.	9,296	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	ELA	575	$ 2.2450	ANR-LEB.	540	05/01/00	05/31/00
Firm	Tetco-800232	Accepted	ELA	2,862	$ 2.2450	KEY-CRANYE	2,687	05/01/00	05/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 3.0100	PGW GATE	1,700	05/01/00	05/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 3.0500	PGW GATE	2,500	05/01/00	05/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 3.0850	PGW GATE	5,800	05/01/00	05/31/00
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 3.2800	PGW GATE	55,212	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 3.0175	PGW GATE	9,528	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3025	PGW GATE	19,056	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3050	PGW GATE	19,056	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 3.0200	PGW GATE	9,528	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	1,149	$ 3.1100	PGW GATE	1,100	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	5,000	$ 2.3000	WSS	5,000	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3100	WSS	20,000	05/01/00	05/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3075	WSS	20,000	05/01/00	05/31/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.0500	PGW GATE	5,000	05/01/00	05/01/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 3.0900	PGW GATE	9,528	05/01/00	05/01/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 3.0900	PGW GATE	9,528	05/02/00	05/02/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 1
Item 53.64(C)(3)
4 of 15

SPOT - FIRM PURCHASES

JUNE-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 4.2550	PGW GATE	4,844	06/01/00	06/30/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 4.3150	PGW GATE	4,235	06/01/00	06/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 4.3200	PGW GATE	921	06/01/00	06/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	6,455	$ 4.3200	PGW GATE	6,000	06/01/00	06/30/00
Firm-Swing	Tetco-800232	Accepted	WLA	475	$ 4.3150	PGW GATE	440	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	M1/24"	891	$ 3.9150	PGW GATE	850	06/09/00	06/30/00
Firm	Tetco-800232	Accepted	STX	10,000	$ 2.2325	ANR-LEB	9,296	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	ELA	575	$ 2.2600	ANR-LEB	540	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	ELA	2,862	$ 2.2600	KEY-CRAYNE	2,687	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	ELA	10,000	$ 2.2400	SS1 POINT	9,351	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	WLA	6,000	$ 2.2400	SS1 POINT	5,594	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	ELA	1,883	$ 2.2600	SS1 POINT	1,761	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	ETX	4,000	$ 2.2300	SS1 POINT	3,740	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	ELA	4,880	$ 2.2600	SS1 POINT	4,376	06/01/00	06/30/00
Firm	Tetco-800232	Accepted	M1/24"	609	$ 3.9150	SS1 POINT	584	06/01/00	06/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 4.3100	PGW GATE	1,700	06/01/00	06/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 4.3350	PGW GATE	2,500	06/01/00	06/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 4.3750	PGW GATE	5,800	06/01/00	06/30/00
Firm-Swing	TGPL- 3804	Accepted	CITY GATE	55,212	$ 4.6375	PGW GATE	55,212	06/01/00	06/30/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 4.3075	PGW GATE	9,528	06/01/00	06/30/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 2.3300	PGW GATE	9,528	06/01/00	06/30/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 2.3400	PGW GATE	9,528	06/01/00	06/30/00
Firm	TGPL- 3691	Accepted	STA65	10,000	$ 4.3100	PGW GATE	9,528	06/01/00	06/30/00
Firm	TGPL-.3691	Accepted	STA45	5,000	$ 2.3200	PGW GATE	4,741	06/01/00	06/30/00
Firm	TGPL- 3691	Accepted	STA30	5,000	$ 2.2950	PGW GATE	4,724	06/01/00	06/30/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3350	WSS	20,000	06/01/00	06/30/00
Firm	TGPL- 3691	Accepted	STA65	20,000	$ 2.3300	WSS	20,000	06/01/00	06/30/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.5100	PGW GATE	9,528	06/01/00	06/01/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/03/00	06/06/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/03/00	06/06/00
Spot	TGPL- 3691	Accepted	STA65	3,000	$ 4.2500	PGW GATE	2,858	06/03/00	06/05/00
Spot	TGPL- 3691	Accepted	STA65	5,248	$ 4.2500	PGW GATE	5,000	06/03/00	06/05/00
Spot	TGPL-.3691	Accepted	STA45	2,500	$ 4.1550	WSS	2,477	06/03/00	06/05/00
Spot	TGPL-.3691	Accepted	STA65	3,000	$ 4.1750	PGW GATE	2,858	06/06/00	06/06/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.1700	PGW GATE	5,000	06/06/00	06/06/00
Spot	TGPL-.3691	Accepted	STA45	2,500	$ 4.1350	WSS	2,477	06/06/00	06/06/00
Spot	TGPL-.3691	Accepted	STA65	3,000	$ 4.4650	PGW GATE	2,858	06/07/00	06/07/00
Spot	TGPL-.3691	Accepted	STA65	20,000	$ 4.3000	PGW GATE	19,056	06/07/00	06/07/00
Spot	TGPL-.3691	Accepted	STA45	2,500	$ 4.4500	WSS	2,477	06/07/00	06/07/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/08/00	06/15/00
Spot	TGPL- 3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/08/00	06/16/00
Spot	TGPL- 3691	Accepted	STA65	3,000	$ 4.2050	PGW GATE	2,858	06/08/00	06/08/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 4.2800	PGW GATE	10,000	06/08/00	06/08/00
Spot	TGPL-.3691	Accepted	STA45	2,500	$ 4.1850	WSS	2,477	06/08/00	06/08/00
Spot	TGPL-.3691	Accepted	STA45	3,200	$ 4.1900	PGW GATE	3,034	06/08/00	06/08/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 3.9800	PGW GATE	10,000	06/09/00	06/12/00
Spot	TGPL- 3691	Accepted	STA65	5,248	$ 3.9200	PGW GATE	5,000	06/09/00	06/09/00
Spot	TGPL- 3691	Accepted	STA65	5,000	$ 3.9450	PGW GATE	4,746	06/09/00	06/09/00
Spot	TGPL- 3691	Accepted	STA65	5,000	$ 4.1500	PGW GATE	4,746	06/10/00	06/12/00
Spot	TGPL- 3691	Accepted	STA45	4,800	$ 3.8800	PGW GATE	4,551	06/09/00	06/09/00
Spot	TGPL- 3691	Accepted	STA45	10,000	$ 3.9350	PGW GATE	9,482	06/09/00	06/09/00
Spot	TGPL-.3691	Accepted	STA45	2,500	$ 3.9350	WSS	2,477	06/09/00	06/09/00
Spot	TGPL-.3691	Accepted	STA45	2,500	$ 4.1250	WSS	2,477	06/10/00	06/12/00
Spot	TGPL-.3691	Accepted	STA45	15,819	$ 4.1650	PGW GATE	15,000	06/13/00	06/13/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

JUNE-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Spot	TGPL-3691	Accepted	STA65	5,000	$ 4.1900	PGW GATE	4,764	06/13/00	06/13/00
Spot	TGPL-3691	Accepted	STA85	10,495	$ 4.1800	PGW GATE	10,000	06/13/00	06/13/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.1650	WSS	2,477	06/13/00	06/13/00
Spot	TGPL-3691	Accepted	STA45	15,819	$ 4.2900	PGW GATE	15,000	06/14/00	06/14/00
Spot	TGPL-3691	Accepted	STA65	5,000	$ 4.2750	PGW GATE	4,764	06/14/00	06/14/00
Spot	TGPL-3691	Accepted	STA85	10,495	$ 4.3200	PGW GATE	10,000	06/14/00	06/14/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.2500	WSS	2,477	06/14/00	06/14/00
Spot	TGPL-3691	Accepted	STA85	8,000	$ 4.3200	PGW GATE	7,858	06/14/00	06/14/00
Spot	TGPL-3691	Accepted	STA45	7,500	$ 4.1300	PGW GATE	7,112	06/15/00	06/15/00
Spot	TGPL-3691	Accepted	STA65	5,000	$ 4.1600	PGW GATE	4,764	06/15/00	06/15/00
Spot	TGPL-3691	Accepted	STA85	10,495	$ 4.1700	PGW GATE	10,000	06/15/00	06/15/00
Spot	TGPL-3691	Accepted	STA65	5,000	$ 4.1700	PGW GATE	4,764	06/15/00	06/15/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.1350	PGW GATE	2,477	06/15/00	06/15/00
Spot	TGPL-3691	Accepted	STA85	5,302	$ 4.1900	PGW GATE	5,076	06/15/00	06/15/00
Spot	TGPL-3691	Accepted	STA30	10,585	$ 4.3200	PGW GATE	10,000	06/16/00	06/16/00
Spot	TGPL-3691	Accepted	STA45	15,819	$ 4.3500	PGW GATE	15,000	06/16/00	06/16/00
Spot	TGPL-3691	Accepted	STA65	5,000	$ 4.3600	PGW GATE	4,746	06/16/00	06/16/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.3400	WSS	2,477	06/16/00	06/16/00
Spot	TGPL-3691	Accepted	STA85	5,302	$ 4.4000	PGW GATE	5,076	06/16/00	06/19/00
Spot	TGPL-3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/17/00	06/19/00
Spot	TGPL-3691	Accepted	STA45	15,819	$ 4.2700	PGW GATE	15,000	06/20/00	06/20/00
Spot	TGPL-3691	Accepted	STA85	10,000	$ 4.3800	PGW GATE	9,528	06/20/00	06/22/00
Spot	TGPL-3691	Accepted	STA65	3,000	$ 4.3600	PGW GATE	2,858	06/20/00	06/20/00
Spot	TGPL-3691	Accepted	STA85	10,000	$ 4.3700	PGW GATE	9,528	06/20/00	06/20/00
Spot	TGPL-3691	Accepted	STA85	10,000	$ 4.3200	PGW GATE	9,528	06/20/00	06/20/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.3350	WSS	2,477	06/20/00	06/20/00
Spot	TGPL-3691	Accepted	STA85	5,302	$ 4.3700	PGW GATE	5,076	06/20/00	06/20/00
Spot	TGPL-3691	Accepted	STA30	8,700	$ 3.9100	PGW GATE	8,329	06/21/00	06/21/00
Spot	TGPL-3691	Accepted	STA45	22,147	$ 3.9400	PGW GATE	21,000	06/21/00	06/21/00
Spot	TGPL-3691	Accepted	STA85	5,000	$ 4.0100	PGW GATE	4,764	06/21/00	06/21/00
Spot	TGPL-3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/21/00	06/22/00
Spot	TGPL-3691	Accepted	STA65	3,000	$ 4.0550	PGW GATE	2,858	06/21/00	06/21/00
Spot	TGPL-3691	Accepted	STA85	5,248	$ 3.9800	PGW GATE	5,000	06/21/00	06/21/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.0300	PGW GATE	2,478	06/21/00	06/21/00
Spot	TGPL-3691	Accepted	STA30	8,700	$ 4.1900	PGW GATE	8,329	06/22/00	06/22/00
Spot	TGPL-3691	Accepted	STA45	15,819	$ 4.1000	PGW GATE	15,000	06/22/00	06/22/00
Spot	TGPL-3691	Accepted	STA85	5,000	$ 4.1200	PGW GATE	4,764	06/22/00	06/22/00
Spot	TGPL-3691	Accepted	STA85	3,000	$ 4.1500	PGW GATE	2,858	06/22/00	06/22/00
Spot	TGPL-3691	Accepted	STA85	5,248	$ 4.1100	PGW GATE	5,000	06/22/00	06/22/00
Spot	TGPL-3691	Accepted	STA45	2,500	$ 4.1300	WSS	2,478	06/22/00	06/22/00
Spot	TGPL-3691	Accepted	STA30	11,000	$ 4.3400	PGW GATE	10,392	06/23/00	06/23/00
Spot	TGPL-3691	Accepted	STA30	12,000	$ 4.3500	PGW GATE	11,338	06/24/00	06/26/00
Spot	TGPL-3691	Accepted	STA85	10,495	$ 4.3800	PGW GATE	10,000	06/24/00	06/26/00
Spot	TGPL-3691	Accepted	STA85	31,486	$ 4.3300	PGW GATE	30,000	06/29/00	06/29/00
Spot	TGPL-3691	Accepted	STA85	10,000	$ 4.3800	PGW GATE	9,528	06/30/00	06/30/00
Spot	TGPL-3691	Accepted	STA65	10,000	$ 4.3800	PGW GATE	9,528	06/30/00	06/30/00
Spot	TGPL-3691	Accepted	STA85	5,248	$ 4.2800	PGW GATE	5,000	06/30/00	06/30/00
Spot	TGPL-3691	Accepted	STA85	10,495	$ 4.3000	PGW GATE	10,000	06/30/00	06/30/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES
JULY-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 4.2550	PGW GATE	4,844	07/01/00	07/31/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 4.2600	PGW GATE	4,235	07/01/00	07/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 4.2800	PGW GATE	921	07/01/00	07/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	6,455	$ 4.2800	PGW GATE	6,000	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	WLA	808	$ 2.2400	PGW GATE	440	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	STX	10,000	$ 2.2525	ANR-LEB.	9,296	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	ELA	980	$ 2.2800	ANR-LEB.	540	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	ELA	2,862	$ 2.2750	KEY-CRAYNE	2,687	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	ELA	10,000	$ 2.2510	SS1	9,351	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	WLA	6,000	$ 2.2400	SS1	5,594	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	ELA	3,672	$ 2.2800	SS1	3,434	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	ETX	4,000	$ 2.2400	SS1	3,740	07/01/00	07/31/00
Firm	Tetco-800232	Accepted	ELA	2,891	$ 2.2800	SS1	2,703	07/01/00	07/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 4.2700	PGW GATE	1,500	07/01/00	07/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 4.3200	PGW GATE	2,500	07/01/00	07/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 4.3600	PGW GATE	5,800	07/01/00	07/31/00
Firm-Swing	TGPL-.3604	Accepted	CITY GATE	55,212	$ 4.6147	PGW GATE	55,212	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 4.2250	PGW GATE	9,582	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 4.2275	PGW GATE	9,528	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA45	5,000	$ 2.3200	PGW GATE	4,741	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA30	5,000	$ 2.2950	PGW GATE	4,724	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 2.3400	WSS	10,000	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3400	WSS	20,000	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3400	WSS	20,000	07/01/00	07/31/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 2.3250	WSS	10,000	07/01/00	07/31/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	10,000	07/01/00	07/31/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	10,000	07/01/00	07/31/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.2800	PGW GATE	5,000	07/01/00	07/05/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.3200	PGW GATE	5,000	07/01/00	07/05/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.3600	PGW GATE	5,000	07/01/00	07/05/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.2500	PGW GATE	5,000	07/06/00	07/06/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 3.9000	PGW GATE	5,000	07/07/00	07/07/00
Spot	TGPL-.3691	Accepted.	STA30	5,293	$ 3.9300	PGW GATE	5,000	07/08/00	07/10/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.2600	PGW GATE	5,000	07/06/00	07/06/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.9800	PGW GATE	5,000	07/07/00	07/07/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.9750	PGW GATE	5,000	07/08/00	07/10/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.3100	PGW GATE	5,000	07/06/00	07/06/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.1800	PGW GATE	5,000	07/06/00	07/06/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 4.0000	PGW GATE	10,000	07/07/00	07/07/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.9300	PGW GATE	5,000	07/08/00	07/10/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.9750	PGW GATE	5,000	07/08/00	07/10/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.1300	PGW GATE	5,000	07/11/00	07/11/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.1100	PGW GATE	5,000	07/12/00	07/12/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.2500	PGW GATE	5,000	07/13/00	07/13/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.0000	PGW GATE	5,000	07/14/00	07/14/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.0900	PGW GATE	5,000	07/15/00	07/17/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.1350	PGW GATE	5,000	07/11/00	07/11/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.1300	PGW GATE	5,000	07/12/00	07/12/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.2700	PGW GATE	5,000	07/13/00	07/13/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.0450	PGW GATE	5,000	07/14/00	07/14/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.1500	PGW GATE	5,000	07/15/00	07/17/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES
JULY-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.1700	PGW GATE	5,000	07/11/00	07/11/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.1600	PGW GATE	5,000	07/11/00	07/11/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 4.1550	PGW GATE	10,000	07/12/00	07/12/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 4.2900	PGW GATE	10,000	07/13/00	07/13/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.0750	PGW GATE	5,000	07/14/00	07/14/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 4.0700	PGW GATE	5,000	07/14/00	07/14/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	9,528	07/16/00	07/20/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	9,528	07/16/00	07/20/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.1400	PGW GATE	5,000	07/18/00	07/18/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 3.9400	PGW GATE	5,000	07/19/00	07/19/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 4.0300	PGW GATE	5,000	07/20/00	07/20/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.0950	PGW GATE	5,000	07/18/00	07/18/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.9550	PGW GATE	5,000	07/19/00	07/19/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.0400	PGW GATE	5,000	07/20/00	07/20/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	9,528	07/21/00	07/25/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	9,528	07/21/00	07/25/00
Spot	TGPL-.3691	Accepted	STA30	5,293	$ 3.8350	PGW GATE	5,000	07/21/00	07/21/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.8500	PGW GATE	5,000	07/21/00	07/21/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.8400	PGW GATE	5,000	07/22/00	07/24/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.6600	PGW GATE	5,000	07/25/00	07/25/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.8500	PGW GATE	5,000	07/21/00	07/21/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.8700	PGW GATE	5,000	07/22/00	07/24/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.6600	PGW GATE	5,000	07/25/00	07/25/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.8600	PGW GATE	5,000	07/21/00	07/21/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.8900	PGW GATE	5,000	07/22/00	07/24/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7200	PGW GATE	5,000	07/25/00	07/25/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	9,528	07/26/00	07/31/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.3600	PGW GATE	9,528	07/26/00	07/31/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.5860	PGW GATE	5,000	07/26/00	07/26/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.5450	PGW GATE	5,000	07/27/00	07/27/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.7300	PGW GATE	5,000	07/28/00	07/28/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.8550	PGW GATE	5,000	07/29/00	07/31/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.5900	PGW GATE	5,000	07/26/00	07/26/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.5700	PGW GATE	5,000	07/27/00	07/27/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7800	PGW GATE	5,000	07/28/00	07/28/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.8700	PGW GATE	5,000	07/29/00	07/31/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.6600	PGW GATE	5,000	07/26/00	07/26/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.5800	PGW GATE	5,000	07/27/00	07/27/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7700	PGW GATE	5,000	07/28/00	07/28/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.8700	PGW GATE	5,000	07/29/00	07/31/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.5900	PGW GATE	5,000	07/26/00	07/26/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.5700	PGW GATE	5,000	07/27/00	07/27/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7900	PGW GATE	5,000	07/28/00	07/28/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

AUGUST-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 3.6750	PGW GATE	4,844	08/01/00	08/31/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 3.7300	PGW GATE	4,235	08/01/00	08/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 3.7450	PGW GATE	921	08/01/00	08/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	6,455	$ 3.7450	PGW GATE	6,000	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	STX	10,000	$ 2.2350	ANR-LEB.	9,296	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	ELA	575	$ 2.2550	ANR-LEB.	540	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	ELA	2,852	$ 2.2550	KEY-CRAYNE	2,677	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	ELA	10,000	$ 2.2600	SS1	9,351	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	WLA	6,000	$ 2.2700	SS1	5,594	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	ELA	3,672	$ 2.2550	SS1	3,434	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	ELA	2,901	$ 2.2550	SS1	2,713	08/01/00	08/31/00
Firm	Tetco-800232	Accepted	ETX	4,000	$ 2.2500	SS1	3,740	08/01/00	08/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 3.7250	PGW GATE	1,700	08/01/00	08/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 3.7800	PGW GATE	2,500	08/01/00	08/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 3.8200	PGW GATE	5,800	08/01/00	08/31/00
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 4.0465	PGW GATE	55,212	08/01/00	08/31/00
Firm	TGPL-.3691	Accepted	STA65	10,000	$ 3.7050	PGW GATE	9,528	08/01/00	08/31/00
Firm	TGPL-.3691	Accepted	STA45	5,000	$ 2.3050	PGW GATE	4,741	08/01/00	08/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3277	WSS	20,000	08/01/00	08/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3450	WSS	20,000	08/01/00	08/31/00
Firm	TGPL-.3691	Accepted	STA65	20,000	$ 2.3100	WSS	20,000	08/01/00	08/31/00
Spot	Tetco-800232	Accepted	ELA	2,044	$ 3.6750	PGW GATE	1,900	08/01/00	08/07/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.7500	PGW GATE	5,000	08/01/00	08/01/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 3.7700	PGW GATE	5,000	08/02/00	08/02/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.0500	PGW GATE	5,000	08/03/00	08/03/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.1900	PGW GATE	5,000	08/04/00	08/04/00
Spot	TGPL-.3691	Accepted	STA45	5,273	$ 4.1900	PGW GATE	5,000	08/05/00	08/07/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 3.8300	PGW GATE	9,528	08/01/00	08/02/00
Spot	TGPL-.3691	Accepted	STA65	6,400	$ 3.8300	PGW GATE	9,528	08/01/00	08/04/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7800	PGW GATE	5,000	08/01/00	08/01/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7200	PGW GATE	5,000	08/02/00	08/02/00
Spot	TGPL-.3691	Accepted	STA65	5,218	$ 3.7700	PGW GATE	5,000	08/01/00	08/01/00
Spot	TGPL-.3691	Accepted	STA65	5,218	$ 3.7200	PGW GATE	5,000	08/02/00	08/02/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 3.7700	PGW GATE	10,000	08/01/00	08/01/00
Spot	TGPL-.3691	Accepted	STA65	10,495	$ 3.7500	PGW GATE	10,000	08/02/00	08/02/00
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 3.7700	PGW GATE	5,000	08/02/00	08/02/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

SEPTEMBER-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 4.4800	PGW GATE	4,844	09/01/00	09/30/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 4.5200	PGW GATE	4,235	09/01/00	09/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 4.5400	PGW GATE	921	09/01/00	09/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	6,455	$ 4.5400	PGW GATE	6,000	09/01/00	09/30/00
Firm	Tetco-800232	Accepted	ELA	10,000	$ 4.5400	PGW GATE	9,295	09/26/00	09/30/00
Firm	Tetco-800232	Accepted	ELA	10,000	$ 4.5400	ANR-LEB.	9,388	09/01/00	09/26/00
Firm	Tetco-800232	Accepted	ELA	477	$ 4.5400	ANR-LEB.	448	09/01/00	09/26/00
Firm	Tetco-800232	Accepted	ELA	2,880	$ 4.5400	KEY-CRAYNE	2,677	09/01/00	09/26/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 4.5200	PGW GATE	1,700	09/01/00	09/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 4.5800	PGW GATE	2,500	09/01/00	09/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 4.6200	PGW GATE	5,800	09/01/00	09/30/00
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 4.8804	PGW GATE	55,212	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.6400	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.7700	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.7525	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.6200	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 45	5,273	$ 4.5700	PGW GATE	5,000	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.4500	WSS	10,000	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.3200	WSS	10,000	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.3000	WSS	10,000	09/01/00	09/30/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 1
Item 53.64(C)(3)
10 of 15

SPOT - FIRM PURCHASES

OCTOBER-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 5.1150	PGW GATE	4,844	09/01/00	09/30/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 5.1750	PGW GATE	4,235	09/01/00	09/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	991	$ 5.2000	PGW GATE	921	09/01/00	09/30/00
Firm	Tetco-800232	Accepted	ELA	5,000	$ 5.2000	PGW GATE	4,648	09/01/00	09/30/00
Firm	Tetco-800232	Accepted	STX	5,000	$ 4.6825	PGW GATE	4,602	09/01/00	09/30/00
Firm	Tetco-800232	Accepted	ETX	5,000	$ 4.9650	PGW GATE	4,648	09/01/00	09/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	1,800	$ 5.1800	PGW GATE	1,700	09/01/00	09/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	2,637	$ 5.2300	PGW GATE	2,500	09/01/00	09/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	6,087	$ 5.2850	PGW GATE	5,800	09/01/00	09/30/00
Firm-Swing	TGPL-.3604	Accepted	CITY GATE	55,212	$ 5.5794	PGW GATE	55,212	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.8600	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 30	5,001	$ 4.8150	PGW GATE	4,724	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 45	15,000	$ 5.2525	PGW GATE	14,223	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 30	5,001	$ 5.0550	PGW GATE	4,724	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.8600	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.8500	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9800	PGW GATE	9,528	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	20,000	$ 5.1975	PGW GATE	19,056	09/01/00	09/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9600	PGW GATE	9,528	09/01/00	09/30/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 5.1800	PGW GATE	5,000	09/06/00	09/10/00
Spot	Tetco-800232	Accepted	ELA	10,758	$ 5.1600	PGW GATE	10,000	09/06/00	09/06/00
Spot	Tetco-800232	Accepted	ELA	10,758	$ 5.2000	PGW GATE	10,000	09/07/00	09/10/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 5.1200	PGW GATE	5,000	09/06/00	09/06/00
Spot	Tetco-800232	Accepted	WLA	5,395	$ 5.1700	PGW GATE	5,000	09/07/00	09/10/00
Spot	Tetco-800232	Accepted	ELA	5,000	$ 4.9900	PGW GATE	4,648	09/10/00	09/10/00
Spot	Tetco-800232	Accepted	WLA	5,000	$ 4.9800	PGW GATE	4,634	09/10/00	09/10/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 4.9800	PGW GATE	5,000	09/11/00	09/11/00
Spot	Tetco-800232	Accepted	ELA	15,758	$ 4.9800	PGW GATE	14,647	09/11/00	09/11/00
Spot	Tetco-800232	Accepted	WLA	10,395	$ 4.9700	PGW GATE	9,633	09/11/00	09/11/00
Spot	Tetco-800232	Accepted	ELA	2,937	$ 4.6000	BOUNDARY PT	2,757	09/30/00	09/30/00
Spot	Tetco-800232	Accepted	ELA	10,000	$ 4.4600	BOUNDARY PT	9,388	09/30/00	09/30/00
Spot	Tetco-800232	Accepted	ELA	2,063	$ 4.6000	PGW GATE	1,918	09/30/00	09/30/00
Spot	Tetco-800232	Accepted	WLA	10,000	$ 4.3500	BOUNDARY PT	9,360	09/30/00	09/30/00
Spot	Tetco-800232	Accepted	STX	5,000	$ 4.3300	BOUNDARY PT	4,648	09/30/00	09/30/00
Spot	Tetco-800232	Accepted	STX	5,000	$ 4.5000	BOUNDARY PT	4,648	09/30/00	09/30/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 5.2800	PGW GATE	9,528	09/01/00	09/12/00
Spot	TGPL-.3691	Accepted	STA65	7,000	$ 5.0700	PGW GATE	6,670	09/07/00	09/11/00
Spot	TGPL-.3691	Accepted	STA65	20,000	$ 5.0700	PGW GATE	19,056	09/10/00	09/10/00
Spot	TGPL-.3691	Accepted	STA65	15,000	$ 5.0800	PGW GATE	14,292	09/11/00	09/11/00
Spot	TGPL-.3691	Accepted	STA65	5,000	$ 5.0800	PGW GATE	4,764	09/11/00	09/11/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 5.2800	PGW GATE	9,528	09/18/00	09/18/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 5.2800	PGW GATE	9,528	09/20/00	09/31/00
Spot	TGPL-.3691	Accepted	STA65	5,000	$ 4.8700	PGW GATE	4,764	09/24/00	09/24/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.8100	PGW GATE	9,528	09/24/00	09/24/00
Spot	TGPL-.3691	Accepted	STA65	5,000	$ 4.8900	PGW GATE	4,764	09/24/00	09/24/00
Spot	TGPL-.3691	Accepted	STA65	5,000	$ 4.7900	PGW GATE	4,764	09/24/00	09/24/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

NOVEMBER-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 4.3450	PGW GATE	4,844	11/01/00	11/30/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 4.3900	PGW GATE	4,235	11/01/00	11/30/00
Firm-Swing	Tetco-800232	Accepted	ELA	11,749	$ 4.4200	PGW GATE	10,921	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	ELA	6,971	$ 4.4200	PGW GATE	6,480	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	M1/30"	24,541	$ 4.6900	PGW GATE	23,400	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	ETX	5,144	$ 4.3600	PGW GATE	4,781	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	STX	9,349	$ 4.3500	PGW GATE	8,604	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	WLA	10,791	$ 4.8683	PGW GATE	10,000	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	STX	5,433	$ 4.8744	PGW GATE	5,000	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	ELA	5,379	$ 4.9645	PGW GATE	5,000	11/01/00	11/30/00
Firm	Tetco-800232	Accepted	ELA	5,379	$ 4.9645	PGW GATE	5,000	11/01/00	11/30/00
Firm	Tetco-800233	Accepted	ELA	3,787	$ 4.4200	PGW GATE	3,520	11/01/00	11/30/00
Firm	Tetco-800233	Accepted	ETX	4,001	$ 4.3600	PGW GATE	3,719	11/01/00	11/30/00
Firm	Tetco-800233	Accepted	STX	7,859	$ 4.3500	PGW GATE	7,233	11/01/00	11/30/00
Firm	Tetco-800233	Accepted	M1/24"	8,128	$ 4.6900	PGW GATE	7,750	11/01/00	11/30/00
Firm	Tetco-800233	Accepted	M1/30"	1,678	$ 4.6900	PGW GATE	1,600	11/01/00	11/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	3,599	$ 4.4050	PGW GATE	3,400	11/01/00	11/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	5,273	$ 4.4500	PGW GATE	5,000	11/01/00	11/30/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	12,175	$ 4.5100	PGW GATE	11,600	11/01/00	11/30/00
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 4.7648	CITY GATE	55,212	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.5100	PGW GATE	9,528	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.5100	PGW GATE	9,528	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9575	PGW GATE	9,528	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.5100	WSS	10,000	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.0350	PGW GATE	9,528	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.8700	PGW GATE	9,528	11/01/00	11/30/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.5100	WSS	10,000	11/01/00	11/30/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 5.7350	PGW GATE	5,000	11/17/00	11/17/00
Spot	Tetco-800232	Accepted	ELA	5,379	$ 5.5200	PGW GATE	5,000	11/18/00	11/20/00
Spot	Tetco-800232	Accepted	ELA	4,967	$ 5.8100	PGW GATE	4,617	11/17/00	11/20/00
Spot	Tetco-800232	Accepted	ELA	10,346	$ 6.1300	PGW GATE	9,617	11/21/00	11/21/00
Spot	Tetco-800232	Accepted	ELA	10,346	$ 6.2150	PGW GATE	9,617	11/22/00	11/30/00
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 4.5100	PGW GATE	9,528	11/01/00	11/03/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

DECEMBER-2000

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,264	$ 5.8300	PGW GATE	4,844	12/01/00	12/31/00
Firm-Swing	Tetco-800232	Accepted	WLA	4,570	$ 5.8850	PGW GATE	4,235	12/01/00	12/31/00
Firm-Swing	Tetco-800232	Accepted	ELA	11,749	$ 5.9000	PGW GATE	10,921	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	ELA	11,094	$ 5.9250	PGW GATE	10,000	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	ELA	3,040	$ 5.0592	PGW GATE	2,740	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	ETX	5,304	$ 5.8600	PGW GATE	4,781	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	STX	9,720	$ 5.8300	PGW GATE	8,604	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	WLA	4,325	$ 4.9850	PGW GATE	3,880	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	STX	5,648	$ 4.9367	PGW GATE	5,000	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	ELA	2,507	$ 5.0592	PGW GATE	2,260	12/01/00	12/31/00
Firm	Tetco-800232	Accepted	ELA	5,547	$ 5.0592	PGW GATE	5,000	12/01/00	12/31/00
Firm	Tetco-800233	Accepted	ELA	3,905	$ 5.9100	PGW GATE	3,520	12/01/00	12/31/00
Firm	Tetco-800233	Accepted	ETX	4,126	$ 5.8600	PGW GATE	3,719	12/01/00	12/31/00
Firm	Tetco-800233	Accepted	STX	8,171	$ 5.8300	PGW GATE	7,233	12/01/00	12/31/00
Firm	Tetco-800233	Accepted	M1/24"	8,323	$ 6.0700	PGW GATE	7,750	12/01/00	12/31/00
Firm	Tetco-800233	Accepted	M1/30"	1,718	$ 6.0700	PGW GATE	1,600	12/01/00	12/31/00
Firm	Tetco-800514	Accepted	ELA	3,594	$ 5.9100	PGW GATE	3,240	12/01/00	12/31/00
Firm	Tetco-800514	Accepted	WLA	3,413	$ 4.9850	PGW GATE	3,060	12/01/00	12/31/00
Firm	Tetco-800514	Accepted	M1/30"	12,564	$ 6.0700	PGW GATE	11,700	12/01/00	12/31/00
Firm	Tetco-800515	Accepted	ELA	3,594	$ 5.9100	PGW GATE	3,240	12/01/00	12/31/00
Firm	Tetco-800515	Accepted	WLA	3,413	$ 4.9850	PGW GATE	3,060	12/01/00	12/31/00
Firm	Tetco-800515	Accepted	M1/30"	12,564	$ 6.0700	PGW GATE	11,700	12/01/00	12/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 30	3,599	$ 5.9400	PGW GATE	3,400	12/01/00	12/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 45	5,273	$ 5.9950	PGW GATE	5,000	12/01/00	12/31/00
Firm-Swing	TGPL-.3691	Accepted	STA 65	12,175	$ 6.0400	PGW GATE	11,600	12/01/00	12/31/00
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 6.3651	CITY GATE	55,212	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.0300	PGW GATE	9,528	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.0300	PGW GATE	9,528	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9225	PGW GATE	9,528	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.0300	PGW GATE	9,528	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.0350	PGW GATE	9,528	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9275	PGW GATE	9,528	12/01/00	12/31/00
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.0300	PGW GATE	9,528	12/01/00	12/31/00

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 1
Item 53.64(C)(3)
13 of 15

SPOT - FIRM PURCHASES
JANUARY-2001

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,472	$ 9.5800	PGW GATE	4,844	01/01/01	01/31/01
Firm-Swing	Tetco-800232	Accepted	WLA	4,724	$ 9.7500	PGW GATE	4,235	01/01/01	01/31/01
Firm-Swing	Tetco-800232	Accepted	ELA	11,749	$ 9.8350	PGW GATE	10,921	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	ELA	11,094	$ 5.3596	PGW GATE	10,000	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	ELA	3,040	$ 5.4042	PGW GATE	2,740	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	ETX	5,304	$ 9.8300	PGW GATE	4,781	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	STX	9,720	$ 9.6200	PGW GATE	8,604	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	WLA	4,325	$ 5.3913	PGW GATE	3,880	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	STX	5,648	$ 9.6275	PGW GATE	5,000	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	ELA	2,507	$ 5.4042	PGW GATE	2,260	01/01/01	01/31/01
Firm	Tetco-800232	Accepted	ELA	5,547	$ 5.4042	PGW GATE	5,000	01/01/01	01/31/01
Firm	Tetco-800233	Accepted	ELA	3,905	$ 9.8200	PGW GATE	3,520	01/01/01	01/31/01
Firm	Tetco-800233	Accepted	ETX	4,126	$ 9.8300	PGW GATE	3,719	01/01/01	01/31/01
Firm	Tetco-800233	Accepted	STX	8,171	$ 9.6200	PGW GATE	7,233	01/01/01	01/31/01
Firm	Tetco-800233	Accepted	M1/24"	8,323	$10.1500	PGW GATE	7,750	01/01/01	01/31/01
Firm	Tetco-800233	Accepted	M1/30"	1,718	$10.1500	PGW GATE	1,600	01/01/01	01/31/01
Firm	Tetco-800514	Accepted	ELA	3,594	$ 9.8200	PGW GATE	3,240	01/01/01	01/31/01
Firm	Tetco-800514	Accepted	WLA	3,413	$ 5.3913	PGW GATE	3,060	01/01/01	01/31/01
Firm	Tetco-800514	Accepted	M1/30"	12,564	$10.1500	PGW GATE	11,700	01/01/01	01/31/01
Firm	Tetco-800515	Accepted	ELA	3,594	$ 9.8200	PGW GATE	3,240	01/01/01	01/31/01
Firm	Tetco-800515	Accepted	WLA	3,413	$ 5.3913	PGW GATE	3,060	01/01/01	01/31/01
Firm	Tetco-800515	Accepted	M1/30"	12,564	$10.1500	PGW GATE	11,700	01/01/01	01/31/01
Firm-Swing	TGPL-.3691	Accepted	STA 30	3,599	$ 9.8650	PGW GATE	3,400	01/01/01	01/31/01
Firm-Swing	TGPL-.3691	Accepted	STA 45	5,273	$ 9.9400	PGW GATE	5,000	01/01/01	01/31/01
Firm-Swing	TGPL-.3691	Accepted	STA 65	12,175	$ 9.9850	PGW GATE	11,600	01/01/01	01/31/01
Firm-Swing	TGPL-.3604	Accepted	CITY GATE	55,212	$10.5033	CITY GATE	55,212	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 9.9700	PGW GATE	9,528	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 9.9700	PGW GATE	9,528	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 9.9875	PGW GATE	9,528	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 9.9700	PGW GATE	9,528	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9500	PGW GATE	9,528	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 4.9475	PGW GATE	9,528	01/01/01	01/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 9.9700	PGW GATE	9,528	01/01/01	01/31/01
Spot	Tetco-800232	Accepted	ELA	11,956	$ 9.2400	PGW GATE	10,777	01/04/01	01/05/01
Spot	Tetco-800232	Accepted	ELA	11,956	$ 9.6700	PGW GATE	10,777	01/06/01	01/08/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 9.9500	PGW GATE	9,528	01/03/01	01/08/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 9.9200	PGW GATE	9,528	01/03/01	01/08/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 9.9200	PGW GATE	9,528	01/05/01	01/05/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 9.9500	PGW GATE	9,528	01/10/01	01/31/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 9.9200	PGW GATE	9,528	01/13/01	01/29/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 9.9200	PGW GATE	9,528	01/12/01	01/29/01

