BRINE DISPOSAL WELL PERMIT APPLICATION

SENECA WELL # 38282
(API # 37-047-32885)

ARM Group Inc.

Earth Resource Engineers and Consultants

Prepared for:

Seneca Resources Corporation
5800 Corporate Boulevard
Pittsburgh, PA 15237

Prepared by:

ARM Group Inc.
1129 West Governor Road
P.O. Box 797
Hershey, PA 17033-0797

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OMB No. 2040-0042 Approval Expires 12/31/2018

EPA

United States Environmental Protection Agency

Underground Injection Control Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number		T/A	C
U			

Read Attached Instructions Before Starting

For Official Use Only

Application approved (mo day year)	Date received (mo day year)	Permit Number	Well ID	FINDS Number

II. Owner Name and Address			III. Operator Name and Address		
Owner Name: Seneca Resources Corporation			Owner Name: Seneca Resources Corporation		
Street Address: 5800 Corporate Blvd., Suite 300		Phone Number: (412) 548-2500	Street Address: 5800 Corporate Blvd., Suite 300		Phone Number: (412) 548-2500
City: Pittsburgh	State: PA	ZIP CODE: 15237	City: Pittsburgh	State: PA	ZIP CODE: 15237

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
☐ Yes ☒ No	☒ Private ☐ Federal ☐ Other	☐ Owner ☒ Operator	1389 - Oil & Gas Field Services, not elsewhere classified.

VIII. Well Status *(Mark "x")*

☐ A Operating	Date Started (mo day year)	☒ B. Modification/Conversion	☐ C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

☒ A. Individual ☐ B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
	1	1	Seneca Well #38282 API # 37-047-32885

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
II	D	N/A	N/A

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
041	036	44.7	078	049	20.2								

XII. Indian Lands (Mark 'x')

☐ Yes
☒ No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
Doug Kepler, Vice President, Environmental Engineering	(814) 771-0281
C. Signature: DAKepler	D. Date Signed: 05/13/16

EPA Form 7520-6 (Rev. 12-11)

Well Class and Type Codes

Class I		Wells used to inject waste below the deepest underground source of drinking water.
Type	**"I"**	Nonhazardous industrial disposal well
	"M"	Nonhazardous municipal disposal well
	"W"	Hazardous waste disposal well injecting below USDWs
	"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II		Oil and gas production and storage related injection wells.
Type	**"D"**	Produced fluid disposal well
	"R"	Enhanced recovery well
	"H"	Hydrocarbon storage well (excluding natural gas)
	"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III		Special process injection wells.
Type	**"G"**	Solution mining well
	"S"	Sulfur mining well by Frasch process
	"U"	Uranium mining well (excluding solution mining of conventional mines)
	"X"	Other Class III wells (not included in Type "G," "S," or "U")
Other Classes		Wells not included in classes above. Class V wells which may be permitted under §144.12. Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	**Attachments**
I new well	A, B, C, D, F, H – S, U
existing	A, B, C, D, F, H – U
II new well	A, B, C, E, G, H, M, Q, R; optional – I, J, K, O, P, U
existing	A, E, G, H, M, Q, R, – U; optional – J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M – S, U
existing	A, B, C, D, F, H, J, K, M – U
Other Classes	To be specified by the permitting authority

INSTRUCTIONS - Underground Injection Control (UIC) Permit Application

Paperwork Reduction Act: The public reporting and record keeping burden for this collection of information is estimated to average 224 hours for a Class I hazardous well application, 110 hours for a Class I non-hazardous well application, 67 hours for a Class II well application, and 132 hours for a Class III well application. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, DC 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

This form must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for permit by the Director.

I. **EPA I.D. NUMBER** - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. **OWNER NAME AND ADDRESS** - Name of well, well field or company and address.

III. **OPERATOR NAME AND ADDRESS** - Name and address of operator of well or well field.

IV. **COMMERCIAL FACILITY** - Mark the appropriate box to indicate the type of facility.

V. **OWNERSHIP** - Mark the appropriate box to indicate the type of ownership.

VI. **LEGAL CONTACT** - Mark the appropriate box.

VII. **SIC CODES** - List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VIII. **WELL STATUS** - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if wells(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

IX. **TYPE OF PERMIT** - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

X. **CLASS AND TYPE OF WELL** - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of the application. When selecting type X please explain in the space provided.

XI. **LOCATION OF WELL** - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR Part 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

XII. **INDIAN LANDS** - Place an "X" in the box if any part of the facility is located on Indian lands.

XIII. **ATTACHMENTS** - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page of the Attachments.

XIV. **CERTIFICATION** - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. **AREA OF REVIEW METHODS** - Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation).The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

B. **MAPS OF WELL/AREA AND AREA OF REVIEW** - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. **CORRECTIVE ACTION PLAN AND WELL DATA** - Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

Class I

A description of each well's types, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include the corrective action proposed to be taken by the applicant under 40 CFR 144.55.

Class II

In addition to requirement for Class I, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. **MAPS AND CROSS SECTION OF USDWs** - Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. **NAME AND DEPTH OF USDWs (CLASS II)** - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA** - Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. **GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II)** - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. **OPERATING DATA** - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. **FORMATION TESTING PROGRAM** - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. **STIMULATION PROGRAM** - Outline any proposed stimulation program.

K. **INJECTION PROCEDURES** - Describe the proposed injection procedures including pump, surge, tank, etc.

L. **CONSTRUCTION PROCEDURES** - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)

M. **CONSTRUCTION DETAILS** - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. **CHANGES IN INJECTED FLUID** - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injection fluid. (Class III wells only.)

O. **PLANS FOR WELL FAILURES** - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, so as to prevent migration of fluids into any USDW.

P. **MONITORING PROGRAM** - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. **PLUGGING AND ABANDONMENT PLAN** - Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

R. **NECESSARY RESOURCES** - Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. **AQUIFER EXEMPTIONS** - If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04.

T. **EXISTING EPA PERMITS** - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. **DESCRIPTION OF BUSINESS** - Give a brief description of the nature of the business.

INTRODUCTION

Seneca Resources Corporation (Seneca) is proposing to convert one of its gas production wells (Seneca Well # 38282, API # 37-047-32885) into an Underground Injection Control (UIC) Class II D Injection Well. The proposed UIC Class II D Injection Well (herein referred to as "Proposed Injection Well") is located in the Kane Field (SRC Warrant 3771) in Highland Township, Elk County, Pennsylvania. Seneca owns and operates numerous gas wells in the Kane Field area.

This application package provides details concerning the Proposed Injection Well and associated monitoring wells (Seneca Well #s 04406, & 04384). In addition, the Proposed Injection Well is less than one-mile south of a recently permitted injection well (Well # 38268, API # 37-047-23835). In 2012, Seneca submitted a Class II D Injection Well Permit Application for Well # 38268. The Permit Application for the Well # 38268 was approved by the United States Environmental Protection Agency (EPA) on June 17, 2014. Both the Proposed Injection Well and Well # 38268 share the same reservoir (Elk 3 Sand). The Elk 3 Sand has been a primary gas reservoir in the Kane Field for over 100 years, as natural gas has been extracted from the Elk 3 sandstone reservoir since 1898. The Elk 3 Sand is now considered to be a depleted reservoir as evidenced by the reservoir pressure decline curves and significant volumes of gas produced since 1898 (as documented herein). As such, Seneca is utilizing the injectivity testing results that were used for Well # 38268 in lieu of additional injectivity testing.

1.0 AREA OF REVIEW METHODS/CALCULATIONS

As part of the UIC Class II D Injection Well Permit Application for Well #38268 (the previously approved injection well), Tetra Tech prepared a document entitled "Area of Review/Zone of Endangerment Analysis for Potential Brine Disposal Injection Well # 38268" dated June 14, 2012. The document summarizes the analytical modeling performed for the area of review/zone of endangerment analysis for Seneca's proposed brine disposal injection Well #38268. The results of the analysis indicated that the increase in head due to the brine disposal injection Well #38268 would remain below the elevation of the lowest most underground source of drinking water (USDW), and that the default area of review of a ¼ mile radius was applicable to the Well #38268 UIC permit application. A copy of the June 14, 2012, document is provided in Appendix B. A copy of the 2012 Injectivity Test Report for Seneca Well #38268 prepared by Tetra Tech is provided in Appendix C. Because of the similarities in well construction and the proximity of the previously permitted Well (#38268) and the Proposed Injection Well, the area of review and injectivity test data are reiterated herein.

The June 14, 2012 Tetra Tech memo referenced above summarized the analytical modeling completed by Tetra Tech. There are multiple methods utilized for calculating the zone of endangerment of an injection well. The most simplistic method is the use of a fixed radius, based on the type of injection well being permitted. Other methods involve calculation of the radius based on well and formation properties. The method used by Tetra Tech is the graphical method first used by EPA Region 6 and involves the calculation of the increase of pressure in the formation due to injection. That pressure is then converted into equivalent feet of head. The increase in head in the formation due to injection is then compared to the equivalent head of the lowest most USDW. When plotted graphically, the intersection of those two curves at some distance (r), determines the radius of the zone of endangerment. The increase in pressure in the formation due to injection depends on the properties of the injection fluid and the formation, the rate of fluid injection, and the length of time of injection. The most common mathematical expression to describe this increase in pressure was developed by Matthews and Russell (1967). Matthews and Russell assume that, for a single well injecting into an infinite, homogeneous and isotropic, non-leaking formation, the increase in pressure (delta p) can be described as:

delta p = $162.6\ Q\ \mu\ /\ kh * [(\log(kt\ /\ \Psi\ \mu C r^2)\ -3.23]$ where:

delta p = pressure change (psi) at radius, r and time, t
Q = injection rate (barrels/day)
μ = injectate viscosity (centipoise)
k = formation permeability (millidarcies)
h = formation thickness (feet)
t = time since injection began (hours)
C = compressibility (total, sum of water and rock compressibility) (psi^{-1})
r = radial distance from well bore to point of investigation (feet)
Ψ = average formation porosity (decimal)

The following parameters were used in the zone of endangerment analysis completed by Tetra Tech. The majority of the parameters are based on the analysis and results of the injection testing performed on Well #38268 in March 2012 (Tetra Tech, 2012). The permeability value was based on the results from the injection testing analysis. For the depth to the lowest most USDW, a conservative estimate based on EPA Region 3 guidance and review of site area hydrogeologic conditions was used (i.e., depth to USDW = 400 feet).

Input Parameters for Well #38268

Q = 3,000 barrels/day
t = 10 years = 87,600 hours
μ = 0.9457 centipoise
k = 190 md
h = 49 feet
C = 7.6e-06 psi^{-1}
Ψ = 13.5%
Well radius = 0.29 feet
Specific gravity of injectate = 1.14
Surface elevation = 2,040 feet
Depth to injection formation = 2,354 feet
Base of lowest most USDW (elevation) = 1,640 feet
Initial pressure at top of injection formation = 24 psi

1.1 Results

The Matthews and Russell equation was solved for various distances from the wellbore based on the parameters listed above for permeability value determined from the injection test. The values of delta p were added to the existing pressure in the injection formation to obtain the total pressure in the formation. These values were then converted to feet of head of formation brine. The results are shown in Figure 1 of Appendix B, which shows the calculated pressure surface within the injection formation, measured as feet of head of formation brine above the top of the injection formation. Also shown is the head of the lowest most USDW. If the two lines were to intersect, it would define the radius of the zone of endangerment. For the permeability value of k = 190 md, the increase in head due to injection would remain below the elevation of the lowest most USDW. This permeability value was obtained from injection testing analysis of Well #38268.

1.2 Conclusions

The Tetra Tech analysis of the area of review/zone of endangerment for proposed brine disposal injection wells is based on a methodology typically used by US EPA. For the permeability value of k = 190 md (obtained from injection testing analysis of Well #38268), increase in head due to injection would remain below the elevation of the lowest most USDW. Based on these results and their applicability to the Proposed Injection Well, the well is an excellent candidate for use as a brine disposal well.

In summary, the default area of review of a 0.25 -mile radius from the Proposed Injection Well is applicable for this application.

2.0 AREA OF REVIEW

According to publicly available records, including the Pennsylvania Geologic Survey's Ground Water Information System (PAGWIS) and the Pennsylvania Department of Environmental Protection's Drinking Water Reporting System (DWRS), there are no groundwater wells within the ¼-mile Area of Review for the Proposed Injection Well. The only active oil and gas wells located within ¼-mile of the Proposed Injection Well are Seneca Wells #04406 and #04384, and both of these wells are proposed as monitoring wells for Well #38282 (Table 1). Seneca Well #38281 is located 0.36 miles from the Proposed Injection Well, and Well #38281 is identified as a monitoring well for the previously permitted injection well (#38268).

According to records available through the DWRS, Highland Township (James City) maintains a public water supply consisting of two springs (one active and one inactive), two reserve water wells, and associated pumps, pipes, and storage tanks which are a minimum of over 5,000 feet from the Proposed Injection Well. PAGWIS indicates that a private water well, owned by Randy Klaiber, is located 1.01-miles from the Proposed Injection Well. Additional private well locations within one-mile of the Proposed Injection Well were identified by Seneca based on field reconnaissance, as shown on Figure 1. There are no other identified intake or discharge structures; hazardous waste treatment, storage, or disposal facilities; mines; or quarries within one mile of the Proposed Injection Well. Available information regarding water wells and springs within one-mile of the Proposed Injection Well is provided in Table 2.

A High Quality-Cold Water Fishery (HQ-CWF)-designated unnamed tributary to the East Branch of Tionesta Creek is located approximately 0.7-miles northeast of Well #38282, a HQ-CWF-designated unnamed tributary to Wolf Run is located approximately 0.23-miles northwest of Well #38282, and a HQ-CWF designated unnamed tributary to Wolf Run is located approximately 0.7-miles west of the Proposed Injection Well. The locations of these tributaries are shown in Figure 1.

3.0 CORRECTIVE ACTION PLAN AND WELL DATA

Two wells penetrated the same zone of injection within 0.25-miles of the subject well: Well #04406, and Well #04384. A third well, Well #38281, penetrated the same zone of injection within 0.36-miles of the subject well. All three wells are owned by Seneca and are gas producing wells. The productive intervals of the subject well (#38282) and the three wells within 0.36-miles are shown on Tables 3, 4, 5, and 6.

3.1 Existing Oil and Gas Wells within the Area of Review

Well completion records are required to be submitted for all wells located within the area of review in order to evaluate the need for corrective action specific to each well. The well completion reports for the Proposed Injection Well (Well #38282), and the proposed monitoring wells (Wells #04406, and #04384) are provided in Appendices D, E, and F, respectively. As discussed further in Section 8, Wells #04406, and #04384 will be utilized as monitoring wells and will be properly constructed for that purpose.

3.2 Plugged and Abandoned Oil and Gas Wells within the Area of Review

There are no plugged and abandoned wells within the ¼-mile area of review (AOR) for the Proposed Injection Well (Well #38282). Therefore, no additional corrective action is necessary within the AOR.

4.0 NAME AND DEPTH OF USDWs

The Proposed Injection Well (Well #38282) lies within the Glaciated High Plateau section of the Appalachian Plateaus Physiographic province. The High Plateau Section consists of broad, rounded to flat uplands cut by deep angular valleys. The uplands are underlain by flat-lying sandstones and conglomerates. Local relief between valley bottoms and adjacent uplands can be as much as 1,000-feet, but typically average approximately 500-feet. Elevations in the area range from 980 to 2,630-feet. Dendritic drainage patterns are typical for this area. The western boundary of the area is the Late Wisconsin glacial border. The area between this border and the Allegheny River a few miles to the east was glaciated by pre-Wisconsin glaciers. The area occurs in northwestern Pennsylvania and includes all of Forest County, most of Venango, Warren, and Elk Counties, and small parts of McKean, Jeffereson, and Clarion Counties (http://www.dcnr.state.pa.us/topogeo/map13).

Potable water is generally obtained from bedrock sources in the project area. The uppermost bedrock unit at the site is the Allegheny Group of Pennsylvanian Age. The Allegheny Group consists of limestone, sandstone, shale, and coal deposits. At a depth of 30 to 35-feet below ground surface (bgs), the Pennsylvanian Pottsville Group also consists of limestone, sandstone, shale, and coal deposits. At approximately 200-feet bgs lies the Mississippian/Devonian-Age Shenango through Oswayo groups (undivided), which consist of sandstone, siltstone, and shale. The Upper Devonian siltstones, shale, and sands are present beneath the site beginning from approximately 500-feet bgs to the total depth of the borehole at 2,565 feet bgs. (http://www.dcnr.state.pa.us/topogeo/index.aspx). The geologic units are described further in Section 5.

The PAGWIS and the DWRS were accessed to determine the sources of drinking water in the site area. According to these publicly available sources, there are no groundwater wells within ¼-mile of the Proposed Injection Well.

According to records available through the DWRS, Highland Township (James City) maintains a public water supply (ID #6240006) consisting of two springs (one active and one inactive), two reserve water wells, and associated pumps, pipes, and storage tanks which are a minimum of over 5,000 feet from the Proposed Injection Well (Well #38282). PAGWIS indicates that a private water well, owned by Randy Klaiber, is located 1.01-miles from the Proposed Injection Well. Additional possible private well locations within one-mile of Well # 38282 (and slightly beyond one mile of Well #38282) were identified by Seneca based on field reconnaissance, as shown on Figure 2. There are no other identified intake or discharge structures; hazardous waste treatment, storage, or disposal facilities; mines; or quarries within one mile of the Proposed Injection Well. Available information regarding water wells and springs within one-mile of the Proposed Injection Well is provided in Table 2.

PAGWIS lists only one well within one-mile of Well #38282; however, the well reporting requirement was only established in 1968. PAGWIS is not considered to be a complete record of water wells in the vicinity and other wells may be present (PAGWIS).

Well #38282 is located in the northeastern portion of Highland Township of Elk County. To better understand the underground sources of drinking water, the PAGWIS was searched for all wells within Highland Township and Jones Township (bordering east of Highland Township) of Elk County, and Wetmore Township (bordering north of Highland Township) of McKean County. The PAGWIS indicated that there are 49 recorded wells in Highland Township. Twelve of these wells are owned by National Fuel Gas and according to PAGWIS are listed as test wells (i.e., natural gas wells) ranging from 1,176 to 2,348-feet deep. The deepest water withdrawal well is listed as 320 feet deep, with reported well depths ranging from 58 to 320-feet deep.

The PAGWIS indicated that there are 155 recorded wells in Jones Township. Four of these wells are owned by National Fuel Gas and are listed as test wells (i.e., natural gas wells) ranging from 2,331 to 2,389-feet deep. The deepest water well is listed as 320-feet deep, with reported well depths ranging from 60 to 320-feet deep.

The PAGWIS indicated that there are 41 recorded water wells in Wetmore Township. The deepest well is listed as 245-feet deep, with reported well depths ranging from 55 to 245-feet deep. Based on the available information, the Allegheny Group, Pottsville Formation, and Shenango Group are utilized as underground sources of drinking water in the site area.

In summary, PAGWIS indicates that the deepest ground water wells in the site area are approximately 320-feet deep. Based on this information and the site geologic conditions, 400-feet bgs has been identified as a conservative estimate of the base of the lowermost USDW for the Proposed Injection Well area. It is noted that surface casing for the Proposed Injection Well extends to 561-feet, which is greater than 200 feet deeper than the deepest groundwater drinking source in the Tri-Township Area.

All of the property located within ¼-mile of the Proposed Injection Well is owned by Seneca.

5.0 GEOLOGIC DATA ON INJECTION AND CONFINING ZONES

The uppermost units at the site are mapped as the Allegheny Group of Pennsylvanian Age and the Pennsylvanian-Age Pottsville Group of which both consist of limestone, sandstone, shale, and coal deposits. At approximately 200-feet bgs, the Mississippian/Devonian-Age Shenango through Oswayo groups (undivided) consist of sandstone, siltstone, and shale to approximately 500-feet bgs. The Upper Devonian siltstones, shale, and sands are present beneath the site beginning from approximately 500-feet bgs. Based on structural contour maps from the Pennsylvania Geological Survey, the Precambrian basement rock is located approximately 9,500 feet below the proposed injection zone.

5.1 Injection and Confining Zones

The Proposed Injection Well is designed to inject into the Upper Devonian Elk 3 Sand, with injection into notched and frac'd intervals at a depth of 2,327 to 2,372 feet bgs. As shown on the generalized stratigraphic column (Figure 6), most of the geologic Groups and Formations overlying the Elk 3 Sand can be considered confining units totaling over 2,000-feet. Although many of these units are predominantly shale and siltstone, the Upper Devonian Speechley Sand also contains reservoir rock. The confining zone immediately above and adjacent to the Elk 3 Sand is designated by Seneca as the Elk 3 shale. There are additional shales, silty shales, and siltstones above the Elk 3 which provide additional confining zones.