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

SPOT - FIRM PURCHASES

FEBRUARY-2001

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,472	$ 5.8250	PGW GATE	4,844	02/01/01	02/28/01
Firm-Swing	Tetco-800232	Accepted	WLA	4,724	$ 6.0500	PGW GATE	4,235	02/01/01	02/28/01
Firm-Swing	Tetco-800232	Accepted	ELA	11,749	$ 6.0900	PGW GATE	10,921	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	ELA	11,094	$ 7.0144	PGW GATE	10,000	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	ELA	3,040	$ 7.7846	PGW GATE	2,740	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	ETX	5,304	$ 6.4230	PGW GATE	4,781	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	STX	9,720	$ 7.0744	PGW GATE	8,604	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	WLA	4,325	$ 7.7798	PGW GATE	3,880	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	STX	5,648	$ 7.5183	PGW GATE	5,000	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	ELA	2,507	$ 7.7846	PGW GATE	2,260	02/01/01	02/28/01
Firm	Tetco-800232	Accepted	ELA	5,547	$ 7.7846	PGW GATE	5,000	02/01/01	02/28/01
Firm	Tetco-800233	Accepted	ELA	3,905	$ 7.7700	PGW GATE	3,520	02/01/01	02/28/01
Firm	Tetco-800233	Accepted	ETX	4,126	$ 6.4230	PGW GATE	3,719	02/01/01	02/28/01
Firm	Tetco-800233	Accepted	STX	8,171	$ 7.0744	PGW GATE	7,233	02/01/01	02/28/01
Firm	Tetco-800233	Accepted	M1/24"	8,323	$ 6.4000	PGW GATE	7,750	02/01/01	02/28/01
Firm	Tetco-800233	Accepted	M1/30"	1,718	$ 6.4000	PGW GATE	1,600	02/01/01	02/28/01
Firm	Tetco-800514	Accepted	ELA	3,594	$ 7.7700	PGW GATE	3,240	02/01/01	02/28/01
Firm	Tetco-800514	Accepted	WLA	3,413	$ 7.7798	PGW GATE	3,060	02/01/01	02/28/01
Firm	Tetco-800514	Accepted	M1/30"	12,564	$ 6.4000	PGW GATE	11,700	02/01/01	02/28/01
Firm	Tetco-800515	Accepted	ELA	3,594	$ 7.7700	PGW GATE	3,240	02/01/01	02/28/01
Firm	Tetco-800515	Accepted	WLA	3,413	$ 7.7798	PGW GATE	3,060	02/01/01	02/28/01
Firm	Tetco-800515	Accepted	M1/30"	12,564	$ 6.4000	PGW GATE	11,700	02/01/01	02/28/01
Firm-Swing	TGPL-.3691	Accepted	STA 30	3,599	$ 6.0600	PGW GATE	3,400	02/01/01	02/28/01
Firm-Swing	TGPL-.3691	Accepted	STA 45	5,273	$ 6.1800	PGW GATE	5,000	02/01/01	02/28/01
Firm-Swing	TGPL-.3691	Accepted	STA 65	12,175	$ 6.4550	PGW GATE	11,600	02/01/01	02/28/01
Firm-Swing	TGPL- 3604	Accepted	CITY GATE	55,212	$ 6.5710	CITY GATE	55,212	02/01/01	02/28/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.2400	PGW GATE	9,528	02/01/01	02/28/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.2400	PGW GATE	9,528	02/01/01	02/28/01
Firm	TGPL- 3691	Accepted	STA 65	10,000	$ 7.0700	PGW GATE	9,528	02/01/01	02/28/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.7474	PGW GATE	9,528	02/01/01	02/28/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 7.0775	PGW GATE	9,528	02/01/01	02/28/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 7.0450	PGW GATE	9,528	02/01/01	02/28/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.2400	PGW GATE	9,528	02/01/01	02/28/01
Spot	Tetco-800232	Accepted	WLA	4,724	$ 5.5500	PGW GATE	4,235	02/03/01	02/07/01
Spot	Tetco-800232	Accepted	ELA	11,956	$ 5.3700	PGW GATE	10,777	02/07/01	02/07/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.1900	PGW GATE	9,528	02/01/01	02/02/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.2200	PGW GATE	9,528	02/01/01	02/02/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.1900	PGW GATE	9,528	02/01/01	02/02/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.1900	PGW GATE	9,528	02/06/01	02/08/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.2200	PGW GATE	9,528	02/06/01	02/08/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.1900	PGW GATE	9,528	02/06/01	02/08/01
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 5.8400	PGW GATE	5,000	02/06/01	02/06/01
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 5.8500	PGW GATE	5,000	02/06/01	02/06/01
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 5.9000	PGW GATE	5,000	02/06/01	02/06/01
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 5.6500	PGW GATE	5,000	02/07/01	02/07/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.1900	PGW GATE	9,528	02/10/01	02/28/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.2200	PGW GATE	9,528	02/10/01	02/28/01
Spot	TGPL-.3691	Accepted	STA65	10,000	$ 6.1900	PGW GATE	9,528	02/10/01	02/28/01
Spot	TGPL-.3691	Accepted	STA65	5,248	$ 6.1300	PGW GATE	5,000	02/10/01	02/12/01

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 1
Item 53.64(C)(3)
16 of 16

SPOT - FIRM PURCHASES

MARCH-2001

Contract Type	Transportation Contract#	Status	Receipt PT.	Receipt Quantity	Price	Delivery PT.	Delivery Quantity	Start Date	End Date
Firm-Swing	Tetco-800232	Accepted	STX	5,472	$ 4.7300	PGW GATE	4,844	03/01/01	03/31/01
Firm-Swing	Tetco-800232	Accepted	WLA	4,724	$ 4.9050	PGW GATE	4,235	03/01/01	03/31/01
Firm-Swing	Tetco-800232	Accepted	ELA	11,749	$ 4.9200	PGW GATE	10,921	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	ELA	3,040	$ 6.0162	PGW GATE	2,740	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	ELA	3,594	$ 6.0138	PGW GATE	3,240	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	M1/30"	12,564	$ 5.0500	PGW GATE	11,700	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	ETX	5,304	$ 5.4740	PGW GATE	4,781	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	STX	9,720	$ 5.7915	PGW GATE	8,604	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	WLA	7,741	$ 5.6736	PGW GATE	6,940	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	STX	5,648	$ 5.4014	PGW GATE	5,000	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	ELA	2,507	$ 6.0162	PGW GATE	2,260	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	ELA	5,547	$ 6.0162	PGW GATE	5,000	03/01/01	03/31/01
Firm	Tetco-800233	Accepted	ELA	3,905	$ 6.0138	PGW GATE	3,520	03/01/01	03/31/01
Firm	Tetco-800233	Accepted	ETX	4,126	$ 5.4740	PGW GATE	3,719	03/01/01	03/31/01
Firm	Tetco-800233	Accepted	STX	8,171	$ 5.7915	PGW GATE	7,233	03/01/01	03/31/01
Firm	Tetco-800233	Accepted	M1/24"	8,323	$ 5.0500	PGW GATE	7,750	03/01/01	03/31/01
Firm	Tetco-800233	Accepted	M1/30"	1,718	$ 5.0500	PGW GATE	1,600	03/01/01	03/31/01
Firm	Tetco-800514	Accepted	ELA	3,594	$ 6.0138	PGW GATE	3,240	03/01/01	03/31/01
Firm	Tetco-800514	Accepted	WLA	3,413	$ 5.6736	PGW GATE	3,060	03/01/01	03/31/01
Firm	Tetco-800514	Accepted	M1/30"	12,564	$ 5.0500	PGW GATE	11,700	03/01/01	03/31/01
Firm-Swing	TGPL-.3691	Accepted	STA 30	3,599	$ 4.9550	PGW GATE	3,400	03/01/01	03/31/01
Firm-Swing	TGPL-.3691	Accepted	STA 45	5,273	$ 5.0050	PGW GATE	5,000	03/01/01	03/31/01
Firm-Swing	TGPL-.3691	Accepted	STA 65	12,175	$ 5.0650	PGW GATE	11,600	03/01/01	03/31/01
Firm-Swing	TGPL-.3604	Accepted	CITY GATE	55,212	$ 5.3081	CITY GATE	55,212	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.8925	PGW GATE	9,528	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.0300	PGW GATE	9,528	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.0475	PGW GATE	9,528	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.0300	PGW GATE	9,528	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.8400	PGW GATE	9,528	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 6.7450	PGW GATE	9,528	03/01/01	03/31/01
Firm	TGPL-.3691	Accepted	STA 65	10,000	$ 5.0300	PGW GATE	9,528	03/01/01	03/31/01
Firm	Tetco-800232	Accepted	ELA	10,000	$ 4.9100	PGW GATE	9,014	03/23/01	03/23/01
Firm	Tetco-800232	Accepted	WLA	2,000	$ 4.8800	PGW GATE	1,793	03/23/01	03/23/01
Firm	Tetco-800232	Accepted	WLA	5,282	$ 5.1200	PGW GATE	4,735	03/24/01	03/24/01

Docket No. R-01XXX
Item 53.64 (c)(4)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(4) An annotated listing of Federal Energy Regulatory Commission or other relevant non-Commission proceedings, including legal action necessary to relieve the utility from existing contract terms which are or may be adverse to the interest of its ratepayers, which affect the cost of the utility's gas supply, transportation or storage or which might have an impact on the utility's efforts to provide its customers with reasonable gas service at the lowest price possible. This list shall include docket numbers and shall summarize what has transpired in the cases, and the degree of participation, if any, which the utility has had in the cases. The initial list filed under this paragraph shall include cases for the past 3 years. Subsequent lists need only update prior lists and add new cases.

Response:

Please see PGW's FERC Book attached for a synopsis of all cases pending before the Federal Energy Regulatory Commission.

PHILADELPHIA GAS WORKS

FERC BOOK

FEDERAL REGULATORY AFFAIRS
REVISED: 4/20/01

TABLE OF CONTENTS

RP01-258

Transcontinental Pipeline Corp.

Transmission Electric Power (TEP) Rate

DATE FILED: March 1, 2001

ISSUES:

PGW has filed for Intervenor status to protect its interest in this case.

BACKGROUND:

Transcontinental Gas Pipeline Corporation ("Transco") tendered for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1, and certain revised tariff sheets, to be effective April 1, 2001.
Transco states that Section 41 of the General Terms and Conditions provides that Transco will file to reflect net changes in TEP rates at least 30 days prior to each TEP Annual Period beginning April 1.
Transco states that the TEP rates are designed to recover Transco's transmission electric power costs for its electric compressor stations (Stations 100, 115, 120, 125, 145 and 205). Transco states that the cost underlying the revised TEP rate consists of the two components the Estimated TEP Costs for the period April 1, 2001 through March 31, 2002 plus the balance in the TEP Deferred Account including accumulated interest as of January 31, 2001.

ACTIVITES:

March 9, 2001- PGW filed a motion with the Commission for "Leave To Intervene".

RP01-253
Transcontinental Pipeline Corp.
Transportation and Storage Rate Schedule Revisions

DATE FILED: March 1, 2001

ISSUES:

PGW has filed for intervenor status at this time to protect its interest in this case.

BACKGROUND:

Transcontinental Gas Pipeline Corporation ("Transco") tendered for filing as part Of its FERC Gas Tariff, Third Revised Volume No. 1, certain revised tariff sheets,
To be effective April 1, 2001.
Transco states that Section 38 of the General Terms and Conditions provides that Transco will file a revised determination of its fuel retention percentages available to
Transportation and storage customers. Transco states that the derivations of the revised fuel retention percentages included therein are based on Transco's estimate of gas required for operations (GRO) for the forthcoming annual period April 2001 through March 31, 2002 plus the balance accumulated in the Deferred GRO Account at January 31, 2001.
Transco states that included in the revised tariff sheets is an increase of 3.52 MMDt in the estimated GRO for the forthcoming annual period due to the results of an inventory verification study conducted in 2000 at Transco's Eminence Storage Facility, a salt-cavern storage facility located in Mississippi.

ACTIVITES:

March 9,2001- PGW filed with the Commission for "Leave to Intervene" in this case.

March 28, 2001- The Commission suspended and accepted effective April 1,2001, as proposed, subject to refund and to further review.

Based upon a review of the filing the Commission concurs with the main thrust of the intervenors in that Transco has failed to adequately justify the amount and the inclusion of the storage inventory correction adjustment in the current revised determination of the fuel percentages for the up coming year. The Commission finds that the proposed rates have not been shown to be just and reasonable and

may be unjust, unreasonable, unduly discriminatory, or other wise unlawful. Accordingly, the Commission shall accept the revised tariff sheets for filing and suspend their effectiveness, subject to the conditions set forth in this order. Transco is ordered to file complete documentation and support for a proposed storage inventory correction adjustment within thirty days of this order. The filing should fully address the concerns put forth by the intervenors.

RP01-245
Transcontinental Pipeline Corp.
General Rate Case

DATE FILED: March 1, 2001

ISSUES:

Transcontinental Gas Pipeline Corporation ("Transco") tendered for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1, certain revised tariff sheets, to be effective April 1, 2001.
Transco states that the tariff sheets submitted in the filing reflect a general rate increase, and the cost of service proposed in the filing is $876,958,109, compared with a cost of service of $649,116,408, found just and reasonable in Docket RP97-71.
Transco states the principle factors supporting the increase in cost of service are (1) an increase in the base resulting from additional plant, (2) an increase in the rate of return and related taxes, and (3) an increase in operation and maintenance expenses.
Transco states that the filing reflects the following changes from its pre-filed methods: (1) a proposed decrease in the annual depreciation accrual rate for three of its plant categories (2) the application of established cost allocation methods to the NIPPS/IEC transportation service, (3) the inclusion of the Commission approved Maiden Lateral Surcharge, (4) the roll in of the Transco's Mobile Bay expansion project approved in Docket No. CP97-92, placed into service in August, 1998, (5) a revision to Transco's revenue sharing provision related to Rate Schedules ISS, ICTS, and PBS, (6) the allocation of 100% of the cost of the capacity formally used to provide the Rate Schedule X-140 service to Mid –Louisiana Gas Company to non-incrementally priced transportation services, and (7) the elimination of the Mobile Bay "at- risk" condition.
Transco states that the filing also proposes on a prospective only bases the following changes to pre-filed methods: (1) to roll in the cost of the Sunbelt, Pocono, and Cherokee expansion transmission facilities, which are currently subject to incremental pricing, and (2) the amendment of the electric tracking mechanism to include cost associated with operation of gas coolers at Transco's various compressor station locations.

PROTEST

General:
In this filing Transco proposes an increase in rate levels and states the increase is designed to generate revenues equal to the indicated cost of service for transportation and storage services. PGW has a broad range of concerns relating to the proposed increase in the filing. Transco seeks to increase the Cost of Service to $875,958,109, from the previous approved level of $649,115,408. This increase is a direct result of changes to Transco's capital structure, rate base, return on equity, inclusion of facilities not previously included in Pipeline's cost of service, software cost, charitable contributions,

an agency agreement with affiliate Williams Field Services (WFS) and various other cost allocations. Transco proposes to further increase its rates to its traditional firm customers by including cost associated with Sunbelt, Pocono, and Cherokee expansion projects.

Absent the proposed roll-in of the aforementioned, PGW's rates are expected to increase more than 34% an as a result of this proceeding. The accumulation of both the proposed rate filing and the impact of the roll-in results are a rate impact of 35% to PGW's firm ratepayers.

PGW requests that the Commission bifurcate the case into two phases, 1) to expedited phase to explore the appropriate capital structure and rate of return and (2) to address issues and concerns surrounding Cost of Service. PGW believes that providing an expedited hearing schedule for the rate of return will allow for an Initial Decision and Commission Decision prior to the end of the suspension period. With the magnitude of the pipeline's requested increase, PGW believes the Commission action would resolve a major component of the Cost of Service and would serve to limit the rate impact to PGW customers.

PGW take exception to several of the proposed changes in the instant proceeding:

Capital Structure

Transco claims that the proposed capital structure reflects an appropriate debt to equity ratio. PGW cannot concur with Transco witness that the debt to equity range should be changed from 60.2/39.8 to 64.29/35.71.

Information provided by Transco's filing is inadequate to justify the $6.8 million increase to its Cost off Service associated with its shift in capital structure. In the absence of detailed information regarding this issue should give the Commission cause for concern in reviewing the filing. The Commission has mandated in Opinion 414-A that Transco's capital structure was the appropriate structure to use in Docket No. RP95-197 and Docket No. RP97-71 proceedings. The Commission should review Transco's financial performance based upon its actual financial results in a matter consistent with Opinion 414-A to determine if Transco's financial performance was consistent with the Commission's expectations.

Rate of Return

Transco states that its level of risk, which is used to calculate its overall rate of return, is in the medium range due primarily to the fact that it suffers from the effects of firm to the wellhead rates. The pipeline claims that the increased return on equity will help the pipeline maintain or increase its ability to raise capital. Transco offers no indication that the current rate of return is inadequate to support the same objectives.

Transco claims that its financial risk presents average or slightly lower than average risk to investors. PGW implores the Commission to carefully review this issue to determine

an appropriate level of risk to be used in determining the Pipeline's rate of return in this proceeding.

With regard to business risk, Transco claims that the uncertainties associated with state deregulation are a threat to throughput on Transco's system. Transco has failed to mention that the state level unbundling of natural gas is designed to increase competition in the natural gas industry, thereby increasing the marketability of natural gas over alternate fuels which ultimately results in increased throughput for the pipelines.

With regard to cost based risk, Transco acknowledges that there are a significant number of natural gas fired power plants being built as a direct result of both increased electric power consumption and clean air regulations. However, this business opportunity is identified by the pipeline as a factor, which increases risk because the pipeline is required to make capital investments to support the new growth. Transco offers no support to indicate that more business from electric generators equals significantly higher risk. There are no studies or conclusions to indicate that electric generation companies represent bad investment opportunities, especially in high growth areas such as those served by Transco.

Transco claims that its allocation of $61 million of fixed costs to volumetric rates contributes to its high degree of risk, however, the testimony fails to identify that this level is significantly lower than the $73 million proposed in RP97-71 rate proceeding which apparently yielded no adverse affects to the pipeline.

Transco claims that decontracting is a threat to revenues and asserts that customers will jettison whatever contract is up for renewal at the time they wish to relinquish capacity. Whether or not this is a true or false statement is irrelevant. What is relevant is the fact that Transco bears no more or less risk with regard to this issue than any other pipeline because customer contracts will terminate on all of the major pipelines at varying times. Transco offers no support to indicate that all of its contracts will terminate prior to its competitor contracts. Additionally, as a capacity subscriber, PGW would give serious weight and consideration to the financial implications of which capacity it would relinquish in the long term. If it were financially beneficial, PGW would support maintaining excess capacity in the short term if it could prove to its regulatory body that by doing so it could relinquish higher priced capacity at a later date thus resulting in long term financial benefits to its customers.

Proposed Capital Expenditures

PGW requests that the Commission review each construction project to be placed into service prior to the end of the base period and to eliminate the costs associated with any project that it determines will not be place into effect during that period.

Mobile Bay at Risk Condition

Transco cites no reason why the at risk condition should be removed from its Mobile Bay facilities as stipulated in the Commission's orders in CP92-405 and CP92-415. While the Pipeline cites various examples of circumstances under which the Commission will remove an at risk condition, it offers little with regard to reasons why its customers should assume the risk for capacity it elected to build regardless of the fact that it did not have an adequate level of contracts to cover the capacity costs. Additionally, while the pipeline identifies the fact that the Mobile Bay facilities are generating revenues in excess of costs, they later state that they are concerned about a 37.8 MMDt decrease in contract levels on the lateral.

X-140 Capacity Costs

PGW opposes the inclusion of 100% of the costs of utilizing the capacity associated with former X-140 service. These facilities were abandoned in Docket CP96-680. Transco's has provided broad assertions that these facilities are required by Transco to provide service. In fact, the pipeline merely identifies that an engineering study indicated that they had used all of their injection/withdrawal rights at the Hester storage facility, including the X-140 capacity. Transco fails to identify if they had simply used those rights as a matter of convenience or if they were used out of genuine need. Transco has not identified to the Commission in any proceeding that these facilities were required to provide service and/or flexibility, therefore, these costs should not be permitted in this rate proceeding.

Roll-In of Costs

PGW opposes the roll-in of costs for the Pocono, Cherokee and SunBelt expansion projects. At some point the Commission must realize that the pipelines traditional LDC customers have not requested additional flexibility, nor do they receive additional benefits from constructing these facilities or for rolling in the costs of these projects. Essentially, the Commission is merely shifting the cost burden of expanded business opportunities to other customers that receive no benefit from the facilities. PGW believes that Transco aggressively seeks out new business because it is assured that in its next rate proceeding, it will be permitted to roll-in the costs associated with these opportunities to its existing customers. This is entirely inapposite to Transco's claims that it experiences a high degree of cost based risk associated with the construction of new facilities. Transco does not provide any empirical evidence that existing system customers receive one iota of benefit from the facilities, nor do they identify any significantly changed circumstances, which would warrant the proposed roll-in.

Software Costs

PGW is concerned that there are a high level of costs being incurred by Transco associated with the development of the Pipeline's new 1Line software which will be enjoyed by all members of the Williams pipeline family. PGW urges the Commission to carefully review both the cost allocation methodology of this service to the various pipelines under the Williams companies and the determination that the software was developed in the most cost-effective manner internally as opposed to externally. Transco's portion of the claimed cost is $60,0132,395.

Charitable Contributions

PGW vigorously opposes Transco's inclusion of $11,160,051 of charitable contributions in its Cost of Service. While PGW applauds the pipelines charitable approach, we are certain that this would be a much more enriching experience for all if they used their own money. Companies such as PGW, have customer bases which are located in densely populated urban areas with a high concentration of low income households that can ill afford to enhance the public image of a multibillion dollar corporation that is requesting a 15.05 percent return on equity.

Williams Field Services – Annual Fee

PGW cannot understand the significant cost increase proposed by Transco's affiliate company (WFS) of $8,249,575; an increase of approximately 28.5%, which brings the cost of the WFS agreement to $37.2 million. WFS had requested that the cost be increased to $42.4 million, which would have resulted in a 48% increase over the existing contract. As a regulated entity, PGW believes that the pipeline should be required to prove to both the Commission and its customers that it is acting prudently, and that WFS is indeed the low cost provider of service through a bidding process that is sanctioned and reviewed by the Commission. Transco's customers have absolutely no protection against price gouging by WFS in its agency role.

ACTIVITES:

March 12.2001- PGW filed a motion with the Commission for "Leave to Intervene and Protest".

March 28, 2001- FERC issued an Order Accepting and Suspending Tariff Sheets Subject to Refund and Conditions and Establishing a Hearing.

The Commission will set hearing for these issues.

A) Proposed Roll-in of Sunbelt, Pocono, Cherokee Facilities Costs.
B) Roll-in of the Mobil Bay Project.
C) Changes to Cost Allocation Methodologies.

Upon review of the filing, the Commission has found the proposed tariff sheets have not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory, or otherwise unlawful. Accordingly the Commission shall accept such tariff sheets for filing and suspend their effectiveness to take effect September 1, 2001, subject to the conditions set forth in this order:

A) The tariff sheets are accepted and suspended, to be effective September 1, 2001, subject to refund and the outcome of the hearings established in this proceeding.
B) Pursuant to the authority of the NGA, particularly sections 4,5,8 and 15 thereof, with exception of the issues reserved herein, a public hearing will be held in Docket No. RP01-245-000 concerning the lawfulness of Transco's proposed rates.

An Administrative Law Judge must convene a prehearing with 20 days.

RP01-236
Transcontinental Pipeline Corp.
Customer Services and Business Practice on 1LINE

DATE FILED: February 28, 2001

ISSUES:

PGW has filed for Intervenor status to protect it interest in this case.

BACKGROUND:

Transcontinental Gas Pipeline Corporation ("Transco") tendered for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1, certain revised tariff sheets, to be effective March 31, 2001.
Transco states that the purpose of the instant filing is to revise its tariff to reflect new customer services and business practices that will be available on 1LINE, a new internet-based, service delivery computer system that will replace Transco's current system. Transco's proposed tariff modifications relate specifically to the following areas:

Offering Operational Balances Agreements at well head receipt points and processing plants to the Transco system:

Revising imbalance resolution provisions to establish Operational Impact Areas, implementing imbalance netting and trading and modifying the existing cash out mechanism

Establishing Operational Controls to adverse operational conditions which impact flexibility

Modify the Nomination, Conformation, and Predetermined Allocation methodologies used to determine the daily allocations and, if necessary, capacity reductions, at receipt and delivery point

Formalizing in Transco's tariff the pooling capabilities provided by Transco by adopting a new Rate Schedule Pooling and a Form of Service Agreement for pooling service; and

Modifying and formalizing certain pipeline business practices including those relating to capacity release, scheduling equality, liquefiable hydrocarbons processing, billing and payment, daily demand rates as well as other operational and business practices on the Transco System.

ACTIVITIES:

March 9, 2001- PGW filed a motion with the Commission for "Leave to Intervene" in this case.

RP01-206
Texas Eastern Transmission Corp.
Electric Power Cost (EPC) Adjustment

DATE FILED: December 29,2000

ISSUES:

PGW has filed for Interveneor status to protect its rights in this case.

BACKGROUND:

Texas Eastern Transmission Corp. (Texas Eastern) tendered for filling as part of its FERC Gas Tariff revised tariff sheets to become effective February 1, 2000. Those tariff sheets are filed pursuant to the Electric Power Cost (EPC) Adjustment, of the General Terms and Conditions (GT&C) of Texas Eastern's FERC Gas Tariff. GT&C provide that Texas Eastern file to be effective each February 1 revised rates for each applicable zone and rate schedule based upon the projected annual electric power cost required for the operation of transmission compressor stations with electric motor prime movers and to also reflect the EPC Surcharge which is designed to clear the balance in the Deferred EPC Account. Texas Eastern states that the rate changes are proposed to the primary firm capacity reservation charges, usage rates and the 100% load factor average costs for full Access Area Boundary service from the Access Area Zone, East Louisiana, to the three market area zones.

ACTIVITES:

January 10, 2001- PGW filed a motion with the Commission for "Leave To Intervene"

RP01-182
Texas Eastern
E-Commerce on Line LINKr System

DATE FILED: December 7,2000

ISSUES:

PGW has only filed for intervenor status at this time to protect its rights in this issue.

BACKGROUND:

Texas Eastern tendered for filing as part of its FERC Gas Tariff, Sixth Revised Volume No. 1, revise certain tariff sheets to make benefits and opportunities of e-commerce available to Texas Eastern's existing and potential customers and to advance the Commission objectives in Order No. 637, of providing equality between pipeline services and capacity release transactions. The tariff modifications permit customers to request service agreements electronically and to execute such contracts on line via the LINKr System, which will facilitate nominations and increase the efficiency and convenience of the Texas Eastern contracting for all customers.

ACTIVITY:

December 19, 2000- PGW filed a motion with the Commission for "Leave to Intervene".

January 5, 2001- FERC accepted effective January 7, 2001 subject to conditions.
I. TETCO's Filing

TETCO proposes to modify Section 3.2 of its General Terms and Conditions (GT&C) to provide that a request for new service can be submitted electronically via the LINK System. TETCO also proposes to modify Section 3.6 of the GT&C to provide that, following TETCO's acceptance of a Customer's request for service, a service agreement can be executed electronically using an Executable Contract Summary via the LINK System. This will serve as the executable, electronic version of the firm Service Agreement associated with each TETCO Rate Schedule. A fully executed Executable Contract Summary will be a valid and enforceable contract that is binding on the parties. For those customers that do not desire to submit requests or execute agreements via the new electronic process, TETCO's tariff will continue to allow such customers to request service and executed service agreements in a written form.

Posting and Bidding Requirements

In order to facilitate the timely effectiveness of new contracts, whether executed electronically or by the traditional written process, TETCO also proposes several posting and bidding requirements for pipeline services and capacity release transactions. Under the current NPV provisions, TETCO has the right, but is not obligated, to post the notice of a request for service and conduct an open season for receiving additional requests for service offerings with a term of less than ninety days. For service offerings with a term of ninety days or longer, TETCO conducts an open season. Currently an open season is held for a minimum of (1) one business day for service offerings with a term of 31 days or less, (ii) two business days for service offerings with a term of more than 31 days but less than ninety days, and (iii) fifteen business days for service offerings with a term of ninety days or longer. To more closely adhere to the bid periods for capacity release transactions, TETCO proposes to convert the minimum open season period to (1) one business day for a service offering with a term of less than ninety days, to the extent an open season is conducted, and (ii) five (5) business days from the posting of the notice of the request for service for the capacity or fifteen (15) business days from the date the capacity in question was first posted as being available for contracting, whichever is the later calendar date, for service offerings with a term of 90 days or longer, as amended in the December 28, 2000 filing.

Matching Period

The current provisions do not give the original requesting shipper the right to match any higher bid submitted during the open season; but provide that capacity will be allocated on a pro rata basis between or among requests producing an equivalent NPV.
To provide comparable rights to all customers seeking to acquire capacity from TETCO or through the capacity release mechanism, TETCO proposes to modify Section 3.12(A)(3) of the GT&C to offer the original requesting shipper a chance to match the best bid during one (1) business day from 3:00 p.m. Central Clock Time on the day that the open season ends to 3:00 p.m. Central Clock Time one business day after the day that the open season ends. The original requesting shipper must notify TETCO in writing within the one business day matching period of its decision to match the higher "best bid." Additionally, to the extent that TETCO has received two or more requests for service that produce an equivalent NPV, whether during an open season or otherwise, TETCO proposes in Section 3.12(A)(4) to award capacity to the bidder whose bid was received first in time, inclusive of the original requester.

Execution and Return of Service Agreements

In view of the streamlining of the contract processes, TETCO proposes to delete the current provision in Section 3.6 of the GT&C regarding the execution and return of service agreements within 30 days after TETCO tendered such agreement for execution. TETCO proposes that all contracts shall be executed by the shipper and returned to TETCO within 15 days, or 10 days provided that the contract is identical to the shipper's .

submitted request for service, of the later of (i) the determination of the winning bid in an open season, or (ii) the tender of a service agreement by TETCO. A bid in the open season will bind the shipper if TETCO chooses such bid as the winning bid. Under Section 3.12(D) of the GT&C TETCO proposes that at the end of the open season, the winning bid is binding on the party that submitted the winning bid and a contract will be deemed to be executed at that time and the customer agrees to comply with the requirements of Section 3.6 of the GT&C.

Commitment to E-commerce Principles

On September 1, 2000, TETCO states that it brought online a new web-based information system providing the market with real time current gas day operational capacity information. This information system provides on an hourly basis, the physical capacity through each compressor station and the total real time confirmed nominations through the point. This map-based system allows the user to pinpoint any segment on the pipeline and quickly compare physical capability with actual confirmed nominations at the identified point. As additional nominations are confirmed within day, the system automatically posts the revised aggregate nominations. This new system also provides the market with access to the pipeline's real time balance providing the user an instantaneous view of the pipeline's net balance (nominations versus actual deliveries).

On November 1, 2000, TETCO also brought online a current customer usage information system. This system provides the customer with real time hourly take data, up to the minute actual accumulations (at the meter level and in total), and a forecasted delivery for the day based on current activity. The system also provides actual real time hourly and daily entitlements based on confirmed nominations. The customers will have the ability to determine their projected daily imbalance any time within the gas

February 9, 2001- FERC accepted effective January 7, 2001. Texas Eastern is revising its tariff sheets to (1) maintain its tariff provision awarding capacity on a pro ratted basis; and (2) continue to allow a shipper to withdraw a request for service prior to the open season.

Docket No. RP01-181
Transcontinental Gas PipeLine Corp.
Track Rate Charges under Rate Schedule GSS

DATE FILED: December 8, 2000

ISSUES:

PGW has only filed for intervenor status at this time to protect its rights in this issue.

BAXKGROUND:

Transcontinental Gas Pipe Line Corp. (Transco) on December 8, 2000 tendered for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1 certain revised tariff sheets. Transco states that the purpose of this filing track rate charges attributable to transportation services purchased from Dominion Transmission, Inc. (Dominion) (formally CNG) under its Rate Schedule GSS the cost of which are included the rates and charges payable under Transco' Rate Schedules GSS and LSS, and storage services purchased from Texas Eastern Transmission Corp. under its Rate Schedule X-28 the costs of which are included in the rates and charges payable under Transco's Rate Schedule S-2.

ACTIVITES:

December 18, 2000-PGW filed a motion with the Commission for "Leave to Intervene".

RP01-171 & RP00-481
Transcontinental Pipeline Corp.
E-Commerce On Line "1LINE" System

DATE FILED: December 1,2000

ISSUES:

PGW has filed for Interveneor status and to protest to protect its rights in this case.

BACKGROUND:

Transco states that the purpose of the instant filing is to revise its tariff to reflect new customer services and business practices that will be available on 1Line, a new state of the art, internet-based, service delivery computer system that will replace Transco's current computer system. Transco's proposed tariff modifications relate specifically to the following areas:

Offering Operational Balancing Agreements at wellhead receipt points and processing plants on the Transco system

Revising imbalance resolution provisions to establish Operational Impact Areas, implementing imbalance netting and trading, modifying the existing cash out mechanism and offering Best Available operational Data;

Establishing Operational Controls to adverse operational conditions which impact flexibility prior to issuing an OFO and tariff provisions to address unauthorized takes and trespass gas;

Modifying the Nomination, Confirmation, and Predetermined Allocation methodologies used to determine the daily allocations and, if necessary, a capacity reduction, at receipt and delivery points.

Formalizing the pooling services by adopting a new Rate Schedule Pooling and a Form of Service Agreement for pooling service; and Modifying and formalizing certain pipeline business practices including those relating to capacity release, scheduling equality, liquefiable hydrocarbons processing, billing and payment, as well as other operational and business practices on the Transco system.

ACTIVITIES:

December 13, 2000- PGW filed a motion with the Commission for "Leave To Intervene and Protest"

PROTEST

A. NEW COMPUTER SYSTEM

While PGW appreciates the efforts of Transco, as a member of the Williams pipeline family, to implement its new computer system across the various pipelines of the Company, concerns still remain. PGW believes the Commission must be aware that the drive to uniformity across the Williams system creates a danger of some loss to the flexibility inherent in the individual pipelines. It also must be aware that this uniformity probably presents equal if not greater benefits to the Williams Companies than to their customers.

The proposed pro forma tariff sheets appear to remain silent on many of the operational characteristics of the new system and PGW reserves its right to protest any degradation of service resulting from the implementation of this system. PGW recognizes the enormous complexity of the undertaking, but it cannot agree to any operational modifications to the Transco system, promulgated by the development and implementation of the new 1Line software, which presents the possibility of actual or potential degradation of its existing no-notice service. PGW is particularly concerned that there be no negative impact on shippers' current flexibility provided by the contingency ranking mechanism. PGW anticipates that the implementation of the 1Line system will in no way degrade the flexibility in Transco's current operations, a key element of which is contingency ranking.

PGW also would like to mention that while it understands the difficulty and unforeseen and unanticipated problems which can arise in so complex an undertaking, it believes that the Commission must require Transco to recognize that the need for operational stability for its customers transcends even the needs of the Williams Companies and that the Commission will no longer tolerate continuing requests for extensions of time to perform pipeline functions and in particular meeting refund deadlines.

B. CASH OUT

PGW does not oppose the OIA inter-zonal mechanism's purpose to limit arbitrage by individual customers for their own interest which operates against the interests of the system customers generally.

PGW supports Transco's revised cashout mechanism and believes that it will help limit cashout imbalances and customers gaming the system by using the cashout mechanism as an alternate fuel supply source.

PGW requests that the Commission act quickly on this issue to allow for the immediate implementation of the revised cashout mechanism using currently approved rate zones. PGW believes that the Commission's decision in RP00-24 to initially implement the cashout mechanism was justified and that Transco has complied with the Commission's Order 637 requirement for the creation of netting and trading services prior to the implementation of the cashout mechanism.

C. OPERATIONAL IMPACT AREAS (OIA)

The Commission in its October 27, 2000 Order in Docket No. RM96-1-014, 93 F.E.R.C. 61,093 (October 27 Order) to which the instant filing responds, requires that the pipeline must explain and justify why the OIA's designated are appropriate (Mimeo p. 6). As part of its Order 637 compliance filing in Docket RP01-171, Transco has identified on its pro forma tariff sheet 251A. OIA's that are inconsistent with existing rate design boundaries currently in place. The impact of establishing these OIA's in a manner inconsistent with existing rate boundaries, coupled with the fact that all imbalances must be resolved within a rate zone nested within an OIA, limits the shippers ability to resolve an imbalance within a rate zone boundary. Of particular concern is the fact that Rate Zone 6 has been divided into three distinct OIA's.

This practice creates additional imbalance charges as a consequence of Transco's proposed transportation charges to balance within an OIA, which contains more than a single rate zone.

Transco has offered no explanation or reason for the OIA's neither it has created nor why they should not be coterminous with a single rate zone. A conclusive assertion that its operational people believe these OIA's constitute the largest areas with similar operational characteristics does not meet, even in the most minimal manner, the Commission's requirement for an explanation. The October 27 Order expressly requires that the pipeline must set forth the operational factors underlying the geographical boundaries of the OIA (Mimeo. p. 6). Transco's OIA boundaries seem to conflict with the reason why the rate zones were established. It would seem that the rate zones are based on common operational and cost characteristics. The splitting of rate zones into separate OIA's creating additional charges is especially confusing. PGW is concerned by the application of OIA boundaries in Section 37.1 of Transco's General Terms and Conditions in Pro Forma Tariff Sheet 360. PGW recommends that the Commission require Transco to utilize existing rate zones.

D. TRANSPORTATION CHARGES

The October 27 Order also explicitly requires that the pipeline explain the reason for any transportation charges for netting and trading of imbalances by showing that netting and/or trading will cause lost transportation revenue (Mimeo. p. 7). The Order also requires that the pipeline establish a mechanism to recover the revenue rather than using the lost revenue as justification for not implementing netting and trading of imbalances. (Mimeo. pp. 8-9). Further, the pipeline must show that without netting and trading of imbalances it would not lose any transportation revenue. (Mimeo. p. 9). Paradoxically, Transco has established the mechanism to recover lost revenue without any showing whatsoever that it may lose any revenue or that not implementing netting and trading would result in no loss of transportation revenue.

E. AUTO TRADING

PGW, in its Intervention and Request for Revenue Sharing in Transco Docket No. RP-00-553, treated Transco's transportation charge for trading imbalances between zones within an OIA as a new service to generate revenue and requested that any revenues be

credited to firm customers on a 75% division with 25% going to the pipeline. Transco proposes the same revenue generating mechanism without any of the justification required by the October 27 Order. Under the auto trading proposal, Section 25.4 makes aggregating imbalances across zones within an OIA after the monthly trading deadline mandatory for positive imbalances.

PGW is concerned that the mechanism used in Auto Trading identified in Transco's Pro Forma Tariff Sheet No. 334A, Section 25.4 may require that the trades will occur across rate zone boundaries first and then within rate zones. Essentially, this practice will generate windfall profits for the pipeline in the form of maximum IT rates for each unit of gas that crosses a rate zone boundary. Since this is a new service, utilizing existing assets with no assigned costs, PGW believes that the revenues generated for providing this service should be shared between the pipeline and the shippers. PGW believes that any revenues generated by inter-zonal netting and trading within a single OIA should be subject to revenue sharing since both the maximum IT rate and the fuel charge include a fixed cost component PGW proposes that the sharing mechanism be set at 25% for the pipeline and 75% for shippers. Regardless of whether the Commission views the application of maximum IT rates as a fee for a service provided or a penalty, the lion's share of the revenue should be credited to those customers that are paying for the fixed assets used to provide that service.

January 4, 2001- The Commission is holding a Technical Conference on this matter.

RP01-131
Transcontinental Gas PipeLine Corp.
Order 587-G and 587-L Compliance Filing

DATE FILED: November 30, 2000

ISSUES:

PGW has filed for Intervenor status at this time to protect its rights in this case.

BACKGROUND:

Transcontinental Gas PipeLine Corp. tendered for filing on November 30, 2000 revised tariff sheets to its FERC Gas Tariff. The purpose of this filing is to reflect the 2001 GRI surcharges approved by the Commission's Order issued on September 19,1999, in docket RP00-313-000. Also in accordance with GRI's 1993 settlement, Transco has calculated the firm transportation service load factor on the actual volumes transported during the 12-month period October 1999 through September 2000.

ACTIVITES:

December 11, 2000 -PGW filed a motion with the Commission for "Leave to Intervene"

RP01-69

Texas Eastern Transmission Company
Applicable Shrinkage Adjustment (ASA)

DATE FILED: October 31,2000

ISSUES:

PGW has filed for Intervenor Status at this time in order to protect its right in this case.

BACKGROUND:

October 31, 2000, Texas Eastern (TETCO) tendered for filing as part of its FERC Gas Tariff, Sixth Revised Volume No. 1 and original Volume No.2, certain tariff sheets to be come effective December 1,2000.
TETCO states that it is reducing its rates to effective an annual cost reduction of approximately $137 million at December 1, 2000 and effect new applicable shrinkage factors for the coming year commencing December 1, 2000. TETCO states that the approximately $137 million rate reduction filing is based upon the projected full recovery of Order No. 636 transition cost as of December 1, 2000, and that if TETCO has in fact over recovered its Non-Spot Cost as of December 1,200, TETCO will return any such excess collection to its customers as described herein by crediting the ASA Deferred Account for ultimate flow back to its customers.
TETCO states that to the extent that the actual data establishes that TETCO has not fully recovered such Non-Spot Costs before December 1,2000, TETCO will voluntarily include any such under-recovered Non-Spot Costs in order to assure its customers a rate reduction for the upcoming winter.
TETCO states that the impact of the filing on TETCO's rates, in combination with the Annual PCB-Related costs filing being filed concurrently, for the upcoming winter, equates to an overall decrease of 8.32 cents for typical long-haul service under rate schedule FT-1 from Access Area Zone East Louisiana to Market Zone 3 (ELA-M30)

ACTIVITES:
November 9, 2000- PGW filed a motion with the Commission for "Leave to Intervene".

RP01-37
Equitrans, LP
Order No. 587-L compliance filing.

DATE: November 21, 2000

ISSUES:

Equitrans tendered its compliance filing on November 21, 2000, revised tariff sheets to its FERC Gas Tariff. The purpose of this filing is to comply with the Commission's October 27, 2000 Order 587 describing how imbalance netting and trading will be preformed on the Equitrans system.

ACTIVITIES:
December 11, 2000-PGW filed for "Leave to Intervene". PGW is a transportation and storage customer of Equitrans and has a direct and substantial interest in this proceeding.

RP01-25

Texas Eastern Transmission Corporation

Order 587-G and 587-L Compliance

DATE FILED: November 27, 2000

ISSUES:

PGW has filed for Intervenor status at this time to protect its rights in this case.

BACKGROUND:

Texas Eastern tendered its compliance filing on November 27, 2000, revised tariff sheets to its FERC Gas Tariff. The purpose of this filing is to comply with the Commission's October 27, 2000 Order (587-G and 587-L) describing how imbalance netting and trading will be preformed on the Texas Eastern system.

ACTIVITIES:

December 11,2000-PGW filed a motion with the Commission for "Leave to Intervene".

RP00-632

Dominion Transmission Inc. (DTI)

Transportation Cost Rate Adjustment (TCRA)

DATE FILED: September 29, 2000

ISSUES:

PGW has filed for intervenor status to protect its rights in this case.

BACKGROUND:

DTI has tendered for filling as part of its FERC Gas Tariff, Third Revised Volume No. 1, and certain tariff sheets, with an effective date of November 1, 2000.
DTI states that the purpose of this filling is to update DTI's effective Transportation Cost Rate Adjustment, through the annual adjustment mechanism described in section 15 of the General Terms & Conditions (GT&C) of its tariff. DTI's surcharge incorporates the balance of its Under-recovered Fuel Cost Reimbursement Sub-account, as set forth in GT&C section16.5, as well as the balance is its under-recovered EPC Reimbursement Sub-account, pursuant to GT&C Section 17.5.

ACTIVITIES:

October 10, 2000-PGW filed a motion with the Commission for "Leave To Intervene".

October 31, 2000- FERC issued an order accepting and suspending tariff sheets subject to refund and other conditions, and establishing a technical conference on January 11, 2001.

January 31,2001-PGW filed initial comments to the technical conference held on January 11, 2001.

A. Background

PGW is concerned about the accounting treatment of cost associated with the TCRA deferred account. This sum of $65 million in under recovery mainly resulted from a $43 million revaluation of non-purchased supply quantities. The commission pointed out in its October 31, 2000 Order which established the technical conference, DTI's filing made clear that the pipeline had not replaced system supplies that it had used for two years. The $43 million alleged under recovery, primarily caused by DTI's failure to adhere to the intent of the Commission's accounting rules set forth in Order 581, according to DTI had two sources. DTI claims that the present increase in prices caused the pre-existing balance of non-purchased supply cost to increase by $28 million and the non-purchased supply cost for the present period to increase by $15 million. It is PGW's position that

nothing in DTI's Answers to Protests or what transpired at the technical conference alleviated PGW's concerns, discussed below, about DTI's purchasing practices or its operational or accounting procedures regarding its treatment of gas used for the Hastings Plant.

B. Purchasing Practices

The October 31 Order made clear that the problem was created by DTI's own voluntary actions, which contravened the intent of the commission's accounting practices. In the October 31 Order the Commission stated "order 581 contemplated that withdrawals of system gas would only temporarily encroach on the system supplies for a short period and be replaced as soon as possible in order to maintain authorized system levels". DTI's practice not only impacts the level of the past claimed deferred account, but also the additional $15 million under recovery for the present period. Had DTI made timely purchases to replace past usage as contemplated by the commission policy, it probably at this time would be in a position to defer purchases, in this price spiked period, until prices resume lower levels. At a minimum, the level of purchases needed to meet operational obligations would have been reduced. DTI claims it did not need gas because of the unusually mild winters in the Northeast for the past three years. This does not obviate the need for the pipeline to replenish its inventory to the levels, which Order 581 requires and it was certificated in order to operate its system in the next winter season. DTI cannot now claim that it has to refill the gas used over the past several years to meet its obligations for a winter that we are now halfway through, when the supplies and associated capacities were certificated to afford the pipeline sufficient operating capacity. Had DTI followed the Commission requirements, the $28 million increase would not exist and, there would probably would not be any necessity for the additional $15 million in cost. Regardless of DTI contravening Commission policy, even if its purchase practices in the resent past can be viewed solely as a result of poor speculative business judgement; there is no reason for its customers to bear the burden of the cost. DTI is relying on Order 581, to justify the increase while its failure to adhere to this order is the cause of the problem. PGW agrees that under DTI's fixed asset methodology, Order 581 requires the use of current market prices to value encroachments. However the Commission explicitly points out in October 31 Order that "this accounting is appropriate when there are timely replacements of storage withdrawals, but may not accurately reflect an estimate of the cost to replace the volumes when, as it appears here, the pipeline indefinitely postpones the replacement of the volumes".

C. Hastings Plant

PGW agrees conceptually with DTI's purchasing strategy as set forth at the technical conference, that if a company can avoid purchases of a commodity in a high market, it should only make such purchases as are necessary, so as not to build inventories of overpriced gas. DTI asserts that its reason for the non-purchase was that it did not need the gas. Perhaps it did not. Nevertheless, it is required to adhere to Commission policy. Further, the lack of need obviously was related to the mild winters

in the Northeast, the last two of that were not predicable after the first of the winters within the time frame that DTI was required by Commission policy to purchase the encroached amounts.

DTI's position is totally refuted by its presentation at the technical conference concerning its distinction between its treatment of gas operationally and from an accounting basis in regard to its Hastings Plant. DTI stated that on an operational basis, the company does not track the gas molecules through the system based on how particular volumes of gas are used. They operate their system as a whole. DTI then explained, contradicting its claimed operational practice, that it purchased gas specifically for the Hastings Plant. DTI thus claims it cannot account for gas used on its system for specific purposes because it operates its system as a single entity precluding identification of the specific use of the gas. At the same time it claims that gas was specifically purchased for Hastings.

The result of the dislocation in the accounting versus operational treatment of the gas is that DTI received the benefit of utilizing all of the inexpensive gas purchased for activities that generated additional revenues for the pipeline while encroaching on system supplies and leaving a huge void that now needs to be replaced by its customers at greatly inflated prices. In short, all of the risk associated with price volatility has been shifted to DTI's system customers, while all of the rewards associated with lower gas prices are enjoyed by the pipeline resulting solely from the company's accounting treatment of the gas purchased, despite the fact that the accounting methodology is incongruent with the operational assertions of the pipeline.

D. Conclusion

DTI is asking its customers to pay for its failures to abide by Commission policy and the risks of its business decisions. At the same time, it reaps the rewards of completely contradictory operational and accounting practices used in the operation of the Hastings Plant. It is the position of PGW that DTI has completely failed to justify the alleged $43 million increase for non-purchased supply and this should be rejected completely. Second, PGW also recommends, based upon the information presented by DTI at the technical conference, that the Commission require DTI to use the same accounting treatment of gas purchases for system use and Hastings and that gas purchases be used first to replenish certificated levels and then the remainder allocated to the Hastings Processing Plant.

RP00-553

Transcontinental Pipe Line Corporation

Order 587-G and 587-L Compliance

DATE FILED: November 22, 2000

ISSUES:

PGW has filed for Intervene status and Request for Clarification and Revenue Sharing in this issue.

BACKGROUND:
The purpose of this filing is to comply with the Commission's October 27,2000 Order describing how imbalance netting and trading will be preformed on the Transco system when such trading becomes operational.

Request for Clarification and Revenue Sharing

PGW believes that Transco should be required to provide fuller explanation of the common operational characteristics both uniting inter-zonal segments into a single OIA operational entity as well as the characteristic which separates each OIA from others which include separate portions of a single rate zone. Since the OIAs traverse the traditional rate zones established by Transco, the dispersion of a rate zone between separate OIAs seems to limit the shipper ability to net their imbalances to less than all the segments within the rate zone rather than the entire zone. In the instance of multiply zone OIAs, in order to trade over the entire OIA, it would be necessary to pay the maximum IT charges as well as the applicable fuel charge. The limitation on netting to a single zone within an OIA creates the resulting imbalances which are subject to the trading charges for inter-zonal trading within a single OIA. It also creates the possibility of multiple charges for trading imbalances within a single zone in the circumstance that each part of the single zone is in separate OIAs and each portion of the zone has imbalances that are traded within separate OIAs.
The proposed multiple zones OIAs with charges for inter-zonal transfers results in generating revenue for the pipeline as opposed to flowing imbalance penalties back to non-offending customers. Clearly Order 637's change in emphasis from penalties to prevention was not to create revenue for the pipeline, but both to mitigate operational problems and penalty revenues.
PGW does not oppose the OIA inter-zonal mechanism's purpose to limit arbitrage by individual customers for their own interest which operates against the system customers

generally. PGW believes that any revenue generated by inter-zonal netting and trading within a single OIA should be subject to revenue sharing since both the maximum IT rate and the fuel charge includes a fixed cost component. These revenues should be shared 75% to non-offending firm customers and 25% to the pipeline.

ACTIVITIES:

December 1, 2000-PGW filed for "Leave to Intervene and Request for Clarification and Revenue Sharing"

RP00-543

Texas Eastern Transmission Corp.

Hourly Flexibility for Rate Schedules CDS, FT-1, SCT, and SS-1

DATE FILED: September 19,2000

ISSUES:

On September 15, 2000 Texas Eastern Transmission Corporation (TETCO) tendered for filing as part of its FERC Tariff, Sixth Revised Vol. No. 1, the revised tariff sheets (Appendix A) to become effective November 1, 2000.

TETCO states the purpose of the filing is to provide its customers firm hourly flexibility up to 110% of 1/24th of their contract MDQ for 6 hours on any day under Rate schedules CDS, FT-1, SCT, and SS-1.

TETCO states it will reserve 130,000 dekatherms per day of capacity on its main line from the Lebanon Lateral to the Zone M2/M3 boundary, and will operate this capacity essentially as additional storage, necessary to provide the firm up of additional hourly capacity.

TETCO will fund the dedication of capacity to provide this additional hourly flexibility through the elimination of the storage cost credit contained in Rate Schedules SS-1, FSS-1, SS, and X-28.

ACTIVITY:

September 27, 2000- PGW filed a motion with the Commission for "Leave to Intervene and Protest" and "Request for Rejection of Filing"

TETCO proposes to laden upon its customers the burden of its operational problems stemming from its long time reluctance to obtain sufficient storage capacity to properly serve its customers. Their continuous streams of OFOs provide ample evidence of this failure (i.e. January 2000). The pipeline further exacerbates the situation by its recent practice of using firm customers capacity made available by OFO restrictions to provide secondary capacity for sale to certain customers for the profit of the pipeline.

As pointed out in PGW's protest in RP00-404-000 (the Philadelphia Lateral Proposal), TETCO proposed, by issuance of OFO's to institutionalize its right to siphon off customer's primary capacity for sale as secondary capacity.

TETCO claims that the capacity used in the filing operates as a surrogate for storage.

There seems to be a very tenuous nexus between capacity derived from line pack and storage which is subject to ratchets and operational parameters such as injection and withdrawal rights.

TETCO admits that the capacity is unsubscribe currently, and the pipeline proposes that its firm storage customers, who pay year round, reservation charges, pay for this part time use of unsubscribed capacity by loss of their storage credit.

The filing gives no consideration to the financial impact on its various rates schedule customers. Large FT customers with little or no storage, who actually contribute to the problem, receive large benefits, as opposed to customers with large SS-1 contracts, who have been enabling the system to operate, lose payment for the pipeline's use of their storage rights.

TETCO does not offer any data support whatsoever that the 130,000 dth/d is an appropriate amount of capacity to address its service problems. PGW requests that TETCO be required to file a Section 4 general rate case to fully examine which assets are and are not fully utilized on the TETCO system. PGW requests rejection of the filing until such assets are identified.

The purpose of this proposal allegedly is to mitigate the need for OFO issuance. However, there is no language or proposal to reduce, in any way, TETCO's unilateral right to issue OFOs. TETCO tariff does not provide a procedure, which identifies order in which services are cut prior to issuance's of an OFO. There should be a reduction of TETCO right to issue OFOs.

While the pipeline proposes use of Zone M-2 capacity, there are no studies or data relating to the impact on Zone M-3.

Certain operational characteristics of TETCO proposed services remain unclear:

1. Can a customer overrun for six consecutive hours?
2. Over what period does the customer have to return the gas?
3. Does the gas have to be returned at an uniformed hourly rate?
4. If gas is returned within the six hours following its use may a customer then complete a second six-hour overrun and return the gas within the same twenty-four hour period.
5. There is no provision for the impact of the filing on released volumes. How does the right to excess volumes apply to the Releaser or Releasee?

PGW questions why TETCO needs to purchase additional gas supplies to render this service. Customers will not be permitted to alter their MDQs and any supplies withdrawn in excess of the 1/24 hourly allocation must be returned within the day. At the end of each day, TETCO's supply balances for the excess gas should be neutral.

PGW opposes the use of the AS Deferred Account as the mechanism to collect the cost of any purchased gas. This mechanism provides no incentive for the pipeline to make the least cost purchases, as the pipeline suffers no impact. This cost should be assigned directly to those customers on whose behalf the cost was incurred.

September 25,2000- FERC issued an order accepting and suspending tariff sheets subject to refund and other conditions.

November 1, 2000- Texas Eastern Filed an Information Response Pursuant to October 25,2000 Order.

November 14, 2000-PGW filed Comments to the Texas Eastern Information Compliance Filing.

FERC in its October 25,2000 order accepting and suspending TETCO September 15,2000 filed tariff sheets purportedly to provide firm hourly flexibility, required TETCO to: (1) support its assertion that the filed service would mitigate its issuance of OFOs; (2) explain why it proposal needed to have an entire year duration rather than restricted to that peak winter season and (3) explicitly assert that the pipeline would no longer need to borrow customer storage to provide no notice services and to document that claim, if made by TETCO, by showing that any reduction in credits to the firm storage customers was matched by a equivalent reduction in cost of using customer storage.

There seems to be a direct conflict between the instant filing which proposes the use of 130,000 dth/t as the solution and the pipeline's filing in Docket No. CP01-8 in which it seems to assert that 70,000-dt/t lease would provide a permanent solution.

There are no current hourly flow restrictions except during the issuance of OFOs.

The result is that TETCO storage customers are being asked to pay to have their rights reduced during those periods when the OFOs restricting hourly flow rights have not been issued.

In its justification for implementation of the proposal for the entire year, TETCO offers only the irrelevant explanation that its summer swing demands have increased, essentially because of use by its cogeneration customers.

In its restructuring filing to supplement its admitted insufficient storage capacity to provide no-notice service during the winter peak period, the current customer storage credit mechanism was approved. There was nothing regarding summer swings by customers who were not customers until years later. The customers whose credits are exposed to elimination generally do not use the services for which they are being asked to pay.

RP00-535
Texas Eastern Transmission Corp.
Right-of –First Refusal

DATE FILED: September 5, 2000

ISSUES:

PGW filed for intervenor status and Request for Clarification to protect its rights in this case.

BACKGROUND:

On September 5, 2000 Texas Eastern Transmission Corp. filed as part of its FERC Gas Tariff, Sixth Revised Tariff sheets.
Texas Eastern states that the purpose of this filing is to comply with the requirements of Order 637 regarding the wavier of the rate ceiling for short-term capacity release transactions and the prospective limitations on the availability of the Right-of -First Refusal.

Request for Clarification

Texas Eastern in the revised Section 3.13 (A) of its General Terms and Conditions GT&C) in the subject filling addresses Order 637's new Right-of-First-Refusal (ROFR) conditions. The language in this section is purporting to comply with the exception to the denial of ROFR rights to either discounted or negotiated rate contracts may be misinterpretation. For the purpose of avoiding future disputes, PGW requests clarification that the meaning of the tariff language precisely echoes the meaning to the Order 637 language in Order 637 series of Orders. Texas Eastern's proposed tariff provides for a one time ROFR exemption for contracts entered into prior to October 2, 2000. PGW requests that the Commission clarify that existing discounted firm service long-term contract holders of contracts entered into prior to the effective date of Order 637 will continue to have ROFR rights upon expiration of their present contracts provided that the new or re-executed firm service contracts are at the maximum rate for a period of twelve (12) consecutive months or for more than one year of service for services which is not available for twelve months.

ACTIVITES:

September 14, 2000- PGW filed a motion with the Commission for "Leave To Intervene and Request for Clarification".

RP00-468

Texas Eastern Transmission Corp.
Compliance with Orders in Docket # RM98-10 RM98-12

DATE FILED: August 15, 2000

ISSUES:

PGW has filed for Intervenor status to protect its rights in this case.

BACKGROUND:

The purpose of Texas Eastern's (TETCO) filing was to comply with the Commission's Orders in docket Nos. RM98-10 and RM98-12, requiring TETCO to submit pro forma tariff sheets complying with the new regulations governing segmentation, scheduling equality, imbalance services, operational orders, and penalties.

ACTIVITES:

August 25,2000- PGW filed with the Commission a motion for "Leave to Intervene"

RP00-313
Gas Research Institute

DATE FILED: June 1,2000

ISSUES:

Gas Research Institute (GRI) filed an application requesting advance approval for its 2001-2005 Five Year Research, Development and Demonstration (RD&D) Plan, and the 2001 RD&D program and the funding of its RD&D activities for 2001, pursuant to the Natural Gas Act and the Commission's Regulations, particularly 18 CRF154.38 (d)(5). GRI proposes to incur contract obligations of $70.0 million in 2001. Consistent with the Commission's April 28.1998 Order approving Settlement, GRI states all $70.0 million of the 2001 contract obligations will be for Core Projects. GRI seeks to collect funds to support its RD&D program through jurisdictional rates and changes during the twelve months ending December 31,2001. Also consistent with the Commission's April 28.1998 Order approving Settlement, GRI proposes to fund the 2001 program with the use of the following surcharges (1) a demand/reservation surcharge of 9.0 cents per Dth per Month for high load factor customers; (2) a demand/reservation surcharge of 5.5 cents per Dth per Month for low load factor customers; (3) a volumetric commodity/usage surcharge of 0.7 cents; and (4) a special small customer surcharge of 1.1 cents per Dth.

ACTIVITES:

June 21,2000 - PGW filed a motion with the Commission for "Leave to Intervene".

September 19,2000- The Commission granted the application as proposed, including advance approval of the 2001-2005 RD&D Plan and the 2001 RD&D Program, and allow pipeline rates containing the proposed 2001 funding components to become effective as of January 1,2001, without suspension or potential refund obligation.

RP00-24
Transcontinental Pipeline Corp.
Revise imbalance trading percent calculation.

DATE FILED: October 25,1999

ISSUES:

PGW has filed for Intervenor Status at this time in order to protect its right in this case.

BACKGROUND:

The filed revised tariff sheets propose to implement and modify the current imbalance "cash-out" provisions of Transco's firm interruptible transportation rate schedules. Specifically, Transco proposes to:

1. Consolidate into a new Section 37, "Cash Out Provisions", in the General Terms and Conditions of its tariff the imbalance "cash-Out" provisions set forth in its firm and interruptible rate schedules and includes in those rate schedules a reference to the terms of the new Section 37;
2. Substitute Gas Daily in place of Natural Gas Week as the source publication for the Spot price indices and to establish a Reference Spot Price and monthly Average Spot Price for each zone to be determine the Reference Spot "Buy" or "Sell" Price and the Average Spot Price at which Transco and buyers under the applicable rate schedules will "cash out" imbalances.
3. Revise the monthly Reference Spot "Buy" and "Sell" Price fore each zone to use the average of the three Lowest or Highest Daily Midpoint Prices, respectively, for that zone in the month determined from Gas Daily, as opposed to the currently used lowest and highest weekly Reference Spot Price for the month determined from the Natural Gas Week, and the monthly Average Spot Price for each zone to be the simple arithmetic average of the Midpoint for that zone in the month from Gas Daily.
4. Revise the imbalance tolerance level to one and one-half percent (1.5%) from two and one-half percent (2.5%), to determine the application of the Weighted Average Spot Price in the "cash out" of imbalances for so-called majority shippers.

ACTIVITIES:

October 25,1999- PGW filed a motion with the Commission for "Leave to Intervene".

November 26,1999- The Commission accepted and suspended the tariff sheets subject to refund, rejecting tariff sheets and establishing a technical conference to be held on January 20,2000.

February 10,2000- PGW comments to the technical conference held on January 20,2000.

Transco's stated purpose for modifying the cash out provision of its tariff was that customers arbitrage the system based on the mechanism in effect at that time.
PGW supports Transco's efforts to control imbalances and, particularly, its efforts to prevent customers from gaming the system. PGW recognizes that occasionally there may be reasons for short term imbalances, but with Transco's end of month cash out methodology, customers have ample time to get in balance. PGW and most other customers have avoided cash out by voluntarily utilizing operational tools, including storage, intra day nominations and contingency ranking, to control imbalances. Customers who effectively manage their loads, stay in balance and already have accepted and incurred firm storage capacity cost to prevent imbalances are now faced with cost incurred through no fault of their own. PGW request that Transco's modifications remain in effect for an entire year and at the end of the year when Transco submits its annual report review is made to determine whether these measures were effective. PGW also requests that, Transco be required in its general report to present specific imbalance data for each customer for each month including throughput, imbalance volumes an associated charges. PGW agrees that Transco should be required to permit netting of a customer's own imbalances. Several of the Protests of parties to this filing pointed out two additional possible sources of the claimed imbalance under-recoveries. One is Transco's accounting procedures and the other is the role of Transco merchant and its affiliates in causing the imbalances. Transco avoided any discussion on these points beyond a conclusive general denial.
PGW strongly believes that at such time as Transco proposes to collect any Under-recoveries, allocation should be made based on the end the month imbalance volumes.

February 25,2000 PGW's reply comments to the technical conference held on January 20,2000.

Transco implemented some suggestions of the Commission, including park and loan services, storage-swing, and netting across a rate schedule. Other tools available include intra-day nominations, contingency ranking and LEAD data.

The underlying compliant of shipper's objecting to Transco's new cash out methodology is that they do not wish to incur additional expense, primarily for storage capacity. PGW does not oppose Piedmont's proposal regarding netting of imbalances across all contracts and use of shipper storage for end of month balancing.
Some transportation shippers, implied that since transportation rates include a contribution of fifteen percent (15%) to the fixed cost of Transco storage service and to Transco's portion of Rate Schedule GSS, this somehow relieves them of their obligation to use own storage capacity to remedy their imbalances. The transportation services contribution relates to the use of the storage services to provide no-notice service and daily and hourly flexibility. It has nothing to do with monthly cash out.

A second bedrock principle set forth in Order 637 is that the pipelines must only penalize conduct that is "actually harmful to the system". There does not seem to be any reason not to net imbalances across all services in adherence to the Final Rule policy so long as operational integrity is not affected. Failure to net imbalance across rate schedules which do not have operational impact is a form of double billing.

In most circumstances the physical sum of the long and short imbalances has no relevance to operational impact which poses a threat to the integrity of the system. Transco has never issued an OFO, which is evidence of the substantial flexibility within the system. Nevertheless, activities that are manageable within the system should not serve as an additional profit center.

PGW states again that Transco does not address the issue of Transco Merchant and/or Affiliate contribution to under-recovery. Transco and its affiliates accounted for 51.1% of the cash-out Sales during July, 1999, the month in which Transco states the largest imbalances occurred and created the most serious strain on its system. PGW repeats, as it has in its various pleadings that Transco has a duty to explain the role of its merchant and/or affiliates on imbalances and cash out, since combined they constitute the largest shipper on the system and a majority of the throughput.

PGW request that Transco's Modifications to its cash out mechanism be approved. PGW also request Transco be required to implement netting of imbalances across all services to the extent that is operational integrity is not threatened and that Transco compute shippers end of the month imbalances based on the lesser of the post monthly true up of its operational and LEAD data or actual.

RP00-17
Transcontinental Gas Pipeline Corp.

DATE FILED: June 30,2000

ISSUES:

The purpose of this filing is to limit capacity usage to the extent that combined nominations of releasing and replacement shipper's original firm capacity entitlement, consistent with the Commission's November 12 1999 "Order on Pro Forma Tariff Sheets Establishing Technical Conference" in the referenced docket ("November 12 Order"). In order to implement its proposal Transco also is filing to remove the rate schedules FT-R and FTN-R Commodity Form of Service Agreement from its Tariff and make changes to its Rate Schedules FT-R and FTN-R Demand Form of Service Agreement to reflect that removal.

ACIIVITY:

July 28,2000- PGW filed a motion with the Commission for "Leave to Intervene".

RP98-317-000
TRANSCO
RATE SCHEDULES X-289 AND X-302

DATE FILED: July 1, 1998

ISSUES:

PGW has only filed for Intervenor status at this time in order to protect its rights in this case.

BACKGROUND:

The purpose of this filing is to terminate Section 7(c) firm transportation service under Rate Schedules X-289 and X-302 and to convert such services to service provided under Rate Schedule FT effective November 1, 1998.Upon conversion of SEP service under Rate Schedules X-289 and X-302, all SEP services will have been converted from Section 7(c) service to Part 284 Service.

ACTIVITY:

July 9, 1998- PGW filed a motion with the Commission for "Leave to Intervene".

RP98-284-000
TRANSCO
GREAT PLAINS SURCHARGE

DATE FILED: June 30, 1998

ISSUES:

PGW has only filed for Intervenor status at this time in order to protect its rights in this case.

BACKGROUND:

The filed tariff sheets adjust Transco's Great Plains Volumetric Surcharge (GPS). The GPS Surcharge is designed to recover: (i) the cost of gas purchased from Great Plains Gasification Associates (or its successor) which exceeds the Spot Index (as defined in Section 39 of the General Terms) and (ii) the related cost of transporting such gas.

The revised GPS Surcharge included therein consists of two components - the Current GPS Surcharge calculated for the period August 1, 1998 through July 31, 1999, plus the Great Plains Deferred Account Surcharge (Deferred Surcharge). The determination of the Deferred Surcharge is based on the balance in the current GPS sub-account plus interest accumulated by April 30, 1998.Appendix B to the filing includes workpapers supporting the calculation of the revised GPS Surcharge of $0.0179 per dth reflected on the tendered tariff sheets.

ACTIVITY:

July 8, 1998- PGW filed a motion with the Commission for "Leave to Intervene".

July 29, 1998- The Commission accepted the revised tariff sheets. However, the revised tariff sheets listed under Docket Nos. RP97-71-010 et al. are accepted subject to further review for compliance with the January 20, 1998 settlement.

RP98-212-000
ANR
ANNUAL CASHOUT REPORT

DATE FILED: May 1, 1998

ISSUES:

PGW has only filed for Intervenor status at this time in order to protect its rights in this case.

BACKGROUND:

This filing represents ANR's annual report of the net revenues attributable to the operation of its cashout program. This filing covers the period January 1, 1997 to December 31, 1997. The Net Cashout Activity for the 12-month period ending December 31, 1997 resulted in a net balance of ($1,461,898). This amount is added to the balance of ($3,162,904) from ANR's previous cashout report plus carrying charges of ($542,459), for a cumulative net cashout balance of ($5,167,261). ANR has computed the cashout price surcharge pursuant to Section 15.5(b) of the General Terms & Conditions of its tariff. The cashout price surcharge of $0.1211 will be subtracted from the cashout price where excess quantities are being cashed out (purchased), and will be added to the cashout price where deficient quantities are being cashed out (sold), consistent with ANR's approved tariff mechanism.

ACTIVITY:

May 11, 1998- PGW filed a motion with the Commission for "Leave to Intervene".

May 29, 1998- The Commission accepted and suspended the proposed tariff sheets, subject to refund and, to be effective June 1, 1998.

CP97-406
CNG RATE CASE

DATE FILED: July 1, 1997

RATES EFFECTIVE: Ranging from January 1, 1999 to February 1, 1999

PGW ACTION: Leave to Intervene and Protest Filed on January 11, 1997

ISSUES:

PGW is a storage customer of CNG. Issues concerning PGW resulting from this case include: the implementing of market based pricing for services provided under a new rate schedule MBA and under existing rate schedules IT and MCS; the suspension of the recovery of cost associated with the purchase of electricity for use at electric powered compressor stations from its current Fuel Adjustment Provision into a new Electric Power Cost Adjustment: the implementation of a new Accelerated Capital Recovery Mechanism, the elimination of the "at-risk" condition on CNG's Lebanon to Leidy facilities; the implementation of exit fees for customers exiting the system under circumstances where CNG has a reasonable expatiation of continued service; and several other tariff and service changes, inducting: tightening penalty procedures. CNG proposed changes to its storage inventory transfer provisions; inducting balancing in the array of CNG's Market Center Services; and instituting economical scheduling of interruptible services.

BACKGROUND:

On July 1, 1997, CNG filed a rate case under Section 4 of NGA to increase jurisdictional revenues by approximately $71.1 million. CNG states that the principle factors supporting the adjustment in rates are an increase in rate base due to additional plant investment, increases in operation and maintenance expenses, an increase in the return allowance on the company's rate base, an increase in the depreciation rate for the company's computers, and increases in other taxes. CNG states that its filing is an integrated package of tariff changes, service enhancements, and pricing mechanisms that are designed to better serve CNG's customers in a competitive marketplace. CNG proposes prospectively to implement market based pricing on its system for all services under Rate Schedules IT and MCS and under new rate schedules MBA. CNG proposes to provide firm transportation and storage service at market based prices under Rate Schedule MBA, in conjunction with Rate FT, GSS-II, and OSS for new contracts under those rate schedules with a primary term of less than five years (i.e. all new contracts for firm service under rate schedules with a term of less than five years and all extensions or roll-overs of existing contracts with a term of less than five years). Thus, CNG states

that it does not propose to implement market based rates for the primary term of existing long-term agreements. CNG does propose to implement market based prices for all short-term services (i.e. short-term firm transportation).

ACTIVITY:

July 11, 1997- PGW files for "Leave to Intervene and Protest".

July 31,1997- The commission issued an "Order Accepting and Suspending Certain Tariff Sheets, Subject to Refund and Conditions, Establishing Hearing Procedures and Rejecting Other Tariff Sheets"- By its July 31 Order, the Commission established separate procedures to address CNG's proposed service-related tariff changes. The Commission also terminated proceedings in Docket No. RP96-144-000, concerning recovery of cost associated with CNG's E-Script computer system.

September 2, 1997- CNG filed work papers in compliance with the Commission's July 31, 1997 order.

September 9, 1997- Pre-hearing conference.

September 12, 1997- Joint motion filed.

September 16, 1997- Order of Chief Judge Adopting Procedural Schedule.

September 18, 1997- "Order Allowing and Confirming the Granting of the Motions to Intervene out of Time"

September 23, 1997- The Commission issued an "Order Granting Rehearing for Further Consideration".

October 6, 1997- "Order Allowing and Confirming the Granting of Motions to Intervene Out of Time".

October 8, 1997- "Order Denying Motion to Strike Testimony" submitted by CNG.

October 10, 1997- Notice of Technical Conference.

October 16, 1997- Rehearing of the July 31 Order. The Commission further addressed certain issues regarding cost of service, cost allocation, rate design and CNG's terms and conditions of service.

October 31, 1997- Commission Staff convenes a Technical Conference regarding the changes to CNG's term and conditions of services.

December 15, 1997- The Commission issued an "Order Granting Rehearing for Further Consideration".

December 19, 1997- "Order Following Technical Conference" Commission rejects many of CNG's service and penalty related tariff modifications by Technical Conference Order. By this order, the Commission also rejects aspects of CNG's proposal to track Account No. 858 and electric and fuel cost and accepted tariff revisions to correct errors and streamline or consolidate parts of CNG's tariff.

December 31, 1997- "Notice of Compliance and Motion Filing"- CNG states that the purpose of its filing is to move its revised tariff sheets into effect, and to include revised tariff sheets in order to address compliance matters raised by the Commission in its suspension and rehearing orders in this proceeding, as well as to reflect the small customer rate revisions it filed on November 26, 1997, in Docket No. RP98-65-000. CNG states that its filing also reflects two voluntary rate reductions to its rates in an effect to reduce the impact of the otherwise applicable increase to CNG's customers. CNG states that it reserves the right to seek prospective recovery of the full increase reflected in its July 1,1997 filing.

January 5, 1998- " Notice of Compliance and Tariff Motion Filing"- CNG states that the purpose of this filing is to comply with the Technical Conference Order, as well as certain aspects of the Commission July 31,1997 Suspension Order in this proceeding, and to move into effect the tariff revisions proposed by CNG in its filing on July 1, 1997. CNG's Tariff sheets reflect the elimination of CNG's proposed exit fee, stranded gathering plant surcharge, and market-based rate proposals, as required by Suspension Order. CNG also removed or modified aspects of its tariff revision proposals directed by the Technical Order. The remaining tariff sheets reflect components of CNG's July 1, 1997, filling that have survived the Commission orders, and those aspects that are of a purely ministerial nature.

January 6, 1998- " Order Scheduling Pre-hearing Conference" Also, CNG filed tariff sheets containing the summery rates applicable to various incremental services and X rate schedules.

January 14, 1998- "Notice of Tariff Motion Filing"- CNG files revised tariff sheets to correct an administrative oversight. CNG states the purpose of this filing is to remove references to an "Excess Injection Charge" in compliance with the suspension order, which CNG had not removed from Sub. Sixteenth Revised Sheet No. 35 filed on December 31, 1997.