As depicted in the graph in Appendix A, Attachment 2, the initial reservoir pressures of 425-440 pounds per square inch (psi) were documented when the Elk 3 reservoir was first produced in 1898. Over time, reservoir pressure decreased as production continued. In June 2013, Seneca shut-in Well #38268 and others around it to record current reservoir pressures. Well # 38268 had a shut-in casing pressure of 26.6 psi and nearby wells had pressures ranging from 20.6 psi to 54.3 psi.

The Elk 3 has been a substantial gas-producing reservoir since the late 1800s. Estimated cumulative production from selected wells near Well #38268 is summarized in the table provided in Appendix A, Attachment 3. The Elk 3 Sandstone is a depleted reservoir, as evidenced by the reservoir pressure decline curves and significant volumes of gas produced since 1898.

Also provided herein are the following documents:

- Appendix D - Seneca #38282 (proposed Seneca injection well) completion record, treatment record, service company job logs documenting cement returns, and geophysical log
- Appendix E - Seneca #04406 (proposed monitoring well) completion record and treatment report
- Appendix F - Seneca #04384 (proposed monitoring well) completion record and treatment report

5.2 Review of Induced Seismicity Potential

The EPA recently published a report that looks at injection-induced seismicity ("Minimizing and Managing Potential Impacts of Induced-Seismicity from Class II Disposal Wells: A Practical Approach," EPA UIC National Technical Workgroup, finalized February 5, 2015), which provides a standard operating procedure for assessing regional and local seismicity when reviewing permit applications. This procedure correlates any area seismicity with past injection practices; evaluates geological information to assess the likelihood of activating any faults; evaluates storage capacity of the formation with consideration of porosity and permeability; includes operational parameters to limit injection rate and volume and to limit operation at below fracture pressure; and requires monitoring of injection pressure and rates. (EPA, 2015)

5.2.1 Induced Seismicity Background

Under certain conditions, disposal of fluids through injection wells has the potential to trigger seismicity. However, induced seismicity associated with brine injection is uncommon, as conditions necessary to trigger seismicity often are not present. Seismic activity induced by Class II wells is likely to occur only where *all* of the following conditions are present: (1) there is a fault in a near-failure state of stress; (2) the fluid injected has a path of communication to the fault; and (3) the pressure exerted by the fluid is high enough and lasts long enough to allow movement along the fault line. Although there are approximately 30,000 Class II-D wastewater disposal wells operating in the United States, only a few of these wells have been documented to have triggered earthquakes of significance and none of these earthquakes has caused injected fluids to flow into or contaminate a USDW.

The presence of a fault in a receiving formation potentially creates a more vulnerable condition for a future seismic event. Where a fault is present near an injection site, injection can potentially trigger seismicity when the pore pressure (pressure of fluid in the pores of the subsurface rocks) in the formation increases to such levels as to overcome the frictional force that keeps the fault stable. Pore pressure increases with increases in the volume and rate of injected fluid. Thus, the probability of triggering a significant seismic event due to injection, where the injection fluid reaches an active fault, increases with the volume and the rate of fluid injected. At high enough pore pressure, the reduction in frictional forces can result in the formation shifting along the fault line, resulting in a seismic event. (EPA, 2015)

5.2.2 Faults Near the Proposed Injection Well

The EPA UIC permit regulations require that all new Class II injection wells be sited in such a fashion that they inject into a formation which is separated from any USDW by a confining zone that is free of known open faults or fractures within the AOR. Open faults, or transmissive faults, may allow fluid to move along the fault and between formations. Nontransmissive faults, on the other hand, act as a barrier which would prevent movement of fluid along the fault and into another formation across the fault. The UIC Class II requirements focus on ensuring that open faults are not present within the area an injection operation could influence. (EPA, 2015)

Seneca has been operating in this area for over 100 years and is not aware of any faults, transmissive or nontransmissive, within the AOR that could be influenced by the injection operation. In addition, Precambrian basement rocks are located approximately 9,500 feet below the proposed injection zone, and therefore, are not considered to be a concern at this location.

The United States Geologic Survey (USGS) tracks, records and maps faults and earthquake epicenters in certain areas throughout the United States. The USGS monitors several active seismometers located in Pennsylvania. The USGS as well as the Pennsylvania Department of Conservation and Natural Resources (PA DCNR) which includes the Bureau of Topographic and Geologic Survey have not recorded any seismic activity that has originated in Elk or McKean County. The following PA DCNR website has an interactive seismicity map and catalog of all recorded seismic events in or near Pennsylvania from 1724 to present: (http://www.dcnr.state.pa.us/topogeo/hazards/earthquakes/index.html).

Reference:

EPA (2015) - Response to Comments for the Issuance of an Underground Injection Control (UIC) Permit for Sammy-Mar LLC, US Environmental Protection Agency - Region III, Environmental Appeals Board, September 10, 2015

6.0 OPERATING DATA

The Proposed Injection Well (#38282) will primarily be utilized to inject produced water and flow-back water from wells completed in the Marcellus Shale, the Elk 3 Sand and other natural gas and oil producing formations. Other oil and gas-related wastewaters associated with the production of oil and natural gas or natural gas storage operations, which are approved by EPA for injection under a UIC Class II D injection well, may also be injected. According to Title 40 Chapter I Sec. 144.6(b)(1), such fluids include those "Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be co-mingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection."

6.1 Injection Rate

Injectivity testing performed on the previously proposed injection well (Seneca Well #38268) indicated the well may be capable of sustaining an injection rate of greater than 2 barrels per minute (bbl/m, approximately 3,000 bbl/d) with pressures remaining under the likely UIC Class IID permit limits for maximum injection pressure. Seneca proposes a maximum injection rate of 3,000 bbl/day for operation of the Well #38282, with an average injection rate of 2,000 bbl/day expected. The Injectivity Test Report for Well #38268 (Tetra Tech, 2012) is provided in Appendix C.

6.2 Maximum Allowable Surface Injection Pressure (MASIP) and Average Surface Injection Pressure

MASIP calculations based on EPA-approved equations are shown below. Based on these calculations, the proposed MASIP is 1,416 psi. Seneca estimates that the average surface injection pressure will be approximately 1,000 psi.

Maximum Injection Pressure (MIP)
Calculations for Seneca Well #38268

1) Frac Gradient (FG) Based on Well #38268 Elk 3 Sand Frac

FG = [ISIP + (0.433 x SG x D)]/D, where

Instantaneous Shut-In Pressure (ISIP) (psi)	Hydrostatic Factor (psi/ft)	Specific Gravity (SG)	Depth (ft)
1,580	0.433	1 (Water)	2,354

FG = [1,580 psi + (0.433 psi/ft x 1 x 2,354 ft)] / 2,354 ft
FG = 1.104 psi/ft

2) Maximum Injection Pressure (MIP)

MIP = [FG - (0.433 x SG)] x D, where

Frac Gradient (FG) (psi/ft)	Specific Gravity (SG)	Depth (ft)
1.104	1.16 (Brine)	2,354

MIP = [1.104 psi/ft - (0.433 psi/ft x 1.16)] x 2,354 ft

MIP = 1,416 psi

Should brine with a specific gravity greater than 1.16 be injected, Seneca understands that the MIP will need to be reduced accordingly.

6.3 Laboratory Analysis of Injection Fluid Samples

A summary of laboratory analytical results for samples representative of the types of brine which will be injected into the Proposed Injection Well are attached in Appendix G. Samples were collected from produced water generated from gas wells in the vicinity of the Proposed Injection Well. The samples are characterized by an average specific gravity of approximately 1.14, an average pH of 6.08, and an average conductivity of 194.09 microSiemens per centimeter (uS/cm). In addition, Seneca completed a Total Organic Carbon (TOC) analysis of the types of brine which will be injected into the Proposed Injection Well. The TOC concentration was reported as 5.49 milligrams per liter (mg/l). The laboratory analytical report is included in Appendix G.

6.4 Monitoring of Injection Fluid Samples and Well

The following identifies the UIC Class II underground injection well regulatory requirements and the operational procedures which will be conducted by Seneca to meet the subject requirements:

1. **Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics.** A sample of fluid will be collected and analyzed from initial loads proposed for disposal. In addition, samples will be collected for analysis from new types of sources (e.g., from different geologic formations, geographic regions, etc.) which would be expected to differ significantly from brine previously characterized for disposal at the facility. Samples will be analyzed for the following parameters at a minimum: specific gravity, total dissolved solids, total organic carbon, and pH.

2. **Observation of injection pressure, flow rate, and cumulative volume at least weekly based on the regulatory requirements for produced fluid disposal operations.** Injection pressures, flow rate, and cumulative volume will be continuously recorded electronically.

3. **A demonstration of mechanical integrity pursuant to 40 CFR Sec. 146.8 at least once every five years during the life of the injection well.** A mechanical integrity test will be performed prior to initiating injection and at least once every five years during the life of the injection well.

4. **Maintenance of the results of all monitoring until the next permit review.** All monitoring records will be maintained throughout the life of the injection well.

In addition to the commitments listed above, Seneca will prepare and submit an annual report to EPA summarizing the results of the required monitoring, including monthly records of injected fluids and any major changes in characteristics or sources of injected fluid.

6.5 Proposed Annulus Fluid

The proposed annulus fluid for the Proposed Injection Well will consist of fresh water and a water-soluble corrosion inhibitor. The corrosion inhibitor will be mixed in accordance with the manufacturer's recommendations and loaded into the well annulus prior to conducting injection operations. Product information for the type of corrosion inhibitor which will be utilized is attached in Appendix H. A similar type product may be substituted by Seneca.

6.6 Facility Layout and Operation

As indicated in the attached facility layout diagram (Figure 7), the injection well facility will include a truck unloading area and holding tanks connected by piping with associated valves, all of which will be situated in a diked containment area. The containment area will be properly sized to account for the entire volume of the largest container, plus 10% freeboard. The brine will be transferred to the injection well utilizing injection pumps situated in the equipment shed along with filters and monitoring equipment. Automatic shut-off valves will be incorporated into the tank design to prevent overflow during filling operations. The facility will be surrounded by a fence equipped with locking entrance and exit gates. A security camera will also be strategically situated on the site. The facility will be continually manned during unloading and injection operations. As indicated above, injection rate, cumulative volume and pressures will be continuously measured and recorded.

7.0 WELL CONSTRUCTION DETAILS

Well construction details for Wells #38282, #04406, and #04384 are provided in Figures 8, 9, and 10, respectively.

8.0 MONITORING PROGRAM

Prior to the commencement of injection operations at Well #38282, Seneca will install 4-½ inch casing, cementing it back to the surface. A 2-⅞ inch tubing will be installed on a packer set immediately above the injection zone. This tubing will be used to convey fluid from the surface directly to the Elk 3 Sand. The annulus between the tubing and the 4-½ inch casing will be filled with anti-corrosive agents to protect both the tubing and the casing. Seneca will monitor pressure and fluid level (utilizing an Echometer) in the annulus between the 4-½ inch casing and the 2-⅞ inch tubing prior to injection operations and quarterly thereafter while injection is occurring at Well #38282. Prior to monitoring being performed at Wells #04406, and #04384, each well will be shut-in and modified to isolate the Elk 3 Sand. This will be done to effectively monitor conditions in the Elk 3 Sand only.

Wells #04406, and #04384 were both drilled in 1942 and will be utilized as monitor wells for injection at Well #38282 (Figure 4). Well construction diagrams for these wells are attached as Figure 9 and 10 respectively. Seneca will plug back above the Elk 3 Sand, install 4-½ inch casing on a formation packer, and then cement the casing in place. Subsequently, the plug, cement, and plug back material will be drilled out in order to regain full communication with the Elk 3 Sand below the production casing.

Seneca proposes to conduct quarterly monitoring at the monitor wells. At the beginning of each monitoring period, each monitoring well will be shut in for a period of approximately one week to allow for equilibration with respect to pressures and fluid levels in the Elk 3 Sand. Once equilibrium has been reached in the monitoring wells, Seneca will record surface pressures and downhole fluid levels. If fluid levels in the Elk 3 Sand in the monitoring wells are stable, Seneca reserves the right to pump, swab, or bail the fluid out of the wellbore in order to effectively produce gas from the injection zone.

If the fluid level in any monitoring well is observed to rise to within 100-feet of the base of the USDW, disposal operations in Well #38282 will be stopped immediately, EPA will be notified, and operating conditions will be evaluated in order to control the fluid levels.

Injection Well	Monitoring Well	Approximate Distance and Direction From Injection Well
Seneca #38282	Seneca #04406	1,000-feet northwest
Seneca #38282	Seneca #04384	1,000-feet northeast

9.0 PLUGGING AND ABANDONMENT PLAN

At the point when the Proposed Injection Well is no longer used, the well will be abandoned in accordance with EPA and PADEP regulations. With regard to PADEP regulations, this currently includes providing a "Notice of Intent to Plug a Well" no less than 3 days and no more than 30 days prior to abandoning the well, to allow a PADEP inspector to be present during the plugging procedure. The PADEP may waive the notification period. The notification that Seneca will provide will include the well location plat, well logs, production logs, injection logs, construction details, and proposed abandonment method. After receiving approval from PADEP to proceed, the well will be abandoned and the abandonment procedures will be documented on a "Certificate of Plugging".

A contractor cost estimate to perform plugging and abandonment according to the proposed plugging plan is attached in Appendix I. The contractor estimate is $22,300. In addition, a $10,000 contingency has been added resulting in a total estimate of $32,300 for plugging and abandonment costs. The EPA will be notified of the plugging activity at least 45 days prior to commencing activities. This notification will include EPA Form No. 7520-14. A proposed plugging plan (Form 7520-14) is attached in Appendix J based on the current PADEP and EPA regulations. However, this may be modified prior to plugging in order to meet the requirements at the time of the plugging activity.

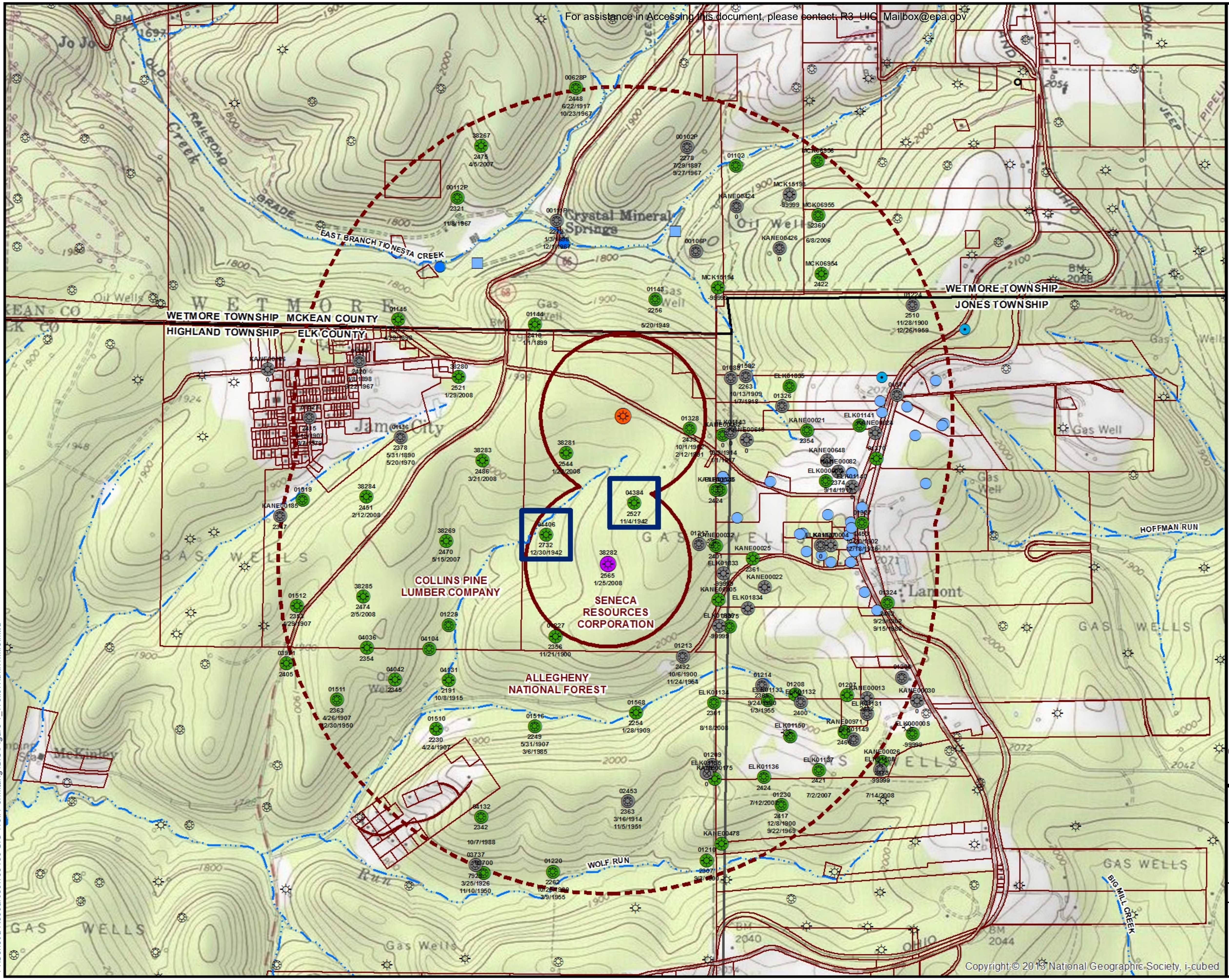
10.0 NECESSARY RESOURCES

Attached are the Seneca Resources Corporation Financial Statements to demonstrate that the company has the resources necessary to plug and abandon the well. Seneca Resources Corporation is a subsidiary of National Fuel Gas Company. The Chief Financial Officer (CFO) of National Fuel Gas Company has completed the CFO Letter for Class II Injection Well Operators on Seneca's behalf (Appendix K). Also enclosed are copies of the 2015 National Fuel Gas Company Annual Report, and the 2015 U.S. Securities and Exchange Commission Form 10-K.

11.0 PLAN FOR WELL FAILURES

Seneca will continuously monitor the pressure in the annulus between the 4 ½-inch casing and tubing during injection at the Proposed Injection Well. Should a pressure increase occur in the monitored space, injection will cease and EPA will be verbally notified within 24 hours and notified in writing within 7 days. The cause of the pressure increase will be investigated by Seneca, and remedial measures will be implemented following discussions with EPA on the proposed approach.

FIGURES



LEGEND

- PERMITTED INJECTION WELL
- PROPOSED INJECTION WELL
- 1/4 MILE RADIUS
- 1 MILE RADIUS
- PROPOSED MONITORING WELL
- PARCEL BOUNDARY
- LOCATED OIL AND GAS WELL
- NO WELL FOUND
- PRIVATE WATER WELL
- POSSIBLE WATER WELL (BASED ON FIELD OBSERVATIONS BY SENECA)
- SPRING (JAMES CITY WATER AUTHORITY)
- WATER WELL (JAMES CITY WATER AUTHORITY)

WELL STATUS

- EXISTING
- PLUGGED/ABANDONED
- LOCATION
- UNKNOWN

REF: Base map from ESRI USA Topo Maps. Refer to USGS 7.5 minute Quads Kane and James City, PA.