January 29, 1998- "Order Accepting and Suspending Certain Tariff sheets Subject to Conditions and Rejecting Other Tariff Sheets" – On December 31,1997, in Docket No. RP97-406-004, CNG filed tariff sheets which it states are to address compliance and rehearing matters in this proceeding, to be effective January 1, 1998. Although the rates are proposed to be an increase above the existing rates in effect at the time of their filing,

they reflect a decrease in the original filed rates in Docket No. RP97-406-000. In lieu of moving into effect the full rate increase proposed and suspended in Docket No. RP97-406-000, CNG proposes to place into effect rates that reflect a 25 percent reduction from the increase originally sought, including certain compliance matters required by the July 31, 1997 suspension order and the October 16, 1997 rehearing order in Docket No. RP97 –406-000. CNG reserves the right to seek prospective recovery of full increases reflected in its Docket No. RP97-406-000 filing. CNG included a motion to place the proposed rates into effect January 14, 1998; in Docket Nos. RP97-406-007 and RP98-65-001; CNG filed a tariff sheet, to be effective January 1, 1998, to remove an excess injection charge for storage services. CNG filed tariff sheets containing rates that are based on its filing in Docket No. RP97-406-00, but recalculated to reflect (1) the removal of cost related to facilities not placed into service as of December 31,1997, in compliance with the Commission's orders, (2) the removal of the uncollected amounts from its cost of service compliance with the Commission's orders, and (3) the elimination from gathering and return transportation of certain plants proposed in Docket No. CP97-549-000 to be re-functionalized as gathering. In addition, consistent with its request for rehearing of the Commission's October 16, 1997 order, CNG states that it did not remove Tejas Gas Corporation (Tejas) Account No. 858 cost as directed in the July 31, 1997 suspension order in Docket RP97-406-000.

CNG states that it also proposes two voluntary reductions in its cost of service. CNG proposes to maintain shrinkage and fuel cost in base rates at the level agreed to in its Docket No.RP94-96-000 settlement, as opposed to the higher levels it proposes in its July 1, 1997 filing in Docket No. RP97-406-000. CNG also proposes to retain its currently effective computer depreciation rate of 10 percent, as opposed to its proposed 20 percent increase in that filing. CNG states that its compliance changes and voluntary adjustment result in a 25 percent reduction in the cost increase originally sought in Docket No. RP97-406-000. However, CNG reserves the right to seek perspective recovery of the full increases reflected in its July 1,1997 filing related to these issues, consistent with the Commission's ultimate decision on the issues in this proceeding. CNG states that it assumed that the small customer rates and stranded gathering plant recovery surcharges proposed in Docket No. RP98-65-000 would be approved, and has included those proposed rates in its filing. In addition, it has removed Rate Schedule OSS rates, consistent with the Commission's order in Docket No. CP96-492.

The Commission finds that CNG's filings are in compliance with the Commission's July 31, 1997 suspension order and October 16, 1997 rehearing order. However, in Docket No. RP97-406-004, CNG is proposing rates that reflect conditional cost of service reductions beyond those required by the Commissions July 31, 1997 and October 16,1997 orders. CNG may file, at any time, to move its suspended rates into effect prospectively, so long as it also files revised tariff sheets that comply with the Commission's July 31, 1997 and October 16, 1997 orders, as well as any relevant rulings in this proceeding. Tejas Account No. 858 Costs. In the July 31, 1997 suspension order, the Commission required CNG to remove the Account No.858 costs attributable to its contract with Tejas on the basis that CNG's exhibits projected no utilization of the

service, and the contract was to terminate November 1, 1997. CNG, in Docket No. RP97-406-003, sought a rehearing, stating that it now projects $1.8 million dth of throughput, and the contract has rolled-over for at least another year. In the instant December 31, 1997 filing, the rates do not reflect removal of these costs based on its rehearing position. The Commission by separate order in Docket No. RP97-406-003, has granted CNG's request for rehearing, and has permitted CNG to reflect the Tejas costs in its rates, subject to CNG supplementing the record within 15 days of the Commission's rehearing order. Therefore, the Commission, in the instant proceeding, will permit CNG to include the Tejas costs, subject to refund and the outcome of CNG's compliance with the Commission's order on rehearing in Docket No. RP97-406-003. CNG's Voluntary Cost of Service Changes states that its December 31, 1997 filing reflects two voluntary cost of service reductions from that initially proposed in Docket No. RP97-406-000. First CNG proposes to maintain its base rate shrinkage and fuel gas costs to a level that it agreed to in its Docket No.RP94-96 settlement. Second, CNG proposes to retain the current depreciation level of 10%, as opposed to its proposed 20% for computer equipment until the Commission issues a final order in this proceeding. CNG did not quantify the cost impact of either change. Upon review of CNG's exhibits, the Commission believes CNG reduced its projected shrinkage by approximately 5.5 million. The second adjustment may account for approximately $3 million in reduced depreciation expense. The East Cost Distributors request that the Commission set these costs of service changes for hearing. The Commission set most cost of service issues in Docket No.RP97-406-000 for hearing. Therefore, the Commission will also set CNG's changed costs in this new rate change filing for hearing. In addition, to give parties in the hearing an idea of what higher rates CNG may move into effect under the Docket No. RP97-407-000 suspension order, CNG is required to file pro forma tariff sheets reflecting rates that comply with the requirements of the Commission's orders in this Docket No. RP97-406-000 proceeding based upon the current procedural status of CNG's various filings, and supporting work papers, within 15 days of the issuance of this order.

Revised Recovery Cost Account (TCRA)- CNG proposes to implement its revised TCRA cost tracker system rates. In Docket No. RP97-406-000, CNG proposed to remove the TCRA electric Fuel costs and recover those costs through its own tracker. The Commission conditionally accepted CNG proposal, subject to certain tariff revisions as to the cost that may be tracked. CNG's filing reflecting those changes was made on January 5, 1998, in Docket No. RP97-406-005, to comply with the Commission's December 19, 1997 order following a technical conference. In that filing, CNG requests waiver of 154.207 of the Commission's regulations to permit those tariff sheets to go into effect January 1,1998. As the result of the two filings, the tariff language permitting CNG to assess the revised TCRA rates is in a different proceeding. The Commission will act on CNG's Docket No. RP97-406-005 filing at a later date. However, it is possible the Commission may not permit CNG's revised TCRA tariff sheets to go into effect January 1,1998. Accordingly, the Commission accepts the tariff sheets filed on December 31, 1997, in Docket No. RP97-406-004, subject, to Commission action in Docket No. RP97-406-005. In Docket No. CP96-492-000, et al., the Commission

made a section 5 finding that required CNG to eliminate Rate Schedule OSS, and to create separate, free standing, open-access Part 284 and individually certificated section 7 storage Rate Schedules out of Rate Schedules GSS and GSS-II. In Docket No. CP96-492-006, et al., CNG proposed tariff sheets to implement the Commission's directions, effective December 15, 1997. An order on that filing is being issued concurrently with this order. Accordingly, the Commission accepts and suspends the tariff sheets listed in Appendix A subject to the outcome of Docket No. CP96-492-006, et al. Commission's December 19, 1997 order following technical conference found that these charges were unduly discriminatory and rejected the overrun charges. CNG, in Docket No. RP97-406-004, proposed to institute the same storage Excess Injection charge that was rejected by the December 19, Effective Date and Waivers CNG requests a January 1, 1998 effective date for its tariff sheets in Docket Nos. RP97-406-004 and RP97-406-007, et al. Its transmittal letter in Docket No.RP97-406-004, in addition to being a compliance filing, identifies it as a motion to place suspended sheets into effect. The Major Non-affiliated Distributors note that CNG's Proposed tariff sheets include the stranded gathering plant recovery surcharge (ACRM). Consistent with its protest in Docket No.RP98-91-000, they request a full five-month suspension for those rates. The Commission will waive the 30-day notice period for Docket Nos. RP97-406-004 and RP97-406-007, et al., and conditionally permit the tariff sheets in Appendix A to go into effect January 1, 1998, subject to refund. 9/ However, the Commission requires CNG to re-file its sheets to remove the ACRM surcharge, as the Commission suspended the effective date of that surcharge for a full five months, to be effective June 15, 1998.

February 5,1998- "Order Accepting Tariff Sheets Subject to Conditions" Commission accepts filed tariff sheet of January 6, effective January 6, 1998, subject to refund and conditions, and directed CNG to revise Volume No. 2A to reflect the rate increase.

February 13, 1998- Notice of Pro Forma Tariff Sheets Filing.

February 18, 1998- " Order Granting Rehearing for Further Consideration"

February 20, 1998- CNG Transmission Corporation filed the referenced tariff sheets that conform CNG's X- Rate Schedules to reflect increased rates proposed in Docket No. RP-406-000, in compliance with a February 5, 1998 Commission Order (82 FERC 61,105). CNG requests a January 6, 1998 effective date, consistent with the February 5th order. The referenced tariff sheets are accepted effective January 6, 1998, subject to the same conditions contained in the February 5, 1998 order. On January 6, 1998, in Docket No. RP97-406-006, CNG motioned into effect the rate summery sheet identifying the rates applicable to the X-Rate Schedules located in CNG's Volume No. 2A. The Commission February 5th order found that CNG had failed to file Volume No. 2A tariff sheets that incorporated its proposed rate increases that corresponded with the rates identified on its X-Rate Schedule rate summary sheet. The commission required CNG to file these sheets to be effective January 6, 1998. CNG's filing complies with that requirement.

February 26, 1998- " Notice of Tariff Compliance Filing"- CNG states that the purpose of this filing is to remove from the base rates in Docket No.RP97-406, effective as of January 1, 1998, CNG's proposal to recover gathering that it intended to recover through ACRM surcharges, but was unable to put into effect because of the Commission's five month suspension in Docket No.RP98-91. CNG's filing is also intended to align its stranded cost surcharge filing in Docket No.RP98-103 with the resulting adjustment to base rate levels, effective as of February 1,1998. CNG states that it is complying with these aspects of the order immediately, in an effort to secure rate certainty for its customers at the earliest possible date. CNG intends to comply with all aspects of the February 25 order, within the fifteen days provided. CNG also reserves the right to pursue rehearing of the February 25 order, and file revised rates that reflect the ultimate outcome of that rehearing request.
March 13,1998- "Order on Rehearing and Clarification" The order also addresses requests for rehearing and clarification of the Commission's December 19, 1997 order following technical conference 1/ in CNG 's section 4 proceeding filed by CNG; Cabot Oil and Gas corporation (Cabot); Independent Oil and Gas Association of West Virginia (IOGA); and Niagara Mohawk Power Corporation, National Fuel Gas Distribution Corp., New York State Electric and Gas Corp. and Rochester Gas and Electric Corp. (Major Non-Affiliated Distributors).

March 13,1998- "Order Accepting Certain Tariff Sheets Subject to Conditions and Rejecting Other Tariff Sheets" The Commission addressed request for rehearing and clarification of the Technical Conference Order. The Commission generally affirmed its Technical Conference Order. Order Accepting Certain Tariff Sheets Subject to Conditions and Rejecting Other Tariff Sheets. On January 5, 1998, CNG filed tariff sheets to comply with the Commission's July 31, 1997 suspension order and the December 19, 1997 order following technical conference. CNG requests that the Commission waive certain regulations to permit a retroactive effective date of January 1, 1998. This Order accepts most of CNG's proposed tariff sheets to be effective January 5, 1998, and rejects certain others, which do not comply with the Commission's orders.

March 20,1998- CNG's Volume 2A tariff sheets accepted and suspended by letter order.

March 30,1998- CNG makes a compliance filing based on the March 13 order.

April 14, 1998- Public Service Commission of New York submits Prepared Direct Testimony to Commission requesting change from SFV rate design.

May 7,1998- Process Gas Group filed a motion requesting summary disposition of the changes from SFV rate design that was sought by the Public Service Commission of New York in submitted Prepared Direct Testimony filed April 14, 1998.

May 13,1998- Commission denied further rehearing as to the elimination of CNG's pre-existing threshold for low volume receipt point meters.

June 1, 1998- Commission accepts CNG's March 30 Compliance Order.

June 10, 1998- "Notice of Information Settlement Conference"- June 17,1998. Also, "Order Granting Motion to Amend Procedural Schedule".

June 12, 1998- ALJ issues an "Initial Decision Granting Motion for Summary Judgment of SFV Rate Design".

July 13, 1998- " Notice of Denial of Rehearing"- Cabot Oil

July 27, 1998- "Order Suspending Procedural Schedule".

August 31, 1998- CNG filed with the Presiding Administrative Law Judge (ALJ) a Stipulation and Agreement (Settlement) that resolves numerous cost of service, cost allocation and rate design issues set forth for hearing or made subject to the outcome of the hearing in Docket No. RP97-406-000, et al. .

October 2, 1998- "Certification of Uncontested Settlement"

October 5, 1998- "Order on Initial Decision"

November 24, 1998- "Order Approving Settlement as Clarified and Granting Abandonment"

December 3, 1998- "Order Granting Rehearing for Further Consideration"

December 24, 1998- "Order on Rehearing"- PSCNY.

January 12 1999- "Notice of Proposed Changes in FERC Gas Tariff" CNG states that the purpose of this filing is to adopt certain tariff revisions as necessary to implement the August 31, 1998 Stipulation and Agreement filed by CNG in Docket No. RP97-406-000, et al. (August 31 Stipulation). The basis of CNG's rate revisions and tariff changes are established in the August 31 Stipulation and its Appendices, specifically Appendices A, B, and E.

RP97-71

Transco General Rate Case

DATE FILED: November 1. 1996

ISSUES:

PGW addresses a variety of issues in this case including rate of return, throughput, cost determination and allocation of incrementally priced facilities. PGW actively participated with a) The Transco Customer Group regarding cost of service and throughput issues, 2) the Transco Municipal Group to address the rate of return issues and 3) the Con-Ed Et. Al. regarding the roll-in of incrementally priced facilities.

BACKGROUND:

On November 1. 1996, in Docket No. RP97-71-000 Transco filed revised tariff sheets to increase its rates pursuant to section 4 of the Natural Gas Act. In addition, Transco proposed to: 1) roll in the cost of the incrementally-priced facilities on the Leidy Line and the Southern Expansion projects, 2) set the rate for interruptible backhaul equal to the rate for its forward haul, and 3) lift Mobil Bay "at-risk" condition. On November 29, 1996, the Commission accepted and suspended the proposed tariff sheets to be effective May 2, 1997, subject to refund and outcome of a hearing. The Commission also consolidated the roll-in issue raised by the proceeding in Docket No. RP95-197-000. On April 1, 1997, in Docket No. RP97-312-000, Transco filed revised tariff sheets to implement a new interruptible parking and borrowing service under Rate Schedule PBS. On April 30, 1997, the Commission accepted and suspended the tariff sheets to be effective, subject to refund, on May 1, 1997, and also consolidated the rate issues raised by the filing with Docket No. RP97-71-000.

ACTIVITIES:

A variety of settlement and technical conferences, depositions and assorted rounds of testimony were completed and filed during 1997 resulting in a settlement offer that was mutually acceptable to all parties.

On January 20, 1998, Transco filed a proposed settlement offer to resolve many of the outstanding issues in Docket No. RP97-71-000, including cost of service (excluding rate of return), throughput and certain allocation and rate design issues. The settlement also modifies Transco scheduling and balancing "cash out" provisions for its firm and interruptible rate schedules and finally, as delineated below, the settlement reserves several issues for further litigation or settlement.

On March 5, 1998, the Presiding Administrative Law Judge as a contested settlement certified the settlement to the Commission. The Presiding Administrative Law Judge

(ALJ), certified the instant settlement offer to the Commission, as contested, because of the comments of several parties (including PGW) requesting changes or clarification of certain provisions of the settlement proposal. However, the ALJ noted that, although (21) twenty-one parties had filed comments on the settlement offer, all of the participants had stated either that they supported or that they did not oppose the Settlement offer.

The Settlement resolves numerous issues on the Transco system.

Article I of the settlement outlines the settlement cost of service. The overall cost of service, as of May 1, 1997, is $689.7 million; a reduction of approximately $103.3 million from the cost of service underlying Transco's filed rates in Docket No.RP97-71. The settlement's after-tax return of 12.00 percent is subject to the Commission's final decision in this proceeding.

Article II and Appendix C of the settlement describes the settlement throughput. The settlement establishes an overall throughput of 2,570,938,716 Dth, exclusive of gathering throughput volumes. This consists of 1,334,000,000 Dth of firm services volumes and 965,000,000 of interruptible service volumes. Overall gathering throughput volumes are established at 52,167,765, Dth for gathering services.

Article III of the settlement describes the settlement cost classification, cost allocation, and rate design. Article III also states that the "at risk" condition imposed by the Commission in certificating Transco's Mobil Bay facilities remains in effect and that the settlement resolves the application of this condition for the Docket No. RP97-71-000 rate period.

Article IV of the settlement describes the provisions for Transco's accumulated deferred income tax account (ADIT) and establishes ADIT levels of $5,364,447 and $1,492,573 for Federal income taxes and for state income taxes (net Federal) of$1,492,573, respectively.

Article V states that Appendix D contains the settlement rate for the period from May 1, 1997, until the effectiveness of the settlement. The settlement rates are subject to the outcome of the reserved issues and the refund floor. Article V further provides that within sixty days of the order becoming effective, Transco will provide refunds with interest and states that Transco's refund obligation is limited by the settlement rates in Docket No. RP95-197-000, as adjusted by the final decision of the Phase I and II issues. Article VI states that effective May 1,1997, Transco will share with certain customers 75 percent of the fixed cost component of revenues from Rate Schedules PBS, ISS, and ICTS and any new service.

Article VI further states that if Transco is authorized to "spin-down" its gathering facilities, it will file a limited Section 4 filling to the extent it is necessary to prevent over collection of costs. Article VI states that Transco will implement a firm gathering service upon the effectiveness of the settlement. Finally, Article VI provides that

Transco will modify its scheduling and balancing "cash out" provisions for its firm and interruptible transportation rate schedules. Appendix F contains the modifications to be implemented upon the effectiveness of the settlement.

Article VII of the settlement reflects Transco's agreement to file a section 4(e) general rate case to be effective no later than September 1, 2001, assuming a five-month suspension period. Article VIII of the settlement sets forth the issue of instant proceeding and the proceeding in Docket No. RP95-197-000 that is reserved for hearing for further settlement. With respect to contingent issues from the Docket No. RP95-197-000 settlement, Article VIII preserves the procedures adopted at the initial pre-hearing conference in the instant proceeding.

Article VIII provides for retention of the participants' right to seek resolution or dismissal of any reserved issue without an evidentiary hearing and sets forth the issues reserved for hearing.

Article IX of the settlement addresses the rights of contesting parties and provides for refunds, with interest, or surcharges to contesting parties.

Article X allows Transco to revise its rate, make refunds and collect surcharges based on the settlement rates, should a court revise or modify the Commission's decision on the settlement offer. This article states that it is severable and survives if the Commission's order approving the settlement is subsequently reversed or modified on appeal.

Article XI contains certain reservation provisions. Among other things, it states that the settlement represents a negotiated compromise and that no participant has agreed to any underlying principle.

Article XII provides that the settlement becomes effective on the first day of the month commencing at least 30 days after the final Commission order approving the settlement.

The settlement provides benefits for Transco customers by reducing Transco's cost of service by approximately $103millon from its initial filing in Docket RP97-71. The settlement also increases the service choices for customers because it would allow Transco's gathering customers the option of electing firm gathering service. Further, the settlement requires that Transco will file a new NGA general rate case by September 1, 2001 which will allow the Commission and Transco's customers a full review of Transco's rates.

With regard to the revenue sharing provision, PGW requests a clarification of the revenue sharing provisions of Article VI, Section A of the settlement offer, which states in part:

Transco shall implement effective May1, 1997, and extending through the RP97-71 Rate Period, revenue sharing procedures under which the fixed cost component of the revenues received by Transco from service provided under its Rate Schedules PBS, ISS, and ICTS and from any new services.... shall be shared, subject to the provisions of this Section A, annually 75% to the customers identified below and 25% to Transco. For the purpose of this Section A only, the RP97-71 Rate Period as defined in Article I, shall not end as a result of a Commission order directing a change to Transco's jurisdictional rates pursuant to NGA Section 5 if and only if Transco agrees, or the Commission determines, that said order will have a de minimis effect on Transco's ability to recover the Settlement Cost of Service.

For the purpose of settlement, PGW states that it agreed to accept the de minimis standard as set out in the settlement offer to allow the revenue sharing provision to continue. However, PGW objected that the settlement offer affords "Transco a unilateral right to make this [de minimis] determination. "PGW request that this section of the settlement offer be clarified so that the de minimis determination be made solely by the Commission's order with all the protections available to the parties pursuant to the proceedings which must precede an order by the Commission.

In its Reply Comments, Transco contends that the requested clarification by PGW is unnecessary. Transco argued that the only unilateral determination is to agree that a particular NGA Section 5 order will have a de minimis effect on its ability to recover its settlement cost of service. In that event, according to Transco, the revenue sharing procedures of the settlement proposal will continue and PGW would be satisfied with the outcome. Transco further argued that if, on the other hand, it does not agree that the effect would be de minimis, PGW's rights are still protected, since the Commission would determine this issue.

Because of the fairly complicated settlement language involved, the Commission believes that a clarification of the settlement is warranted on this issue. PGW, has, in essence, requested that the Commission clarify that the Commission alone, not Transco, will make the determination of whether an NGA section 5 order, which would otherwise terminate the Docket No. RP97-71 Rate period, will have a de minimis effect on Transco's ability to recover settlement cost of service. The settlement ambiguously provides or the agreement by Transco or a determination by the Commission. While the Commission generally agreed with Transco's explanation, the process by which this de minimis finding will be made should be clarified. Given the operation of the settlement provisions, as described above, the Commission must first issue an NGA section 5 order, which would otherwise terminate Docket No. RP97-71 Rate period in order for the de minimis standard contained in Article I, Section A to come into play. Because the commission must first specifically determine that a NGA section 5 rate order has the effect of terminating the Docket No. RP97-71 Rate Period, it will also specifically determine in the same proceeding whether such a rate order will have a de minimis effect on

Transco's ability to recover its settlement cost of service and as a result, will specifically order revenue crediting either to continue or to terminate. As Transco indicated, if it agrees that the effect is de minimis, the Commission will order revenue crediting to continue. If Transco dose not agree, then the Commission will determine whether or not the effect is de minimis and will issue a ruling and an order deciding the matter. In so doing, the Commission will fully evaluate the effect of its NGA section 5 order and give due consideration to Transco's position, as well as the position of the other parties, on the matter.

Outstanding Issues of Importance to PGW

This case was divided into two phases plus the resulting severed issues. The settlement only addresses issues contained in Phase II as described above. Phase I refers to the rate of return issue which cannot be settled until the Commission makes a determination on Rule 404 which determines the appropriate use of a company's capital structure or that of its parent, appropriate risk assessment and the rate of return. Please see RP95-197 for additional details regarding this matter.

Due to the size and complexity of this issue, coupled with the variety of outcomes that could be generated, PGW cannot determine a rate level or an associated refund level. PGW has no procedural basis believe that any associated refund resulting from settlement of this issue will necessarily occur in PGW's 1999-00 year.

ACTIVITIES:

On April 16, 2001, the Commission issued its Order on Initial Decision in this proceeding. The order, among other things, reversed the Presiding Administrative Judge's (ALJ) rejection of Transco's proposal to roll in the cost of its Leidy Line and Southern expansion facilities, which were subject to incremental pricing. The order also remanded to the ALJ a number of issues concerning the implementation of rolled-in rates, which were not addressed in the initial decision since the ALJ had ruled that none of the cost of the incremental facilities should be rolled in.

The Commission is not persuaded by Con Edison et al.'s arguments that Transco failed to meet its section 4 burden with regards to its roll-in proposal. Transco has sufficiently shown that rolled-in rates are just and reasonable as evidenced by the Commission's findings that (1) the expansion facilities are fully integrated with Transco's system,
(2) the expansion facilities provide significant system benefits, and (3) the rate impact of rolling in the cost of the expansion facilities is less than 5 percent. On March 1, 2001, Transco filed a new general section 4-rate case in Docket No. RP01-245-000, and in a contemporaneous order the Commission is accepting and suspending that rate filing to be effective September 1, 2001. If Transco desires to implement its rolled-in rate proposal before September 1, 2001, it may do so in a limited section 4 filing that revises its current effective rates to roll in the cost of the

Leidy Line and the Southern expansions. Transco also may revise its proposed rates in Docket No. RP01-245-000 to reflect the roll-in.

During, April, 2001 the Con-Ed Et Al. customer group, to which PGW is a party, requested the Commission to grant a rehearing and to find that Transco has not demonstrated that its proposal is just and reasonable.

RP93-162 & CP88-391

Transcontinental Gas Pipeline Corp.

Annual Cash-out Purchases Cost

ACTIVITIES:

November 6, 2000- PGW filed a motion with the Commission for "Leave to Intervene".

On October 26,2000 Transco filed its annual report of cash-out purchases for the period August 1, 1999 through July 31,2000. Transco states that it is filling the report to comply with the cash-out provisions in Section 15 of the general Terms and Conditions, its FERC Gas Tariff. Transco states that the report shows that for the annual cash0out period ending July 31, 2000, Transco had a net over recovery of $11,422,274. Transco has carried forward a net under recovery of $13,346,248 from the previous twelve-month period. this results in a net under recovery cash-out balance of $1,923,974, excluding carrying charges, as of July 31, 2000.
Transco states that in accordance with Section 15 of its tariff it will carry forward such net under recovery to offset any net over recovery that may occur in the future cash-out periods.

ACTIVITIES:

November 6, 2000-PGW filed for "Leave to Intervene". PGW is a transportation and storage customer of Transco and has a direct and substantial interest in this proceeding.

CP-01-8

Texas Eastern Transmission Corp.

Leasing Capacity from Algonquin Gas Transmission Co.

FILED DATE: October 10, 2000

ISSUES:

PWG has filed for intervenor status, Protest, and a Request to Hold in Abeyance to protect its rights in this case.

BACKGROUND:

On October 10, 2000, TETCO filed an application for a certification of public connivance and necessity authorizing the leasing of capacity on the Algonquin Gas system. TETCO seeks authorization to lease 80,000 Dth per day of capacity on Algonquin's system. The leased capacity will extend from the interconnection near Beverly, Massachusetts between Algonquin's proposed facilities in Docket No. CP01-5 and the facilities proposed by Maritimes & Northeast Pipeline, L.L.C. (Maritimes & Northeast) in Docket No. CP01-4 to the existing interconnection between TETCO and Algonquin in Lambertvelle, NJ. The term of the lease is for 20 years and will commence on November 1, 2002, which coincides with the in-service dates of the proposed Algonquin and Maritimes & Northeast facilities.
The fixed monthly lease payment under this agreement is $559,360; additional TETCO will pay a volumetric charge equal to the maximum commodity charge applicable to Rate Schedule AFT-1 per dekatherm delivered at Lambertville. Algonquin states that the monthly lease payment is less than the maximum recourse rate and thus meets Commission standards for lease payments. TETCO states the lease capacity will provide certain firm hourly swing rights, and will further the goals of Order 637 by enhancing TETCO's ability to provide imbalance management services on its system and mitigate the need to issue OFO's.

PROTEST:

A. OFO's

TETCO states that the leased capacity will provide a permanent solution to providing firm hourly swing rights. PGW believes that it currently has firm hourly swing rights under TETCO's tariff, and that such rights are being undermined by the pipeline's continual issuance of OFO's which seem to be occasioned more to recapture firm capacity to sell to secondary firm customers and its failure to enforce the imbalance control provisions in its tariff. The pipeline claims that it has proposed changes in its

scheduling procedures and OFO provisions to implement this firm up of hourly *flexibility*. Yet nowhere in this or the *RP00-543* filings are there any proposals or indications that TETCO is reducing either the number or the severity of its OFO's restrictions. TETCO has proposed no operational measures or tariff provisions that limit its unilateral right in its sole judgement to issue the restrictive measures it has applied in the past. This failure creates a certain lack of confidence in the proposed solutions and gives cause for continued concern. PGW does not believe TETCO's purported assurances provide sufficient support for the Commission to accept this filing as a solution. The Commission must undertake both in this docket and the related docket RP00-543, a thorough review of TETCO's OFO policies. For the purpose of analysis, the Commission must require TETCO to provide data concerning its secondary firm capacity sales for the periods during which the OFO's have been issued,
the volume of curtailed firm capacity and the volume of imbalance overages and identity of the offending parties prior to the issuance of OFOs. Without this, PGW is fearful that the additional capacity leased by TETCO from its affiliate pipeline will be used, as has occurred in the prior TETCO practice, to create more secondary firm capacity sales opportunities at the expense of primary firm capacity holders on the system.

B. OPERATIONAL ISSUES.

PGW has reviewed both the affiliate Algonquin Hub Line and Phase III of the Maritimes & Northeast projects. The proposed lease capacity seems to represent a significant proportion of the capacity proposed for those aforementioned projects. Both the lease proposal in this docket and the use of unsubscribed capacity at the expense of the storage customers in the Docket No. RP00-543 represents innovative proposals. However both seem designed more to serve the pipelines corporate purpose than to solve failures of its own operations. Under the cover of providing benefits to its customers, TETCO proposes mechanisms allegedly to deal with problems it itself has created. TETCO refuses to enforce its own tariff imbalance control provisions. It does not present any analysis to indicate the effect of not selling secondary firm during the periods when the OFO restrictions are in effect or not enforcing its tariff. There is no explanation of why the lease must include non-peak periods at a time when there does seem to be a need for additional capacity.
The only support to the proposals is TETCO's conclusory statement, which seems to be a self-serving proposal to resolve its operational problems.

REQUEST TO HOLD IN ABEYANCE

It is PGW's belief that any attempted solution TETCO proposes to address the issues of firm hourly swing rights and undue issuance of OFOs on its system can have only limited success unless TETCO makes operational changes. First the Commission must not permit the pipeline to use the OFO mechanism to deprive firm customers of their capacity in order to create capacity to sell as secondary firm. Secondly, while the Commission supports the imbalance prevention goals of Order 637 it believes TETCO must be

required to enforce its tariff against offending shippers. TETCO states that the filing complies with the Commission's policy in determining the need for the project. Unless the two mentioned operational changes are put into effect immediately and given a trial period, the Commission will be unable to determine whether the instant project or TETCO's proposal in RP00-543 are either needed, or will mitigate the problems which customers have had on the TETCO system.

PGW request that the implementation of both the subject proposal and the project proposed in Docket No. RP00-543 be held in abeyance until such time as TETCO implements (a) measures to enforce its tariff provision to control imbalances and (b) ceasing to sell secondary firm when ever there seems to be the threat that a OFO may have to be issued. PGW believes that the implementation of these two measures will help provide sufficient capacity to permit the firm hourly swing rights. Only by this analysis will the Commission be able to determine whether the proposals in this docket or in Docket No. RP00-543 are required, and if so the appropriate size. PGW is fearful that absent a through review and analysis of TETCO's OFO policies, the additional capacity leased from its affiliate may do nothing more than support additional secondary firm sales service at the expense of firm capacity holders on TETCO's system and impose unnecessary expense on the customers of the Algonquin Hub Line and Phase III Maritimes & Northeast Projects.

CP00-404
Columbia Liberty Electric Power Plant Project

DATE FILED: July 13,2000

ISSUES:

PGW has filed a motion to Intervene, Conditional Protest and request for Conditions and *Rejection of Waiver.*

Texas Eastern filed an application seeking a certificate of public connivance and necessity to upgrade the maximum allowable operating pressure (MAOP) of its existing Line No. 1-A in the Philadelphia area, and to construct, own, operate, and maintain certain facilities to render a firm lateral transportation service for up to 84,000 Dekatherms per day (Dth/d) of natural gas for PG&E Energy Trading-Power, LP (PGET), and Liberty Electric Power, LLC (LEP), and to establish a initial recourse rate for the incremental facilities proposed.
Columbia Liberty Plant is a 567.7-megawatt gas fired power plant. In order to provide this service, Texas Eastern proposes to expand its existing Philadelphia Lateral system to make available 84,000 dth/d of firm transportation capacity required to fuel the Columbia Liberty Plant. Texas Eastern proposes to install a 4,000 horsepower (hp) electric compressor at its existing Eagle Compressor Station site (Eagle Station) replacing, in situ, Various segments of the existing 20-inch Line No. 1-A, and constructing approximately 0.6 miles of 12-inch pipeline and associated metering facilities, To establish the connection with the Columbia Liberty Plant. Texas Eastern conducted an in line inspection of its existing 20-inch Line No. 1-A. Based on the evaluation of that inspection, Texas Eastern proposes to replace certain pipeline anomaly segments identified on its existing 20-inch Line No. 1-A. Texas Eastern states that this is a lateral-only service agreement; PGET and LEP will have no rights under this FT-1 service agreement to receive any service on any portion of Texas Eastern's system other than the Philadelphia Lateral facilities and this service will be provided at a negotiated rate.
Texas Eastern states that in conjunction with the Lateral Service Agreement, PGET, LEP, and Texas Eastern have entered into, as an essential component of this transaction, the Mainline Service Agreement, which is a Rate Schedule FT-1 service agreement for mainline service in market Zone M3 on a secondary basis. This mainline Zone M3 service allows for secondary firm transportation rights in Texas Eastern's Zone 3 at a negotiated rate.
This service was required by PGET and LEP and is intended for utilization only during those periods and to the extent that the Columbia Liberty Plant is not operating at full load. Since the Mainline Service Agreement provides secondary only transportation rights, Texas Eastern states there is no firm capacity reserved for the Mainline Service Agreement. Because no firm capacity is reserved for this service agreement, Texas

Eastern contends it did not award this contract under its net present value allocation mechanism included in Section 3.12 of the GT&C of Texas Eastern's FERC Gas Tariff. Texas Eastern request a waver of Section 3.12 of the GT&C of Texas Eastern's FERC Gas Tariff for the award of the Mainline Service Agreement.

The Mainline Service Agreements limited to a total aggregate quantity of 84,000 Dth/d being delivered under the Mainline Service Agreement and the Lateral Service Agreement. These secondary rights will allow PGET and LEP to utilize secondary transportation rights only in Zone M3 after existing customers' primary firm transportation entitlements have been scheduled and will not have an adverse impact on Texas Eastern's ability to meet its primary firm service obligations. Texas Eastern states that PGET and LEP will obtain its own gas supply, and that natural gas will be delivered to the Columbia Liberty Project facilities at the up stream terminus of the Philadelphia Lateral facilities, by acquisition of capacity through capacity release, by utilizing interruptible capacity or by third-party deliveries under other service agreements. Texas Eastern proposes to establish a NGA Section 7 (c) initial recourse rate, which is cost based and separately stated incremental reservation rate equal to $4.461 per Dth per month under Texas Eastern's Rate Schedule FT-1 for the lateral only service to PGET and LEP. Texas Eastern request that the proposed tariff sheets detailing the negotiated transactions with PGET and LEP be approved as part of the certificate issued in this proceeding. Texas Eastern submits that good cause exists for granting this waiver, as the negotiated rate agreements are integral components of this proposal.

Conditional Protest, Request for Conditions and Rejection of Waiver

Absent resolution of PGW's concerns through discussions with Texas Eastern, the subject proposal seems to be a carefully crafted mechanism to circumvent basic Commission principles underlying OFO and flexible receipt and delivery points policies, as well as Texas Eastern's own tariff and Commission approved secondary capacity bidding procedures in order to permit the pipeline to create favorable conditions to market this incremental project at the expense of its existing customers.

During the last service year Texas Eastern invoked an OFO reducing and pro-rating firm customers capacity. As a result, allegedly secondary capacity was created by which customers were able to receive deliveries via capacity on the Philadelphia Lateral, while firm system customers were deprived of their full rights. Section 3.12 of V's GT&C facially seems to permit this devise. The manipulation of both thee tariff provision and the secondary policies had the result, that firm customers, subject to reduced capacity under OFO, freed up firm capacity which was then sold on a secondary basis. The Mainline secondary service seems crafted to replicate that situation. Use of OFO to create capacity directly violates Commission OFO policy. This mechanism also thwarts the capacity release against the will of the releaser, with the pipeline getting the benefit of the sale of the involuntarily released capacity. This proposed device opens the door for what could be firm mainline service at a fraction of the system rate and creates what are firm rights, using existing system firm customers capacity at secondary service rates.

Secondary Rights

Texas Eastern admits that primary rights on the proposed lateral expansion do not give secondary rights on the interconnecting mainline. The proposal attempts to thwart this policy by its mainline Zone M3 secondary service proposal. This is an attempt to create flexible receipt and delivery points by charging a nominal fee, compared to firm rates, for this right. Flexible points are not permitted under section 7 (c) service in order 637A and reaffirmed in Docket No. RP97-406.

PGW request that, in the event that the expansion is authorized, the certificate be operationally conditioned that the proposed Mainline M3 Secondary Service is not available and cannot be used if Texas Eastern issues an OFO reducing Zone M3 firm capacity rights for its Mainline firm customers.

Bidding Procedures

The M3 mainline secondary service proposal violates Commission capacity release bidding policy. If Texas Eastern is permitted to repeat what it has already done, in actuality; firm service is created under the M3 service proposal. An involuntary capacity release is created. Pursuant to Texas Eastern's GT&C Section 3.12 there must be bidding for firm capacity. Obviously the OFO issuance is during peak periods of constrained capacity, so that the rates for the released capacity would be at maximum and probably above under the recent removal of price caps on releases. Texas Eastern must not be permitted to circumvent the bidding requirements and charge a greatly reduced rate for this service.

PGW requests that if this service is certificated, any capacity so created is subject to bidding procedures and Texas Eastern's request for waver is denied.

Rate issues

Texas Eastern's filing indicates a cost of service rate of $4.461, yet the proposed rate is $3.65, which also includes fuel, shrinkage and unaccounted for gas charges. It is not clear from the documentation supporting the filing, how the proposed rate can sustain the project. The Commission must require Texas Eastern to demonstrate that the system customers will not be subsidizing the fuel, shrinkage and unaccounted for gas cost of this project.

Operational Issues

There are several issues, which are not addressed in the filing.

1. It is the analysis of the technical personal at PGW that the subscribed capacity does not seem sufficient to operate a plant of the size indicated in the filing and there seems to be some indication that the project is relying on an OFO to create the additional required capacity.
2. PGW has concerns that the additional pressure needed for this project at station 30, at which it receives its gas, will create additional problems for it and other customers during peak demand periods. PGW therefore request that Texas Eastern be required to increase its contractual pressure at Station 30 to 250 PSIG to avoid this difficulty. And, that the Commission condition in any certificate issued that Texas Eastern is prohibited from installing any regulators downstream of the new facility in order to control downstream pressure.
3. It is necessary for the Texas Eastern system to be fully operational by September 1, 2001 in order for PGW to provide service during the peak winter season. The filing does not make clear that this date will be met. PGW requests that the Commission requires Texas Eastern to provide assurances and adhere to its assurance that this deadline will be met.

ACTIVITIES:

August 8,2000- PGW filed for "Leave to Intervene, Conditional Protest, and Request for Conditions and Rejection of Waiver"

April 12, 2001- FERC order issuing certificate to proceed with Texas Eastern's Columbia Liberty Lateral Expansion Project.

CP00-165

Transcontinental Gas Pipeline Corp.

Sundance Expansion Project

DATE FILED: April 3, 2000

ISSUES:

PGW has filed for intervenor status to protect its rights in this case.

BACKGROUND:

On April 3, 2000, Transco filed an application for a certificate of public connivance and necessity authorizing the Sundance Expansion Project (Sundance), located in Alabama, Georgia, Mississippi, and North Carolina, an incremental expansion of the existing pipeline system which will provide236, 383 dekatherms per day (dth/d) of new firm transportation capacity to serve increased market demand in the Southeastern region of the U.S. by a proposed service date of May 1, 2002.
Transco states that in order to create the firm transportation capacity for the Sundance Project, it proposes to construct and operate the following facilities on its mainline pipeline system:

1. 12.03 mi. of 42-inch diameter pipeline loop from milepost (MP) 772.91 on Transco's mainline in Clark County, Mississippi to (MP) 784.48 in Choctaw county, Alabama (DeSoto loop).
2. 9.36 mi. of 48-inch diameter pipeline loop from (MP) 851.46 on Transco's mainline in Dallas, County, Alabama to (MP) 860.82 in Perry County, Alabama (Summerfield loop).
3. Piping modifications at Transco's existing Compressor Station No. 105, which is *located in Coosa County, Alabama.*
4. 8.97 mi. of 42-inch pipeline loop from (MP) 1247.03 on Transco's mainline in Cleveland County, North Carolina to (MP) 1256.00 in Graston County, North Carolina (Kings Mountain loop).
5. 7.67 mi. of 42-inch diameter pipeline loop from (MP) 1287.11 on Transco's mainline to (MP) 1294.78 in Iredell County North Carolina (Mooresville loop).
6. Install one new 18,975 horsepower (h/p) compressor unit, and the up grading of an existing 15,000 and 16,000 h/p compressor units to 18,975 h/p each at Transco's existing Compressor Station No. 115 which is located in Coweta County, Georgia. The proposed Sundance project will increase the total certificated compression at this station to 56,424 h/p.
7. Install one new 15,000 h/p compressor unit and upgrade the existing 4,000 h/p compressor unit to 4,800 h/p Transco's compressor Station No. 125, which is

located in Walton County Georgia. The Sundance project will increase the total certificated compression to 38,800 h/p.

8. Install gas coolers at Transco's Compressor Station No. 150, which is located in Iredell County, North Carolina.

Transco states that the total estimated cost for the proposed facilities would be $134.67 million.

Transco asserts that the proposed facilities will be installed within or immediately adjacent to existing pipeline or utility rights-of-way and Transco's existing compressor stations.

Transco states that it held an open session from April 16 through June 1, 1999, during which written expressions of interest from potential shippers desiring new firm transportation service are made available as a result of the Sundance project. Transco declares that it executed precedent agreement with the following twelve shippers: Carolina Power and Light Co. (75000dts/d); City of Buford, Georgia (2,588 dth/d); Clinton-Newberry Natural Gas Authority, South Carolina (200 dth/d); City of Commerce, Georgia (207 dth/d); City of Covington, Georgia (776 dth/d); City of Fort Hill, South Carolina (8000 dth/d); City of Fountain Inn, South Carolina (3,500V City of Greer South Carolina (2,500 dth/d); City of Sugar Hill, Georgia (518 dth/d); City of Toccoa, Georgia (1,035 dth/d); City of Winder, Georgia (259 dth/d); and Southern Company Services, Inc. (140,000 dth/d). Transco states that 100% of the firm capacity to be created by the Sundance project is subscribed to by these twelve shippers. This transportation service will be provided under Rate Schedule FT of Transco's FERC Gas Tariff, Volume No 1, and Transco's blanket certificate under part 284(G) of the Commission's regulations. The proposed cost-based recourse rate for the Sundance project is based on the straight fixed-variable rate design methodology and an incremental cost of service.

ACTIVITES:

April 21, 2000- PGW filed a motion with the Commission for "Leave To Intervene".

March 28, 2001- FERC issued an order granting a certificate of public convince and necessity to Transco for the Sundance project.

CP98-540-000
TRANSCO
MARKETLINK PROJECT

DATE FILED: May 13, 1998

ISSUES:
PGW has only filed for Intervenor status at this time in order to protect its rights in this case.

BACKGROUND:

The purpose of this filing is for authorization to construct and operate certain pipeline facilities to create additional firm transportation capacity of 700,000 dekatherms per day (dth/d) to serve increased market demand in the Mid-Atlantic and South Atlantic regions of the United States by a proposed in-service date of no later than November 1, 2000 (MarketLink Project).

Transco states that the MarketLink Project will provide a link in the transportation of Canadian and Midwestern natural gas supplies, from expansion projects currently under development and proposed, to markets in New York, New Jersey, Pennsylvania and upstream markets along the Atlantic Seaboard which are accessible through backhaul arrangements on Transco's system. Transco also states that the MarketLink Project provides shipper access to diverse gas supplies at the developing market hub at Leidy, Pennsylvania, including gas supplies sources on any of the six interstate natural gas pipelines that interconnect with Transco at Leidy (including the pipeline system proposed by Independence Pipeline Company) or gas supplies delivered from storage at the Leidy hub.

Transco proposes to provide firm transportation service on an open access, non-discriminatory basis for the following shippers:

Shipper	Maximum Daily Term Quantity (Dth/d)	(Yrs.)
AEC Marketing (USA) Inc.	15,000	10
Coral Energy Resources, LP	50,000	10
Eastern Energy Marketing, Inc.	90,000	10
Engage Energy (U.S.), LP	210,000	10
Enron Capital & Trade Resources Corp.	30,000	10
LFG Energy, LLC	5,000	15
Natural Gas Clearinghouse	30,000	5
Renaissance Energy (U.S.) Inc.	23,000	10
Williams Energy Services Company	210,000	10
	Total 663,000	

The firm transportation service under the MarketLink Project will be provided under Rate Schedule FT of Transco's FERC Gas Tariff, Volume No. 1, and Transco's blanket certificate under Part 284(G) of the Commission's regulations. Transco states that the MarketLink shippers were provided the option of paying a cost based recourse rate or an individually negotiated rate plus fuel and all applicable surcharges under Rate Schedule FT. Transco states that the proposed recourse rate is based on a straight fixed-variable rate design methodology and an incremental cost of service.

Transco states that in order to create the additional 700,000 Mcf/d of firm capacity, Transco proposes to construct and operate the following facilities:

1. The Haneyville Loop; 24.19 miles of 42-inch diameter pipeline loop between milepost 161.29 in Lycoming County, Pennsylvania and milepost 185.48 in Clinton County, Pennsylvania,

2. The Williamsport Loop; 13.23 miles of 42-inch diameter pipeline loop between milepost 129.51 in Lycoming County and milepost 142.74 in Lycoming County, Pennsylvania and 1.79 miles of 36-inch diameter pipeline loop between milepost 142.74 in Lycoming County and milepost 144.53 in Lycoming County, Pennsylvania,

3. The Benton Loop; 17.73 miles of 42-inch diameter pipeline loop between milepost 28.56 in Luzerne County, Pennsylvania and milepost 115.18 in Columbia County, Pennsylvania,

4. The Allentown Loop; 6.27 miles of 42-inch diameter pipeline loop between milepost 30.29 in Northampton county, Pennsylvania and milepost 36.56 in Northampton County, Pennsylvania,

5. The Clinton Loop; 29.23 miles of 42-inch diameter pipeline loop between milepost 0.14 in Somerset County, New Jersey and milepost 29.37 in Warren County, New Jersey,

6. The Stirling Loop; 23.88 miles of 42-inch diameter pipeline loop between milepost 1789.53 in Somerset County, New Jersey and milepost 1812.36 in Morris County, New Jersey,

7. The Roseland Loop; 18.81 miles of 36-inch diameter pipeline loop between milepost 1820.66 in Essex County, New Jersey and milepost 1839.47 in Bergen County, New Jersey,

8. The Woodbridge Loop; 5.46 miles of 42-inch diameter pipeline loop between milepost 1802.73 in Middlesex County, New Jersey and milepost 1808.19 in Union County, New Jersey,

9. The Bordentown Loop; 7.10 miles of 36-inch diameter pipeline loop between milepost 18.96 in Burlington County, New Jersey and milepost 26.06 in Burlington County, New Jersey,

10.The Raritan River Loop; 0.30 miles of 42-inch diameter pipeline loop crossing the Raritan River between milepost 1794.70 in Middlesex County, New Jersey and milepost 1795.00 in Middlesex County, New Jersey,

11.The Mt. Laurel Replacement; The replacement of an existing 6.3 miles of 12-inch diameter pipeline loop between milepost 30.53 in Burlington County, New Jersey and milepost 36.83 in Burlington County, New Jersey, with a 36-inch diameter pipeline loop. The 12-inch pipeline segment will be removed and the 36-inch replacement pipeline will be installed in the same trench,

12.Impeller replacement on two (2) existing 12,600 horsepower, turbine-driven compressor units at Transco's existing Compressor Station 520, located at milepost 157.52, in Lycoming County, Pennsylvania,

13.The installation of two (2) new 15,000 horsepower, turbine-driven compressor units, re-wheeling of one (1) existing 12,600 horsepower, turbine-driven compressor unit and impeller replacement on two (2) existing 5,500 horsepower, turbine-driven compressor units at Transco's existing Compressor Station 517, located at Milepost 115.80, in Columbia County, Pennsylvania,

14.The installation of one (1) 15,000 horsepower, turbine-driven compressor unit, the re-wheeling and up-rating of an existing 12,600 horsepower, turbine-driven compressor unit to 15,000 horsepower at Transco's existing Compressor Station 515 located at milepost 68.95, in Luzerne County, Pennsylvania,

15.The installation of one (1) 15,000 horsepower, electric motor-driven compressor unit and impeller replacement on two (2) existing 7,000 horsepower, electric motor-driven compressor units at Transco's existing Compressor Station 205 located at milepost 1773.30 in Mercer County, New Jersey,

16.The installation of a 36-inch diameter interconnecting pipeline from the proposed meter building outlet of Independence Pipeline Company, (as proposed in Docket No. CP97-315) to Transco's existing 23-inch Leidy Line "A", 24-inch Leidy Line "B", and 30-inch Leidy Line "C" at milepost 194.06 in Clinton County, Pennsylvania,

17.Modifications to reduce pressure in Transco's 42-inch Mainline C from 1,200 psig to 800 psig at Transco's existing Centerville Regulator Station located at milepost 0.11 in Somerset County, New Jersey,

18.Modifications to reduce pressure in Transco's 36-inch Mainline D from 800 psig to 638 psig at Transco's existing Roseland Regulator Station, located at milepost 1820.66 in Essex County, New Jersey,

19.Modifications to reduce pressure in Transco's 42-inch Mainline E from 800 psig to 638 psig at Transco's existing Linden Regulator Station, located at milepost 1808.19 in Union County, New Jersey, and

20.Modification of inlet/outlet headers at existing Compressor Station 200 at milepost 1722.24 in Chester County, Pennsylvania to provide flow control under certain operating conditions on Transco's Trenton Woodbury Lateral.

The proposed facilities, for the most part, will be installed either entirely within or immediately adjacent to existing pipeline or utility rights-of-way and Transco's existing compressor station yards. Transco states that the proposed facilities will cost an estimated $528,767,973.Transco requests that the Commission issue a preliminary determination on the non-environmental aspects of its proposal by November 1, 1998, and a final order granting the authorizations requested herein by May 1, 1999.

ACTIVITY:

June 5, 1998- PGW filed a motion with the Commission for "Leave to Intervene.

TM99-6-29

Transcontinental Gas Pipe Line Corporation
Redetermination of Fuel Retention Charges (GRO)

DATE FILED: March 8,1999

ISSUES:

PGW has filed for Intervenor status and Comments at this time to protect its rights in this case.

BACKGROUND:

March 1,1999 Transcontinental Gas Pipe Line Corp. (Transco) tendered for filing to become part of its FERC Gas Tariff, certain revised tariff sheets with an effective date of April 1,1999. Transco states that this filing is submitted pursuant to Section 38 of the General Terms and Conditions of Transco's FERC Gas Tariff which provides that Transco will file, to be effective each April 1, a redetermination of its fuel retention percentages applicable to transportation and storage rate schedule. The derivations of the revised fuel retention percentages included herein are based on Transco's estimate for operations (GRO) for the forth coming annual period April 1999, through March 2000 plus the balance accumulated in the Deferred GRO Account at January 31, 1999. Transco included two adjustments in the estimates GRO for the forthcoming annual period. The first is an increase in the system Transportation estimate GRO to reflect prior period adjustment for the period August 1991 through July 1998 that will be recorded in February 1999. This adjustment accounts for an error in V's accounting system (which was converted in August, 1998) that incorrectly generated offsetting entries for certain receipts during that period, which resulted in an inaccurate determination of V's actual GRO for that period. The second adjustment is an increase in the Rate Schedule GSS estimated GRO to reflect a gas measurement correction that will also be recorded in February 1999. Consistent with the Commission's October 2,1998 Letter Order in Docket No. TM98-9-29-001, Transco has included these known adjustments to the estimated GRO to accurately reflect the estimated GRO quantity.

ACTIVITIES:

March 8, 1999-PGW filed with the Commission a motion for "Leave to Intervene and Comments".
October 30, 2000- FERC issued an order that: (A) granted Transco request for a rehearing limited to the extent discussed in the order. (B) Within 30 of the issuance of the order Transco shall file tariff sheets reflecting its FRP rates pursuant to the remedy approved by the order, to be effective April 1,1999, and shall include a calculation of the appropriate refunds, including interest, as provided for by 154.501 of the Commission's regulations,

and billing adjustments, both fully supported by work papers, and narrative explanations of its plan.

December 29, 2000-Transco filed a notice of compliance to the Commissions October 30, 2000 order.

January 5, 2001-PGW filed with the Commission, "Comments" to the Transco Compliance filing of December 29, 2000.
PGW does not take a position in this pleading on weather or not Transco should be permitted to recover Gas Required for Operations (GRO) cost for the period April 1, 1999 through December 3, 2000. PGW is concerned that the pipeline is proposing to collect approximately $1.68 million in interest, plus the calculated interest for the collection period going forward. In contrast to the Commission expressly requiring interest to be added to customer refunds in both its Orders issued in this proceeding (February 23,2000 and October 30, 2000) there is no mention in either Order of interest to be added to the principal amounts to be recovered by Transco. PGW request that the Commission carefully reviews the appropriateness, and the precedent potential, of allowing the pipeline to receive interest payments for cost incurred through the pipeline's error, as occurred in this instance.


RECYCLED

Docket No. R-01XXX
Item 53.64 (c)(5)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(5) A listing and updating, if necessary, of projections of gas supply and demand provided to the Commission for any purpose—see § 59.67 (relating to formats). In addition, provide an accounting of the difference between reported gas supply available and gas supply deliverable—including storage—from the utility to its customers under various circumstances and time periods.

Response:

Please see the attached document.

ANNUAL RESOURCE PLANNING REPORT

Philadelphia Gas Works

Philadelphia, Pennsylvania

2000

Forms 1 & 2

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Philadelphia Gas Works
800 West Montgomery Avenue
Philadelphia, Pennsylvania 19122

ANNUAL RESOURCE PLANNING REPORT
Forms 1 & 2

Information Submitted in Compliance with and Pursuant to Title 52
Pennsylvania Code Section 59.81

PHILADELPHIA GAS WORKS

TABLE OF CONTENTS

Section 59.81: **General**

Pursuant to Section 59.81 (a), each major jurisdictional gas utility must file an annual resource planning report (ARPR) on or before June 1, 1996 and June 1 of each succeeding year, except Form 1A/2A which filing date is March 1. One (1) original and seven (7) copies of the report must be submitted to:

Secretary
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

One copy should be submitted unbound for ease of duplication.

One courtesy copy should also be submitted to:

Pennsylvania Public Utility Commission
Conservation, Economics and Energy Planning
P.O. Box 3265
Harrisburg, PA 17105-3265
Attn. Calvin Birge

Also submit one (1) copy to the following:

Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1921

Office of Small Business Advocate
Suite 1102, Commerce Building
300 N. Second Street
Harrisburg, PA 17101

Be sure to indicate the name and telephone number of at least one individual at the company who is familiar with the filing and will be available to answer any questions the Commission staff may have. You may also wish to list those individuals who are directly involved in the preparation of the various document components.

Information contained in annual resource planning reports must be utility-specific. The report should follow an outline similar to that which is contained herein, with narrative accompanying the required data. Forms may be modified to accommodate wide columns of numbers and enhance readability, but the general format should be used to maintain consistency.

This information is not generally considered confidential. Utilities are obligated to provide complete information. However, we will treat as confidential those portions of the report designated by the utility as proprietary. If a utility's proprietary claim is challenged, the Commission will direct the utility to file a petition for protective order pursuant to 52 PA Code 5.423.

All questions concerning the reporting requirements for Forms IRP Gas 1A through 9 should be addressed to Pennsylvania Public Utility Commission Bureau of Conservation, Economics and Energy Planning.

Response:

An original, seven (7) copies, and one unbound copy of Forms 1A, 1B, 2A, 2b, and 2C along with a general discussion of the methodologies, data sources, and assumptions are being submitted to meet the requirements of the March 1 filing.

All questions concerning the ARPR should be directed to Mr. William Muntzer, Director, Gas Planning, Rates and Regulatory Affairs at (215) 684-6623. The following individual will be available to answer questions concerning each section:

Mr. Pascal (Pat) J. Durante, Manager, Gas Planning at (215) 684-6317

Section 59.81 **Forms IRP-Gas 1A, and 1B – Annual and Peak Day Demand**

The load growth projections shall reflect the effects of price elasticity, market induced conservation, building and appliance efficiency standards, and the effects of the utility's existing and planned conservation and load management activities.

Response: Please see the attached documentation and forms.

FORM-IRP-GAS-1A: ANNUAL GAS REQUIREMENTS
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(VOLUMES IN MMcF)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	1998-1999	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
Firm Sales:						
Retail Residential	42,851	42,136	46,941	45,386	45,201	44,731
Retail Commercial	9,429	11,351	11,991	12,006	12,218	12,149
Retail Industrial	1,406	1,299	1,494	1,544	1,599	1,622
Electric Power Generation						
Exchanges with Other Utilies						
Unaccounted For Gas	2,286	3,659	3,272	2,158	2,261	2,247
Company Use	67	69	81	93	93	93
Other (Off-system/Unbilled Estimate)						
Subtotal Firm Sales	56,039	58,514	63,779	61,187	61,372	60,843
Interruptible Sales:						
Retail	8,273	8,396	7,643	10,110	10,438	9,644
Electric Power Generation	169	208	137	168	167	122
Company's Own Plant	427	449	478	539	535	519
Unaccounted For Gas	294	293	258	285	295	277
Subtotal Interruptible Sales	9,163	9,346	8,516	11,101	11,436	10,561
SUBTOTAL FIRM AND INTERRUPTIBLE SALES:	65,201	67,860	72,295	72,288	72,808	71,404
Transportation:						
Firm Residential						
Firm Commercial						
Firm Industrial	11,115	11,012	9,228	10,546	10,546	10,083
Interruptible Residential						
Interruptible Commercial		-	-	-	-	-
Interruptible Industrial	2,427	2,988	3,263	3,802	4,216	7,525
Electric Power Generation						
Subtotal Tranportation	13,542	14,000	12,491	14,348	14,762	17,608
TOTAL GAS REQUIREMENTS	78,743	81,860	84,786	86,636	87,570	89,012
Increase (Decrease)	na	3,117	2,926	1,850	934	1,442
Percent Change (%)	na	3.96%	3.57%	2.18%	1.08%	1.65%

FORM-IRP-GAS-1B:PEAK DAY REQUIREMENTS
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(VOLUMES IN MMcF)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	1998-1999	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
Firm Sales:						
Retail Residential	384.5	413.2	379.0	519.0	516.5	511.1
Retail Commercial	84.4	111.3	96.8	137.1	139.5	139.1
Retail Industrial	12.6	12.6	12.4	17.5	17.5	18.1
Electric Power Generation	0.0	0.0	0.0	0.0	0.0	0.0
Exchanges with Other Utilies	0.0	0.0	0.0	0.0	0.0	0.0
Unaccounted For Gas	20.6	36.2	26.3	24.5	25.9	25.7
Company Use	0.5	0.6	0.5	1.4	1.4	1.4
Other (Off-system/Unbilled Estimate)	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal Firm Sales	502.7	573.8	514.9	699.5	700.8	695.3
Interruptible Sales:						
Retail	37.5	52.9	4.2	0.0	0.0	46.9
Electric Power Generation	0.3	0.3	0.0	0.0	0.0	0.0
Company's Own Plant	1.3	1.9	1.1	0.0	0.0	0.0
Unaccounted For Gas	0.2	2.0	0.2	0.0	0.0	1.7
Subtotal Interruptible Sales	39.3	57.1	5.5	0.0	0.0	46.9
SUBTOTAL FIRM AND INTERRUPTIBLE SALES:	541.9	630.9	520.4	699.5	700.8	742.2
Transportation:						
Firm Residential	0.0	0.0	0.0	0.0	0.0	0.0
Firm Commercial	0.0	0.0	0.0	0.0	0.0	0.0
Firm Industrial	15.7	30.7	20.5	0.0	0.0	0.0
Interruptible Residential	0.0	0.0	0.0	0.0	0.0	0.0
Interruptible Commercial	0.0	0.0	0.0	0.0	0.0	0.0
Interruptible Industrial	1.0	2.9	0.8	0.0	0.0	0.0
Electric Power Generation	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal Tranportation	16.7	33.6	21.3	0.0	0.0	0.0
TOTAL GAS REQUIREMENTS	558.6	664.6	541.7	699.5	700.8	742.2
Increase (Decrease)	na	106	(123)	158	1	41
Percent Change (%)	na	18.96%	-18.49%	29.13%	0.20%	5.91%

Introduction

By Order entered January 11, 1996, the Pennsylvania Public Utility Commission (PUC) adopted final regulations (52 PA Code §§ 59.81 - 59.84) which set forth revised requirements for filing an Annual Resource Planning Report (the Plan). The Plan submitted represents Philadelphia Gas Works' (PGW or the Company) belief that integrated resource planning (IRP) is a workable approach to utility planning.

This plan summary contains historical data and projections for annual, winter and peak day supply to meet projected customer requirements in a least cost manner, while ensuring adequate and reliable service. It is organized into the following 6 sections:

I. PGW's Overall Approach to Integrated Resource Planning

II. Supply Forecasting Methodology and Assumptions

III. Demand Forecasting Methodology and Assumptions

IV Peak Day Forecasting Methodology and Assumptions

V. PGW Corporate Modeling System

I. PGW's Overall Approach to Integrated Resource Planning

PGW Optimization Standard for Purchasing and Utilizing Gas Supplies

As reasonably anticipated, PGW intends meeting its contractual obligations to supply all of its current customers in its service territory on the coldest day and throughout the season. Projected customer requirements for design day and design winter conditions form the basis for capacity commitments for pipeline supply, storage, and transportation contracting.

Natural gas supplies are purchased under a portfolio approach, intending to secure the lowest overall price, consistent with the primary corporate goals of reliability and security of supply. In addition, consideration is given to maintaining a diversity of sources and types of supply, coupled with contractual and operational flexibility on both a daily and seasonal basis. Short term purchases from spot market sources are utilized to the maximum degree that they are more economical, available, and transportable.

Natural gas supplies are utilized so as to maximize net contributions subject to reliability constraints. Supply contract obligations are honored and prudent Gas Control operational requirements are assumed. Storage contracts are drawn upon so as to always maintain an inventory level sufficient for protection in the event that design temperature conditions should occur in the remaining segment of any winter season. Within the above parameters, priority is given to utilizing the most economical sources of supply first, within the context of preserving the capability of meeting seasonal and annual demands rather than the momentary daily requirements. All facilities and sources of supply, flowing, storage and LNG are available to achieve the intended end; namely, maximizing net contributions subject to reliability constraints.

II. Supply Forecasting Methodology and Assumptions
Basic Assumptions

The PGW Gas Supply Policy Committee, representing senior corporate management as well as Gas Planning, Gas Control, Gas Supply, Regulatory and Marketing departmental management, approved the aforementioned Optimization Standard for Purchasing and Utilizing Gas Supplies (Section I). All natural gas purchases continue to be made in accordance with this standard. Projected sales, revenues and natural gas expenses in this report reflect application of this agreement, particularly in the areas of inventory valuation, priorities of gas selection and interruptible supply availability.

PGW's supply strategy incorporates maintaining full current winter day deliverability with regard to transportation capacity. A variety of long term supply contracts are necessary to support pipeline transportation capacity because reliance upon best effort spot suppliers to fill wintertime capacity required to meet firm customers' demands has proven to be an unreliable alternative. As a result, longer-term contracts are utilized to support firm transportation capacity. To accomplish this end, the Company purchases winter supply contracts with daily deliverability equal to approximately 58% of the contractual daily transportation entitlements on its two interstate pipelines with direct connections to PGW's service territory. Additionally, these supply contracts match the contractual entitlements of the two pipelines by sourcing supply in a manner consistent with the pipeline's upstream contractual requirements. In this way, PGW not only helps ensure the security of supply by sourcing the gas from geographically diverse supply regions but also this diversity allows PGW to take advantage of the pricing basis differential inherent in these supply locations.

These contracts all contain the ability to fix the price for upcoming months as well as to allow the pricing to default to an agreed upon market index when there is no market advantage in fixing a price before the month begins. PGW uses this fixed price option in conjunction with its Gas Cost Rate (GCR) filing (GCR filing includes pricing based upon the Standard and Poors' "DRI Price Forecast") by always attempting to buy under the DRI forecasted prices.

II. Supply Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

Through the matching of the duration supply contracts to a seasonal demand, such as the Winter operating season, the firm rate payers benefit from not paying demand charges year-round.

A second component of PGW's supply portfolio, or a volume equal to 32% of pipeline capacity, is purchased gas based on a first-of-the-month index pricing methodology, with contracts that allow for daily change in volumetric take. This allows the Company to effectively shut-off higher priced supply, replacing such supply with daily cheaper spot priced gases. Under assumed normal winter conditions, PGW utilizes certain storage fields (ANR, Equitrans, Eminence and Washington), in a manner similar to third party supply.

Specifically, these storage contracts do not contain bundled transportation to the PGW city gate. Therefore, storages must flow within PGW's contractual upstream capacity rights on TETCO and TGPL. Typical daily delivery from these fields utilizes approximately 10% of the daily TETCO and TGPL capacity rights to the Philadelphia city gates. These storage fields also act as a physical fixed price counter to winter price conditions since the WACOG in these storages typically reflects a winter/summer pricing differential.

PGW's summer purchasing strategy also incorporates a portfolio approach to the purchase of system supply and storage refill. The GCR filing, with its Standard and Poors' based pricing, is again used as a yardstick in purchasing supply for both system supply and storage refill. PGW attempts to always purchase a portion of its supply needs below the projected GCR cost estimate with a portion of the portfolio purchased at default, first-of-the-month pricing. These first of the month pricing option contracts, in most instances, allow PGW to evaluate daily spot prices and provide for a turn-off of first-of-the-month index priced supply in favor of the purchase of more advantageous daily spot purchases or, operating conditions permitting, use of underground storage and LNG.

II. Supply Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

Operating flexibility is sustained by variations in contract stipulations, to permit the system to swing on the most economical gas supplies available while maintaining the ability to supply rapidly fluctuating temperature requirements. Storage facilities are substituted wherever opportunity affords to reduce annual expense for flowing 365 day pipeline service without damage to peak day and peak winter season delivery capability. Direct control of all storage permits PGW to minimize winter costs by injecting lower priced summer purchases and to cycle storage to balance daily take fluctuations to avoid overrun/balancing charges.

Operating conditions permitting, the Company enters into the FERC approved capacity release market to offset demand charges it pays for its firm transportation and/or the incremental off-systems sales market when it is economically advantageous for the firm rate payer. In both instances, these opportunities are sought only when firm customer needs are satisfied. Additionally, PGW's bundled storages and LNG can be utilized as a substitute for higher price gas supply based on market pricing conditions and the results of PGW's weekly status report. Effectively, the Gas Supply Group is at all times studying the market for any economic advantage it can bring to the firm rate payer.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions

PGW uses a combination of four basic methods to develop demand projections. They are:

1) Customer Survey - Information as gathered by PGW's Marketing Department and used for annual projections by month and year.
2) Relative End Use -- Projections via Marketing methods of customer load sizing by appliance type, maximum input, maximum summer and winter full load hour (FLH) calculations which are used to develop yearly and monthly demand requirements.
3) Historical Data -- data showing long-term demand trends, conservation and utilization patterns by the various classes of customers -- Residential, Commercial, Industrial and Interruptible.
4) Judgement -- Experienced opinion as applied to the evaluation of the combination of all data to develop the basic demand requirements.

Customer Demand

The total system-wide demand is a function of the projected gas demand per customer and the anticipated number of customers in each class. In determining customer demand, consideration is given to projecting current customer usage, augmented by significant gains or losses in each of 49 homogeneous groups for the period being projected. The Gas Planning Department attempts to determine, for each customer class, the level of demand reliable to experienced temperature and the component of demand that is apparently not affected by changes in temperature. Within each class the most recent summer and winter usage patterns are established from historical records. Summer data provides an insight into each class of customer's non-temperature sensitive load requirements, baseload, which can be expressed in terms of thousands of cubic feet (Mcf) per day, per customer. Similarly, winter data, after removal of the daily baseload level, reveals the temperature sensitive load requirements for each class of customer.

This usage primarily reflects space heating, but also includes such other temperature sensitive needs as water heating attributable to colder ground water inlet temperatures and similar process variations, as well as supplementary range heating. This overall heating requirement can be expressed in terms of the cubic feet of gas utilized per degree of temperature change on a per customer basis for each separate customer classification.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

In addition, consideration must be given to the variation of customer utilization patterns, for space heating over the year, recognizing the transitional fall start-up of heaters, the deep winter period needs and the tapering off and shut-down which occurs in the spring. These usage patterns taken in conjunction with anticipated customer counts and appropriate temperature patterns form the basis of determining class and total system demands. Due to the inconsistencies of weather and weather forecasting techniques, no attempt is made to predict the specific daily temperatures of the projection period. Instead, PGW has developed a normal monthly temperature pattern by analyzing statistical records of actual temperature patterns over a 40-year period. This pattern reflects 4600 degree days annually distributed in a stylized pattern preserving the monthly range of colder to warmer daily temperatures experienced, but without regard to calendar date.

The term "degree days" quantifies the number of degrees of temperature below a base level of 65 degrees Fahrenheit as a tool to measure space heating requirements, i.e., on a day experiencing an average temperature of 40 degrees F. there would be counted 25 degree days. The annual 4600 degree days, which compose the PGW normal monthly temperature patterns, form the basis of the calculation of the temperature sensitive component of demand. The application of the above described baseload and space heating factors and customer counts, when applied to a calendar based daily temperature pattern, produces a daily statement of total customer requirements identified as sendout. It should be noted that there is a difference between sendout volume and sales volume. Sendout represents those volumes that left the plant initially to supply customers' requirements, while sales are those volumes reported on customer meters. The variation between sendout and sales is that portion which is lost and unaccounted for in the PGW distribution system. In addition, they differ on a monthly basis in the distribution pattern. For the convenience of distributing meter reading and billing efforts uniformly over the available number of working days in a month, the majority of PGW customers are divided into 20 individual groups or cycles, containing residential, commercial and industrial accounts within a specific geographic area.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

In addition, consideration must be given to the variation of customer utilization patterns, for space heating over the year, recognizing the transitional fall start-up of heaters, the deep winter period needs and the tapering off and shut-down which occurs in the spring. These usage patterns taken in conjunction with anticipated customer counts and appropriate temperature patterns form the basis of determining class and total system demands. Due to the inconsistencies of weather and weather forecasting techniques, no attempt is made to predict the specific daily temperatures of the projection period. Instead, PGW has developed a normal monthly temperature pattern by analyzing statistical records of actual temperature patterns over a 40-year period. This pattern reflects 4600 degree days annually distributed in a stylized pattern preserving the monthly range of colder to warmer daily temperatures experienced, but without regard to calendar date.

The term "degree days" quantifies the number of degrees of temperature below a base level of 65 degrees Fahrenheit as a tool to measure space heating requirements, i.e., on a day experiencing an average temperature of 40 degrees F. there would be counted 25 degree days. The annual 4600 degree days, which compose the PGW normal monthly temperature patterns, form the basis of the calculation of the temperature sensitive component of demand. The application of the above described baseload and space heating factors and customer counts, when applied to a calendar based daily temperature pattern, produces a daily statement of total customer requirements identified as sendout. It should be noted that there is a difference between sendout volume and sales volume. Sendout represents those volumes that left the plant initially to supply customers' requirements, while sales are those volumes reported on customer meters. The variation between sendout and sales is that portion which is lost and unaccounted for in the PGW distribution system. In addition, they differ on a monthly basis in the distribution pattern. For the convenience of distributing meter reading and billing efforts uniformly over the available number of working days in a month, the majority of PGW customers are divided into 20 individual groups or cycles, containing residential, commercial and industrial accounts within a specific geographic area.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

When these cycle customers are billed each month, they reflect meter reading usage not for the calendar month being billed, but for the number of days and temperature pattern of degree-days experienced during their specific interval between readings.

For example, assume the month of January contained 900 degree-days. The customers in cycle 10 being billed for the month of January might have had meter readings taken on December 15 and again on January 17. Sales billed and reported in company records for these customers would have reflected the number of days and degree days between these reading dates rather than the 900 degree days of the month. Similarly, cycle 1 customers that might have had meter readings taken on December 1 and January 2 would reflect principally the December temperature experience, while cycle 20 customers, with meter readings taken possibly December 28 and January 29, would reflect principally the January temperature experience.

An average of the 20 cycles (Average Cycle Degree-Days) is used as the temperature patteren upon which to project the potential volume of sales in the estimation period. Both projections of sales and sendouts represent the full potential demand for that period from both firm and interruptible customers.

Methodology Used to Develop Monthly Estimates

A trial domestic factor is developed by class of customer from sales reported for the previous year's summer months. This average factor is then utilized in the sendout formula with the customer counts for the months of July, August and September. A comparison between what the formula calculates and the actual experienced for those three months is ascertained and the trial domestic factors are finalized to replicate the total sendout experienced. The finalized domestic factors (DOMs) are then utilized in conjunction with the actual sales and customer counts for the months of December, January and February to determine the average Mcf per degree day for each of the individual months for the remaining temperature sensitive load. The results are weighted by degree-days to give an average value which is utilized as a trial value for the heating factor.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

The finalized domestic factor and the trial heating factor developed, as such, are then applied in the sendout calculations, together with customer counts for the months of December, January and February, the peak winter cold period, to project an estimated sendout for each of these months. The projected sendout is then compared with the actual sendout experienced. Any variation between the projected and actual is adjusted to force the replication of the actual sendout experience, thus resulting in the determination of a finalized heating factor.

To project the number of customers for each individual rate class, the following categories of customers are reviewed and accumulated individually: current customers are ascertained from the number of billings data available from sales and revenue actually experienced immediately prior to the commencement of a budget run. Declines are projected for anticipated losses to electric and other fuels or demolitions and from transfers to other rates. Direct transfers from a non-heating to a heating account, as a result of a current customer's conversion to gas heat, moves the domestic load to the new category. Projected additional customers are developed within the Marketing Department, where staff dealing with individual classes of customers and having the most direct knowledge of conditions within their sphere, project annual load additions which are translated into count based upon typical customer usage for that individual customer class. The approximate month of turn-on is also developed to permit reflection of the effective portion of the load addition within the fiscal period under study. Interruptible class customers, as well as other large special accounts, are detailed individually incorporating expected gains and losses as direct contact has indicated.

The base revenue projections for both firm and interruptible customer groups are derived as the product of the projected sales volumes and the present tariff rate for each individual customer class within each group. The GCR revenue projections are derived as the product of the GCR factor and the projected sales volumes to the non-interruptible customers.

IV. Peak Day Forecasting Methodology and Assumptions

Each year, a six year estimate of Peak Day requirements anticipated under design peak day operating conditions is prepared to ensure that adequate resources are under contract. Additionally, to further ensure that PGW can fulfil its utility obligation to its firm customer requirements on the design peak day and design peak hour.

The projected demands for design day, as delineated on Form 1B (attached), are developed utilizing previous winter period data; for this report, from 1994-95 through 1999-00, for all weekdays where the temperature average for the day is 32 degrees Fahrenheit or below. The total sendout for these days as recorded under actual conditions is reduced to base sendout by removal of the interruptible load. A computer generated linear regression procedure is utilized to develop a calculated sendout versus the actual sendout from which the necessary constants (factors) required to have the calculated sendout match, within a reasonable percent of error to the actual sendout are developed. The process is repeated in a quadratic regression and a cubic regression procedure. This approach produces a curvilinear regression method, the results of which are analyzed by statistical significance testing and the best-fit curve is selected for use in developing the design day sendouts. The factors derived from the curve selected are used to calculate current load requirements for a 0 degrees F day and a -5 degrees F hour. PGW's Marketing Department's load projections for present and future years are then applied to these requirements to develop design day and design hour present and future load requirements. This is achieved by the addition of the projected marketing load growth expectations on an annual basis (by day) to the derived base-year design day requirements.