0 750 1,500 3,000 4,500
SCALE IN FEET

Wells Within 1 Mile of Seneca Wells 38268 & 38282

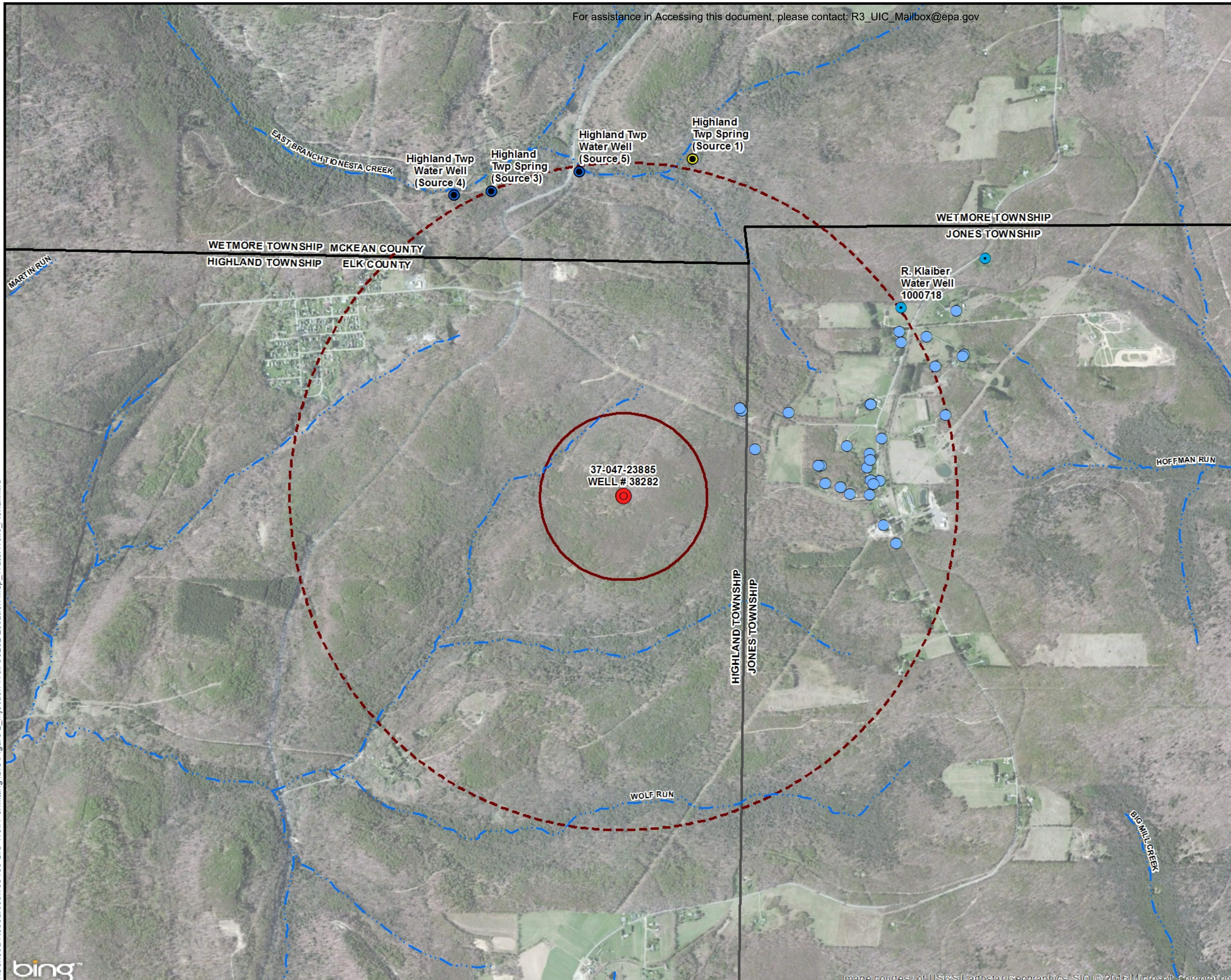
Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

May, 2016	Scale: 1" = 1,500'	160105

ARM Group Inc.
Earth Resource Engineers and Consultants
www.armgroup.net

Figure 1

For assistance in Accessing this document, please contact: R3_UIC_Mailbox@epa.gov



LEGEND

- WELL # 38282
- AREA OF REVIEW (1/4 MILE)
- 1 MILE RADIUS
- PRIVATE WATER WELL
- POSSIBLE WATER WELL (BASED ON FIELD OBSERVATIONS BY SENECA)
- ACTIVE WATER SUPPLY
- BACKUP WATER SUPPLY

REF: Base map from Bing Maps, dated 2011.

0 750 1,500 3,000 4,500
SCALE IN FEET

Location Map (Aerial) with Water Sources

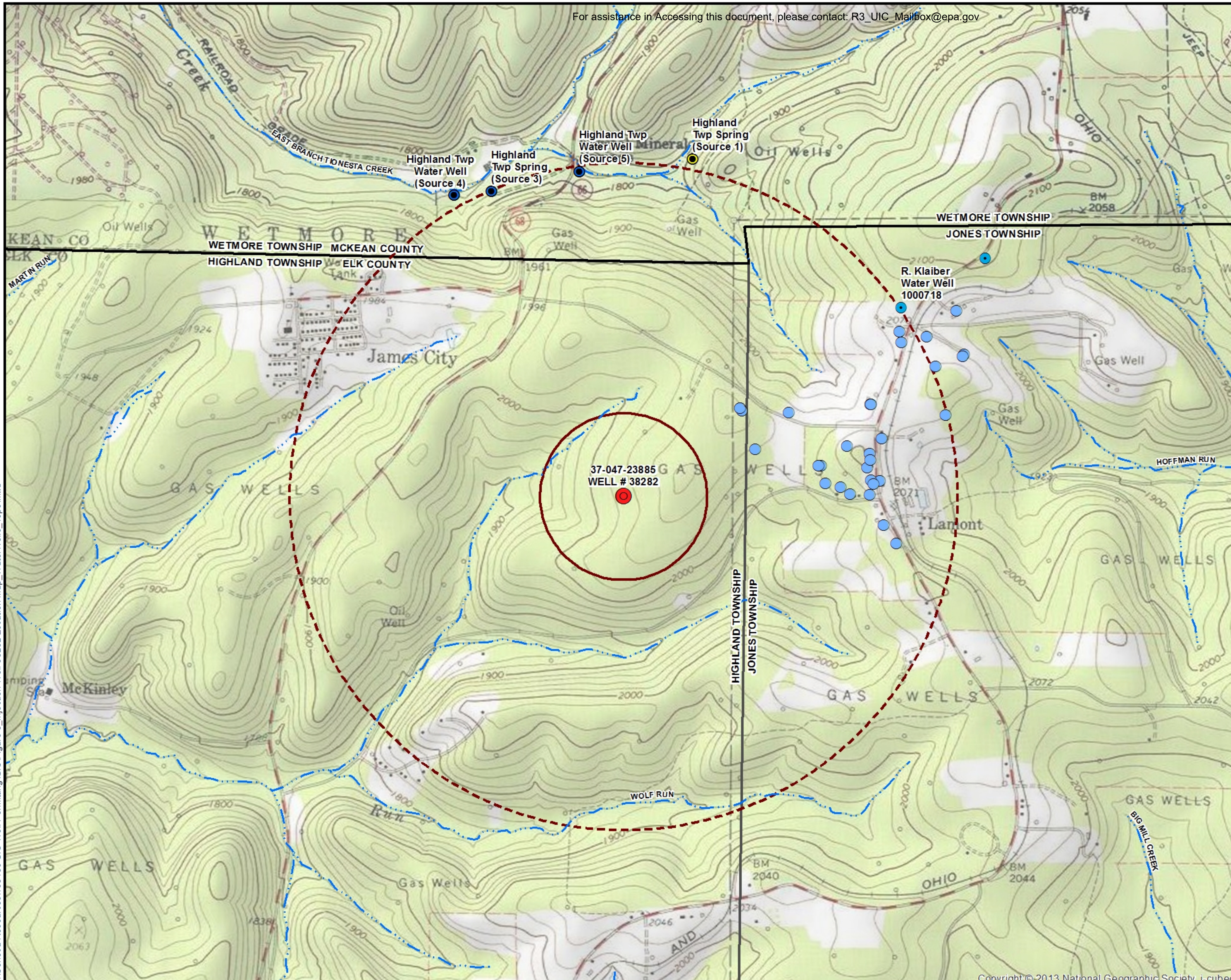
Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

March, 2016	Scale: 1" = 1,500'	160105

ARM Group Inc.
Earth Resource Engineers and Consultants
www.armgroup.net

Figure 2

P:\Seneca Resources\160105 UIC Well Permitting\GIS\Figure 2_Injection Well 38282 Location Map_WaterWells_Aerial.mxd



P:\Seneca Resources\160105 UIC Well Permitting\GIS\Figure 3_Injection Well 38282 Location Map_WaterWells_Topo.mxd

N

LEGEND

- WELL # 38282
- AREA OF REVIEW (1/4 MILE)
- 1 MILE RADIUS
- PRIVATE WATER WELL
- POSSIBLE WATER WELL (BASED ON FIELD OBSERVATIONS BY SENECA)
- ACTIVE WATER SUPPLY
- BACKUP WATER SUPPLY

REF: Base map from ESRI USA Topo Maps. Refer to USGS 7.5 minute Quads Kane and James City, PA.

0 750 1,500 3,000 4,500

SCALE IN FEET

Location Map (Topo) with Water Sources

Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

March, 2016	Scale: 1" = 1,500'	160105

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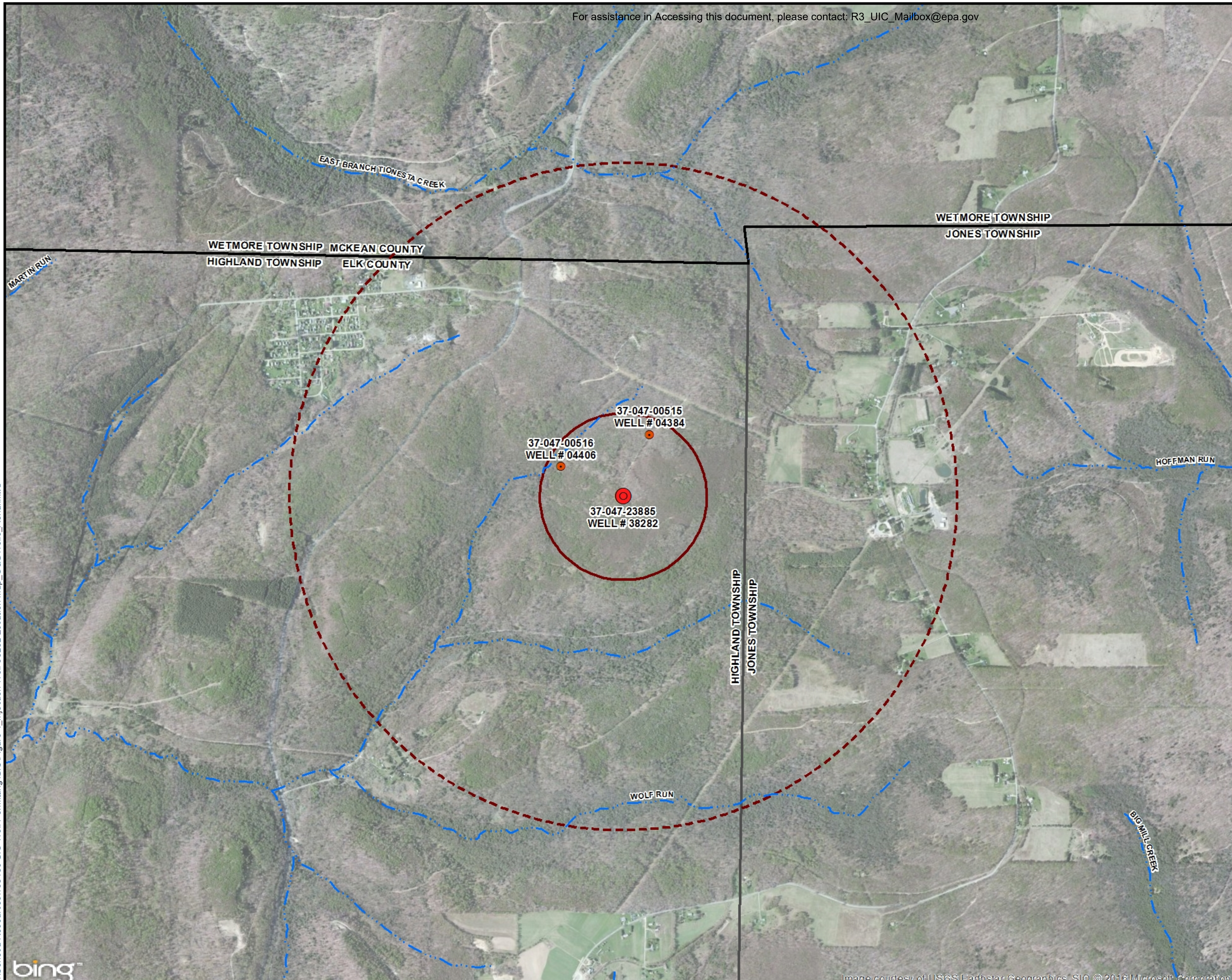
Figure 3



P:\Seneca Resources\160105 UIC Well Permitting\GIS\Figure 4_Injection Well 38282 Location Map_O&GWells_Aerial.mxd

LEGEND

- WELL # 38282
- AREA OF REVIEW (1/4 MILE)
- 1 MILE RADIUS
- OIL AND GAS WELL

REF: Base map from Bing Maps, dated 2011.

0 750 1,500 3,000 4,500
SCALE IN FEET

Location Map (Aerial) with Oil and Gas Wells

Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

March, 2016	Scale: 1" = 1,500'	160105

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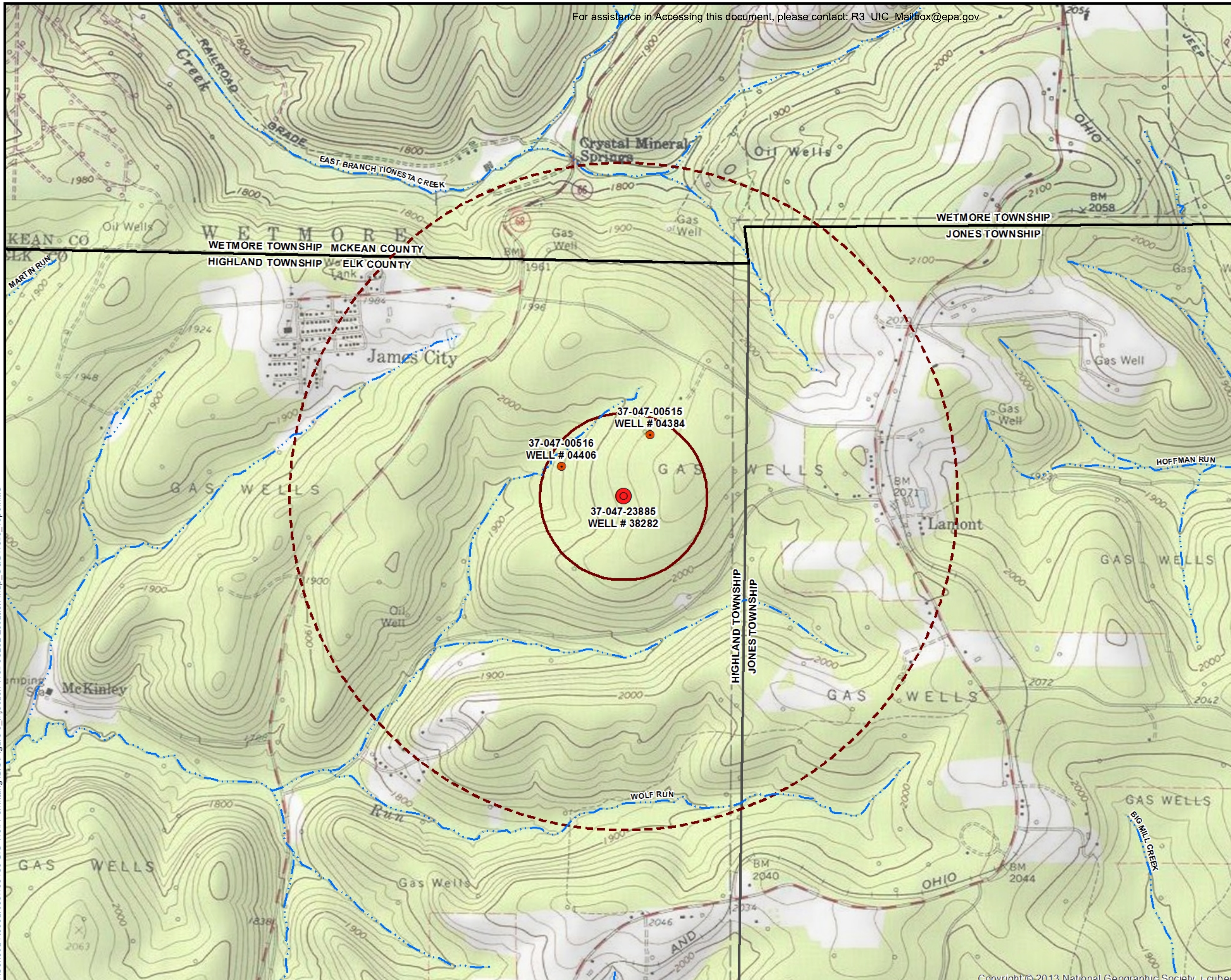
Figure
4



N

LEGEND

- WELL # 38282
- AREA OF REVIEW (1/4 MILE)
- 1 MILE RADIUS
- OIL AND GAS WELL

REF: Base map from ESRI USA Topo Maps. Refer to USGS 7.5 minute Quads Kane and James City, PA.

0 750 1,500 3,000 4,500

SCALE IN FEET

Location Map (Topo) with Oil and Gas Wells

Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

March, 2016	Scale: 1" = 1,500'	160105

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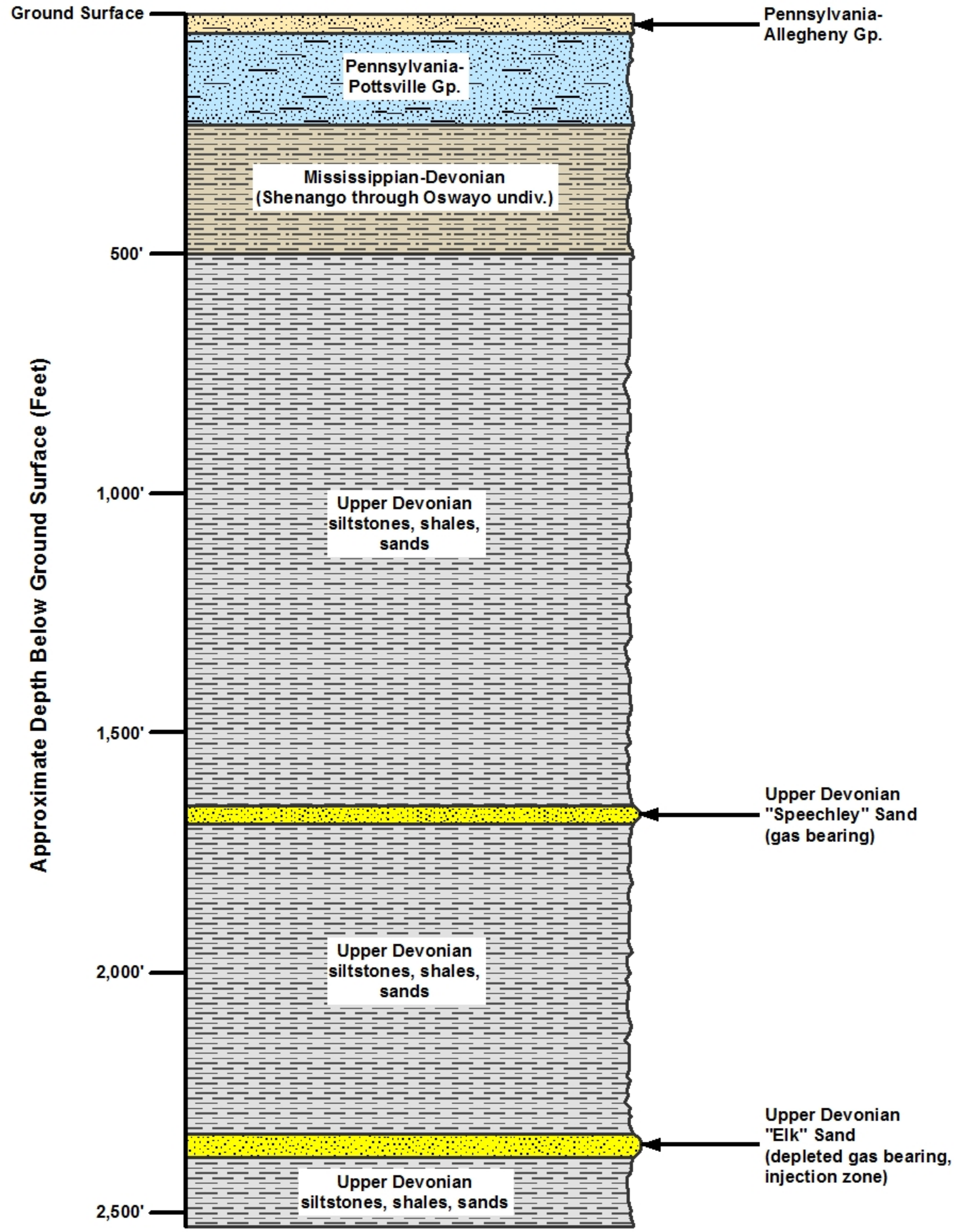
Figure 5

P:\Seneca Resources\160105 UIC Well Permitting\GIS\Figure 5_Injection Well 38282 Location Map_O&GWells_Topo.mxd



Generalized Geologic Stratigraphic Column

Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

February, 2016	Not To Scale	160105

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Figure
6

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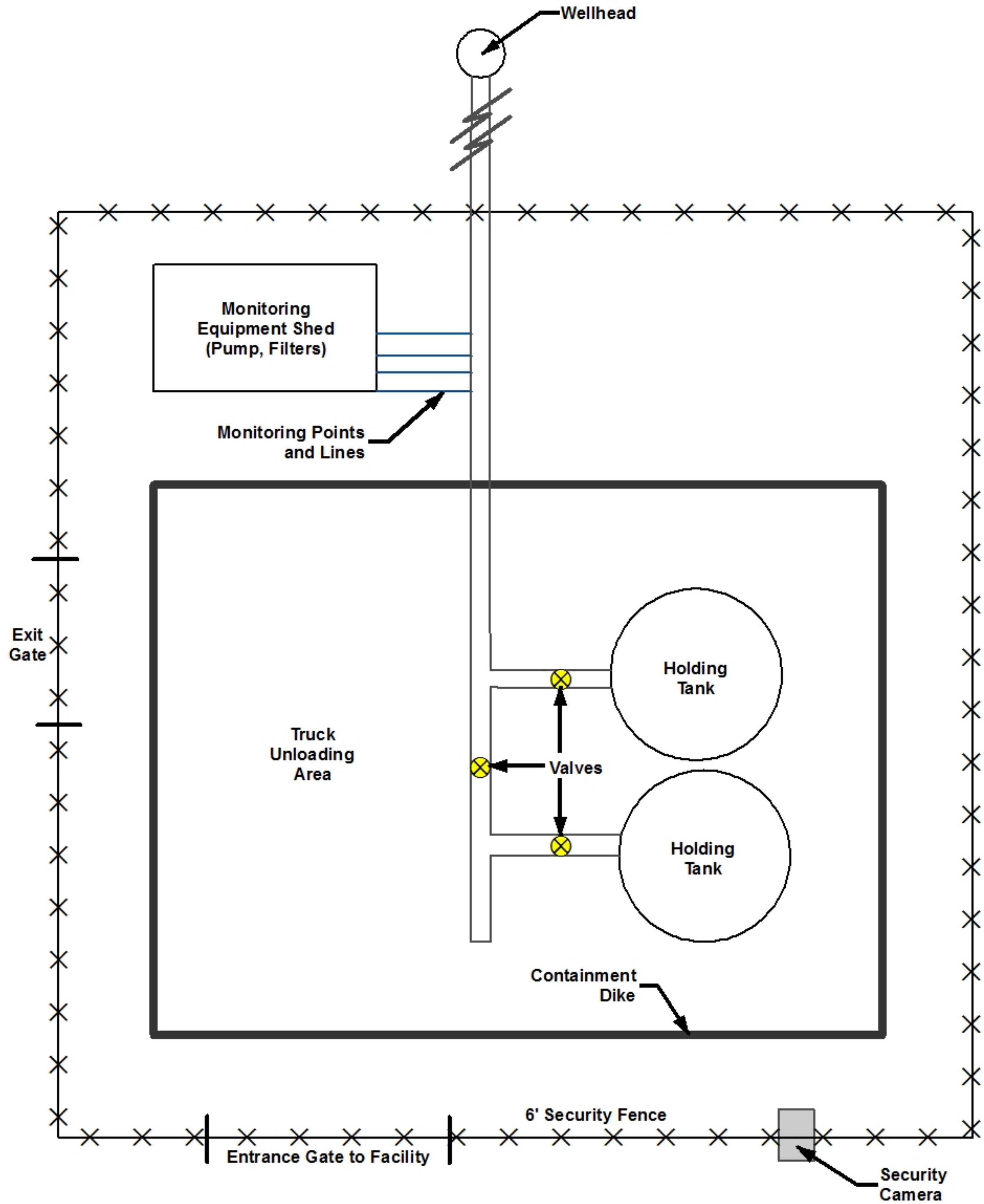

N

Generalized Injection Well Surface Facility Schematic

Seneca Resources Corporation
Highland, Jones and Wetmore Townships,
McKean and Elk Counties, Pennsylvania

February, 2016	Not To Scale	160105

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www.armgroup.net

Figure 7

I:\Seneca Resources\160105 UIC Well Permitting\GIS\Figure 7_Injection Well_Surface Facility Schematic.mxd

Figure 8

Well Construction Diagram

Proposed Injection Well

Seneca Well #38282
Highland Township
Elk County, PA
37-047-32885

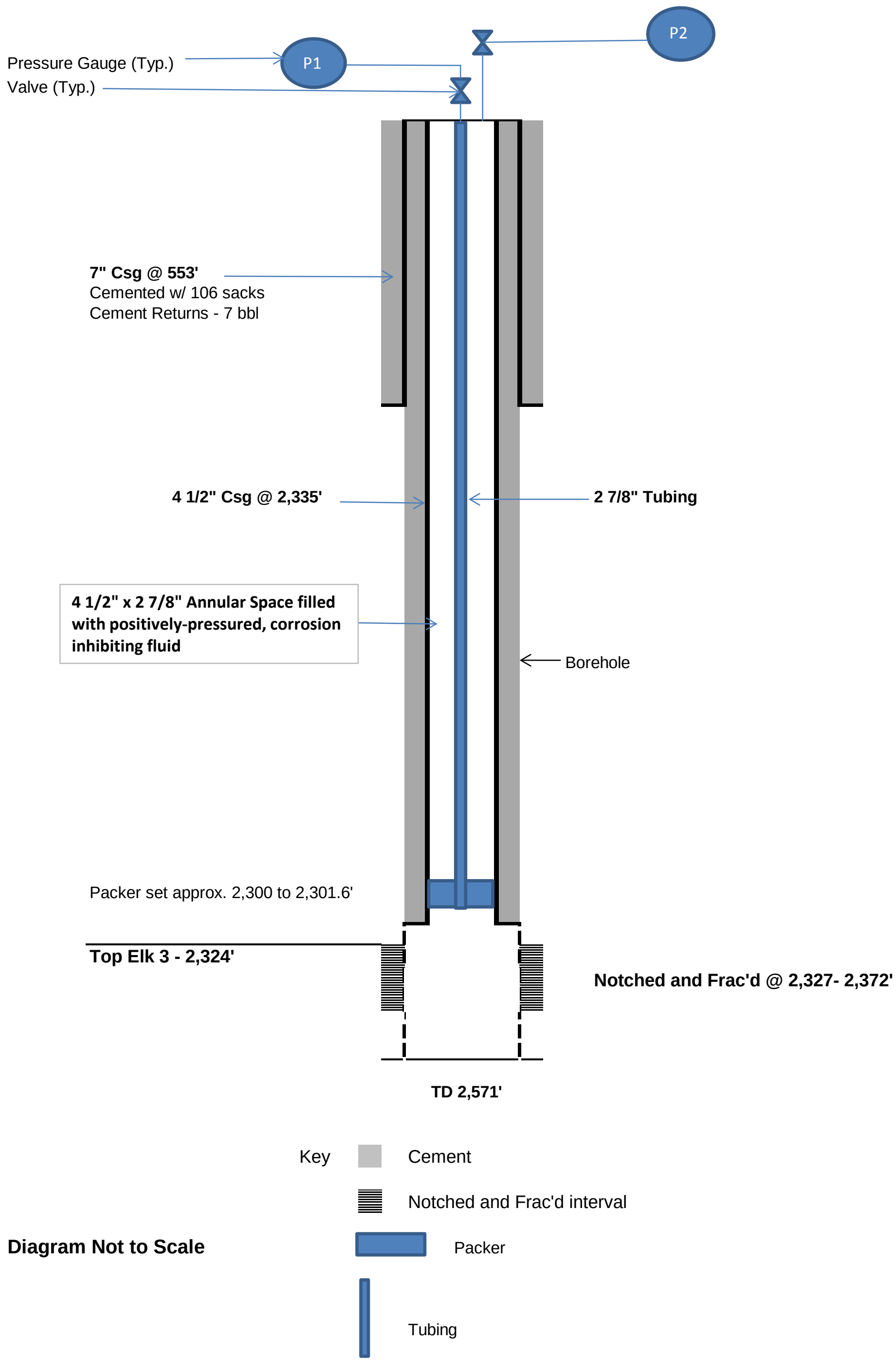


Diagram Not to Scale

Figure 9

Well Construction Diagram

Proposed Monitoring Well

Seneca Well #04406
Highland Township
Elk County, PA

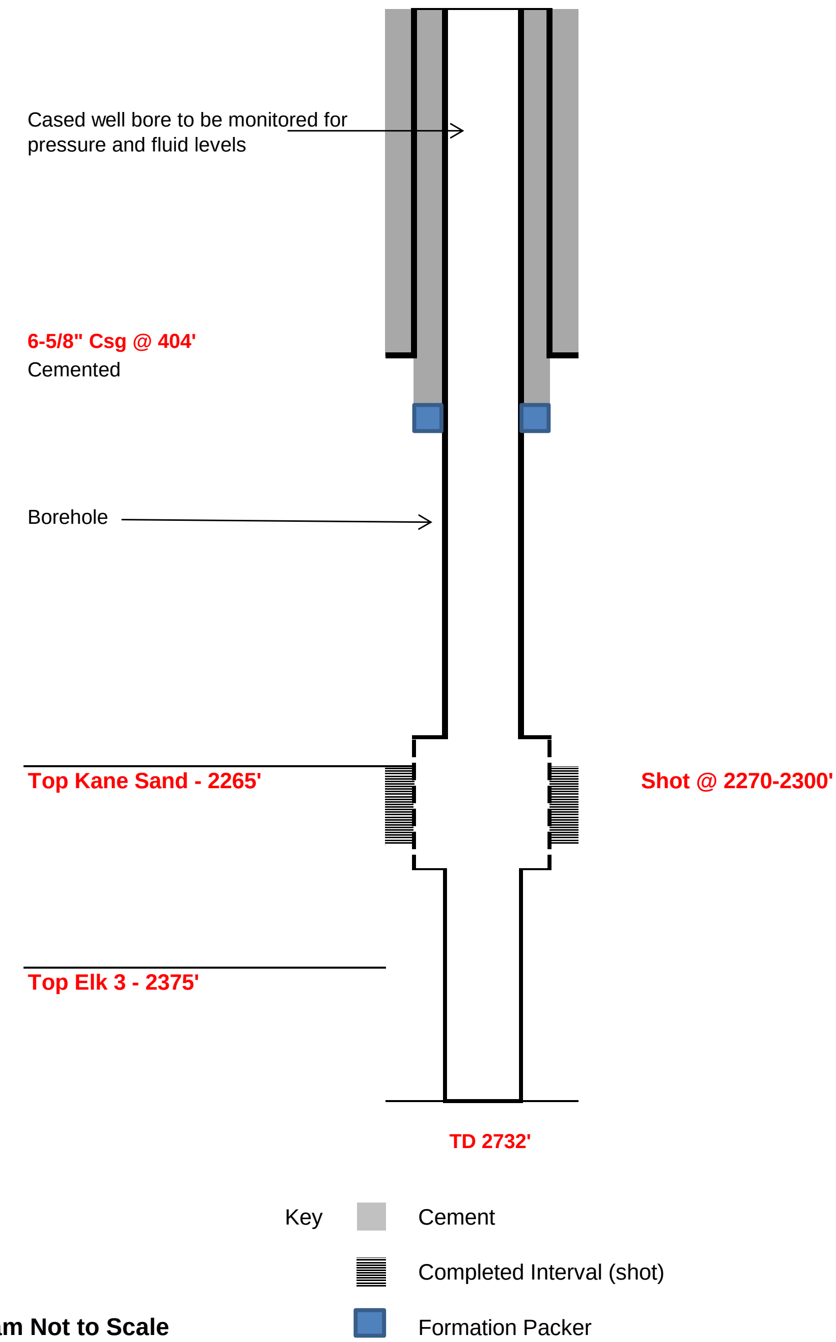


Diagram Not to Scale

January 21, 2013

Figure 10

Well Construction Diagram

Proposed Monitoring Well

Seneca Well #04384
Highland Township
Elk County, PA

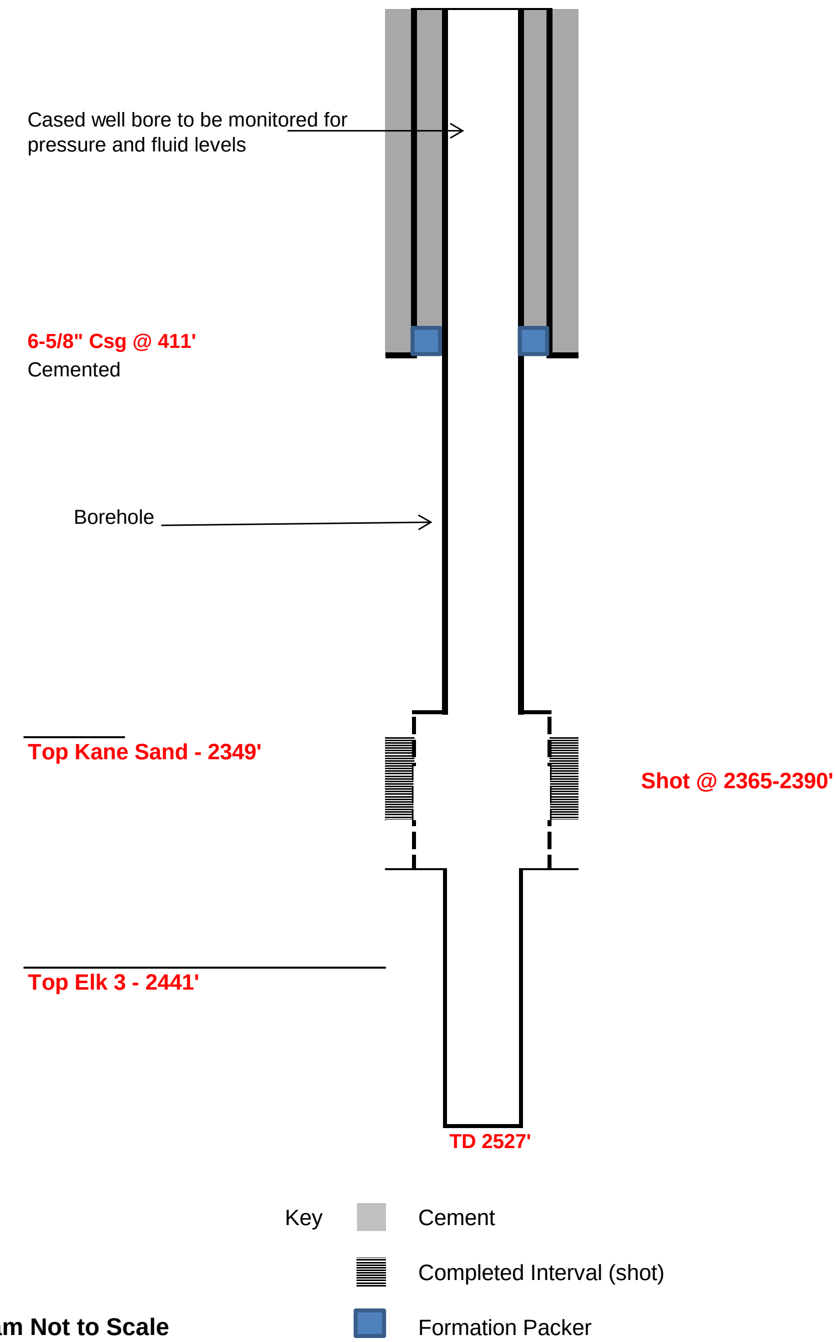


Diagram Not to Scale

January 21, 2013

TABLES

TABLE 1
Oil and Gas Wells Within 1/4 Mile of Proposed Injection Well #38282

Seneca Resources Corporation
Highland Township, Elk County, PA

Operator	Completion Date	API	Well ID	Elevation (ft msl)	Total Depth (ft)	Conductor Casing Depth (ft)	Casing Depth (ft)	Completion	Comments	Distance from #38282 (miles)
Seneca Resources Corp	1/25/2008	37-047-32885	38282	2,030	2,571	40	553	Notched & Frac'd: 2,327-2,372'	Subject of UIC Class IID Permit Application	N/A
Seneca Resources Corp	1/22/2008	37-047-32884	38281	2,020	2,540	47	602	Notched & Frac'd: 2,339-2,390'	Monitoring Well for Well #38268	0.36
Seneca Resources Corp	12/30/1942	Not available	04406	Not available	2,732	35	404	Shot: 2,270 - 2,300	Monitoring Well	0.21
Seneca Resources Corp	11/4/1942	Not available	04384	Not available	2,527	29.5	411	Shot: 2,365 - 2,390	Monitoring Well	0.2

TABLE 2
USDW Within 1 Mile of Proposed Injection Well #38282

Seneca Resources Corporation
Highland Township, Elk County, PA

Springs Within 1 Mile Radius

PA ID	Owner	Comments	Distance from #38282 (feet)
DWRS6240006 Source 1	Highland Township Water Authority	Primary water supply for James City	5,442
DWRS6240006 Source 3	Highland Township Water Authority	Backup water supply for James City; PADEP DWRS notes this source is "abandoned".	5,256

Water Wells Within 1 Mile Radius

PA Well ID	Date Drilled	Owner	Well Depth	Depth to Bedrock (ft)	Well Use	Bore Hole Diameter (in)	Casing Bottom (ft)	Casing Diameter (ft)	Distance from #38282 (feet)
DWRS6240006 Source 4	Not available	Highland Township Water Authority	206	Not available	Municipal Backup	8	30	6 in., pump set at 170 ft.	5,467
DWRS6240006 Source 5	Not available	Highland Township Water Authority	161	Not available	Municipal Backup	8	28	6 in., pump set at 140 ft.	5,186
1000718	8/1/1987	Klaiber, Randy	130	28	Withdrawal	Not available	Not available	Not available	5,314

TABLE 3

Notched and Frac'd Intervals of Injection Well #38282
Seneca Resources Corporation
Highland Township, Elk County, PA

Formation	Notched and Frac'd Interval	Thickness (h)	Comments
Speechley 6	1,644 to 1,655 feet	11 feet	Gas producing interval (Situated above packer)
Tiona 1	1,714 feet	1 foot	Gas producing interval (Situated above packer)
Tiona	1,722 feet	1 foot	Gas producing interval (Situated above packer)
Cooper 6	1,907 feet	1 foot	Gas producing interval (Situated above packer)
Cooper 6	1,930 feet	1 foot	Gas producing interval (Situated above packer)
Kane 3	2,117 feet	1 foot	Gas producing interval (Situated above packer)
Elk 3	2,327 to 2,372 feet	45 feet	Gas producing interval (Injection Interval)

TABLE 4

Notched and Frac'd Intervals of Injection Well #04406
Seneca Resources Corporation
Highland Township, Elk County, PA

Formation	**Notched and Frac'd Interval**	**Thickness (h)**	**Comments**
Clarendon Sand	Noted to be present from 1,582 to 1,591 feet	No Frac	Gas producing interval
Cooper	Noted to be present from 2,045 to 2,056 feet	No Frac	Gas producing interval
Bradford Sand	Noted to be present from 2,172 to 2,232 feet	No Frac	No gas or water
Kane 3	Shot: 2,270 to 2,300	30 feet	Gas producing interval
Elk 3	Noted to be present from 2,375 to 2,401 feet	No Frac	No water or gas reported from Elk Sand

TABLE 5

Notched and Frac'd Intervals of Injection Well #04384
Seneca Resources Corporation
Highland Township, Elk County, PA

Formation	**Notched and Frac'd Interval**	**Thickness (h)**	**Comments**
Clarendon Sand	Noted to be present from 1,666 to 1,682 feet	No Frac	Gas producing interval
Bradford Sand	Noted to be present from 2,275 to 2,321 feet	No Frac	Gas producing interval
Kane 3	Shot: 2,365 to 2,390	25 feet	Gas producing interval
Elk 3	Noted to be present from 2,441 to 2,449 feet	No Frac	Gas producing interval

APPENDICES

APPENDIX A

Additional Requested Information Associated with the Depletion of the Elk 3 Gas Producing Reservoir

June 13, 2013

Mr. Roger Reinhart
Groundwater and Enforcement Branch (3WP22)
Office of Drinking Water & Source Protection
United States Environmental Protection Agency Region 3
1650 Arch Street
Philadelphia, PA 19103-2029

Re: Response to Request for Additional Information dated May 8, 2013
Underground Injection Control (UIC) Program
Class IID Injection Well #38268 (API No. 37-047-23835)

Dear Mr. Reinhart:

Seneca Resources Corporation (Seneca) received an e-mail on May 8, 2013 following up on a verbal request for additional information to support our application for a brine disposal injection well (Class IID) in Highland Township, Elk County, Pennsylvania (Permit ID: PAS2D025BELK). In the phone call and subsequent e-mail US EPA Region 3 requested information regarding reservoir pressures in the Elk 3 reservoir as well as any available production information to support our statement that the Elk 3 reservoir is depleted.