V. *PGW Corporate Modeling System*

General Description

The corporate model system is a tool used by PGW management to project sales, revenues and expenses, as well as to examine key planning strategies and evaluate their effects on company operations. The system provides the ability to determine the results of alternate plans and scenarios, while at the same time allowing for responses to "what if" type situations quantifying revenue and expenses. The system is totally interactive in that it combines the power of the computer with the experience of management to develop both short and long range projections based upon experienced historical data for sales and sendout volumes, raw material expenses and sale revenues. The corporate model system is composed of five separate models. Each model operates independently, but requires substantial external data inputs as well as data output results from one or more of the other models in the system.

Gas Demand Model

The gas demand model is used to forecast total requirements for gas based upon current customer usage experience with adjustments for projected gains and losses. Input data includes domestic and space heating usage factors, customer counts by rate classifications, temperature patterns and results in projections of sales and sendout volumes. Detail and summary reports include average usage per customer and demands by rate classification. This data is transferred to the supply model.

Gas Supply Model

The supply model is used to dispatch the various supply sources in accordance with contract availability limitations. It develops the necessary balance between supply and demand, which reflects plant fuel and storage re-injection requirements as well as customer demands, by identifying the availability of interruptible load balancing sales. Detail and summary reports include daily and monthly load requirements, the volumes taken from each source by pipeline contract, storage balances, supplemental fuel requirements, etc. Data is transferred to both the cost model and the revenue model downstream.

V. *PGW Corporate Modeling System (Continued)*

Gas Cost Model

The gas cost model is used to determine natural gas and other raw material costs dispatched. The model tracks the various cost components of each contract - the demand, capacity, commodity, injection and withdrawal charges - providing monthly and annual details and summary information, including inventory valuations and expenses for supplemental LPG and LNG supplies. It transfers these expenses to the Gas Cost Rate Model.

Gas Cost Rate Model

The gas cost rate model is used to develop a base fuel charge and a fuel adjustment factor known as the Gas Cost Rate (GCR). It ascribes responsibility for the raw material costs, to firm and interruptible classes in accordance with PGW's tariff requirements, assigning cost on an as-used basis to customer classes applicable to such charges, and compensates for natural gas refunds and previous over or under billing of fuel expenses. Detail summary reports include specifics of raw material adjustment, statements of reconciliation, and determination of applicable sales and expenses, transferring its results to the revenue model.

Revenue Model

The revenue model is used to project billed revenue by rate classification in accordance with PGW's rate tariffs. It prepares both base non-fuel and base fuel revenue statements, GCR revenues, senior citizen discounts, and cycle and budget billing information, all detailed by rate classification. The detail and summary reports provided by this model are directed to the accounting and financial departments for inclusion in various financial reviews.

Summary

The corporate model system allows PGW management to effectively address supply/demand balancing, supply facilities planning, projected sales, cost, revenues, and sendout volumes in a timely manner. Results assist in the development of PGW's annual Operating Budget.

V. PGW Corporate Modeling System (Continued)

The model allows the evaluation of future winter requirements on both normal and design temperature patterns and the extrapolation of current years based upon the experience to date and an assumption of temperatures anticipated for the remaining period of the year, this latter acting as a guide for both financial cash flow planning and winter operations.

Other Forecasts

In addition to the Operating Budget forecasts identified above in conjunction with the modeling system, capital budget planning is facilitated by providing a forecast of design day/design hour load requirements. This recognizes the usage patterns exhibited during the most recent five winters on weekdays with temperatures of 32 degrees F. and below. Load growth assumptions extend this experience into future years. The design day conditions represent a weekday at 0 degree F. The design hour represents a -5 degree F. temperature and approximately 5% of the total peak day load requirements.

Section 59.81 **Forms IRP-Gas 2A, 2B and 2C - Annual and Peak Day Energy Resources, Transmission and Storage Contracts**

The forecast of energy sources shall indicate sources of all presently available and new supplies which the utility estimates will become available, displayed by component parts.

Response: Please see the attached documentation and forms.

FORM-IRP-GAS-2A: NATURAL GAS SUPPLY
TABLE : PEAK DAY SUPPLY
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(Volumes in MMcf)

	Historical Data		Current Year	Three Year Forcast		
Index Year Actual Year	-2 1998-1999	-1 1999-2000	0 2000-2001	1 2001-2002	2 2002-2003	3 2003-2004
Gas Supply for Sales Service						
TETCO	119	119	95	118	118	118
TRANSCO	118	114	138	136	136	136
Spot Purchases						
Storage Withdraws	216	198	166	210	211	211
LNG/SNG/Propane Purchases	88	198	122	234	235	277
Company Production						
Local Purchases						
Exchanges with other LDCs						
Other						
Total Gas Supply for Sales	541	629	521	699	701	742
Total Transportation Services						
TOTAL SALES, GAS SUPPLY AND TRANPORTATION SERVICE	541	629	521	699	701	742
Deductions						
Curtailments						
Underground Storage Injections						
LNG Liquefactions						
Sales to other LDC's						
Total Deductions						
NET GAS SUPPLY	541	629	521	699	701	742

conversion @ 1028 Btu

2000-2001 Due to operational emergency deliverablity reduced.

FORM-IRP-GAS-2B: NATURAL GAS TRANSPORTATION
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(volumes in Mmcf)

	Historical Data				Current Year		Three Year Forcast					
Index Year	-2		-1		0		1		2		3	
Actual year	1998-1999		199-2000		2000-2001		2001-2002		2002-2003		2003-2004	
City Gate Transportation Contracts:	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak
CONSOLIDATED	3,723	52	3,723	52	3,723	52	3,723	52	3,723	52	3,723	52
TETCO	2,570	43	2,570	43	2,570	43	2,570	43	2,570	43	2,570	43
TETCO	2,390	20	2,390	20	2,390	20	2,390	20	2,390	20	2,390	20
CONSOLIDATED	453	4	453	4	453	4	453	4	453	4	453	4
Total	9,137	120	9,137	120	9,137	120	9,137	120	9,137	120	9,137	120
Upstream Transportation Contracts:												
TRANSCO	58,546	160	58,546	160	58,546	160	58,546	160	58,546	160	58,546	160
TETCO	26,578	73	26,578	73	26,578	73	26,578	73	26,578	73	26,578	73
TETCO	8,442	23	8,442	23	8,442	23	8,442	23	8,442	23	8,442	23
TETCO	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17
TETCE	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17
TRANSCO	172	2	172	2	172	2	172	2	172	2	172	2
Total	98,456	293	98,456	293	98,456	293	98,456	293	98,456	293	98,456	293
Storage-Related Transportation Contracts:												
CONSOLIDATED	9,110	22	9,110	22	9,110	22	9,110	22	9,110	22	9,110	22
CONSOLIDATED	2,760	7	2,760	7	2,760	7	2,760	7	2,760	7	2,760	7
EQUITABLE	1,911	5	1,911	5	1,911	5	1,911	5	1,911	5	1,911	5
Total	13,781	33	13,781	33	13,781	33	13,781	33	13,781	33	13,781	33

Conversion @ 1030 Btu

FORM-IRP-GAS-2C: NATURAL GAS STORAGE [1]
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(volumes in Mmcf)

	Historical Data				Current Year		Three Year Forcast					
Index Year	-2		-1		0		1		2		3	
Actual year	1999		2000		2001		2002		2003		2004	
	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak
Consolidated Natural Gas	3,723	52	3,723	52	3,723	52	3,723	52	3,723	52	3,723	52
Consolidated Natural Gas	3,481	28	3,481	28	3,481	28	3,481	28	3,481	28	3,481	28
Transcontinental Transmission Corp.	3,086	36	3,086	36	3,086	36	3,086	36	3,086	36	3,086	36
Texas Eastern Transmission Corp.	2,467	43	2,467	43	2,467	43	2,467	43	2,467	43	2,467	43
Texas Eastern Transmission Corp.	2,219	20	2,219	20	2,219	20	2,219	20	2,219	20	2,219	20
ANR	1,824	13	1,824	13	1,824	13	1,824	13	1,824	13	1,824	13
Equitrans	507	5	507	5	507	5	507	5	507	5	507	5
Consolidated Natural Gas	453	4	453	4	453	4	453	4	453	4	453	4
Transcontinental Transmission Corp.	165	16	165	16	165	16	165	16	165	16	165	16
Total	17,925	218	17,925	218	17,925	218	17,925	218	17,925	218	17,925	218

1 Rank contracts in order of magnitude for the current year, noting the transportation provided and termination date for each contract reported
Reporting should proceed along rank ordering until 75% of total is accounted for, or until ten contracts have been listed, whichever occurs first.

Conversions at 1030 Btu

	Contract Expiration Date [2]
Consolidated Natural Gas	3/31/13
Consolidated Natural Gas	3/31/06
Transcontinental Transmission Corp.	Evergreen
Texas Eastern Transmission Corp.	4/30/12
Texas Eastern Transmission Corp.	4/30/12
ANR	3/31/13
Equitrans	3/31/02
Consolidated Natural Gas	4/15/01
Transcontinental Transmission Corp.	10/31/13

2 For purposes of this report, contracts due to expire are assumed renewed for the forecast years.

Docket No. R-01XXX
Item 53.64 (c)(6)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(6) Each Section 1307(f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning the staffing and expertise of its fuel procurement personnel, a discussion of its methodology for obtaining a least cost and reliable source of gas supply, including a discussion of any methodologies, assumptions, models or rules of thumb employed in selecting its gas supply, transportation and storage mix, its loss prevention strategy in the event of fraud, nonperformance or interruption of performance, its participation in capacity release and reallocation programs, the impact, if any, upon least cost fuel procurement by constraints imposed by local transportation end users, interruptible service, balancing, storage and dispatching options, and its strategy for improving its fuel procurement practices in the future and timetable for implementing these changes.

Response:

I. Current Strategy

PGW's current strategy for meeting the system's supply requirements is to use a portfolio approach in both contract structures and pricing. The Company's gas supply portfolio is split into three distinct categories:

(1) The Company enters into winter-only supply contracts. These winter-only supply arrangements provide gas supply

which fills approximately sixty percent (60%) of PGW's daily firm transportation entitlements on Texas Eastern Transmission Corporation (Tetco) and Transcontinental Gas Pipe Line Corporation (Transco). The Tetco and Transco pipelines represent the only interstate pipeline facilities with physical connections to the PGW service territory. These supply contracts also recognize pipeline receipt and delivery rights. By sourcing supply in this manner, PGW not only ensures security of supply from the pipelines, but also can take advantage of varying basis differentiated pricing in the market. These contracts all contain the ability to "lock up" the price for upcoming months, or to have the pricing default to an agreed upon market index if there is no market advantage in fixing a price before the month begins.

(2) Approximately thirty percent (30%) of PGW's portfolio is purchased on "first of the month index" priced contracts that allow for daily change in volume. These contracts also include pricing flexibility, which allows the company to turn off what may be higher priced gas from day to day and purchase spot priced gas when it is to the advantage of the ratepayer.

(3) The company utilizes two pipeline storage fields, which act as an additional source of supply. These contracts do not contain bundled transportation and therefore move to PGW City gates within PGW's firm interstate pipeline capacity. These services represent ten percent (10%) of supply and also act as a physical fixed price counter to market conditions. Additionally, PGW utilizes bundled storage and LNG to meet operational requirements and to accomplish other cost saving initiatives. Specifically, once design winter sendout requirements are ensured, the company may utilize bundled storage and LNG as a substitute for higher priced gases based on both market conditions including anticipated refill pricing. PGW's summer policy uses a portfolio approach to address system supply and storage refill. The Gas Supply area uses the GCR filing as a template to purchase gas volumes for both system supply and storage refill below the projected cost, where possible, on a proportional basis while leaving a portion of its needs to default to "first of the month" pricing. This provides the ability to turn off "first of the month" supply in order to purchase supply on a daily basis, where advantageous. PGW seeks to recoup demand charges for its firm transportation through the FERC approved capacity

release mechanism. The Company also enters into the incremental off systems sales market to generate additional revenue when it is economically advantageous to do so. Further, the Company continues to periodically participate in LNG arrangements that generate margins, which reduce GCR applicable expenses. At all times the Company is studying the market for any economic advantage that can be derived in support of the firm ratepayer. This can take the form of caps and collars on pricing, puts to the system, and short term lending from the system to supplier/marketers.

II. Overview of Supply Services

The Department is responsible for ensuring that there is an adequate supply of natural gas available at all times to meet the requirements of PGW's 500,000 firm customers as well as all interruptible sales customers of the Company. The Department accomplishes this through consultation of its two areas: the Gas Acquisitions and the Gas Control sections. The area interacts on a regular basis with the Gas Planning, Federal Regulatory, State Regulatory and Marketing sections of the Marketing & Supply Services Department. It must also interact with the Gas Processing and Distribution Departments on a regular basis.

The Department is required to maintain an in-depth working knowledge of all facets of the natural gas supply markets. Furthermore, the Department is required to maintain a thorough working knowledge of PGW natural gas facilities security for the purpose of ensuring the operation of a safe and efficient system, which is in accordance with company procedures, and in compliance with federal, state, and local regulations.

III. Organization and Staffing

Director of Supply Services: This person has a twelve-year history in the gas supply services area and two-year history in the gas control area. He has an MBA and BS degree. A background, which takes into account the initial stages of FERC Order 636 and its effect on supply portfolio management.

Director of Gas Supply and Transportation: This person has a nine-year history in the Supply Services area. He has a BA as well as having a natural gas accounting, allocation and confirmation experience under the first stages of FERC Order 636, and its effect on supply portfolio management.

Manager Gas Supply: This person has six-year history in the gas control area as well as experience in the gas-processing department of the Company. He has a MBA and a BS degree. He has direct responsibility for the day-to-day operation of this area.

These three people interact individually and due to their experience provide real time coverage in all situations pertaining to the gas supply portfolio. Reporting to these people are the gas accountants, administrator of gas supply, the coordinator of gas transportation and the gas control area.

Administrator of Gas Supply is responsible for the direct oversight of the gas accountants and coordinator of gas transportation. This person has six years history in the area with expertise in the movement of gas on the interstate pipelines which PGW holds contracts.

Gas Accountants (2) are responsible for the correct payment of all invoices pertaining to natural gas supply and for invoicing and tracking any deals which the area enters. One person has over five years experience while the other has less than one year in the department. These individuals both have BS degrees, one holds a MBA while the other is working towards this goal.

Coordinator of Gas Transportation: Responsible for the nomination and confirmation of both PGW system supply and PGW customers who transport on the system. This person has been in this position for less than one year but has been in the area for over two years in various projects.

Manager of Gas Control: This person has over six years in the area, is responsible for the day-to-day pressure management of the city distribution grid as well as daily confirmation of each day's gas volumes. This acts as a redundancy to the Coordinator position. He supervises the gas control staff and is available for consultation at anytime. He has a BS degree and extends duty in the Distribution Department's network analysis area.

Gas Controllers: These nine people work around the clock monitoring the gas pressures throughout the city as well as the confirmation of the interstate pipeline confirmations.


RECYCLED

Docket No. R-01XXX
Item 53.64 (c)(7)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(7) A list of off system sales, including transportation, storage or capacity releases by the utility at less than the weighted average price of gas, or at less than the original contract cost of transportation, storage or capacity supplied to the utility for its own customers.

Response:

The attached schedules illustrate off system sales and capacity release for the period of April 2000 to March 2001. Schedule 1 (one) reflects all off sales margins for the period of April 2000 to March 2001. Schedule 2 (two) reflects the one off system sales transaction which was done at less than weighed average cost of gas. All capacity release deals are done subject to bid. Schedule 3 (three) illustrates all capacity release credits. Schedule 4 (four) illustrates the individual capacity release transactions which were done at less than the weighed average cost of capacity.

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 1
Item 53.64(C)(7)

Off-System Sales			
MONTH	Total Revenue	Ratepayer Margin	Total Credit To GCR
April-00	$0	$0	$0
May-00	$ 1,133,657	$ 49,387	$1,133,657
Jun-00	$0	$0	$0
Jul-00	$0	$0	$0
Aug-00	$0	$0	$0
Sep-00	$ 166,500	$ 13,209	$166,500
Oct-00	$ 145,500	$ 145,500	$145,500
Nov-00	$ 454,000	$ 165,000	$454,000
Dec-00	$ 1,015,000	$ 883,377	$1,015,000
Jan-01	$0	$0	$0
Feb-01	$0	$0	$0
Mar-01	$ 429,000	$ 361,830	$429,000

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 2
Item 53.64(C)(7)

Off System Sale Profits Per Actual Cost	
Date	11/6/00
Buyer	Reliant
Quantity	100,000 Dth
Sale Price	$4.54 Per Dth
Point of Sale	Storage Inventory
Total Revenue	$454,000
Fuel Cost	$2.89 Per Dth
Actual Fuel Cost	$289,000
RatePayer Margin/ Actual Cost	$165,000

Off System Sale Profits Per Actual Cost	
Quantity	100,000 Dth
Sale Price	$4.54 Per Dth
Total Revenue	$454,000
Nov. 2000 CG WACOG	$4.65 Per Dth
Actual Fuel Cost	$464,800
RatePayer Margin/ Wacog	($10,800)

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

Schedule 3
Item 53.64(C)(7)

	Capacity Release		
	Total	Total	Total
	TGPL	TETCO	GCR
MONTH	Credits	Credits	Credits
April-00	$9,800	$20,160	$29,960
May-00	$0	$41,425	$41,425
Jun-00	$33,500	$218,005	$251,505
Jul-00	$81,527	$52,833	$134,361
Aug-00	$27,250	$188,290	$215,540
Sep-00	$23,000	$232,103	$255,103
Oct-00	$29,450	$79,112	$108,562
Nov-00	$132,800	$34,200	$167,000
Dec-00	$0	$0	$0
Jan-01	$0	$0	$0
Feb-01	$176,400	$2,160	$178,560
Mar-01	$257,300	$6,975	$264,275

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

M / YR	PIPELINE	PATH	RECALL STATUS	MONTHLY VOLUME DTH	TOTAL MONTHLY CREDIT	CREDIT DTH	TOTAL GCR CREDIT	REPLACEMENT SHIPPER
April-00	TRANSCO	Z3 -Z6	N	96,000	$9,800.00	$0.1021	$9,800.00	TRIAD ENERGY
	TETCO	WLA - M-3	N	540,000	$10,080.00	$0.0187	$10,080.00	Grays Ferry
	TETCO	WLA - M-3	N	540,000	$10,080.00	$0.0187	$10,080.00	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$3,600.00	$0.0065	$3,600.00	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$3,600.00	$0.0065	$3,600.00	Grays Ferry
	TETCO	WLA - M-3	N	402,318	$12,069.54	$0.0300	$12,069.54	OG&E
	TETCO	WLA - M-3	N	738,513	$22,155.39	$0.0300	$22,155.39	OG&E
May-00	TETCO	WLA - M-3	N	540,000	$86,922.00	$0.1610	$86,922.00	Grays Ferry
	TETCO	WLA - M-3	N	540,000	$86,922.00	$0.1610	$86,922.00	Grays Ferry
	TETCO	WLA - M-3	N	389,340	$15,573.60	$0.0400	$15,573.60	OG&E
	TETCO	WLA - M-3	N	714,690	$28,587.60	$0.0400	$28,587.60	OG&E
June-00	TRANSCO	Z3 -Z6	N	300,000	$33,500.00	$0.1117	$33,500.00	CPLC
	TETCO	WLA - M-3	N	540,000	$86,922.00	$0.1610	$86,922.00	Grays Ferry
	TETCO	WLA - M-3	N	540,000	$86,922.00	$0.1610	$86,922.00	Grays Ferry
	TETCO	WLA - M-3	N	389,340	$15,573.60	$0.0400	$15,573.60	OG&E
	TETCO	WLA - M-3	N	714,690	$28,587.60	$0.0400	$28,587.60	OG&E
July-00	TRANSCO	Z3 -Z6	N	155,000	$ 18,480.00	$0.1192	$18,480.00	RELIANT ENERGY
	TRANSCO	Z3 -Z6	N	155,000	$ 17,729.00	$0.1144	$17,729.00	RELIANT ENERGY
	TRANSCO	Z3 -Z6	N	155,000	$ 17,729.00	$0.1144	$17,729.00	COOK INLET
	TRANSCO	Z3 -Z6	N	155,000	$ 16,210.00	$0.1046	$16,210.00	CORAL ENERGY
	TRANSCO	Z3 -Z6	N	46,614	$ 11,379.30	$0.2441	$11,379.30	TRIAD ENERGY
	TETCO	WLA - M-3	N	558,000	$3,600.00	$0.0065	$3,600.00	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$3,600.00	$0.0065	$3,600.00	Grays Ferry
	TETCO	WLA - M-3	N	402,318	$16,092.72	$0.0400	$16,092.72	OG&E
	TETCO	WLA - M-3	N	738,513	$29,540.52	$0.0400	$29,540.52	OG&E
August-00	TRANSCO	Z3 -Z6	N	155,000	$ 17,750.00	$0.1145	$17,750.00	PERRY GAS
	TRANSCO	Z3 -Z6	N	71,127	$ 11,177.10	$0.1571	$11,177.10	TRIAD ENERGY
	TETCO	WLA - M-3	N	558,000	$93,971.00	$0.1684	$93,971.00	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$93,971.00	$0.1684	$93,971.00	Grays Ferry
	TETCO	WLA - M-3	N	402,318	$16,092.72	$0.0400	$16,092.72	OG&E
	TETCO	WLA - M-3	N	738,513	$29,540.52	$0.0400	$29,540.52	OG&E

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending March 31, 2001

M / YR	PIPELINE	PATH	RECALL STATUS	MONTHLY VOLUME DTH	TOTAL MONTHLY CREDIT	CREDIT DTH	TOTAL GCR CREDIT	REPLACEMENT SHIPPER
September-00	TRANSCO	Z3 -Z6	N	300,000	$ 23,000.00	$0.0767	$23,000.00	TPC
	TETCO	WLA - M-3	N	540,000	$93,971.00	$0.1740	$93,971.00	Grays Ferry
	TETCO	WLA - M-3	N	540,000	$93,971.00	$0.1740	$93,971.00	Grays Ferry
	TETCO	WLA - M-3	N	389,340	$15,573.60	$0.0400	$15,573.60	OG&E
	TETCO	WLA - M-3	N	714,690	$28,587.60	$0.0400	$28,587.60	OG&E
October-00	TRANSCO	Z3 -Z6	N	155,000	$ 14,950.00	$0.0965	$14,950.00	PANCANADIAN
	TRANSCO	Z3 -Z6	N	155,000	$ 16,500.00	$0.1065	$16,500.00	PERRY GAS
	TETCO	WLA - M-3	N	558,000	$20,340.00	$0.0365	$20,340.00	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$20,340.00	$0.0365	$20,340.00	Grays Ferry
	TETCO	WLA - M-3	N	402,318	$16,092.72	$0.0400	$16,092.72	OG&E
		WLA - M-3	N	738,513	$29,540.52	$0.0400	$29,540.52	OG&E
	TRANSCO	Z3 -Z6	Y	160,000	$ 34,064.54	$0.2129	$34,064.54	OGE ENERGY
November-00	TRANSCO	Z3 -Z6	Y	160,000	$ 36,753.44	$0.2297	$36,753.44	SPRAGUE ENERGY
	TRANSCO	Z3 -Z6	Y	320,000	$ 68,090.56	$0.2128	$68,090.56	TPC
	TETCO	WLA - M-3	Y	270,000	$19,620.00	$0.0727	$19,620.00	COOK INLET
	TETCO	WLA - M-3	Y	252,000	$18,060.00	$0.0717	$18,060.00	PANCANADIAN
				0	$0.00	0	$0.00	
December-00								
				0	$0.00	0	$0.00	
January-01								
February-01	TRANSCO	Z3 -Z6	Y	280,000	$ 64,775.00	$0.2313	$64,775.00	OGE ENERGY
	TRANSCO	Z3 -Z6	Y	280,000	$ 67,817.00	$0.2422	$67,817.00	SPRAGUE ENERGY
	TRANSCO	Z3 -Z6	Y	280,000	$ 61,733.00	$0.2205	$61,733.00	TPC
	TETCO	WLA - M-3	Y	216,000	$2,854.26	$0.0132	$2,854.26	CORAL ENERGY
March-01	TRANSCO	Z3 -Z6	Y	310,000	$ 64,775.00	$0.2090	$64,775.00	OGE ENERGY
	TRANSCO	Z3 -Z6	Y	310,000	$ 67,817.00	$0.2188	$67,817.00	SPRAGUE ENERGY
	TRANSCO	Z3 -Z6	Y	620,000	$ 123,466.00	$0.1991	$123,466.00	TPC
	TETCO	WLA - M-3	Y	414,000	$6,376.94	$0.0154	$6,376.94	CINERGY


RECYCLED

Docket No. R-01XXX
Item 53.64 (c)(8)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(8) A list of agreements to transport gas by the utility through its system, for other utilities, pipelines or jurisdictional customers including the quantity and price of the transportation.

Response:

Please see the attached list of gas transportation agreements for PGW's jurisdictional customers.

Transportation Contracts

Contract #	Maximum Company Obligation Dth/D	Rate
1	/1	/2
2	881	/2
3	60,000	/2
4	1,243	/2
5	10,000	/2
6	12,000	/2
7	50,000	/2
8	50,000	/2
9	250	/2
	184,374	

Notes:

/1 Customer is no longer a GTS customer.

/2 PGW currently has 7 GTS customers with 9 contracts. PGW believes that due to the small number of customer in this rate class, it would be impossible to publish the individual rates without violating customer confidentiality.

Docket No. R-01XXX
Item 53.64 (c)(9)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

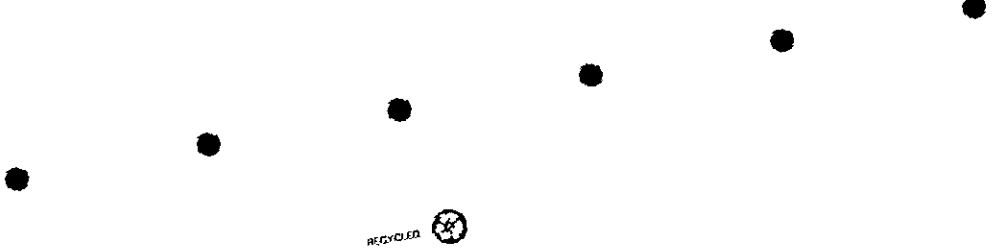
(9) A schedule depicting historic monthly end-user transportation through-put by customer. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to § 5.423 (relating to orders to limit availability of proprietary information).

Response:

Please see the attached schedule depicting the monthly end-user transportation through-put by customer.

The Philadelphia Gas Works
1307(f) - 2000
Apr-2000 - Mar-2001 (dth)

No. (1)	Service (2)	Apr-00 (3)	May-00 (4)	Jun-00 (5)	Jul-00 (6)	Aug-00 (7)	Sep-00 (8)	Oct-00 (9)	Nov-00 (10)	Dec-00 (11)	Jan-01 (12)	Feb-01 (13)	Mar-01 (14)
1	GTS-I	12,598	10,307	12,500	15,557	18,990	16,682	21,511	22,878	23,640	12,158	8,458	13,065
2	GTS-I	163,178	307	923	5,791	153,204	13,901	81,493	90,510	0	167	1,312	10
3	GTS-F	8,556	9,552	7,448	8,524	9,016	8,820	10,349	9,867	9,775	9,587	9,151	10,424
4	GTS-I	0	0	0	0	0	0	0	0	0	0	0	0
5	GTS-I	154,810	141,543	137,058	141,863	36,232	0	0	112,689	0	0	0	0
6	GTS-F	0	0	0	0	0	0	2,686	0	0	0	0	1,345
7	GTS-F	1,026,563	841,316	968,253	967,800	986,804	833,684	321,458	686,312	718,653	120,125	372,429	799,996
8	GTS-I	8,604	7,585	3,091	10,897	9,919	7,437	5,898	7,874	7,011	94	1	0


RECYCLED

Docket No. R-01XXX
Item 53.64 (c)(10)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the *Consumer* Advocate, Small Business Advocate and to intervenors upon request:

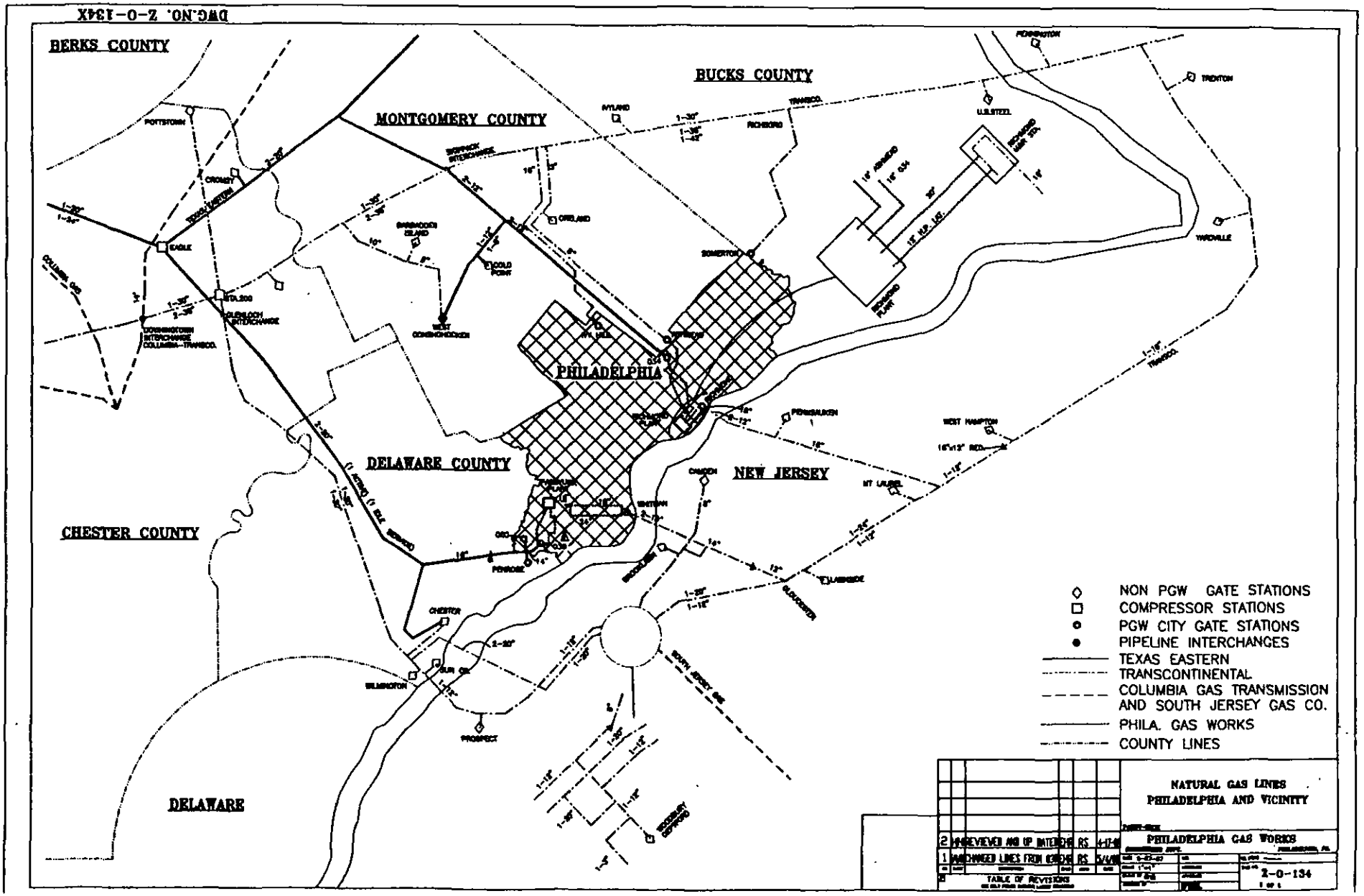
(10) A schematic system map, locating and identifying by name, the pressure and capacity of all interstate or intrastate transmission pipeline connections, compressor stations, utility transmission or distribution mains 6 inches or larger in size, storage facilities, including maximum daily injection and withdrawal rates, production fields, and each individual supply or transportation customer which represents 5% or more of total system throughput in a month. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to § 5.423.

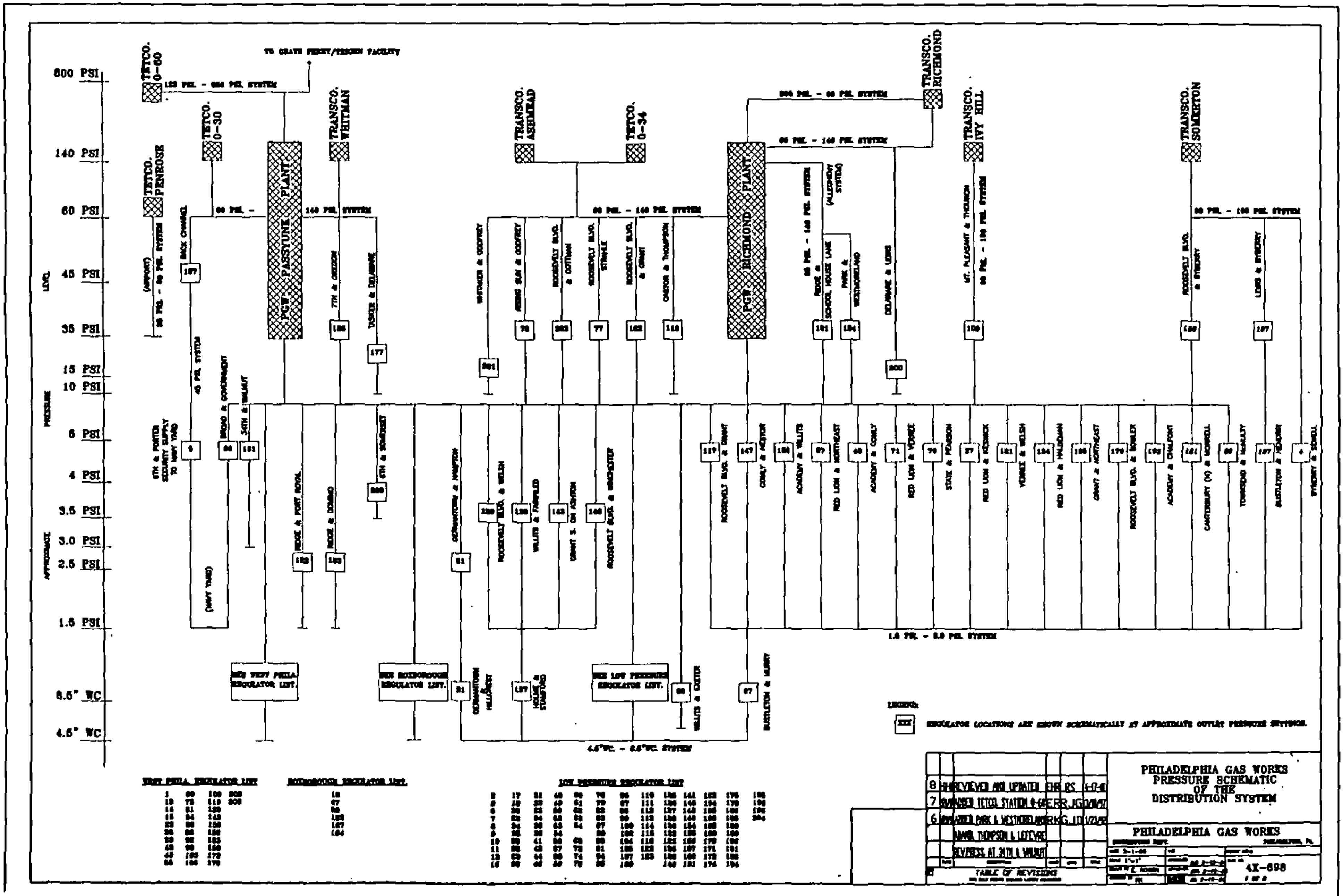
Response:

Please note that PGW's service territory is confined solely to the city/county of Philadelphia, PA. The city has an extensive low pressure system to provide service to its predominantly residential customer base. Much of the low pressure system is comprised of distribution mains that are six (6) inches or greater in diameter. The number of maps that would need to be produced to identify all of these facilities is significant. PGW will make these maps available for inspection at its location upon reasonable requests.

Schedule 1 – Map of interstate pipelines that provide service to PGW.
Schedule 2 – Detailed flow diagram of PGW's system.
Schedule 3 – Detailed listing of PGW gate stations including pressure and capacity information.
Schedule 4 - PGW plant capacities.