Seneca was able to locate reservoir pressure and production histories for several wells near the subject well (Attachment 1). As depicted in the attached graph (Attachment 2), initial reservoir pressures of 425-440 pounds per square inch (psi) were documented when the reservoir was first produced in 1898. Over time, reservoir pressure decreased as production continued. In June 2013, Seneca shut in the subject well and others around it to record current reservoir pressures. The subject well had a shut-in casing pressure of 26.6 psi and nearby wells had pressures ranging from 20.6 psi to 54.3 psi.

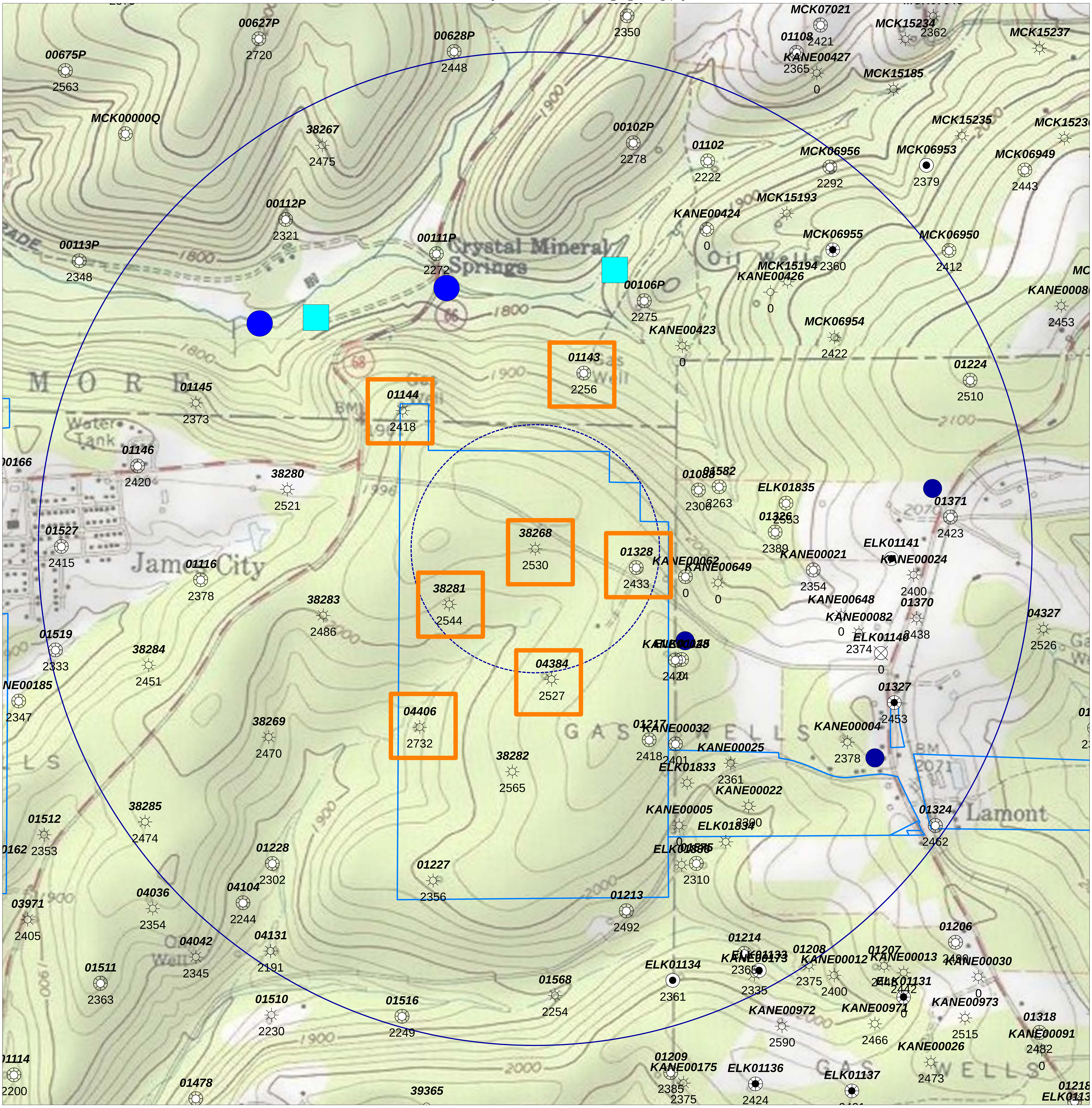
The Elk 3 has been a substantial gas-producing reservoir. Estimated cumulative production from selected wells near 38268 is summarized in the attached table (Attachment 3).

The Elk 3 Sandstone is a depleted reservoir, as evidenced by the reservoir pressure decline curves and significant volumes of gas produced since 1898.

Should you have any questions or concerns, or need additional information, please contact Amanda Veazey at (412) 548-2533 or me at (412) 548-2513.

Sincerely,

Doug Kepler
Vice President, Environmental Engineering



Private Water Wells

Straight hole well

Straight hole well

Highland Township Water Authority

Point

TYPE

SPRING

WATER WELL

Wells with historic pressure and/or production data

1000 0 1000 ft

0.5000 0 0.5000 mi

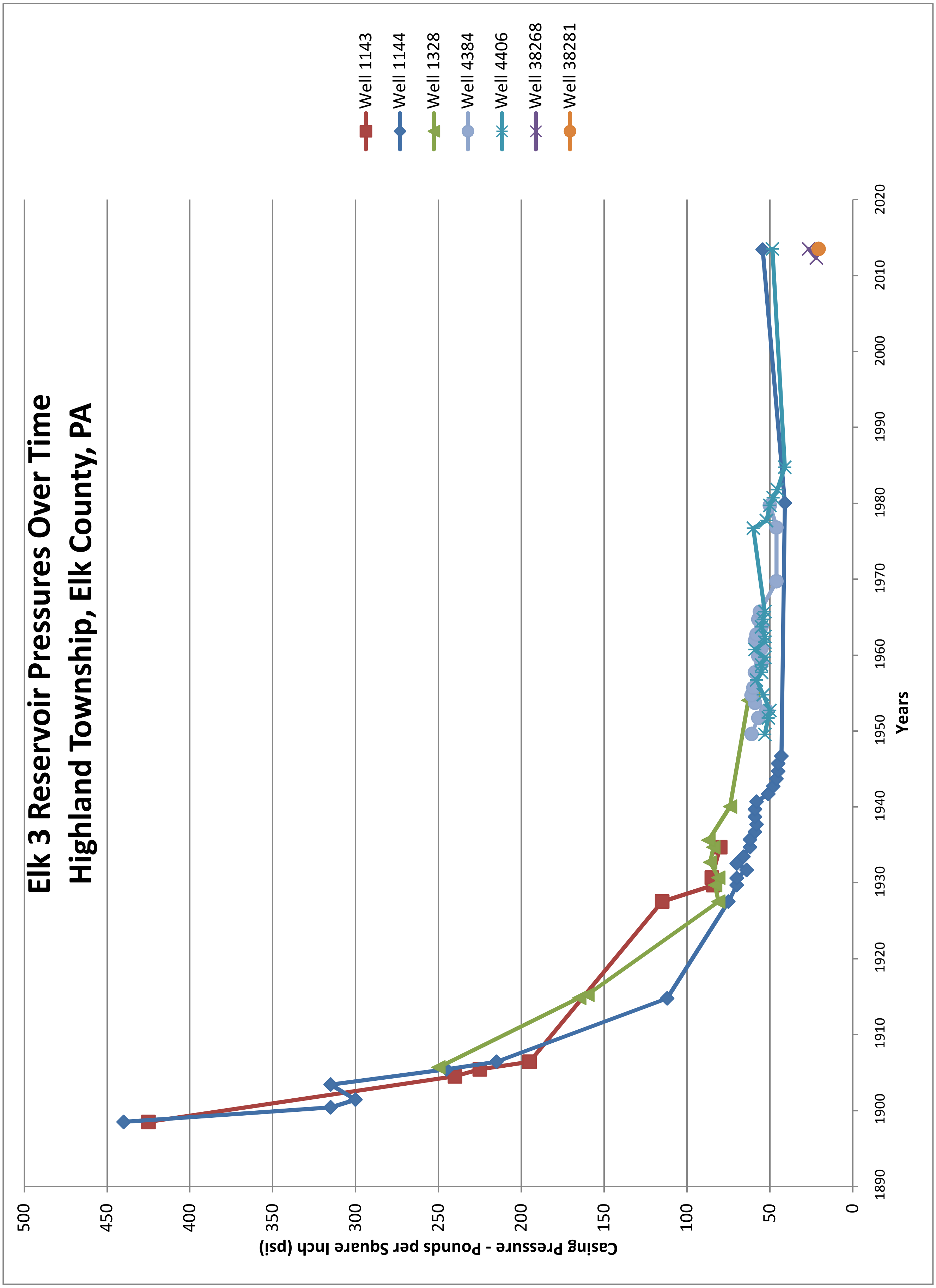
15 minute topographic quadrangle maps:
Kane, PA
James City, PA

SENECA RESOURCES

Seneca Well 38268
Known Gas Wells within ¼ mile
Known Water Wells/Supplies within 1 mile

Author: Amanda Veazey		**Date:** June 13, 2013
	Scale: See Scale Bar	

For assistance in Accessing this document, please contact: R3_UIC_Mailbox@epa.gov



Attachment 3

Estimated Cumulative Gas Production For Selected Wells Near Seneca Well #38268

Well #	Year Drilled	Year Plugged & Abandoned	Estimated Cumulative Production (MMCF)
1143	1898	1949	280
1144	1898		422
1328	1902	1991	412
4406	1943		150
38268	2007		82*

* Well 38268 was completed open-hole in both the Elk 3 and Speechley 6 reservoirs. Production is commingled. Estimated Ultimate Recovery for this well is 135 MMCF.

APPENDIX B

Area of Review/Zone of Endangerment Analysis for Potential Brine Disposal Injection Well #38268

TETRA TECH

21335 Signal Hill Plaza, Suite 100, Sterling, VA 20164 703-444-7000 703-444-1685 (FAX)

TECHNICAL MEMORANDUM - DRAFT

TO: Dale Skoff, Tetra Tech NUS

FROM: Jeffrey Benegar

DATE: June 14, 2012

RE: Area of Review/Zone of Endangerment Analysis for Potential Brine Disposal Injection Well #38268

EXECUTIVE SUMMARY

This technical memorandum (TM) summarizes the analytical modeling we have performed for the area of review/zone of endangerment analysis for potential brine disposal injection well #38268 for Seneca Resources. Well #38268 is located in Highland Township, Elk County, PA. Brine disposal via injection well would take place into the Elk 3 Sandstone. Our analysis is described in more detail below.

OVERVIEW AND METHODOLOGY

There are several methods proposed for calculating the zone of endangerment of an injection well. The most simplistic method is the use of a fixed radius, based on the type of injection well being permitted. Other methods involve calculation of the radius based on well and formation properties. The method used here is the graphical method first used by US EPA Region 6. It involves the calculation of the increase of pressure in the formation due to injection, then converting that pressure into equivalent feet of head. The increase in head in the formation due to injection is then compared to the equivalent head of the lowest most underground source of drinking water (USDW). When plotted graphically, the intersection of those two curves at some distance, r, determines the radius of the zone of endangerment.

The increase in pressure in the formation due to injection depends on the properties of the injection fluid and the formation, the rate of fluid injection, and the length of time of injection. The most common mathematical expression to describe this increase in pressure was developed by Matthews and Russell (1967). Matthews and Russell assume that, for a single well injecting into an infinite, homogeneous and isotropic, non-leaking formation, the increase in pressure (delta p) can be described as:

delta p = 162.6 Qμ / kh * [(log(kt / ΦμCr^2) – 3.23] where:

delta p = pressure change (psi) at radius, r and time, t
Q = injection rate (barrels/day)
μ = injectate viscosity (centipoise)
k = formation permeability (millidarcies)
h = formation thickness (feet)
t = time since injection began (hours)
C = compressibility (total, sum of water and rock compressibility) (psi^{-1})
r = radial distance from wellbore to point of investigation (feet)
Φ = average formation porosity (decimal)

PARAMETERS USED IN THE ANALYSIS

The following parameters were used in the zone of endangerment analysis. The majority of the parameters are based on the analysis and results of the injection testing performed on well #38268 in March 2012 (Tetra Tech, 2012). The permeability value was based on the results from the injection testing analysis. For the depth to the lowest most USDW, a conservative estimate based on US EPA Region 3 guidance and review of site area hydrogeologic conditions was used (i.e., depth to USDW = 400 feet)

<u>Input Parameters for Well #38268</u>
Q = 3,000 barrels/day
t = 10 years = 87,600 hours
μ = 0.9457 centipoise
k = 190 md
h = 49 feet
C = 7.6e-06 psi^{-1}
Φ = 13.5%
Well radius = 0.29 feet
Specific gravity of injectate = 1.14
Surface elevation = 2040 feet
Depth to injection formation = 2354 feet
Base of lowest most USDW (elevation) = 1640 feet
Initial pressure at top of injection formation = 24 psi

RESULTS

The Matthews and Russell equation was solved for various distances from the wellbore based on the parameters listed above for permeability value determined from the injection test. The values of delta p were added to the existing pressure in the injection formation to obtain the total pressure in the formation. These values were then converted to feet of head of formation brine. The results are shown in Figure 1. The plot shows the calculated pressure surface within the injection formation, measured as feet of head of formation brine above the top of the injection formation. Also shown is the head of the lowest most USDW. Where the two lines intersect, the radius of the zone of endangerment can be estimated. For the permeability value of k = 190 md, the increase in head due to injection would remain below the elevation of the lowest most USDW. This permeability value was obtained from injection testing analysis of well #38268.

CONCLUSIONS

Our analysis of the area of review/zone of endangerment for the proposed brine disposal injection wells is based on a methodology typically used by US EPA. For the permeability value of k = 190 md (obtained from injection testing analysis of well #38268), increase in head due to injection would remain below the elevation of the lowest most USDW. Based on the results, we believe the well is an excellent candidate for use as a brine disposal well.

In summary, the default area of review of a ¼ mile radius from the proposed injection well is applicable for this application.

REFERENCES

Matthews, C.S., Russell, D.G., (1967) Pressure Buildup and Flow Tests in Wells, SPE Monograph Series, Volume 1, New York.

Tetra Tech, (2012) Injectivity Test Report, Seneca Resources Well #38268, Highland Township, Elk County, PA. May 2012.

FIGURES

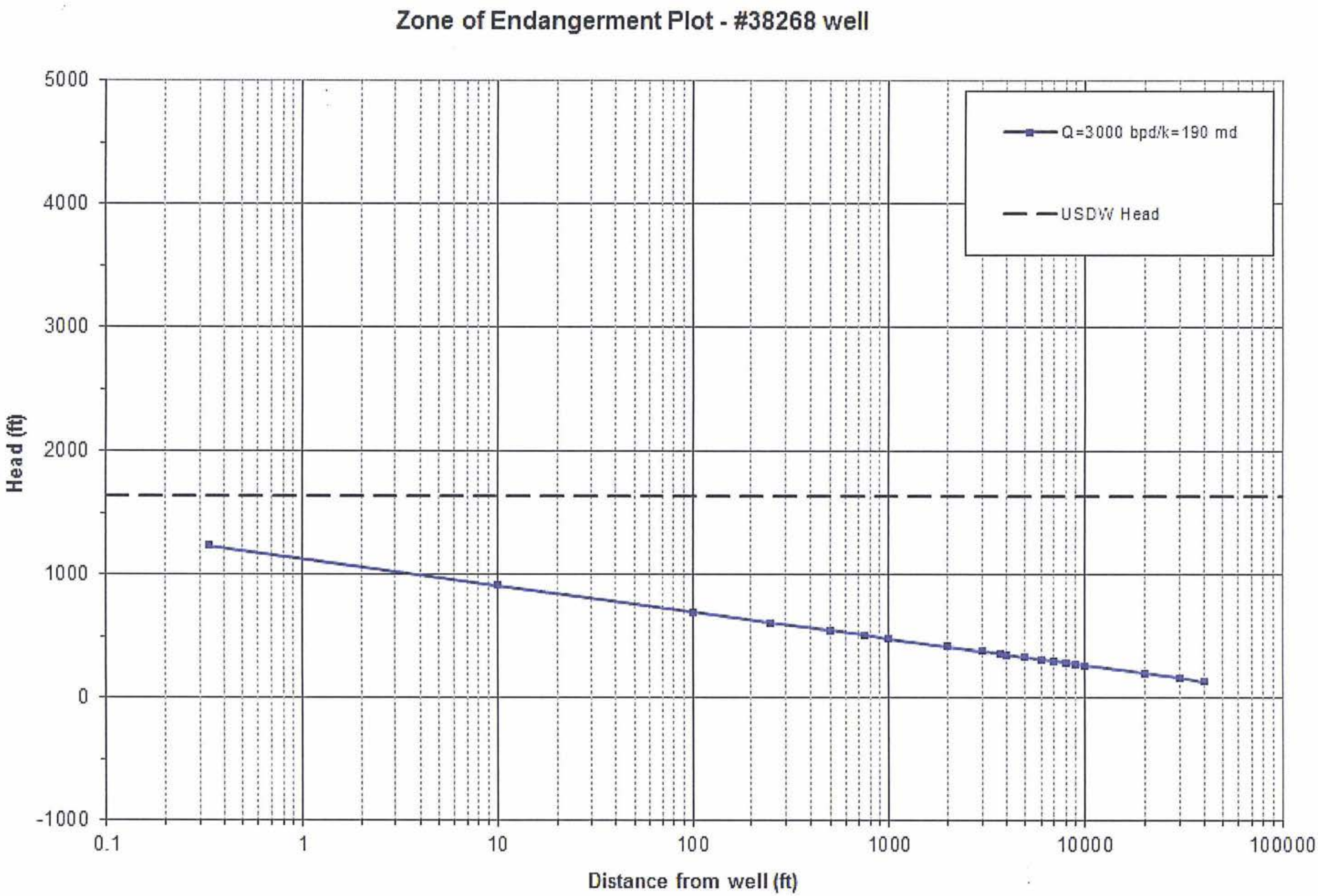


Figure 1. Feet of head of injection formation and USDW vs. distance from the well for #38268 well

TETRA TECH, INC.

APPENDIX C

Tetra Tech, (2012) Injectivity Test Report, Seneca Resources Well #38268, Highland Township, Elk County, PA. May 2012

TETRA TECH

INJECTIVITY TEST REPORT

SENECA RESOURCES WELL #38268
(API# 37-047-23835)

Highland Township
Elk County, Pennsylvania

Seneca Resources Corporation
5800 Corporate Blvd.
Suite 300
Pittsburgh, PA 15237

June 2012

complex world CLEAR SOLUTIONS™

INJECTIVITY TEST REPORT

SENECA RESOURCES WELL # 38268
(API# 37-047-23835)

Highland Township
Elk County, Pennsylvania

Seneca Resources Corporation
5800 Corporate Blvd.
Suite 300
Pittsburgh, PA 15237

June 2012

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1.0 INTRODUCTION AND BACKGROUND

This report summarizes the injectivity testing performed in March 2012 at the Seneca Resources Corporation's (Seneca's) Well # 38268 (API #37-047-23835), located in Highland Township, Elk County, Pennsylvania. Seneca is considering converting this well into a brine disposal well for disposal of produced water from its Marcellus Shale and other natural gas producing operations. Seneca retained Tetra Tech, Inc. (Tetra Tech) to investigate the hydraulic feasibility of utilizing Well #38268 for brine disposal. Tetra Tech designed and implemented a testing program to determine hydraulic parameters for this potential injection well, including information about reservoir characteristics such as transmissivity, bottom-hole injection pressure, reservoir static pressure, potential sustainable injection rates and geologic boundaries. This report summarizes the injectivity test procedures and results for the injectivity test conducted at Well #38268 in March 2012.

1.1 Site Location

Well #38268 is located in Highland Township, Elk County, Pennsylvania (see **Figure 1** – Site Map).

1.2 Test Well Construction and Background

Well #38268 was drilled in March 2007 and completed in the following intervals for natural gas production as shown below in **Table 1.**

Table 1 - Notched and Frac'd Intervals of Well #38268

Formation	Notched and Frac'd Interval	Thickness (h)	Comments
Speechley 5	1667	1 foot	Gas producing interval (situated above packer)
Speechley 6	1671.5 to 1676 feet	4.5 feet	Gas producing interval (situated above packer)
Speechley 7	1721	1 foot	Gas producing interval (situated above packer)
Tiona 1	1739.5	1 foot	Gas producing interval (situated above packer)
Elk 3	2354 to 2403 feet	49 feet	Gas producing interval Test injection interval

Figure 2 is a well construction diagram for the test well. As indicated, the well has 553.2 feet of cemented 7-inch surface casing, with the remaining portion of the well having open hole completion. In preparation for the injectivity test, tubing and packer were placed in the well, with the bottom of the packer placed at a depth of approximately 2304 ft., which is approximately 50 ft above the top of the targeted Elk 3 Sandstone injection interval. Also prior to injection, a bottom-hole pressure gauge was placed at 2275 feet. A surface pressure gauge was also placed at the wellhead. Both gauges had data storage capability.

A review of the neutron-density log for the test well indicates that a maximum porosity for the upper 6 ft of the Elk Sandstone is in the 18 percent range with the entire frac interval having an average porosity of 13.5%.

1.3 Observation Well Construction and Background

Seneca Well #38281 (API# 37-047-23884), located 1320 feet to the southwest of the subject test well, was utilized as an observation well and monitored during the injectivity testing of Well #38268. The location of this well is shown on **Figure 1**. **Figure 3** is a well construction diagram for Well #38281, which is an operating gas well producing from the Speechley, Tiona, Kane, and Elk 3 intervals (**Table 2**). As indicated, 602 feet of cemented surface casing is present followed by open hole completion. The well is configured with tubing and rods and a pump jack to remove accumulated water.

Table 2 - Notched and Frac'd Intervals of Well #38281

Formation	**Notched and Frac'd Interval**	**Thickness (h)**	**Comments**
Speechley 6	1650 to 1662	12 feet	Gas producing interval
Speechley 7	1704 to 1719 feet	15feet	Gas producing interval
Tiona Sandstone	1728 to 1734 feet	6 feet	Gas producing interval
Kane 1	2123 feet	1 foot	Gas producing interval
Kane 2	2133 to 2151 feet	18 feet	Gas producing interval
Kane 3	2156	1 foot	Gas producing interval
Elk 3	2339 to 2390 feet	51 feet	Gas producing interval

2.0 INJECTIVITY TESTING CONDITIONS AND IMPLEMENTATION

2.1 Injectivity Test Conditions

On February 28, 2012, Seneca provided EPA with an injectivity test request for performing the injection test at Well #38268 followed by an email dated February 29, 2012, which included additional information requested by EPA. In a letter dated March 12, 2012, EPA approved conducting the injectivity test under the following conditions:

1. **Injection Zone** – The well will be utilized to perform testing of the Elk 3 Sandstone. Injection into the Elk 3 will be conducted through tubing and packer set no more than 50 feet above the upper perforated (notched) interval in the Elk 3 which is located at 2354 feet.
2. **Duration of Test** – The duration of the injectivity test shall not exceed a maximum of thirty (30) consecutive days.
3. **Total Volume Limitation** – During the testing period, the total volume of fluid to be injected shall not exceed a maximum of 5000 barrels of produced fluid (brine).
4. **Maximum Injection Pressure** – The maximum injection pressure for the test into the Elk 3 is based on an instantaneous shut-in pressure of 1580 psi (based on the first stage fracture information), a specific gravity of the injection fluid of 1.14 and a packer setting depth of 2304 feet. The injection pressure for this test shall not exceed the maximum surface injection pressure of 1433 psi. If, during testing, it is observed that this pressure causes formation breakdown/fracturing to occur, the test shall be stopped and EPA contacted immediately to discuss possible alternative testing procedures.
5. **Injection Fluid** – Injection fluid shall consist of produced fluid (brine) obtained from Seneca's production operations with a specific gravity of 1.14.
6. **Monitoring** – Injection volume and pressure shall be monitored and recorded on a continuous basis. Both the injection pressure and annulus pressure, between the injection tubing and 7-inch casing, will be monitored. In addition, production Well #38281 shall be monitored throughout the injectivity test. Prior to testing, Well #38281 will be shut-in and the pressure and fluid level monitored. The pressure and fluid level in this well will also be monitored during the test and once following completion of the test. EPA encouraged the continuous monitoring of the formation pressure decline after injection has concluded. This data should further enhance analysis of the transmissivity and storage capacity of the proposed injection formation and allow for an estimation of the protracted effects on the formation. A final report must be submitted to EPA.

2.2 March 2012 Injection Test Implementation

The project team conducting the field work consisted of Seneca operations staff (overall test management, well access and brine mobilization), Eastern Reservoir Services (ERS) (wireline services, pressure gauges and flowmeter), WPD (Western Pump and Dredge) (filtering equipment and injection pumps), Champion (brine water treatment prior to injection), and Tetra Tech (test oversight and data evaluation). The brine utilized for the injection was obtained from Seneca's nearby James City Marcellus production area.

The injectivity test was performed on Well #38268 in March 2012 with the brine injection conducted on March 27 and 28, 2012. The test consisted of injection through tubing/packer into the frac'd intervals corresponding to the Elk 3 Sandstone while monitoring injection rates and well head and bottom hole pressure during the injection phase and the pressure falloff after the well was shut-in. Also as required by the EPA approval letter, annular pressure was monitored during the test for any evidence of packer failure or tubing leak.

The initial phase of injection consisted of “loading the well” with brine to establish wellhead pressure. This was necessary because the well was taking the brine on vacuum. The injectivity test work plan included a Step-Rate Test (SRT) which was to be performed once significant wellhead pressure was established in the well. Although the injection rate after the first 4.5 hours of injection was approximately 3 bpm (barrels/minute), no significant wellhead pressure was developing. (Approximately 1000 barrels of brine had been injected by that time.) Based on this condition and rate limitations of the injection pump available onsite, it was decided to forego the SRT and proceed directly to the Constant Rate Test (CRT). Initially, a 10 µm filter and a 25 µm filter were utilized to filter the brine water prior to being injected into the well. It was discovered that during the latter part of the test the injection rate could not be sustained with a 10 µm filter, and therefore two 25 µm filters were utilized for the last 8 hours of the injection test to maintain a relatively constant rate of 2.1 bpm.

Most of the data required for data analysis were recorded electronically during the injectivity test. An exception was injection rate and cumulative volume which was recorded manually in the field book based on readings taken from the in-line digital flow meter situated on the piping approximately 6 feet from the well head. In addition, field data sheets were used to record the most relevant data by hand to ensure these data were being recorded in an event of a failure of the electronic systems and to summarize test conditions for review to optimize field procedures as necessary.

The following data were measured and recorded by Tetra Tech staff during the injection test:

- Injection rate and time
- Wellhead pressure
- Annulus pressure

(It is noted there was no surface readout associated with the bottom hole pressure gauge, which was later retrieved for downloading the data.)

Injection was initiated on March 27, 2012 at 1003 hrs. Injection rates during the test varied from 1.1 to 7.1 bpm. During the final 8 hours of the injection period, the injection rate was held relatively constant at approximately 2.1 bpm. The average rate over the entire injection phase was 2.67 bpm.

Injection was halted on March 28, 2012 at 1856 hours and the well shut-in to begin the Falloff Test (FOT) portion of the injectivity test. A total of 5,000 barrels of brine were injected during the test over a cumulative injection time of 1973 minutes (approximately 33 hours). Pressure data was collected during the FOT portion of the test for approximately 116 hours (4.8 days). It is noted that there were only minor changes in the annulus pressure during the injectivity test, indicating there were no issues of packer failure or tubing leaks.

2.3 Surface Hydraulic Analysis of March 2012 Injection Test

The maximum pressure (surface) observed during the injection test was approximately 31.3 psi, which was approximately 1401.7 psi below the EPA specified MIP of 1433 psi. The average

surface pressure observed was 13.47 psi. Injection rate and surface pressure data recorded during the injectivity test are included in **Appendix A**.
During the injectivity test two samples of the brine were collected for field testing for density (specific gravity). **Table 3** summarizes the analytical results for the injectate samples.

Table 3 - Injectate Samples Analytical Results for Well #38268

Parameter	Units	3/27/12	3/28/12
Specific Gravity	Unitless (Relative ratio to density of water at 4°C)	1.16	1.14

2.4 Observation Well Results

Well #38281, located 1320 feet to the southwest of the subject test well, was utilized as an observation well. Well #38281 was shut-in for a period of approximately five days prior to the injectivity test to allow for equilibrium in pressures and fluid levels to be attained. Pressures and fluid levels (utilizing an Echometer) were measured in the annulus between the 7-inch casing and tubing prior to injection at Well #38268, daily during the injection at Well #38268; and during the falloff period of the test. Monitoring at the observation well was performed at the completion of the test, the day after the completion of the test, and five days after the completion of the test. The annulus pressure on the observation well held steady between 23 and 26 psi before, during, and after the injection. A comparison of wellhead pressures between the two wells is shown below on **Table 4**.

Table 4 – Injection and Observation Well Pressure Readings

Injection Well #38268								
	Pre-Test	During Test		Post - Test				
Date	3/27/12 - AM	3/27/12 - PM	3/28/12	3/28/12	3/30/12	3/31/12	4/1/12	4/2/12
Annulus PSI	19.75	20.8	22.8	23.6	26.5	28.4	29.9	30
Wellhead PSI	22	17.3	28	-12	-11.3	-10.7	-5.3	29.1

Observation Well #38281											
	Pre-Test					During Test		Post - Test			
Date	3/23/12	3/24/12	3/25/12	3/26/12	3/27/12	3/27/12	3/28/12	3/28/12	3/30/12	3/31/12	4/1/12	4/2/12
Annulus PSI	20	21	22	24	25	23	24	23	26	26	26	26

As indicated above, the pressure in the observation well was relatively constant before during and after injection at Well #38268. Based on the collected data, there is no apparent relationship between pressure changes in the injection and observations wells.

ERS staff conducted fluid level measurements in the injection well for the annulus and well head (tubing) prior to the injection test and then during the falloff portion of the test. The fluid levels in the observation well were also taken by ERS staff prior to the injection test, during the injection test and during the falloff period. **Appendix B** includes the fluid level data obtained from the

Echometer measurements. The results are summarized below in **Table 5**. It is noted that negative time values represent time prior to initiation of injection.

Table 5 – Liquid Level Measurements

Injection Well # 38268 - Casing	
Elapsed time (min)	**Depth to Liquid Level (ft)**
-1513	2201.55
8894	2185.24
Water level change	16.31

Injection Well # 38268 - Tubing	
Elapsed time (min)	**Depth to Liquid Level (ft)**
-1512	2452.81
8922	2439.65
Water level change	13.16

Observation Well # 38281	
Elapsed time (min)	**Depth to Liquid Level (ft)**
-1414	2172.57
-46	2167.41
491	2165.59
1377	2153.22
1444	2151.07
2015	2144.63
2840	2118.59
8950	2116.83
Water level change	55.74

When comparing pre- and post-injection fluid levels, the fluid level in the injection well rose 13.16 feet in the tubing and 16.31 feet in the casing (i.e., annular space between 7-inch and tubing). (There were no fluid level readings in the injection well during the injection phase.) The fluid level rose 55.74 feet in the observation well during this same period. Although the obersvation well was shut-in for use in injectivity test monitoirng, the observation well is an operating gas well with rods and a pump jack to remove accumulating water. It is not known whether the observed increase in fluid levels in this well is a result of influence from injection at Well #38268 or attributable to produced water from the various gas productive intervals in the observation well. As discussed above, there were no significant pressure changes in the observation well over the duration of the test which may indicate that the increase in fluid levels was from produced water intervals within the well. **Figure 4** illustrates the fluid level changes in both wells.

3.0 BOTTOM HOLE PRESSURE DATA ANALYSIS

The plot of measured bottom-hole pressure and injection rate versus time is shown in **Figure 5**, and the plot of measured bottom-hole pressure and temperature is shown in **Figure 6**.

Analysis of the falloff portion of the test was performed using Fekete F.A.S.T. WellTest™ (Version 7.4.3.161) software. F.A.S.T. WellTest™ allows for the identification of flow regime, computation of the pressure derivative function, and reservoir parameter analysis by both type curve matching (log-log plot) and superposition analysis (semilog plot). **Figure 7** shows the log-log plot of the pressure and derivative curve versus elapsed time for the falloff portion of the injection test. **Figure 8** shows the semilog plot of pressure versus elapsed time for the falloff portion of the injection test and **Figure 9** shows the semilog plot of pressure versus superposition radial time for the falloff portion of the injection test.

For the purposes of this analysis, it was assumed that only the Elk 3 Sandstone frac interval (from 2354 to 2503 ft, a thickness of 49 ft) was to be used as the representative thickness for the formation as the vast majority of the flow during the injection test was likely being taken by this interval. An average porosity of 13.5% was utilized based on log analysis.

Radial flow is flow in the horizontal radial direction and occurs during the infinite-acting time period of the falloff (before the pressure transient has reached boundaries of the reservoir). The purpose of analyzing radial flow data is to determine permeability (k). The signature of radial flow data on a derivative plot for a constant rate test is a straight line whose slope is at or approaching zero. This portion of the derivative curve is denoted on **Figure 7** and shows that radial flow occurs at approximately 19 hours after shut-in. The position of this line is used to calculate permeability. The value of the derivative of radial flow data corresponds to the vertical position of the horizontal straight line and is used to calculate permeability as follows:

$$k = 70.6 \bullet \frac{qB\mu}{Der \bullet h}$$

where k = permeability (md), q = final water rate (bbl/d), B = formation volume factor, μ = viscosity (cP), Der = derivative (psi), and h = net pay (ft).
Test data are shown in **Table 6**.

Table 6 - Test Data for #38268 Well March 2012 Test

Parameter	Value
Interval Thickness (Net Pay) (h)	49 ft
Porosity	13.5%
Formation Temperature (T)	72°F
Specific Gravity (G)	1.14
Viscosity (μ)	0.9457 cP
Final Flowing Pressure	1162.8 psi
Water Saturation (S_w)	100%
Final Water Rate (q)	2937.3 bbl/d
Corrected Flow Time (t_c)	40.7 hr
Well Radius (r_w)	0.29 ft
Total Compressibility (c_t)`	7.593e-06 psi^{-1}
Final Flowing Pressure (p_{wfo})	1162.8 psi
Extrapolated Pressure (p*)	-6.3 psi
Formation Volume Factor (B)	1.0

Based on the test data in Table 6, and a derivative value (Der) of 21.09 psi, the estimated permeability is equal to:

$$k = 70.6 \bullet \frac{(2937.3 \bullet 1.0 \bullet 0.9457)}{(21.09 \bullet 49)}$$

$$k = 190\, md$$

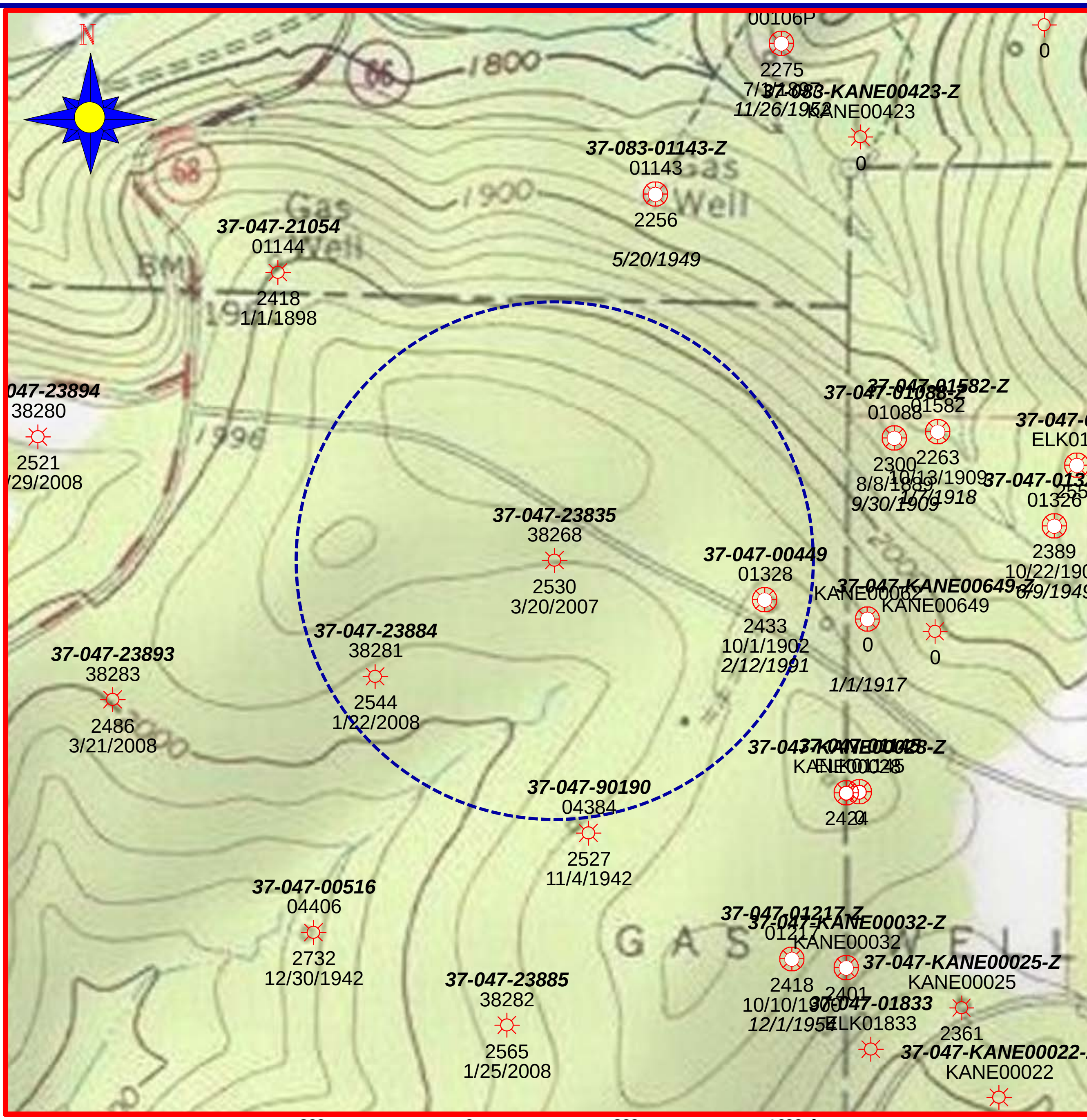
4.0 SUMMARY

The following are key findings based on injectivity testing performed on the Elk 3 Sandstone interval of Seneca Well #38268:

- During the injection portion of the test, the injection rate varied, but was maintained at approximately 2.1 bpm for the last 8 hours of injection. The average injection rate for the entire test period was 2.67 bpm.
- A total of 5,000 bbls were injected during the test.
- The maximum surface wellhead pressure recorded during the test was only approximately 31 psi, which is well below the MIP (surface) of 1433 psi approved by EPA for the test. This condition suggests the well would have been able to sustain higher injection rates during the test if not for the limits of the pumping system.
- The maximum bottom-hole pressure measured during the test was approximately 1163 psi.
- Falloff pressure data analysis indicates an estimated permeability of 190 md, based on a formation thickness of 49 feet, a porosity of 13.5%, and S_w = 100%
- No indications of significant geologic boundaries were identified during the test.
- An evaluation of fluid levels and pressure data from the observation well are inconclusive regarding the potential influence from injection at Well #38268. Although fluid levels rose approximately 56 feet in the observation well during the test, this increase may be attributable to accumulating produced water from the various gas producing intervals in the well.
- No evidence of formation breakdown/fracturing was observed during the test.

In summary, an evaluation of injectivity test data for the March 2012 test on Seneca Well #38268 indicates that the well has significant potential for brine disposal through injection into the Elk 3 Sandstone interval. This is consistent with the relatively thick, porous characteristics of the injection interval based on log analysis. It is not possible to accurately predict long-term injection well performance based on a relatively short duration test; however, the test results suggest that the well could sustain an injection rate of greater than 2 bpm (approximately 3000 bpd) with pressures remaining under the likely UIC Class IID permit limits for maximum injection pressure.