DWG.NO. 2-O-134X





PHILADELPHIA GAS WORKS
PRESSURE SCHEMATIC
OF THE
DISTRIBUTION SYSTEM
PHILADELPHIA GAS WORKS
4X-698
TABLE OF REVISIONS
800 PSI
140 PSI
60 PSI
45 PSI
35 PSI
15 PSI
10 PSI
6 PSI
4 PSI
3.5 PSI
3.0 PSI
2.5 PSI
1.5 PSI
6.5" WC
4.5" WC
APPROXIMATE PRESSURE LEVEL
TETCO. 0-60
TETCO. 0-30
TETCO. PENROSE
TRANSCO. WHITMAN
TRANSCO. ASHMEAD
TETCO. 0-34
TRANSCO. RICHMOND
TRANSCO. IVY HILL
TRANSCO. SOMERTON
PGW PASSYUNK PLANT
PGW RICHMOND PLANT
LEGEND:

PGW GATE STATIONS

	0-30	0-60	0-34	PENROSE	WHITMAN	RICHMOND	ASHMEAD	IVY HILL	SOMERTON
MAX. WINTER FLOW (MMSCFD)	92	92	137	5.00	104	126	40	34	36
MAX SUMMER FLOW (MMSCFD)	107	107	137	5.00	60	70	41	45	42
MAX INLET PRESSURE (PSIG)	800	800	800	800	800	800	800	800	800
MAX OUTLET PRESSURE (PSIG)	140	656	140	60	140	140	140	100	100

NOTES: THE COMBINED FLOW FROM RICHMOND AND WHITMAN CANNOT EXCEED 130 MMSCFD DURING THE SUMMER PERIOD (TARIFF)
THE COMBINED FLOW FROM RICHMOND AND WHITMAN CANNOT EXCEED 142 MMSCFD DURING THE WINTER PERIOD (TARIFF)
THE COMBINED FLOW FROM ASHMEAD AND IVY HILL CANNOT EXCEED 64 MMSCFD DURING THE WINTER PERIOD (TARIFF)
THE COMBINED FLOW FROM ASHMEAD AND IVY HILL CANNOT EXCEED 60 MMSCFD DURING THE SUMMER PERIOD (TARIFF)
THE COMBINED FLOW FROM 0-30 AND 0-60 CANNOT EXCEED 133 MMSCFD
DO NOT EXPECT MAX OUTLET PRESSURE AT MAX FLOW.
WINTER PERIOD: OCTOBER THTOUGH APRIL (TARIFF)
SUMMER PERIOD: MAY THROUGH SEPTEMBER (TARIFF)

FLOW DATA GATHERED FROM: PGW DESIGN HOUR LOAD REQUIREMENTS, HIGH PRESSURE DISTRIBUTION SYSTEM 2000-2001
GROUND RULES SPREADSHEET.
TRANSCO TARIFF, THIRD REVISED VOLUME NO. 1, SECOND REVISED SHEET NO. 320, EFFECTIVE 11-1-1998

1 REVISED PRESSURES

TABLE OF REVISIONS

PHILADELPHIA GAS WORKS
GATE STATIONS
MAX FLOWS, INLET, OUTLET,
SUMMER & WINTER PERIODS

PHILADELPHIA GAS WORKS

4X-698

Plant Capacities

Maximum LNG Storage	4,299,000 MCF	
Usable LNG Storage	3,934,000 MCF	
LNG Liquefaction Rate		
Plant Rates Capacity	23,500 MCFD	
Plant Lifetime Average	17,931 MCFD	
Plant 2000 Rate	21,685 MCFD	
Vaporization Capacity*	Planned Usage	Maximum
Richmond	350,000 MCFD	450,000 MCFD
Passyunk	45,000 MCFD	90,000 MCFD

*Note: LNG plant vaporization capacity is stated independent of distribution system dynamics and system pressure requirements. Depending on distribution system pressures, flow and total load requirements , it may not be possible or prudent to achieve the above stated vaporization rates under various conditions.

Docket No. R-01XXX
Item 53.64 (c)(11)

Philadelphia Gas Works

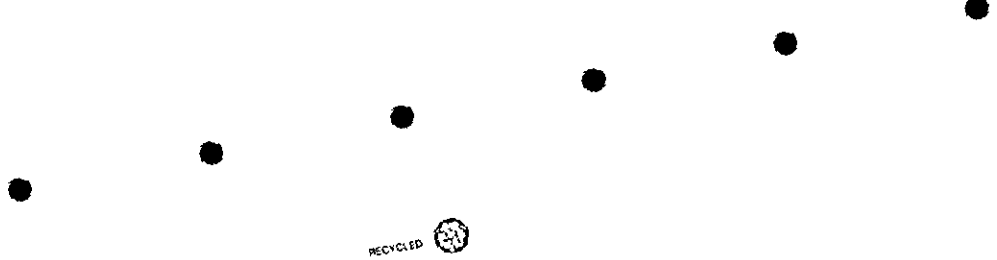
Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(11) If any rate structure or rate allocation changes are to be proposed, a detailed explanation of each proposal, reasons therefore, number of customers affected, net effect on each customer class, and how the change relates to or is justified by changes in gas costs proposed in the Section 1307(f) tariff filing. Explain how gas supply, transportation and storage capacity costs are allocated to customers which are primarily nonheating, interruptible or transportation customers.

Response:

PGW is not proposing any rate structure or rate allocation changes in the instant proceeding, therefore, no testimony has been provided in this May 1, filing. However, PGW would like to reserve its right to file testimony regarding gas procurement strategies in its June 1 final filing. PGW avers that the filing of testimony related to future gas procurement strategies in the June 1 filing will not prejudice any party to this proceeding.



Docket No. R-01XXX
Item 53.64 (c)(12)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(12) A schedule depicting the most recent 5-year consecutive 3-day peak data by customer class (or other historic peak day data used for system planning), daily volumetric throughput by customer class (including end-user transportation throughput), gas interruptions and high, low and average temperature during each day.

Response:

Schedule 1 – Three-day peak for FY 96-97 through 00-01.
Please note that PGW performs its three-day peak analysis by total sendout and does not identify Residential, Commercial or Industrial usage. However, PGW does perform a peak day analysis provided in 53.64(c)(13) which addresses firm sendout requirements.

Schedule 2 – Identifies a listing of gas interruptions, their duration and the high, low and average temperatures for each day that the interruption was in effect.

GAS PROCESSING DEPARTMENT'S
3 DAY PEAK ANALYSIS

Prepared for William Munzter, Marketing Department

Winter Peak Season	Date	Average Temperature	Hi Temperature	Low Temperature	Total Sendout (mcfs)	Firm Sendout (mcfs)	Cogen Sendout (mcfs)	LBS Sendout (mcfs)	BPS Sendout (mcfs)	GTS Sendout (mcfs)
1995-1996	Jan 6	16	19	10	610,315	555,869	21	20,604	20,098	13,723
1995-1996	Jan 7	18	24	12	602,358	546,913	21	20,370	18,900	16,154
1995-1996	Jan 8	22	26	19	584,150	529,180	116	19,773	19,412	15,669
1996-1997	Jan 17	13	16	10	632,069	588,114	0	14,388	25,163	4,404
1996-1997	Jan 18	12	17	8	661,715	618,675	0	13,420	25,843	3,777
1996-1997	Jan 19	19	22	9	604,543	566,643	0	12,624	23,275	2,001
1997-1998	Dec 30	33	37	28	414,689	381,376	250	14,053	18,158	853
1997-1998	Dec 31	25	36	18	482,106	448,857	190	11,959	20,361	739
1997-1998	Jan 1	30	39	23	458,461	424,927	265	12,338	20,077	854
1998-1999	Jan 4	23	31	13	513,894	475,659	270	12,350	22,455	3,160
1998-1999	Jan 5	23	30	17	541,880	502,667	280	12,946	22,961	3,026
1998-1999	Jan 6	33	37	23	492,533	451,307	280	14,124	22,983	3,839
1999-2000	Jan 26	25	33	15	524,100	481,941	340	17,370	20,518	3,931
1999-2000	Jan 27	16	21	12	629,033	582,621	350	18,791	23,258	4,013
1999-2000	Jan 28	21	25	16	602,336	556,101	355	18,340	23,722	3,818
2000-2001	Dec 24	29	37	21	444,640	421,627	0	19,800	2,550	663
2000-2001	Dec 25	20	26	17	520,086	515,045	0	1,376	2,831	834
2000-2001	Dec 26	25	30	22	486,331	478,958	0	1,673	4,682	1,018

Interruptions Over 5 Year Period (Sept. 1, 1996 through August 31, 2001)

Temperature Information

Date	High	Low	Average	Date	High	Low	Average
12/24/96	62	30	47	1/1/01	36	25	30
12/25/96	37	28	32	1/2/01	29	20	24
12/26/96	36	28	34	1/3/01	37	26	30
12/27/96	52	35	42	1/4/01	38	24	31
12/28/96	53	40	48	1/5/01	38	29	32
12/29/96	56	45	51	1/6/01	40	28	34
12/30/96	48	35	41	1/7/01	47	35	39
12/31/96	38	15	27	1/8/01	42	31	37
1/1/97	35	15	28	1/9/01	34	26	30
1/2/97	48	35	43	1/10/01	40	28	34
1/3/97	60	47	52	1/11/01	51	31	41
1/4/97	52	44	47	1/12/01	48	28	35
1/5/97	62	44	54	1/13/01	47	29	37
1/6/97	52	30	41	1/14/01	44	35	40
1/7/97	37	26	30	1/15/01	44	37	39
1/8/97	39	27	32	1/16/01	46	36	40
1/9/97	35	26	31	1/17/01	45	32	38
1/10/97	41	26	34	1/18/01	39	35	37
12/20/00	32	23	26	1/19/01	42	36	39
12/21/00	36	29	32	1/20/01	36	23	31
12/22/00	34	12	21	1/21/01	32	22	27
12/23/00	31	19	25	1/22/01	39	23	29
12/24/00	37	21	29	1/23/01	41	29	34
12/25/00	26	17	20	1/24/01	47	32	38
12/26/00	30	22	25	1/25/01	40	24	31
12/27/00	34	23	29	1/26/01	39	28	33
12/28/00	28	17	22	1/27/01	42	21	37
12/29/00	34	23	28	1/28/01	40	28	34
12/30/00	31	23	26	1/29/01	42	34	37
12/31/00	37	24	29	1/30/01	58	36	47
				1/31/01	53	39	44

Interruptions Over 5 Year Period (Sept. 1, 1996 through August 31, 2001)

Date	BPS-S	BPS-H /1	BPS-L	LBS-S	LBS-L	LBS - XL
12/24/96				X	X	X
12/25/96				X	X	X
12/26/96				X	X	X
12/27/96				X	X	X
12/28/96				X	X	X
12/29/96				X	X	X
12/30/96				X	X	X
12/31/96				X	X	X
1/1/97				X	X	X
1/2/97				X	X	X
1/3/97				X	X	X
1/4/97				X	X	X
1/5/97				X	X	X
1/6/97				X	X	X
1/7/97				X	X	X
1/8/97				X	X	X
1/9/97				X	X	X
1/10/97				X	X	X
12/20/00	X	X	X	X	X	X
12/21/00	X	X	X	X	X	X
12/22/00	X	X	X	X	X	X
12/23/00	X	X	X	X	X	X
12/24/00	X	X	X	X	X	X
12/25/00	X	X	X	X	X	X
12/26/00	X	X	X	X	X	X
12/27/00	X	X	X	X	X	X
12/28/00	X	X	X	X	X	X
12/29/00	X	X	X	X	X	X
12/30/00	X	X	X	X	X	X
12/31/00	X	X	X	X	X	X

BPS-S	BPS-H /1	BPS-L	LBS-S	LBS-L	LBS - XL	
1/1/01	X	X	X	X	X	X
1/2/01	X	X	X	X	X	X
1/3/01	X	X	X	X	X	X
1/4/01	X	X	X	X	X	X
1/5/01	X	X	X	X	X	X
1/6/01	X	X	X	X	X	X
1/7/01	X	X	X	X	X	X
1/8/01	X	X	X	X	X	X
1/9/01	X	X	X	X	X	X
1/10/01	X	X	X	X	X	X
1/11/01	X	X	X	X	X	X
1/12/01	X	X	X	X	X	X
1/13/01	X	X	X	X	X	X
1/14/01	X	X	X	X	X	X
1/15/01	X	X	X	X	X	X
1/16/01	X	X	X	X	X	X
1/17/01	X	X	X	X	X	X
1/18/01	X	X	X	X	X	X
1/19/01	X	X	X	X	X	X
1/20/01	X	X	X	X	X	X
1/21/01	X	X	X	X	X	X
1/22/01	X	X	X	X	X	X
1/23/01	X	X	X	X	X	X
1/24/01	X	X	X	X	X	X
1/25/01	X	X	X	X	X	X
1/26/01	X	X	X	X	X	X
1/27/01	X	X	X	X	X	X
1/28/01	X	X	X	X	X	X
1/29/01	X	X	X	X	X	X
1/30/01	X	X	X	X	X	X
1/31/01	X	X	X	X	X	X

Notes: X - Denotes that service to this rate schedule was interrupted on the specified date.
/1 BPS-H was not in existence until June 2000.

Docket No. R-01XXX
Item 53.64 (c)(13)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending August 31, 2001

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(13) Identification and support for any peak day methodology used to project future gas demands and studies supporting the validity of the methodology.

Response:

Please see the attached Peak Day analysis and discussion. Additionally, in 1997, ICF Kaiser prepared a *Gas Supply Study* on PGW's behalf. The final study is attached as PGW's response to Item 53.64(c)(14). In addition to that study, ICF Kaiser was also asked to review PGW's peak day methodology as a supplemental study. The results of that study are attached. PGW's analysis methodology has not changed since the study was completed.

Peak Day Analysis

PGW performs a peak day analysis on an annual basis to determine its projected sendout requirements during peak conditions. Essentially this process is completed by collecting sendout and average temperature data for all days where the temperature is below 32 degrees Fahrenheit, excluding holidays and weekends. All transportation and interruptible volumes are removed from total sendout to arrive at firm sendout on a daily basis.

Generally, the company would elect to utilize current year data, however, common statistical practices warrant that no less than thirty (30) data points be utilized in the analysis to ensure its integrity. Therefore, it is often desirable to use data from multiple consecutive years. PGW attempts to limit the population of data points to three (3) where possible to reflect the most current consumption behaviors. For this analysis, PGW has utilized data for the three (3) year period September 1, 1998 through March 31, 2001. This period yielded 53 data points where the average temperature was at or below 32 degrees Fahrenheit.

Degree days are calculated by subtracting the average daily temperature from sixty five (65).

A standard linear regression was performed on the data using the calculated degree days and the actual firm daily sendout information. Additionally, in order to confirm the accuracy of the analysis, and to smooth the charting of the data, a quadratic and a cubic regression analysis were also completed.

A resulting R^2 (Correlation Coefficient) indicates that there is an 81.44% correlation between firm sendout and degree days. Since PGW's General Service rate schedule includes some commercial and industrial process load, the 81% correlation is acceptable. If the commercial and industrial load were removed from the firm sendout, it is expected that the correlation coefficient would be closer to 100% correlation. Historically, prior period analyses indicated a 79% to 85% correlation. The multiple regression correlation coefficient, R2, is a measure of the proportion of variability explained by, or due to the regression (linear relationship) in a sample of paired data. It is a number between zero and one and a value close to zero suggests a poor model.

To verify the level of confidence we can ascribe to the model, we developed the attached Linear Regression Confidence Level Table. Essentially, this table compares the actual versus projected sendout to determine the level of variance expressed as a standard deviation. A standard deviation represents the positive square root of the variance where the variance simply represents the dispersion about the mean. In this analysis the sample standard deviation is 22,708 Mcf.

To determine the level where the relationship between consumption and degree days is "significant" it is necessary to incorporate Degrees of Freedom and the Student's T Statistic. Degrees of freedom refer to how many cases in the sample are free to vary.

The sample looses one degree of freedom for each estimated parameter. Thus, with a sample of 100 paired values and two estimated parameters (one for the constant and one for the coefficient of "degree days"), there are 100 – 2 = 98 degrees of freedom. In this analysis, we had 53 data points, therefore, there were 51 Degrees of Freedom.

The critical value is the value the Student's T statistic must equal or exceed to conclude that there is a 97.5% chance that the relationship between consumption and degree days is not 0. A Student's T statistic of 2.00 is required for a sample with 98 degrees of freedom.

The Student's T statistic is the distribution of the (mean/standard deviation) of a sample of normal distributed values with unknown variance. In this case, it is a measure of the likelihood that the estimated coefficient for "degree days" is actually zero. The farther the statistic is from 0, the greater the likelihood that the sample pairs are related. The Student-T distribution varies with the number of independent values (Degrees of Freedom) from which the variance is calculated. For this example, the T-statistic is calculated as SQRT((R2*(degrees of freedom)/(1- R2)) = 14.95942789. The calculated Student's T statistic of 14.95942789exceeds the critical value of 2.00. Thus, we can conclude that the relationship between consumption and degree days is "significant" at the 97.5% level.

Finally, based upon the models developed, it can be determined that the company's projected peak day sendout should be set at 768,086 Mcf per day at 0 degrees Fahrenheit. This calculation is performed using the X Coefficient (i.e. slope) multiplied by the number of degree days and adding the Constant (Y Intercept). In this case the calculation was performed at a temperature of 0 degrees Fahrenheit and at 15 degrees Fahrenheit.

Winter 98-99 Through 00-01 Data for Daily Temperatures <= 32 Degrees Fahrenheit

W/O Holidays, Weekends

Day	Date	Month	Fiscal Year	Daily Temp	Degree Days X	X^2	X^3	Actual Firm Sendout (Mcf)	Linear Projected Firm Sendout (Mcf)	Quadratic Projected Firm Sendout (Mcf)	Cubic Projected Firm Sendout (Mcf)
Friday	17	Mar.	99/00	32	33	1,089	35,937	326,961	393,926	396,661	393,447
Wednesday	1	Dec.	99/00	32	33	1,089	35,937	404,239	393,926	396,661	393,447
Wednesday	26	Jan.	99/00	25	40	1,600	64,000	481,932	475,774	473,249	473,122
Tuesday	1	Feb.	99/00	31	34	1,156	39,304	441,275	405,619	406,844	406,836
Monday	31	Jan.	99/00	32	33	1,089	35,937	436,322	393,926	396,661	393,447
Thursday	3	Feb.	99/00	31	34	1,156	39,304	437,969	405,619	406,844	406,836
Thursday	20	Jan.	99/00	25	40	1,600	64,000	477,350	475,774	473,249	473,122
Thursday	13	Jan.	99/00	28	37	1,369	50,653	432,575	440,696	438,910	441,857
Tuesday	8	Feb.	99/00	30	35	1,225	42,875	428,508	417,311	417,280	419,241
Friday	14	Jan.	99/00	24	41	1,681	68,921	496,742	487,466	485,201	483,588
Tuesday	28	Dec.	99/00	31	34	1,156	39,304	416,603	405,619	406,844	406,836
Wednesday	2	Feb.	99/00	28	37	1,369	50,653	466,785	440,696	438,910	441,857
Tuesday	18	Jan.	99/00	20	45	2,025	91,125	559,262	534,236	535,533	530,707
Friday	28	Jan.	99/00	21	44	1,936	85,184	556,101	522,544	522,571	517,762
Tuesday	25	Jan.	99/00	28	37	1,369	50,653	459,964	440,696	438,910	441,857
Thursday	27	Jan.	99/00	16	49	2,401	117,649	582,621	581,006	589,908	595,280
Friday	21	Jan.	99/00	16	49	2,401	117,649	595,717	581,006	589,908	595,280
Friday	8	Jan.	98/99	31	34	1,156	39,304	432,594	405,619	406,844	406,836
Tuesday	23	Feb.	98/99	29	36	1,296	46,656	458,972	429,004	427,969	430,852
Friday	15	Jan.	98/99	30	35	1,225	42,875	431,805	417,311	417,280	419,241
Thursday	7	Jan.	98/99	28	37	1,369	50,653	434,310	440,696	438,910	441,857
Wednesday	23	Dec.	98/99	25	40	1,600	64,000	439,124	475,774	473,249	473,122
Monday	4	Jan.	98/99	23	42	1,764	74,088	475,235	499,159	497,405	494,391
Monday	11	Jan.	98/99	29	36	1,296	46,656	460,371	429,004	427,969	430,852
Thursday	31	Dec.	98/99	26	39	1,521	59,319	476,401	464,081	461,550	462,804
Monday	8	Mar.	98/99	25	40	1,600	64,000	444,632	475,774	473,249	473,122
Wednesday	30	Dec.	98/99	24	41	1,681	68,921	460,360	487,466	485,201	483,588
Monday	22	Feb.	98/99	24	41	1,681	68,921	480,589	487,466	485,201	483,588
Tuesday	22	Dec.	98/99	30	35	1,225	42,875	357,135	417,311	417,280	419,241
Thursday	14	Jan.	98/99	28	37	1,369	50,653	472,871	440,696	438,910	441,857
Thursday	24	Dec.	98/99	29	36	1,296	46,656	411,314	429,004	427,969	430,852
Tuesday	5	Jan.	98/99	23	42	1,764	74,088	502,157	499,159	497,405	494,391
Thursday	25	Jan.	00/01	31	34	1,156	39,304	399,075	405,619	406,844	406,836
Monday	18	Dec.	00/01	30	35	1,225	42,875	397,489	417,311	417,280	419,241
Wednesday	21	Feb.	00/01	32	33	1,089	35,937	369,974	393,926	396,661	393,447
Thursday	23	Nov.	00/01	32	33	1,089	35,937	372,786	393,926	396,661	393,447
Wednesday	6	Dec.	00/01	32	33	1,089	35,937	387,999	393,926	396,661	393,447
Wednesday	22	Nov.	00/01	31	34	1,156	39,304	396,409	405,619	406,844	406,836
Thursday	21	Dec.	00/01	32	33	1,089	35,937	392,478	393,926	396,661	393,447
Thursday	4	Jan.	00/01	31	34	1,156	39,304	416,936	405,619	406,844	406,836
Friday	5	Jan.	00/01	32	33	1,089	35,937	399,081	393,926	396,661	393,447
Tuesday	9	Jan.	00/01	30	35	1,225	42,875	415,039	417,311	417,280	419,241
Tuesday	2	Jan.	00/01	24	41	1,681	68,921	482,801	487,466	485,201	483,588
Tuesday	26	Dec.	00/01	25	40	1,600	64,000	479,001	475,774	473,249	473,122
Wednesday	20	Dec.	00/01	26	39	1,521	59,319	446,239	464,081	461,550	462,804
Wednesday	3	Jan.	00/01	30	35	1,225	42,875	437,794	417,311	417,280	419,241
Monday	1	Jan.	00/01	30	35	1,225	42,875	421,003	417,311	417,280	419,241
Friday	29	Dec.	00/01	28	37	1,369	50,653	426,519	440,696	438,910	441,857
Friday	22	Dec.	00/01	21	44	1,936	85,184	510,670	522,544	522,571	517,762
Thursday	28	Dec.	00/01	22	43	1,849	79,507	498,294	510,851	509,862	505,720
Monday	22	Jan.	00/01	29	36	1,296	46,656	417,590	429,004	427,969	430,852
Wednesday	27	Dec.	00/01	29	36	1,296	46,656	416,465	429,004	427,969	430,852
Thursday	22	Feb.	00/01	24	41	1,681	68,921	473,537	487,466	485,201	483,588

Count 53

Firm Sendout Projection Based Data From 09-99 Through 00-01
Data for Daily Temperatures <= 32 Degrees Fahrenheit

R Squared	Increase	Student's T	Degrees of Freedom	Critical Value	@ 97.5% Significant
0.814400	*0.81440000*	*14.95942789*	*51*	*2.00*	Yes
0.816658	0.00225800	0.78472229	50	2.02	No
0.819253	0.00259500	0.83874737	49	2.02	No

Degrees of Freedom	51	50	49
97.5% Significance Level	2.00	2.02	2.02
95.0% Significance Level	1.67	1.68	1.68

Linear Projection at Zero Degrees Fahrenheit	768,086	Mcf
Linear Projection at 15 Degrees Fahrenheit	592,699	Mcf

*Student's T = Square Root[(Increase * Degrees of Freedom)/(1 - R Squared)]*

*Linear SO = Constant + (X * X Coefficient)*

*Quadratic SO = Constant + (X * X Coeff) + (X 1u2 * X 1u2 Coeff)*

*Cubic SO = Constant + (X * X Coeff) + (X 1u2 * X 1u2 Coeff) + (X 1u3 * X 1u3 Coeff)*

Regression Results

Winter 98-99 Through 00-01

Based On Data for Daily Temperatures <= 32 Degrees Fahrenheit

Linear			Quadratic			Cubic			
Regression Output:			Regression Output:			Regression Output:			
Constant		8073.729	Constant		202323.2	Constant		-1833982	
Std Err of Y Est		23148.62	Std Err of Y Est		23236.31	Std Err of Y Est		23305.52	
R Squared		0.814400	R Squared		0.816658	R Squared		0.819253	
No. of Observations		53	No. of Observations		53	No. of Observations		53	
Degrees of Freedom		51	Degrees of Freedom		50	Degrees of Freedom		49	
X Coefficient(s)	11692.5	126.3043	X Coefficient(s)	1720.98	126.3043	X Coefficient(s)	155274.6	-3696.93	31.4252
Std Err of Coef.	781.6144	160.9563	Std Err of Coef.	12731.44	160.9563	Std Err of Coef.	183524.3	4561.242	37.46776

Linear Regression Utilizing FY 00-01 Data Only

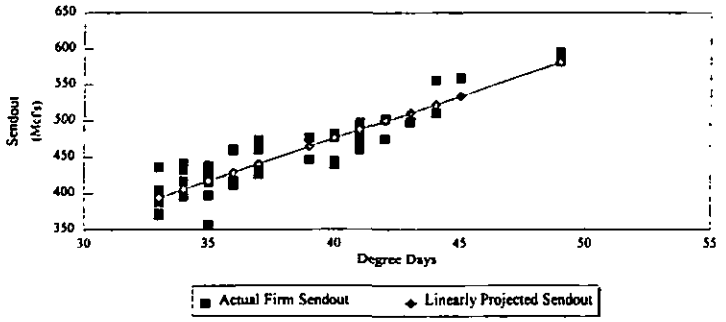
Regression Output:		
Constant		19786.99
Std Err of Y Est		11311.42
R Squared		0.926995
No. of Observations		21
Degrees of Freedom		19
X Coefficient(s)	11180.17	
Std Err of Coef.	719.7976	

Regression Chart Analysis

Based Upon Data For Temperatures Of <= 32 Degrees F.

Winter 99-99 Through 00-01

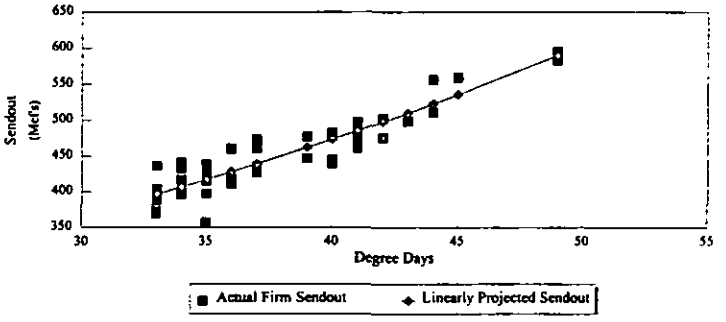
Linear Regression vs. Actual



Linear Regression Output:

Constant		8,073.73
Std. Error Of Y Estimate		23,148.62
R Squared		0.814400
Number of Observations		53
Degrees of Freedom		51
	X	
X Coefficient	11,692	
Std. Err. Of Coefficient	782	

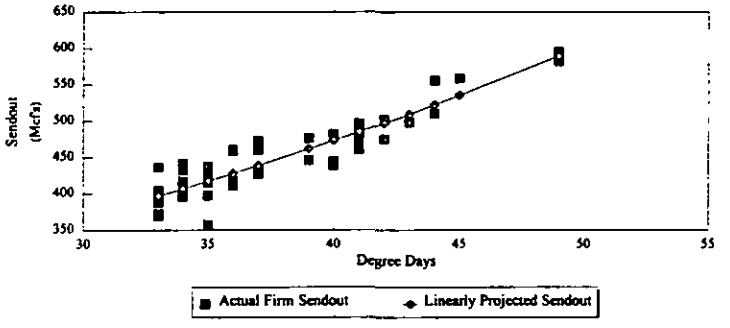
Quadratic Regression vs. Actual



Quadratic Regression Output:

Constant	202,323	
Std. Error Of Y Estimate	23,236	
R Squared	0.816658	
Number of Observations	53	
Degrees of Freedom	50	
	X	X^2
X Coefficient	1,721	126
Std. Err. Of Coefficient	*12,731*	*161*

Cubic Regression vs. Actual



Cubic Regression Output:

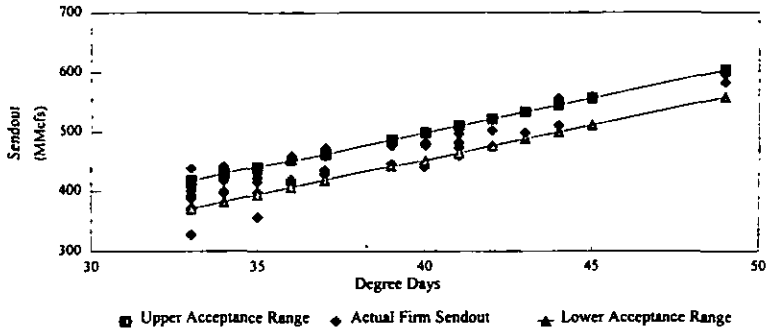
Constant	(1,833,982)		
Std. Error Of Y Estimate	23,306		
R Squared	0.819253		
Number of Observations	53		
Degrees of Freedom	49		
	X	X^2	X^3
X Coefficient	155,275	(3,697)	31
Std. Err. Of Coefficient	183,524	4,561	37

Deviation Analysis

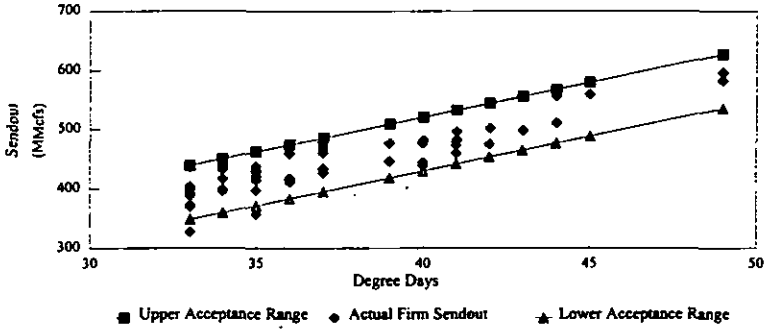
Based Upon Data For Temperatures Of <= 32 Degrees F.

Winter 99-99 Through 00-01

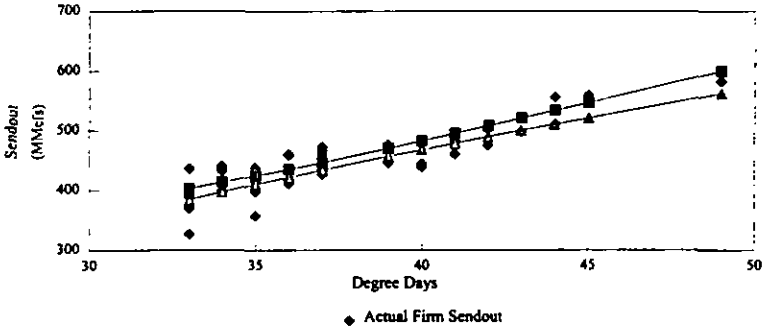
Acceptance Range @ 1 Std Deviation



Acceptance Range @ 2 Std Deviations



97.5% Confidence Interval



Linear Regression Confidence Level Table

Count	Degree Days X	Actual Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Y dc	Difference Actual Versus Projected Y - Yc	Actual Versus Projected Squared (Y - Yc)²	(Degree Days - Xm) X - Xm	(Degree Days - Xm) Squared (X - Xm)²	s dyc	t*s dyc	Y dc - t*s dyc	dc + t*s dy d	Y dc - s dy dc	Y dc + s dy dc	Y dc - 2s dy dc	Y dc + 2s dy dc
1	33	326,961	393,926	(66,965)	4,484,324,481	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
2	33	404,239	393,926	10,313	106,355,927	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
3	33	392,478	393,926	(1,448)	2,096,991	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
4	33	387,999	393,926	(5,927)	35,130,502	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
5	33	372,786	393,926	(21,140)	446,903,785	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
6	33	369,974	393,926	(23,952)	573,703,046	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
7	33	399,081	393,926	5,155	26,573,005	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
8	33	436,322	393,926	42,396	1,797,412,423	(5)	21	4,678	9,356	384,570	403,282	371,218	416,634	348,511	439,341
9	34	432,594	405,619	26,975	727,672,472	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
10	34	399,075	405,619	(6,544)	42,818,636	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
11	34	396,409	405,619	(9,210)	84,816,641	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
12	34	441,275	405,619	35,656	1,271,379,214	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
13	34	416,936	405,619	11,317	128,083,655	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
14	34	416,603	405,619	10,984	120,657,152	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
15	34	437,969	405,619	32,350	1,046,548,700	(4)	13	4,138	8,277	397,342	413,895	382,911	428,326	360,203	451,034
16	35	421,003	417,311	3,692	13,630,191	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
17	35	437,794	417,311	20,483	419,549,556	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
18	35	428,508	417,311	11,197	125,370,768	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
19	35	397,489	417,311	(19,822)	392,915,297	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
20	35	431,805	417,311	14,494	210,073,394	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
21	35	415,039	417,311	(2,272)	5,162,398	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
22	35	357,135	417,311	(60,176)	3,621,161,944	(3)	6	3,680	7,360	409,951	424,671	394,603	440,019	371,896	462,726
23	36	411,314	429,004	(17,690)	312,921,495	(2)	2	3,337	6,674	422,329	435,678	406,296	451,711	383,588	474,419
24	36	460,371	429,004	31,367	983,914,585	(2)	2	3,337	6,674	422,329	435,678	406,296	451,711	383,588	474,419
25	36	458,972	429,004	29,968	898,089,583	(2)	2	3,337	6,674	422,329	435,678	406,296	451,711	383,588	474,419
26	36	417,590	429,004	(11,414)	130,269,973	(2)	2	3,337	6,674	422,329	435,678	406,296	451,711	383,588	474,419
27	36	416,465	429,004	(12,539)	157,216,169	(2)	2	3,337	6,674	422,329	435,678	406,296	451,711	383,588	474,419
28	37	472,871	440,696	32,175	1,035,225,266	(1)	0	3,147	6,294	434,402	446,991	417,988	463,404	395,281	486,111
29	37	432,575	440,696	(8,121)	65,951,994	(1)	0	3,147	6,294	434,402	446,991	417,988	463,404	395,281	486,111
30	37	434,310	440,696	(6,386)	40,782,060	(1)	0	3,147	6,294	434,402	446,991	417,988	463,404	395,281	486,111
31	37	459,964	440,696	19,268	371,252,615	(1)	0	3,147	6,294	434,402	446,991	417,988	463,404	395,281	486,111
32	37	466,785	440,696	26,089	680,631,576	(1)	0	3,147	6,294	434,402	446,991	417,988	463,404	395,281	486,111
33	37	426,519	440,696	(14,177)	200,989,690	(1)	0	3,147	6,294	434,402	446,991	417,988	463,404	395,281	486,111
34	39	446,239	464,081	(17,842)	318,339,656	1	2	3,312	6,624	457,457	470,705	441,373	486,789	418,666	509,496
35	39	476,401	464,081	12,320	151,780,541	1	2	3,312	6,624	457,457	470,705	441,373	486,789	418,666	509,496
36	40	477,350	475,774	1,576	2,485,127	2	6	3,642	7,284	468,489	483,058	453,066	498,481	430,358	521,189
37	40	439,124	475,774	(36,650)	1,343,191,091	2	6	3,642	7,284	468,489	483,058	453,066	498,481	430,358	521,189
38	40	444,632	475,774	(31,141)	969,788,756	2	6	3,642	7,284	468,489	483,058	453,066	498,481	430,358	521,189
39	40	481,932	475,774	6,158	37,926,242	2	6	3,642	7,284	468,489	483,058	453,066	498,481	430,358	521,189

Linear Regression Confidence Level Table

Count	Degree Days X	Actual Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Y dc	Difference Actual Versus Projected Y - Yc	Actual Versus Projected Squared (Y - Yc)²	(Degree Days - Xm) X - Xm	(Degree Days - Xm) Squared (X - Xm)²	s dyc	t*s dyc	Y dc - t*s dyc	dc + t*s dy d	Y dc - s dy dc	Y dc + s dy dc	Y dc - 2s dy dc	Y dc + 2s dy dc
40	40	479,001	475,774	3,227	10,416,295	2	6	3,642	7,284	468,489	483,058	453,066	498,481	430,358	521,189
41	41	482,801	487,466	(4,665)	21,762,856	3	12	4,091	8,182	479,284	495,648	464,758	510,174	442,051	532,881
42	41	460,360	487,466	(27,106)	734,738,900	3	12	4,091	8,182	479,284	495,648	464,758	510,174	442,051	532,881
43	41	473,537	487,466	(13,929)	194,018,924	3	12	4,091	8,182	479,284	495,648	464,758	510,174	442,051	532,881
44	41	480,589	487,466	(6,877)	47,295,021	3	12	4,091	8,182	479,284	495,648	464,758	510,174	442,051	532,881
45	41	496,742	487,466	9,276	86,042,922	3	12	4,091	8,182	479,284	495,648	464,758	510,174	442,051	532,881
46	42	502,157	499,159	2,998	8,990,621	4	20	4,624	9,249	489,910	508,407	476,451	521,866	453,743	544,574
47	42	475,235	499,159	(23,924)	572,336,898	4	20	4,624	9,249	489,910	508,407	476,451	521,866	453,743	544,574
48	43	498,294	510,851	(12,557)	157,679,749	5	30	5,216	10,432	500,419	521,283	488,143	533,559	465,436	556,266
49	44	510,670	522,544	(11,874)	140,981,327	6	42	5,849	11,697	510,846	534,241	499,836	545,251	477,128	567,959
50	44	556,101	522,544	33,557	1,126,102,061	6	42	5,849	11,697	510,846	534,241	499,836	545,251	477,128	567,959
51	45	559,262	534,236	25,026	626,298,079	7	56	6,510	13,020	521,216	547,256	511,528	556,944	488,821	579,651
52	49	582,621	581,006	1,615	2,608,108	11	131	9,319	18,637	562,369	599,643	558,298	603,714	535,591	626,421
53	49	595,717	581,006	14,711	216,412,457	11	131	9,319	18,637	562,369	599,643	558,298	603,714	535,591	626,421
Tot/Avg	38	447,094	447,094		27,328,780,813		877								

t = 2.00

Xm = 37.547

Population Standard Deviation of Regression Squared = 515,637,372

Population Standard Deviation of Regression = 22,708

	Upper Range	Lower Range
1s	469,802	424,386
2s	492,509	401,679

MEMORANDUM

May 2, 1997

To: B.Z. Karachiwala, PGW
Craig White, PGW

From: ICF Kaiser

Subject: Design Weather Conditions for Supply Planning at PGW

As part of ICF Kaiser's assignment to assist PGW in assessing its optimal supply planning configuration, we were asked to assess PGW's design day and design winter planning methodologies. To the extent that the approach to defining the design day or design winter leads to an overly conservative estimation of design conditions (that is, the estimated design conditions are higher than requirements), PGW could be over-investing in capacity or not using its existing capacity optimally.