FIGURES



800 0 800 1600 ft

1 inch = 800 feet

Legend

Well Symbols

Well Status

37-047-00449	**API Number**
01328	Seneca's Well ID
2433	Well Depth
10/1/1902	Spud Date
2/12/1991	*Abandoned Date*

AGAS

D&A

GAS

SENECA RESOURCES

Proposed Injection Test Well (38268)
James City, Elk County, PA

Author: A.M. Veazey		**Date:** February 22, 2012
	Scale: 1" = 800'	

Figure 2
Well Construction Diagram
Injection Test Well

Seneca Well #38268
Highland Township
Elk County, PA
37-047-23835

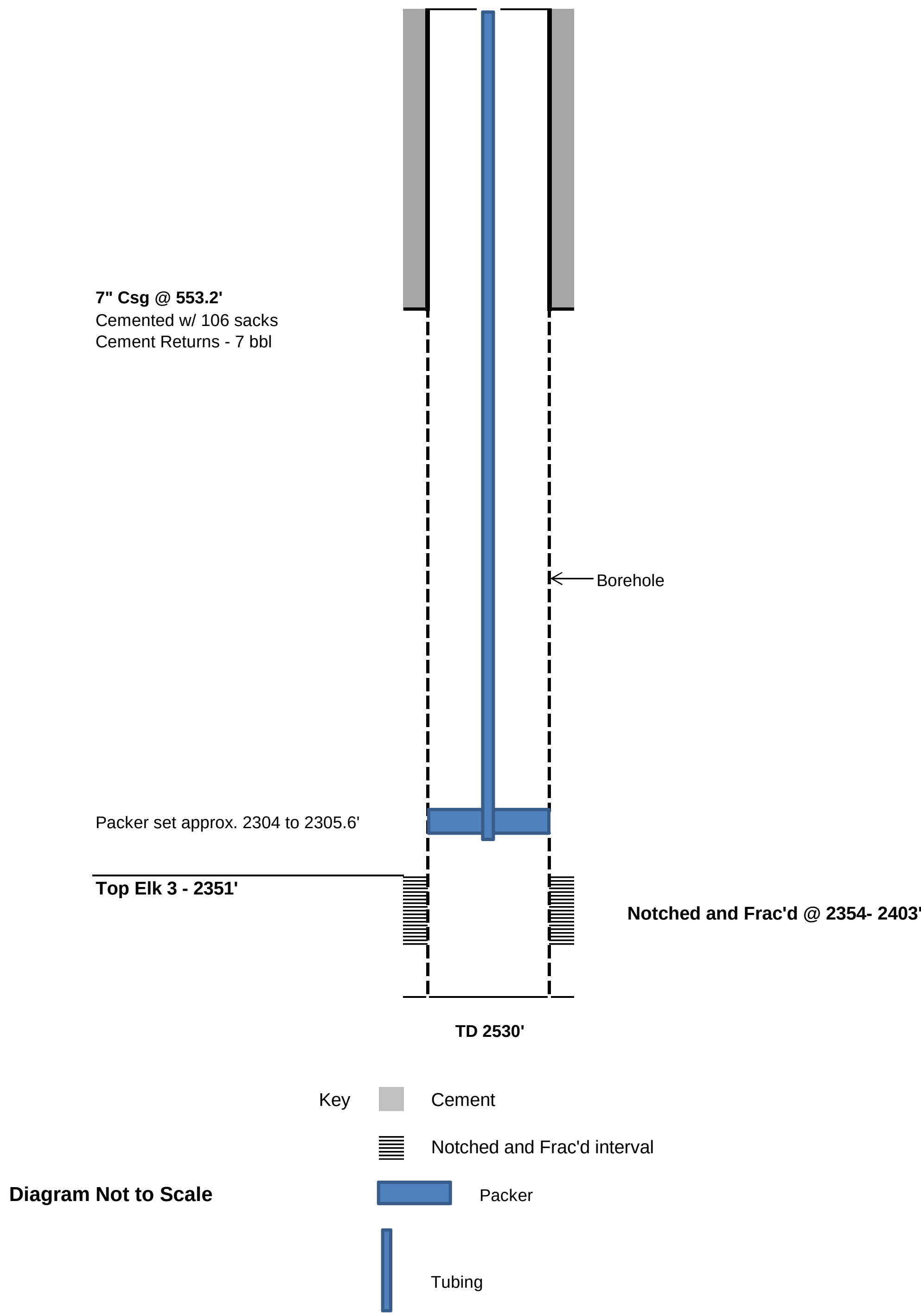


Figure 3

Well Construction Diagram

Observation Well

Seneca Well #38281

Highland Township

Elk County, PA

37-047-23884

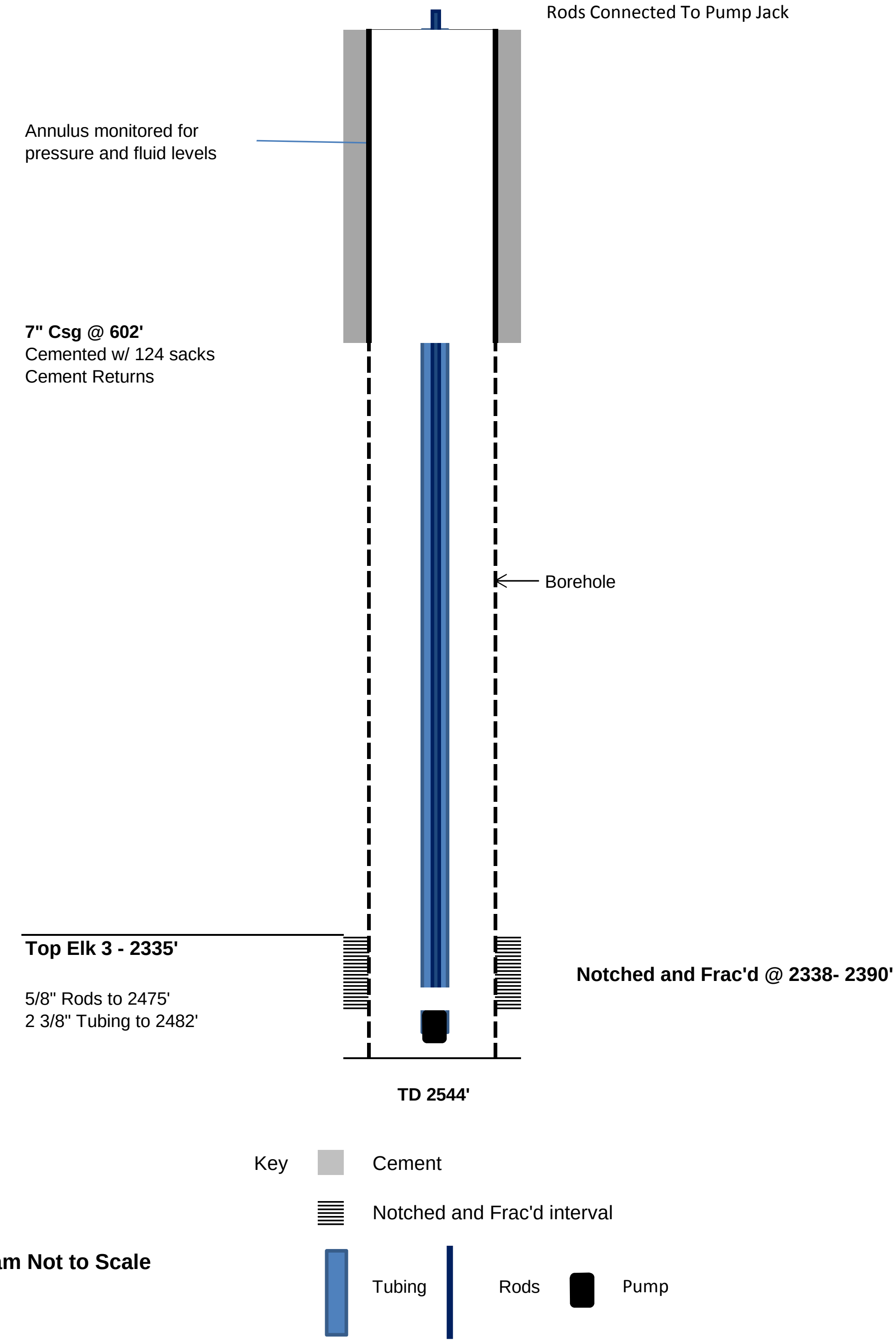


Diagram Not to Scale

For assistance in Accessing this document, please contact: R3_UIC_Mailbox@epa.gov

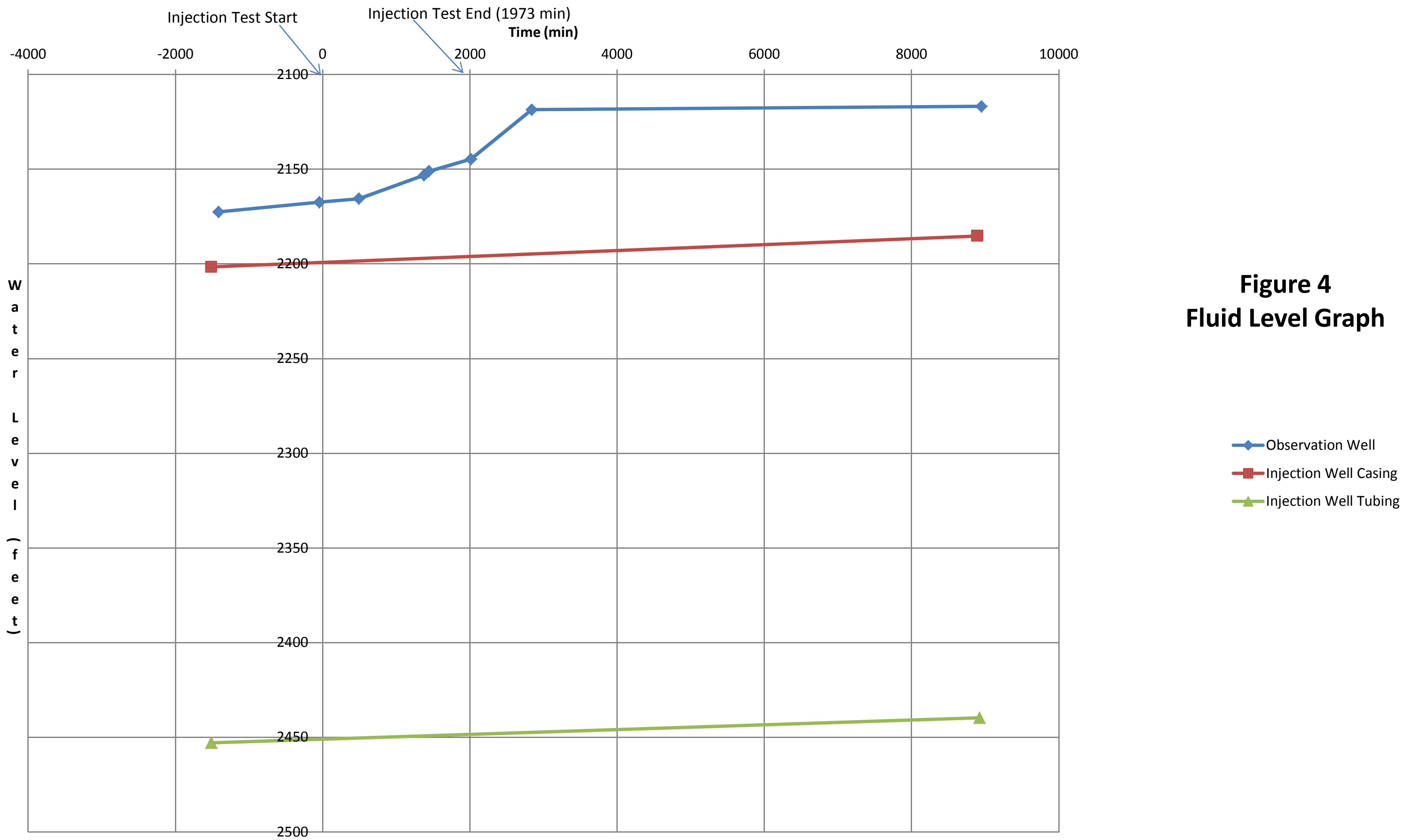


Figure 4
Fluid Level Graph

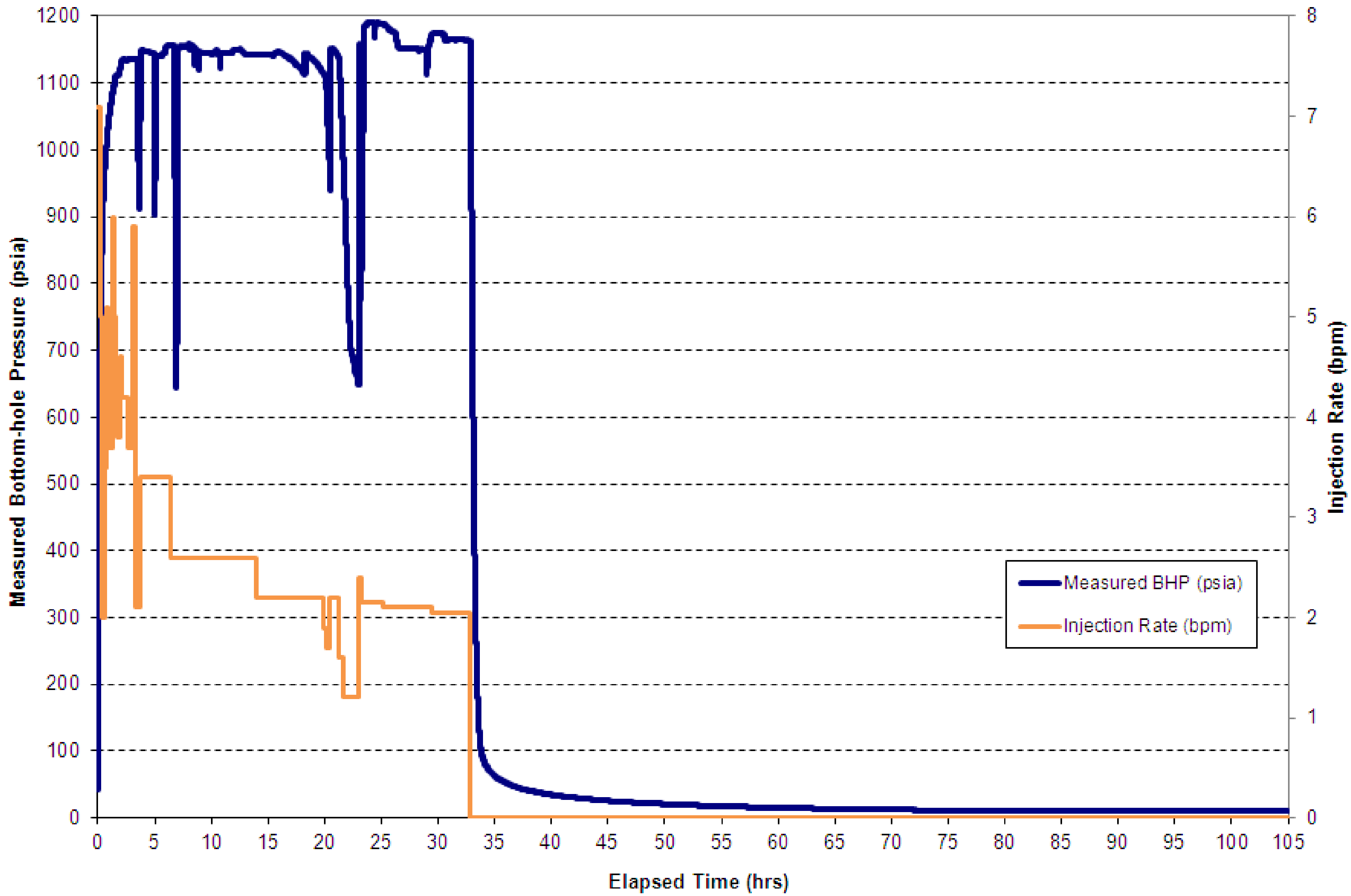


Figure 5. Measured bottom-hole pressure and injection rate versus elapsed time for Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

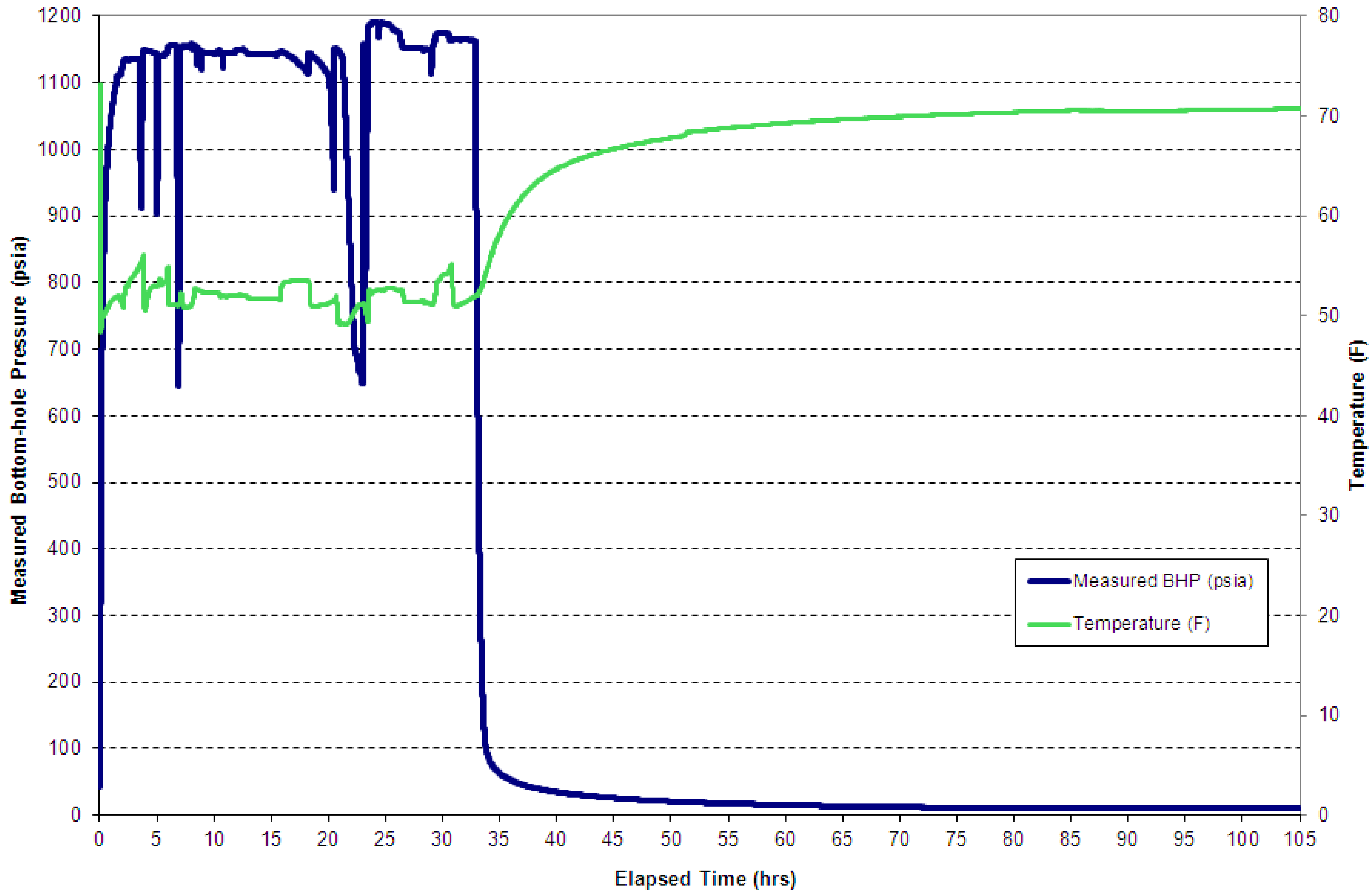


Figure 6. Measured bottom-hole pressure and temperature versus elapsed time for Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

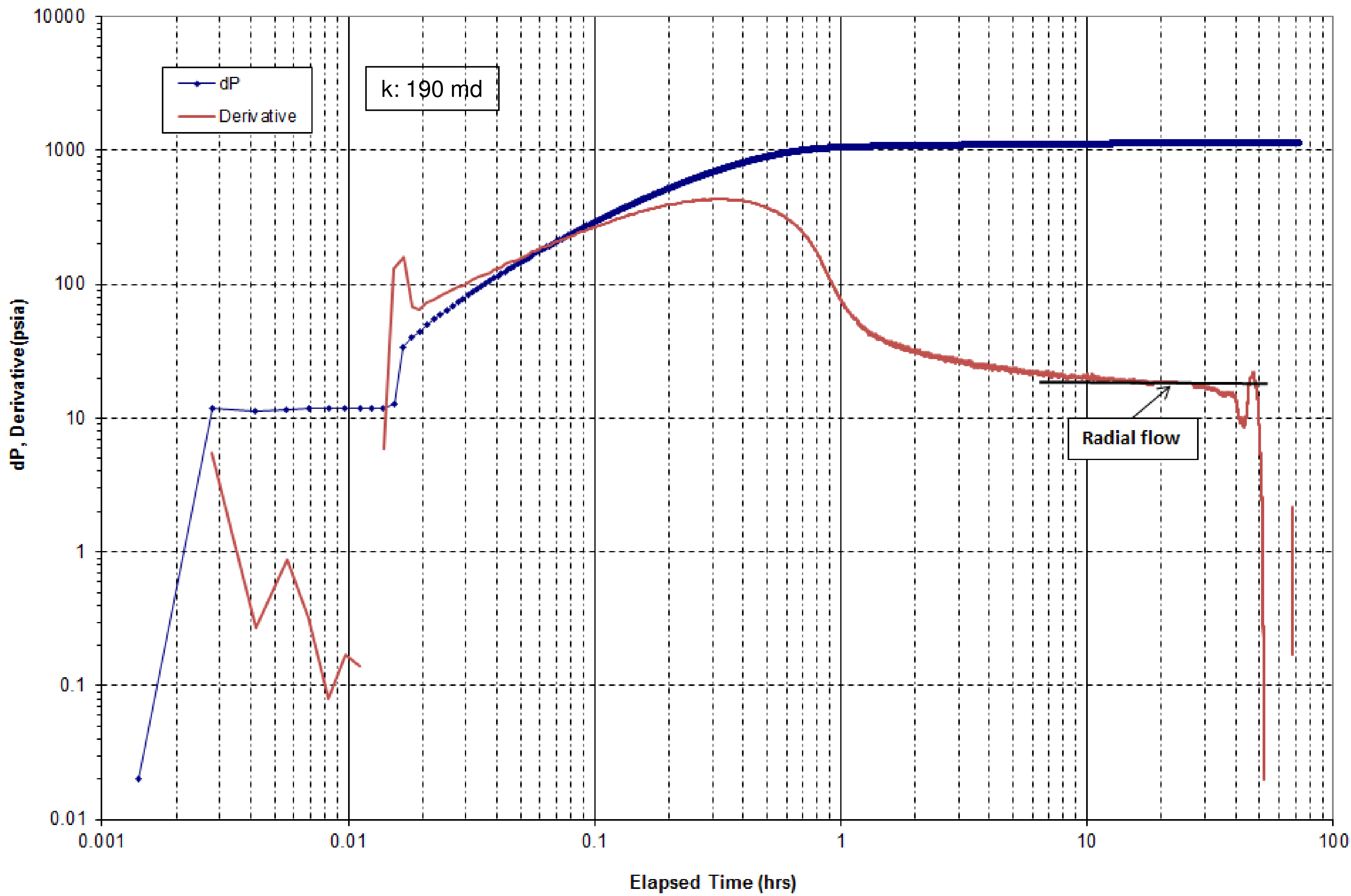


Figure 7. Log-log plot of pressure and derivative curves versus elapsed time for Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