ICF evaluated the design winter gas demand estimation methodology currently used by PGW. As a first step, we reviewed the design winter and design day demand estimation methodologies and evaluated the critical assumptions underlying the methodologies using historical data and statistical tools.

PGW estimates its design day demand using a valid statistical procedure. PGW's degree day estimates for a design winter and a design day are *consistent* with the historical weather data and the degree day estimates used by other utilities in the region. The following table compares PGW's design winter with the historical weather data.

Data Set (1948-1996)	Nov	Dec	Jan	Feb	Mar	Winter Season
Historical Mean Winter Degree Days	554	884	1018	869	703	4025[a]
Historical Peak Winter Degree Days	743	1219	1390	1170	997	4640[a]
Lower limit of 95% confidence level (Mean - 2 std.dev.)	395	615	717	644	504	3353[a]
Upper limit of 95% confidence level (Mean + 2 std.dev.)	705	1157	1318	1093	901	4698[a]
PGW's Design Winter Degree Days	617	994	1160	987	808	4566
Probability of PGW's Design Winter	1:5	1:4	1:6	1:7	1:7	1:16

Notes:
[a] Individual month estimates do not add up to this total, because it has been calculated independently using the historical winter season data or standard deviation for the season total.

These statistical estimates indicate the following:

- PGW's design winter is 74 degree days short of 48-year historical peak winter.
- PGW's monthly design winter conditions are 126 to 230 degree days less than 48-year historical monthly peak winter conditions.
- PGW's design winter conditions lie well within the 95 percent confidence level. This indicates that the likelihood of a winter being colder than PGW's design winter is greater

than 5 percent. This suggests that PGW's design winter conditions are not overly *conservative.*

- A winter that is *as cold as or colder than* PGW's design winter is likely to occur once in 16 years.

This memorandum summarizes the results of this study in two sections: (1) a summary of the methodology used by PGW to estimate design conditions; and (2) a statistical analysis of PGW's design winter. We have supplied more detail on our assessment in two attachments (Appendices A & B) to this memorandum.

Overview of PGW's Design Winter/Day Gas Demand Estimation Methodology

The design day and design winter are the periods which define the largest amount of gas that PGW must deliver to meet system requirements and to maintain system integrity. The design day is the coldest day resulting in the highest expected coincident demand on the system; the design winter is defined as the coldest experienced winter, combined with the coldest experienced January (historically, the coldest month in Philadelphia). As such, the design conditions are used to for determining annual total storage and pipeline capacity, storage injection and withdrawal patterns, and supply plans for the PGW system. Design sendout is a function of three factors: (1) weather expressed in degree days, (2) number of customers, and (3) the demand response of those customers to cold weather.

As noted above, this memorandum addresses PGW's approach to describing design weather conditions. We have not evaluated PGW's approach to estimating the demand response or the number of customers. Rather, we have focused on addressing the issue of whether the design day or winter conditions are in excess of what may be considered statistically reasonable. The technical description of each is defined as follows:

- The design day at PGW is a day when the mean temperature is zero degree F, or 65 degree days. Under these conditions, PGW plans to send 714 Mmcf of natural gas to firm (i.e., after the interruptible customers have been dropped from the system) on-system customers. Because PGW owns about 291 Mmcf of pipeline capacity from supply areas and can vaporize between 450 and 540 Mmcf of LNG on any day, design day conditions appear not to be constraining even without employing PGW's approximately 160 Mmcf per day of peak storage withdrawal capacity.

- Design winter describes a colder than normal winter combined with a colder than normal January. The design winter has 4,566 degree days; the design year has 5,280 degree days.

The design winter demand is estimated by summing the demands of each customer rate class over the winter period (November through March). More specifically, the following equation is used to estimate the total monthly demand for each rate class of customers.

For each customer rate class:

Monthly Demand = No. of customers * UAF * [{Domestic Load Adjustment Factor * (DOM * 12/365 * No.of days in the month)} + {(CFDD * Heating Degree Days) * Heating Adjustment Factor}]

where

DOM, domestic load factor per customer per month, is the minimum or base load requirement;
CFDD is the heating demand factor per customer per degree day; and
UAF is the unaccounted for gas adjustment factor per customer.

The Domestic Load Adjustment Factor is used to adjust the seasonal variation in the non-heating gas demand (i.e., domestic load). Heating Adjustment Factor, on the other hand, is used to adjust the seasonal variation in the gas demand for space heating (i.e., sendouts for heating), due to differences in the responsiveness of customers to changes in heating degree days between seasons.[1]

DOM factor is calculated for each customer rate class (excluding interruptible customers) by adjusting the estimated (or trial) sendouts--during the previous year's summer months, July through September--by the Domestic Load Adjustment Factor. As such the DOM factor accounts for baseload, non-weather demand by PGW's customers. CFDD is calculated for each customer rate class (excluding interruptibles) by adjusting the estimated total heating gas demand by *actual* heating degree days--during the previous year's peak winter months, December through February--and the Heating Adjustment Factor.

The design winter gas demand for each customer rate class is calculated by using PGW's design winter degree days. PGW's design winter consists of 4,566 heating degree days over the 151-day period of November through March.

Design day gas demand projections are made using a statistically estimated equation. More specifically, using linear regression analysis, a peak winter day gas demand equation is estimated by regressing the actual sendouts on those weekdays (excluding holidays) during the previous year's winter season when temperature was 32°F or below. The gas demand equation is:

$$\text{Weekday actual sendout} = a + b * \text{Degree Days} + \varepsilon$$

where
a is the intercept;
b is the slope; and
ε is the residual, not captured by the estimated demand equation.

The design day consists of 65 degree days or a day with a mean temperature of zero degree F with a design hour of -5°F. Using the regression estimates of a and b and 65 degree days, design day gas demand is calculated. An additional 5% contingency is normally added to the estimated total gas demand.

To attach a degree of confidence (e.g., 95%) to the demand estimate thus calculated, an interval of gas demand estimates are developed using (plus or minus two times) standard deviation of the weekday actual sendouts. This implies that 95% of the time actual gas demand will be within the interval of estimates thus computed. This establishes the response of the firm customers under cold weather conditions. Although this demand equation can be used to estimate the total gas

[1] For example, the gas demand for space heating in response to an increase in the number of heating degree days during September is likely to be less than the gas demand for space heating in response to a corresponding increase in the number of degree days during January.

demand on other severe winter days (ranging from 33 to 65 degree days), it will not be statistically valid to use this equation to estimate gas demand on days when the weather conditions are milder.

ICF's Assessment of Design Winter Estimation Methodology

A critical factor in estimating design winter gas demand is the number of heating degree days. ICF evaluated PGW's estimate of the design winter total (i.e., 4,566 degree days) and individual design winter monthly degree days to determine whether better estimates could be generated using purely statistical approaches. Historical winter degree days during the past 48 years (1948-95) were statistically analyzed and compared to the PGW's design winter to determine the extent to which PGW's design winter is representative of historically colder than average winters. Following are the key findings.

- PGW's design winter, as expected, *exceeds* the historical mean by about 540 degree days; however, it is about 75 degree days *lower* than the historical maximum.

- On average, once in every 16 years, a winter is likely to be *as cold as or colder than* PGW's design winter.

- PGW's ranking of design winter months are, on average, *consistent* with the ranking of historical winter months. January is the coldest month; December is the second coldest month, followed by February; March is the fourth coldest month; and November as the fewest heating degree days.

- The PGW's design winter is *consistent with* the design winters adopted by other utilities in the region.

- On average, PGW's design winter is *less likely* to occur than (1) any of its design winter month, (2) a combined design December and January, or (3) a combined design December through February. The design winter, however, is *more likely* to occur than a combined design December through March. Essentially, this indicates that design months occur randomly, independent of design winter conditions. It may be more likely that a string of colder than normal winter months will occur than a design winter; but it is less likely that these months will include March.

- There is *no correlation* between January, February, and March heating degree days. Although statistically significant relationships do exist between monthly heating degree days, these relationships are *highly sensitive* to the sample data set used. Thus, one cannot say if March will be colder or warmer than normal based on February or other winter months.

- PGW's Design Day temperature, as expected, *exceeds* the historical mean by over 10 degree days; however, it *almost equals* the historical peak.

- On average, once in every 16 years, temperature (excluding wind-chill effect) is likely to be 2°F or below on the coldest day of the year. This implies that PGW's design day is *almost as likely* to occur as its design winter.

- Historically, winter temperature (excluding wind-chill effect) of 5°F or below always occurred in January. In addition, on average, coldest day of the year is *more likely* to be a day in January than in any other month. These imply that PGW's planning for the design day to occur in January is *consistent* with the historical data.

- Historically, winter temperature (excluding wind-chill effect) in March has always been above 10°F. In addition, on average, the likelihood of the coldest day of the year occurring in March, rather than in any other month, is 4%. Therefore, it is *consistent* with the historical data to say that Design Day conditions are *not likely* to occur in March.

To evaluate if PGW's design winter estimate, we (1) estimated a set of alternative design winters based on historical weather data and simple statistical criteria, and computed associated risks of not being able to meet the gas demand due to colder than alternative design winters; (2) surveyed other utilities in the region and compiled their design winter criteria and estimates; and (3) compared these estimates to those of PGW's. Similar analysis was performed on PGW's design day estimate. The results of our analyses suggest that PGW's design winter and design day are *reasonable estimates*. Appendix B contains the statistical results of these analyses.

Conclusion

As mentioned earlier, design sendout is a function of three factors: (1) weather expressed in degree days, (2) number of customers, and (3) the demand response of those customers to cold weather. We analyzed PGW's degree day estimates for design winter/day, using historical data, statistical tools, and degree day estimates of other utilities in the region. The results of our analysis indicate that the PGW's degree day estimates are consistent with the historical weather data and the degree day estimates of other utilities in the region. We examined the PGW's winter gas demand estimation methodologies and found them to be satisfactory.

If you have any questions or comments, please call Leonard Crook at (202)-862-2952.

APPENDIX A

PHILADELPHIA GAS WORKS' (PGW) DESIGN WINTER/DAY NATURAL GAS DEMAND ESTIMATION[1]

The design day and design winter are the periods which define the largest amount of gas that PGW must deliver to meet system requirements and to maintain system integrity. The design day is the coldest day resulting in the highest expected coincident demand on the system; the design winter is defined as the coldest experienced winter, combined with the coldest experienced January (historically, the coldest month in Philadelphia). As such, the design conditions are used to for planning annual total capacity and supply necessary for the PGW system. Following are PGW's design winter conditions.

- Design winter describes a colder than normal winter combined with a colder than normal January. The design winter consists of 4,566 degree days over the 151-day period of November through March; the design year has 5,280 degree days.

- The design day at PGW is a day when the mean temperature is 0°F, or 65 degree days, with a design hour of -5°F.

Design sendout (i.e., gas demand) is a function of three factors: (1) weather expressed in degree days, (2) number of customers, and (3) the demand response of those customers to cold weather. PGW's design sendout estimation methodologies are described below in two parts: (1) Design Winter demand and (2) Design Day demand.

I. DESIGN WINTER DEMAND ESTIMATION

Design winter demand comprises of domestic load and heating demand. Domestic load is determined by number of customers and domestic load requirement per customer. Heating demand, on the other hand, is determined by number of customers, heating degree days, and heating demand requirement per customer per degree day.

The design winter demand is estimated by summing the demands of each customer rate class over the 151-day winter period (November through March). More specifically, the following equation is used to estimate the total monthly demand for each rate class of customers.

For each customer rate class:

Monthly Demand = No. of customers * UAF * [{Domestic Load Adjustment Factor * (DOM * 12/365 * No.of days in the month)} + {(CFDD * Heating Degree Days) * Heating Adjustment Factor}]

---

[1] Our understanding of PGW's design winter/day demand estimation methodology is primarily based on our review of PGW's document "Gas Cost Rate (GCR) Fiscal Year 1995-96 for the Philadelphia Gas Works,Volume1--Gas Supply/Demand Strategy, Section A: Statistical Reference Data Schedules," submitted before the Philadelphia Gas Commission, August 1995. This document contains the methodology used by PGW to estimate (in March 1995) its annual gas demand for 1995-96 and for every planning year thereafter until 2000-01. In this appendix, we have generalized the methodology without making reference to any particular year.

where

DOM, domestic load factor per customer per month, is the minimum or base load requirement;
CFDD is the heating demand factor per customer per degree day; and
UAF is the unaccounted for gas adjustment factor per customer.

The methodologies used to estimate each of these components are described below in detail.

DOMESTIC DEMAND

Domestic gas demand or baseload is estimated for each customer rate class by multiplying minimum load requirement per customer (i.e., DOM) by PGW's projections of number of customers in that rate class. The methodologies for estimating DOM and the domestic load adjustment factor are explained below.

DOMESTIC LOAD FACTOR (DOM)

DOM is the per customer minimum or base load requirement, which varies across customer rate class. It is calculated (1) by adjusting the estimated (or trial) sendouts--during the previous year's summer months of July through September--calculated for each customer rate class (excluding interruptible customers) by the domestic load adjustment factor described below, and (2) by dividing the estimates by the number of customers in each rate class.[2]

DOMESTIC LOAD ADJUSTMENT FACTOR

The Domestic Load Adjustment Factor is used to adjust the seasonal variation in the non-heating gas demand (i.e., domestic load). This factor is calculated by adjusting (previously) estimated sendout to actual sendout, during the previous year's summer months of July through September.

Domestic Load Adjustment Factor
= 3 month-total of actual firm sendout / 3-month total estimated firm sendout

HEATING DEMAND

Heating demand is determined by the following three factors: (1) demand response of customers to cold weather; (2) number of degree days; and (3) number of customers. For each customer rate class, heating demand for a design winter is calculated by multiplying the following factors: (1) heating requirement per degree day per customer; (2) PGW's design winter degree days; and (3) PGW's projections of number of customers.[3] To this estimate a heating demand adjustment factor is applied to correct for the seasonal variation in the gas demand for space heating.

---

[2] We understand that trial sales were calculated based on the previous year's load calculation.

[3] Number of customers is based on projections developed by the Marketing department and historical assessments of customer attrition.

HEATING FACTOR (CFDD)

It is the heating gas demand requirement per degree day per customer. It varies by customer rate class. It is calculated as follows: first, Trial Heating Factor (Trial CFDD) is calculated; second, heating adjustment factor is calculated using DOM, Trial CFDD, and baseload estimates during peak winter months for each customer rate class; and last, Final CFDD is calculated by adjusting trial CFDD by the heating adjustment factor. The heating factor estimation methodology is described below in detail.

TRIAL HEATING FACTOR (TRIAL CFDD): It is calculated by dividing the total amount of gas demanded for heating (only) by the total degree days during the previous year's peak winter months, December through February.

Trial CFDD = Total Gas Demand for heating over previous year's peak winter months (Dec.-Feb.) / total degree days during this period

This calculation involves two steps:

(1) Calculate total heating gas demand for each of the 3 months (MCF) by subtracting the DOM factor from the actual sendout. For example, *for December*:

$$MCF_{dec} = [\{(\text{Actual Sales}_{dec}/\text{Number of Customers}_{dec}) - DOM\}/\text{Degree Days}_{dec}] * \text{Degree Days}_{dec}$$

(2) Add MCF_{dec}, MCF_{jan}, and MCF_{feb}, and divide by total degree days during this three month-period.

$$\text{Trial CFDD} = (MCF_{dec} + MCF_{jan} + MCF_{feb}) / \text{Degree Days}_{dec+jan+feb}$$

Note: Degree days vary by customer rate class. Calendar degree days are used for customer rate class 1-18; cycle degree days are used for customer rate class 37-57; and previous month's cycle degree days are used for customer rate class 36.

FINAL CFDD: Final CFDD is calculated by adjusting trial CFDD by the heating adjustment factor (which is described below) as follows:

Final CFDD = Trial CFDD * Heating Adjustment Factor.

HEATING ADJUSTMENT FACTOR

Heating Adjustment Factor is used to adjust the seasonal variation in the gas demand for space heating that arises from differences in the responsiveness of customers to changes in heating degree days between seasons. It is calculated by adjusting the (previously) estimated sendout to the actual sendout during the previous year's peak winter months.

To avoid over-or under projections of heating gas demand, PGW (1) calculates the difference between actual and estimated total gas sendouts during the previous year's peak winter months, December through February and (2) inflates (deflates) the planned sendout by adding (subtracting) the difference if the actual sendout exceeded (fell below) estimated sendout. Heating Adjustment Factor is calculated as follows:

Heating Adjustment Factor = [(Actual Sendout - Estimated Sendout)/(Estimated Sendout - Baseload)] + 1

where Estimated Sendout is calculated using trial CFDD and Baseload is calculated for the peak winter months, setting trial CFDD to zero.

Heating adjustment factor of, for example, 1.0735 implies the following: (1) actual total sendout (during the previous year's peak winter months) exceeded the estimated total sendout (as indicated by the greater than unity value of the heating adjustment factor is); (2) this difference between estimated and actual sendouts accounts for about 7.35% of the estimated heating demand; and (3) in the future, heating sendouts will be increased by 7.35% of the estimated sendout.

The heating adjustment factor remains constant across all customers and customer rate classes.

UNACCOUNTED FOR GAS FACTOR (UAF)

UAF is used to adjust the difference between actual sendout and gas consumption by customers. This difference can arise from factors, such as pipeline leaks, pressure differentials, and unmetered deliveries. For example, UAF of 1.031 indicates 103.1 Mcf of natural gas must be sent out to meet 100 Mcf of gas demand. Therefore, UAF is usually calculated by dividing actual total gas sendout by total gas consumed by customers in that month. This factor remains constant across all customers and customer classes.

PGW'S DESIGN WINTER DEGREE DAYS

PGW's design winter has 4, 566 degree days during the 151 days of a winter season. Following is the monthly spread:

617 - November
994 - December
1,160 - January
987 - February
808 - March

II. DESIGN DAY DEMAND ESTIMATION

Design day gas demand projections are made using a statistically estimated equation. More specifically, using linear regression analysis, a peak winter day gas demand equation is estimated by regressing the actual sendouts on those weekdays (excluding holidays) during the previous year's winter season when temperature is 32°F or below.

For example, design day projections for 1995-96 were developed by PGW through a demand equation, estimated by regressing the actual sendout when daily temperature was 32°F or below (during 1994-95 winter weekdays, i.e., excluding weekends and holidays) on a constant and degree days during the same period. The 5% contingency normally applied to the baseload was not used, because, the near design conditions of continuous severe weather was experienced during 1994-95. The following is the design day gas demand model, estimated by PGW.

$$\text{Gas Demand} = a + b_1 * \text{Degree Days} + b_2 * \text{Degree Days}^2 + b_3 * \text{Degree Days}^3 + \varepsilon$$

where

a is the intercept;
b_1 is the slope;
b_2 & b_3 indicate the shape; and
ε is the residual, not captured by the estimated demand equation.

Using 22 observations, three models were estimated by PGW with linear, quadratic, and cubic terms for degree days (i.e., Degree Days, Degree Days^2, and Degree Days^3 respectively). The model with linear term for degree days (hereafter, referred to as linear model, for simplicity) fitted the data better than the others, with an adjusted R^2 of 0.905.[4] The adjusted R^2 value, however, informs us that about 90% of the variation in the actual sendout data are explained by the estimated demand equation.

PGW's linear model estimates are: a =-16.883 and b_1=12,275. We observe that the negative estimate of a is not consistent with the conventional wisdom, because it implies that domestic load per customer is negative. Nevertheless, the objective is to estimate a demand equation that fits actual peak winter day sendout data the best, so that in the future, best possible design day sendout estimates can be developed using the estimated demand equation. Therefore, it is *reasonable* to use the model estimates to calculate design day sendouts.

Design day gas demand is calculated using the linear model estimates of a and b and 65 degree days. To attach a degree of confidence (e.g., 95%) to the demand estimate thus calculated, an interval of gas demand estimates are developed using (plus or minus two times) standard deviation of the weekday actual sendouts. This implies that 95% of the time actual gas demand will be within the interval of estimates thus computed. This establishes the gas demand response of PGW's firm customers under cold weather conditions.

Although this demand equation estimated by PGW can be used to estimate gas demand on other severe winter days (ranging from 33 to 64 degree days), it will not be statistically valid to use this equation to estimate gas demand on days when the weather conditions are milder, because it is estimated based on a restricted (i.e., only when temperature was 32°F or below) sendout sample and because the gas demand response of customers may be different at milder weather conditions.

[4] ICF calculated *Adjusted* R^2 from PGW's unadjusted R^2 estimate (of the linear gas demand model), by adjusting it for the degrees of freedom.

APPENDIX B

ARE PGW'S DESIGN CONDITIONS REPRESENTATIVE OF THE HISTORICAL WINTER?

A critical factor in estimating design winter gas demand is the number of heating degree days. ICF evaluated PGW's estimate of the design winter total (i.e., 4,566 degree days) and individual design winter monthly degree days to determine whether better estimates could be generated using purely statistical approaches. Historical winter degree days during the past 48 years (1948-95) were statistically analyzed and compared to the PGW's design winter to determine the extent to which PGW's design winter is representative of historically colder than average winters.[1] The results and the findings of these analyses are presented below in terms of questions and answers (Qs & As). These Qs & As are presented in two parts: (1) Design Winter and (2) Design Day conditions.

I. DESIGN WINTER CONDITIONS

1. What are the sample statistics of the Historical Winter Degree Days?

Data set (1948-95)	Nov	Dec	Jan	Feb	Mar	Winter Season
Historical Mean Degree Days	554	884	1,018	869	703	4,025[b]
Historical Peak Degree Days	743	1,219	1,390	1,170	997	4,640[b]
No. of Sample Observations	49	49	48	48	48	48
Sample Standard Deviation	80	135	150	112	99	336
Variability of Historical Data Relative to Mean[a] (%)	14	15	15	13	14	8[b]
PGW's Design Degree Days	617	994	1,160	987	808	4,566

Notes:
[a] It is coefficient of variation, calculated as (sample standard deviation/sample mean)*100.
[b] Individual months do not add up to this total, because it has been calculated independently using the historical winter season data or the standard deviation for the season total.

Findings:

- PGW's design winter, as expected, *exceeds* the historical mean by about 540 degree days; however, it is about 75 degree days *lower* than the historical maximum.

- PGW's ranking of design winter months are, on average, *consistent* with the ranking of historical winter months. January is the coldest month; December is the second coldest month, followed by February; March is the fourth coldest month; and November as the fewest heating degree days.

- The number of total degree days during winters is less variable (by about 5%-7%) than the number of degree days during individual winter months. This implies that if historical data is used to develop a design winter, more reliance can be placed on a design winter,

[1] Bowen, K. Earl and Starr, Martin K. 1982. *Basic Statistics for Business and Economics*. McGraw-Hill Book Company, New York.

developed using historical mean (such as mean ± 1.5 standard deviation) than on any similarly developed individual design winter month.

2. What is the probability that PGW's design winter conditions will occur?

Design Winter Months	Number of PGW'sDesign Degree Days	No. of times a design or a colder winter occurred during 1948-96.	Historical Probability that a design or a colder winter will occur (number of years)	Historical Probability that a design or a colder winter will occur (%)
November	617	9	1/5	18
December	994	12	1/4	24
January	1160	8	1/6	17
February	987	7	1/7	15
March	808	7	1/7	15
Dec. & Jan.	2154	7	1/7	15
Dec. through Feb.	3141	4	1/12	8
Dec. through March	3949	2	1/24	4
Nov. through Feb.	3758	4	1/12	8
Design Winter	4566	3	1/16	6

Findings:

- On average, once in every 16 years, a winter is likely to be *as cold as or colder than* PGW's design winter.

- On average, PGW's design winter is *less likely* to occur than (1) any of its design winter month, (2) a combined design December and January, or (3) a combined design December through February. The design winter, however, is *more likely* to occur than a combined design December through March. Essentially, this indicates that design months occur randomly, independent of design winter conditions. It may be more likely that a string of colder than normal winter months will occur than a design winter; but it is less likely that these months will include March.

3. What do winter conditions during early winter months inform us about the winter conditions during rest of the winter season? (Anecdotally, observers think that there may be a positive correlation between early winter and severity of winter, but apparently there does not seem to exist any scientific meteorological relationship.)

To examine if cold weather in early winter is any indicator of cold weather in late winter months or rest of the winter, correlation coefficients (r) were calculated and analyzed for several sub-sample data sets. The data set was divided on the basis of severity of winter and November winter conditions as follows:

(i) complete data set 1948-95;
(ii) only those years, when winter conditions were average or milder, i.e., 4,025 degree days or below;

(iii) only those years, when winter conditions were colder than average, i.e., above 4,025 degree days;
(iv) only those years, when winter was much colder than average, i.e., at least 4,100 degree days;
(v) only those years, when winter conditions during November were average or milder, i.e., 554 degree days or below;
(vi) only those years, when November was colder than average, i.e., above 554 degree days; and
(vii) only those years, when November was much colder than average, i.e., above 600 degree days.

Findings:

- There is *no correlation* between January, February, and March heating degree days. Although statistically significant relationships do exist between monthly heating degree days, these relationships are *highly sensitive* to the sample data set used. Thus, one cannot say if March will be colder or warmer than normal based on February or other winter months.

4. Compare PGW's Design Winter with those of other utilities in the region.

Utilities	Design Winter Criterion	Time period used	No. of Design Degree Days
PGW, Philadelphia, PA			4,566
UGI, Reading, PA	Mean of 40 winters +1.645*std.dev.	1957-95	4,616
PECO, Philadelphia, PA	Mean of 28 winters * 112%	1968-95	4,483
South Jersey Gas, Folsom, NJ	30 year-peak winter	1966-95	4,613
Elizabethtown, Bedminster, NJ	30 year-peak winter	1966-95	4,613
Historical Maximum		1948-95	4,640

Source: ICF Kaiser's Survey and Historical Temperature Data Analysis.

Findings:

- The PGW's design winter is *consistent with* the design winters adopted by other utilities in the region.

5. Is there a statistical criterion that can be used to estimate design winter conditions, based on historical data?

The objective is to evaluate PGW's design winter conditions against statistically developed winter conditions; if PGW's design winter conditions are much colder than the winter conditions statistically developed, for example, with 95% confidence level, PGW's design winter conditions could be considered overly conservative. Under such conditions PGW could be over-investing in capacity or under-utilizing existing capacity.

A principal advantage of using statistical methodology to estimate design winter conditions is that it would us to construct intervals of estimates, within which winter conditions can be

expected to lie 95% or 99% of the time. Therefore, a statistical criterion could be to develop *estimates of winter conditions such that 95% of the time winter conditions will be within this* range of estimates. Validity of such estimates, however, is dependent upon the validity of the assumption that we make about the underlying distribution of the weather conditions (that extend beyond our sample data pertaining to 1948-95). Therefore, we have developed below confidence intervals for winter conditions with and without assumption about the underlying distribution of winter weather conditions.

Assuming that the winter degree days are normally distributed about the mean, (i) 68% of winter degree days will lie between the following interval of sample mean ± 1 standard deviation, (ii) 95% of winter degree days will lie between the interval of sample mean ± 2 standard deviation, and (iii) 99.7% of winter degree days will lie between the interval of sample mean ± 3 standard deviation.

However, if winter degree days are not normally distributed, the above conclusions will not hold and the confidence level could be lower. Nevertheless, we can conclude that (i) *at least* 75% of winter degree days will lie between the interval of sample mean ± 2 standard deviation and (ii) at least 88% of winter degree days will lie between the interval of sample mean ± 3 standard deviation (*Chebyshev Inequality Theorem).*

Month	PGW's Design Winter	Sample mean - 1 Std. Dev	Sample mean + 1 Std. Dev	Sample mean - 2 Std. Dev	Sample mean + 2 Std. Dev
Nov	617	473	628	395	705
Dec	994	751	1022	615	1157
Jan	1160	867	1168	717	1318
Feb	987	756	981	644	1093
Mar	808	603	802	504	901
Season Total	**4566**	**3689[a]**	**4362[a]**	**3353[a]**	**4698[a]**

Note: [a] Individual months do not add up to this total, because it has been calculated independently using the standard deviation for the season total.

Findings:

- PGW's design winter falls within the 95% confidence interval estimates, developed assuming winter conditions are normally distributed. This indicates that there is *no statistically based criterion* that can be used to optimally estimate PGW's design winter better. Nevertheless, there may be other *policy* criteria--such as cost-benefit (i.e., and an acceptable trade off between risks and potential cost savings) criterion and maximum acceptable risk criterion--that can be used to optimally estimate design winter conditions.

6. To facilitate setting up an optimal policy criterion, evaluate the risks associated with alternative design winters and compare them to PGW's design winter.

To estimate an optimal design winter for PGW, we *need to establish* a probability or a cost-benefit "*criterion*"--such as (a) a probability (i.e., relative frequency) limit *above* which a winter may not be colder than a design winter; or (b) a criterion for an acceptable trade-off between the risks and the potential cost-savings from reduced supply capacity due to reduced design winter conditions. We observe that currently, PGW does not appear to have any such criterion.

Setting up an optimal criterion, however, will require evaluating a wide range of alternative criteria. To facilitate such a comparison, we established simple *alternative* design winter criteria. [Note: there is no significance attached to these design winter criteria; the design winters calculated must be simply considered as alternative thresholds without any importance attached to them.] Based on these criteria, alternative design winters and probabilities of winter being *as cold as or colder than* these design winters were calculated. These results, presented below, are then compared to the PGW's design winter.[2]

Alternative Design Winter Criterion	**Alternative Design Winter (Deg.days)**	**No. of times the winter was *as cold as or colder than* the alternative design winter during the past 48 years**	**Probability that a winter is *as cold as or colder than* the *alternative* design winter (years and %)**
Sample Mean (upper limit of the 99% confidence interval) (1948-95)	4,157	19	2/5 (=40%)
Sample Mean + 1 standard deviation	4,362	10	1/5 (=21%)
(Sample Mean + 1 std. dev.) + 1% of this total, added as contingency	4,406	7	1/7 (=15%)
(Sample Mean + 1 std. dev.) + 2% of this total, added as contingency	4,450	6	1/8 (=13%)
(Sample Mean + 1 std. dev.) + 3% of this total, added as contingency	4,493	5	1/9 (=10%)
(Sample Mean + 1 std. dev.) + 4% of this total, added as contingency	4,537	4	1/12 (=8%)
(Sample Mean + 1 std. dev.) + 5% of this total, added as contingency	4,580	3	1/16 (=6%)
PGW's Design Winter	4,566	3	1/16 (=6%)

Findings:

- If PGW's design winter is reduced by about 115 degree days (to 4,450), the *risk* of *not being able to meet the total winter gas demand* will *increase* by about 100%.
- If PGW's design winter is reduced by about 75 degree days (to 4,493), the *risk* of *not being able to meet the total winter gas demand* will *increase* by about 65% (i.e., two-third).
- If PGW's design winter is reduced by about 30 degree days (to 4,537), the *risk* of *not being able to meet the total winter gas demand* will *increase* by about 35% (i.e., one-third).

[2] Because, winter conditions that are below planned design winter conditions are always preferred, we assume that if a winter is as cold as or colder than the design winter, there will be a risk of not being able to meet total winter gas demand.

II. DESIGN DAY CONDITIONS

7. What are the sample statistics of historical monthly peaks?

Data Set (1948-95)	Nov	Dec	Jan	Feb	Mar	Winter Season
Average Daily Temperature (°F)	47	36	32	34	42	38[a]
Lowest Temperature Ever (°F)	21	6	1	6	15	1[a]
Sample Mean of monthly peak day temperatures (°F)	32	21	16	18	27	13[a]
Standard Deviation of peak day temperatures	4.5	5.4	7.2	5.4	5.4	5.3[a]
PGW's monthly Peak Day/Design Day Winter Temperature (°F)	22	11	0	5	18	0
Lower Limit of the 95% Confidence Interval for monthly peak day temperature (Peak Mean - 2 std.dev) (°F)	23	21	18	21	21	21[a]
Upperlimit of the 95% Confidence Interval for monthly peak day temperature (Peak Mean + 2 std.dev) (°F)	41	32	30	29	38	24[a]
By how many degrees PGW's monthly peak day/Design Day temp. is colder than the 95% confidence interval? (°F)	1	10	18	16	3	21[a]
Lower Limit of the 99% Confidence Interval for monthly peak day temperature (Peak Mean - 3 std.dev) (°F)	19	5	-6	2	11	-3[a]
Upperlimit of the 99% Confidence Interval for monthly peak day temperature (Peak Mean + 3 std.dev) (°F)	46	37	38	34	43	29[a]
No.of observations in the sample	49	49	49	48	48	48

[a] Individual months do not add up to this total, because it has been calculated independently using the historical winter season data or the standard deviation for the season total.

Findings:

- PGW's Design Day temperature is *almost equal to* the historical peak.
- PGW's Design Day temperature, as expected, *exceeds* the mean of historical peaks by over 10 degree days.
- On average, once in every 16 years, temperature (excluding wind-chill effect) is likely to be 2°F or below on the coldest day of the year. This implies that PGW's design day is *almost as likely* to occur as its design winter.

8. What is the historical frequency distribution of cold days (i.e., ≤0°F, 5-10°F, 10-15°F, 15-20°F, 20-25°F, and 25-30°F) during the winter months?

Winter Temperature	Nov	Dec	Jan	Feb	Mar	Winter	Historical	PGW's

(during 1948-95)	(days)	(days)	(days)	(days)	(days)	Season (days)	Yearly Average (days)	Design Winter (days)
0°F or below	0	0	0	0	0	0	0	1
1°F - 5°F	0	0	7	0	0	7	0.1	4
6°F -10°F	0	2	16	10	0	28	0.6	0
11°F -15°F	0	12	45	16	1	74	2	5
16°F - 20°F	0	57	105	73	8	243	5	11
21°F - 25°F	3	111	190	132	32	468	10	10
25°F - 30°F	22	196	254	220	68	761	16	20
Total number of days winter temperature was 30°F or below	25	378	617	451	109	1,581	33	51
Average no. of days in a year winter temperature was 30°F or below	0.5	8	12	9	2	33	-	-

Findings:

- Historically, winter temperature of 5°F or below always occurred in January. This implies that PGW's planning for the design day to occur in January is *consistent* with the historical data.

- Historically, winter temperature in March has always been above 10°F; over the past 48 years, fewer than 5 times, the temperature has been 15°F or below during March. Therefore, it is *consistent* with the historical data to say that Design Day conditions are *not likely* to occur in March.

9. What is the probability that the coldest winter day in a year will occur in January?

Sample Data Set: 1948-95	Nov	Dec	Jan	Feb	Mar
Mean of monthly peak day temperatures (°F)	32	21	16	18	27
Lowest Temperature ever (°F)	21	6	1	6	15
No. of times the coldest day in a year occurred this month during the past 48 yrs.	0	10	23	16	2
Probability that the coldest day in a year will fall in this month (number of years)	0	1/5	1/2	1/3	1/24
Probability that the coldest day in a year will fall in this month (%)	0	20	47	33	4
PGW's Monthly Peak day/Design Day Winter Temperature (°F)	22	11	0	5	18

Findings:

- On average, coldest day of the year is *more likely* to be a day in January than in any other month. This implies that PGW's planning for the design day to occur in January is *consistent* with the historical data.

- On average, the likelihood of the coldest day of the year occurring in March is 4%. In other words, 96% of the time, the coldest day of the year is likely to occur in December, January,

or February. Therefore, it is *consistent* with the historical data to say that coldest day of the year is *less likely* to occur in March.

10. How does PGW's design day compare with those of other utilities in and around the region?

To evaluate PGW's design day with that of other utilities in the region, we compiled design day criteria adopted by other utilities in the region. To facilitate comparison across the design day planning criteria adopted by utilities and to compare other utilities' design day sendout planning with that of PGW's, we estimated relative potential design day sendout. It was calculated as follows: Relative potential Design Day Sendout = Sendout when the temperature is 0°F, which is assumed to equal 100% * [(65 degree days - Design Day Mean Temp.)/65] * (1 + PGW's sendout adjustment factor for wind speed + reserve margin). This formula assumes that sendout increases linearly to increases in wind speed and heating degree days. The following table compares the design day adopted by other utilities in the region with PGW's design day.

Utilities	Design Day Mean Temperature (°F)	Probability of Design Day occurrence[a] (years)	Design Day Wind Speed (mph)	Design Day Reserve Margin (%)	Increase in heating demand resulting from Design Day Wind Speed[b] (%)	Relative Potential Design Day Sendout[c] (%)
PGW, Philadelphia, PA	0	-	-	-	-	100
Baltimore Gas & Electric, Baltimore, MD	2.7	1:25	15	10.7	5	111
Peoples Natural Gas, Pittsburg, PA	-9	1:15	15.8	10[d]	5.6	132
UGI, Reading, PA	-1.1	1:20	-	-	-	102
Washington Gas Light, Washington, DC	5	-	17	0.6	6.2	99
48-year Historical Peak (1948-96)	1	1:48	n/a	-	-	98

Sources: (1) PGW's documents on Design Day Planning and Sendout Estimation; (2) "Analysis of LDC Peak Day Planning," prepared by Fosters Associates for American Gas Association. *Gas Energy Review*. March 1996, pp:7-10; (3) ICF Kaiser's Historical Temperature Data Analysis.

Notes:

[a] It is a design day planning criterion adopted by some utilities.

[b] It is the sendout adjustment factor used by PGW. For example, for a wind speed of 15 mph, other things equal, PGW will increase the sendout by 5%. There is no adjustment factor for wind speed of below 10 mph.

[c] It is the design day sendouts of utilities, relative to the peak winter day of 65 heating degree days.

[d] *Applies only to interstate supplies.*

n/a = Data not available.

Findings:

- PGW's design day is *consistent with* other utilities' design day planning and 48-year historical peak winter.

FILE

CONTINUED