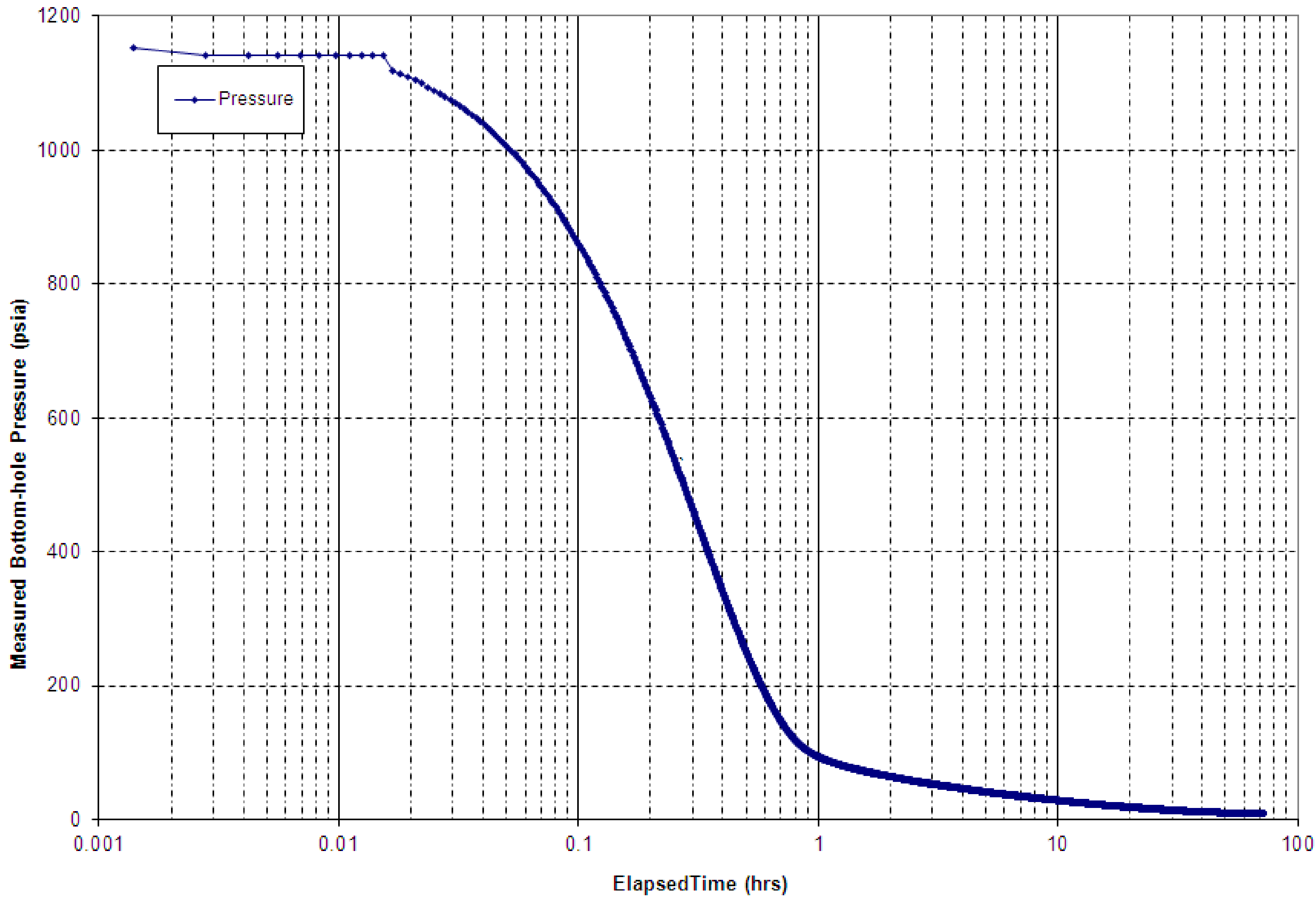


Figure 8. Semi-log plot of measured bottom-hole pressure versus elapsed time for falloff portion of Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

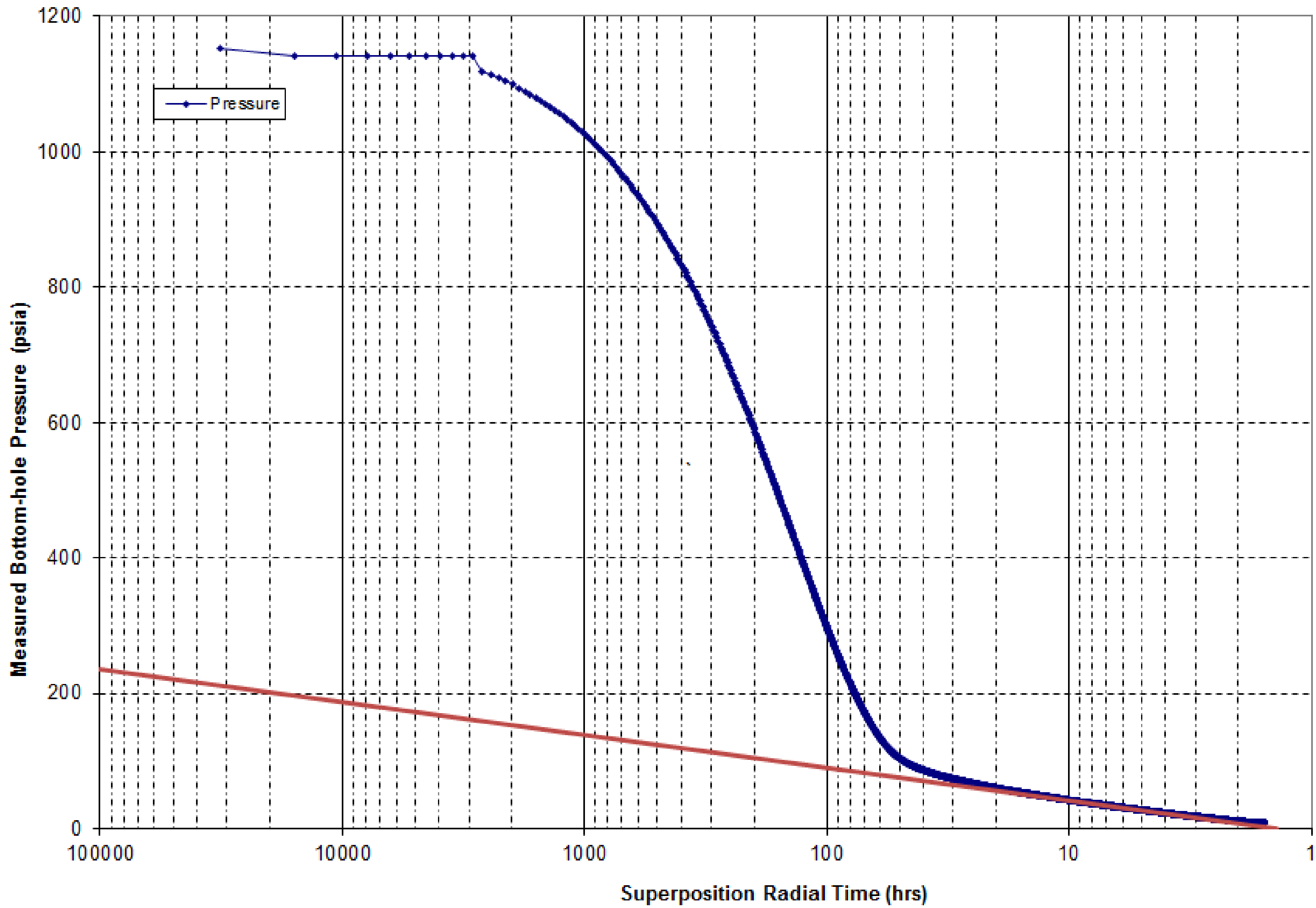


Figure 9. Semi-log plot of measured bottom-hole pressure versus superposition time for falloff portion of Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

APPENDIX A

Well #38268 Wellhead Pressure and Injection Rate Field Measurements

APPENDIX A - WELL # 38268 WELLHEAD PRESSURE AND INJECTION RATE FIELD MEASUREMENTS

Date	Eastern Standard Time	Time	Elapsed Time (min)	BBLs inj.	BBLM	Wellhead Pressure
3/27/2012	10:03 AM	1003	0	0	0	0
3/27/2012	10:13 AM	1013	10	71	7.1	-1.7
3/27/2012	10:27 AM	1027	24	106	5	-4
3/27/2012	10:37 AM	1037	34	127	2	-3.9
3/27/2012	10:47 AM	1047	44	162	3.5	-3.8
3/27/2012	10:57 AM	1057	54	213	5.1	-4
3/27/2012	11:07 AM	1107	64	253	4.3	-3.9
3/27/2012	11:17 AM	1117	74	290	3.7	-4.1
3/27/2012	11:27 AM	1127	84	350	6	-4.1
3/27/2012	11:37 AM	1137	94	400	5	-3.8
3/27/2012	11:47 AM	1147	104	445	4.5	-3
3/27/2012	11:57 AM	1157	114	483	3.8	1
3/27/2012	12:08 PM	1208	125	534	4.6	2
3/27/2012	12:18 PM	1218	135	579	4.5	2.2
3/27/2012	12:28 PM	1228	145	619	4	2.6
3/27/2012	12:38 PM	1238	155	660	4.1	2.3
3/27/2012	12:48 PM	1248	165	695	3.5	2.5
3/27/2012	12:58 PM	1258	175	734	3.9	2.7
3/27/2012	1:08 PM	1308	185	771	3.7	2.5
3/27/2012	1:18 PM	1318	195	830	5.9	2.8
3/27/2012	1:28 PM	1328	205	857	2.7	2.5
3/27/2012	1:48 PM	1348	225	893	1.8	7.4
3/27/2012	1:58 PM	1358	235	928	3.5	7.9
3/27/2012	2:08 PM	1408	245	968	4	7.4
3/27/2012	2:18 PM	1418	255	999	3.1	7
3/27/2012	2:28 PM	1428	265	1029	3	6.9
3/27/2012	2:38 PM	1438	275	1064	3.5	6.8
3/27/2012	2:48 PM	1448	285	1110	4.6	6.6
3/27/2012	2:58 PM	1458	295	1140	3	6.6
3/27/2012	3:12 PM	1512	309	1180	4	1.7
3/27/2012	3:30 PM	1530	327	1230	3.3	2.8
3/27/2012	3:45 PM	1545	342	1279	3.28	5.8
3/27/2012	4:00 PM	1600	357	1328	3.28	13.6
3/27/2012	4:15 PM	1615	372	1375	3.07	15.7
3/27/2012	4:30 PM	1630	387	1410	3	16
3/27/2012	4:45 PM	1645	402	1455	2.98	15.9
3/27/2012	5:05 PM	1705	422	1511	4.32	-1.7
3/27/2012	5:15 PM	1715	432	1544	2.97	13.9
3/27/2012	5:30 PM	1730	447	1589	2.92	13.8
3/27/2012	5:45 PM	1745	462	1632	2.9	13.6
3/27/2012	6:00 PM	1800	477	1677	2.92	17.3
3/27/2012	6:15 PM	1815	492	1716	2.87	17.8
3/27/2012	6:30 PM	1830	507	1762	2.9	17.7
3/27/2012	6:45 PM	1845	522	1803	2.82	17.6
3/27/2012	7:00 PM	1900	537	1844	2.81	17.2
3/27/2012	7:15 PM	1915	552	1886	2.79	17.1
3/27/2012	7:30 PM	1930	567	1927	2.77	16.7
3/27/2012	7:45 PM	1945	582	1970	2.76	16.5
3/27/2012	8:00 PM	2000	597	2008	2.75	16.3
3/27/2012	8:15 PM	2015	612	2045	2.75	18.2
3/27/2012	8:30 PM	2030	627	2086	2.73	18.1
3/27/2012	8:45 PM	2045	642	2145	2.67	18.8

APPENDIX A - WELL # 38268 WELLHEAD PRESSURE AND INJECTION RATE FIELD MEASUREMENTS

Date	Eastern Standard Time	Time	Elapsed Time (min)	BBLs inj.	BBLM	Wellhead Pressure
3/27/2012	9:00 PM	2100	657	2171	2.63	18.2
3/27/2012	9:15 PM	2115	672	2211	2.6	18.2
3/27/2012	9:30 PM	2130	687	2250	2.56	18.2
3/27/2012	9:45 PM	2145	702	2286	2.55	18.1
3/27/2012	10:00 PM	2200	717	2326	2.55	22.3
3/27/2012	10:15 PM	2215	732	2373	2.51	22.1
3/27/2012	10:30 PM	2230	747	2409	2.49	21.9
3/27/2012	10:45 PM	2245	762	2439	2.48	21.6
3/27/2012	11:00 PM	2300	777	2478	2.44	21.5
3/27/2012	11:15 PM	2315	792	2509	2.44	21.2
3/27/2012	11:30 PM	2330	807	2549	2.43	20.9
3/27/2012	11:45 PM	2345	822	2587	2.41	20.8
3/28/2012	12:00 AM	2400	837	2623	2.4	20.5
3/28/2012	12:15 AM	15	852	2656	2.39	20.2
3/28/2012	12:30 AM	30	867	2696	2.37	20
3/28/2012	12:45 AM	45	882	2729	2.37	19.8
3/28/2012	1:00 AM	100	897	2766	2.36	19.6
3/28/2012	1:15 AM	115	912	2800	2.35	19.6
3/28/2012	1:30 AM	130	927	2836	2.34	19.1
3/28/2012	1:45 AM	145	942	2873	2.36	22.5
3/28/2012	2:00 AM	200	957	2906	2.34	22.1
3/28/2012	2:15 AM	215	972	2940	2.31	20.8
3/28/2012	2:30 AM	230	987	2973	2.29	18.1
3/28/2012	2:45 AM	245	1002	3010	2.27	14.5
3/28/2012	3:00 AM	300	1017	3044	2.25	12.5
3/28/2012	3:15 AM	315	1032	3078	2.24	8.3
3/28/2012	3:30 AM	330	1047	3108	2.22	5.5
3/28/2012	3:45 AM	345	1062	3143	2.2	0.1
3/28/2012	4:00 AM	400	1077	3173	2.18	-11.3
3/28/2012	4:15 AM	415	1092	3200	2.15	-18
3/28/2012	4:22 AM	422	1099	3221	2.21	7.9
3/28/2012	4:30 AM	430	1107	3235	2.26	19.1
3/28/2012	4:45 AM	445	1122	3270	2.24	16.6
3/28/2012	5:00 AM	500	1137	3300	2.22	13.3
3/28/2012	5:15 AM	515	1152	3333	2.22	9.4
3/28/2012	5:30 AM	530	1167	3367	2.2	4.5
3/28/2012	5:45 AM	545	1182	3398	2.18	-0.4
3/28/2012	6:00 AM	600	1197	3431	2.16	-7.7

APPENDIX A - WELL # 38268 WELLHEAD PRESSURE AND INJECTION RATE FIELD MEASUREMENTS

Date	Eastern Standard Time	Time	Elapsed Time (min)	BBLs inj.	BBLM	Wellhead Pressure
3/28/2012	6:15 AM	615	1212	3463	1.9	-12
3/28/2012	6:30 AM	630	1227	3490	1.7	-12.2
3/28/2012	6:45 AM	645	1242	3530	2.36	4.2
3/28/2012	7:00 AM	700	1257	3560	2.2	-3.4
3/28/2012	7:15 AM	715	1272	3594	2.16	-10.4
3/28/2012	7:30 AM	730	1287	3626	1.77	-12.2
3/28/2012	7:45 AM	745	1302	3650	1.53	-12.5
3/28/2012	8:00 AM	800	1317	3671	1.27	-12.4
3/28/2012	8:15 AM	815	1332	3689	1.14	-12.5
3/28/2012	8:30 AM	830	1347	3707	1.24	-12.4
3/28/2012	8:45 AM	845	1362	3725	1.17	-12.5
3/28/2012	9:00 AM	900	1377	3743	1.12	-12.5
3/28/2012	9:15 AM	915	1392	3775	2.4	-13.3
3/28/2012	9:45 AM	945	1422	3844	2.23	26.5
3/28/2012	10:00 AM	1000	1437	3873	2.19	26.6
3/28/2012	10:15 AM	1015	1452	3905	2.17	27.2
3/28/2012	10:30 AM	1030	1467	3937	2.16	28
3/28/2012	10:45 AM	1045	1482	3972	2.14	27.8
3/28/2012	11:00 AM	1100	1497	4002	2.13	27.9
3/28/2012	11:15 AM	1115	1512	4033	2.10	27.4
3/28/2012	11:30 AM	1130	1527	4064	2.10	30
3/28/2012	11:45 AM	1145	1542	4096	2.10	29.5
3/28/2012	12:00 PM	1200	1557	4128	2.10	30.1
3/28/2012	12:15 PM	1215	1572	4159	2.10	30.6
3/28/2012	12:30 PM	1230	1587	4190	2.05	31.2
3/28/2012	12:45 PM	1245	1602	4223	2.13	30.2
3/28/2012	1:00 PM	1300	1617	4254	2.13	30
3/28/2012	1:15 PM	1315	1632	4286	2.12	29.8
3/28/2012	1:30 PM	1330	1647	4318	2.11	29.3
3/28/2012	2:45 PM	1445	1662	4349	2.11	30.1
3/28/2012	2:00 PM	1400	1677	4381	2.1	30
3/28/2012	2:15 PM	1415	1692	4412	2.1	29.5
3/28/2012	2:30 PM	1430	1707	4443	2.09	29.3
3/28/2012	2:45 PM	1445	1722	4474	2.09	29.2
3/28/2012	3:00 PM	1500	1737	4506	2.08	28.8
3/28/2012	3:15 PM	1515	1752	4538	2.1	26.1
3/28/2012	3:30 PM	1530	1767	4579	2.08	28.8
3/28/2012	3:45 PM	1545	1782	4611	2.07	29.9
3/28/2012	4:00 PM	1600	1797	4641	2.06	29.7
3/28/2012	4:15 PM	1615	1812	4671	2.05	29.4
3/28/2012	4:30 PM	1630	1827	4702	2.05	29.1
3/28/2012	4:45 PM	1645	1842	4734	2.02	31.3
3/28/2012	5:00 PM	1700	1857	4764	2.05	30.1
3/28/2012	5:15 PM	1715	1872	4795	2.05	30.4
3/28/2012	5:30 PM	1730	1887	4825	2.05	30.2
3/28/2012	5:45 PM	1745	1902	4855	2.05	30.7
3/28/2012	6:00 PM	1800	1917	4887	2.04	30.4
3/28/2012	6:15 PM	1815	1932	4917	2.04	30.1
3/28/2012	6:30 PM	1830	1947	4947	2.04	30
3/28/2012	6:45 PM	1845	1962	4978	2.03	29.7
3/28/2012	6:56 PM	1856	1973	5000	2.03	29.7

APPENDIX B

Fluid Levels from Echo Meter Readings

APPENDIX B - FLUID LEVELS FROM ECHOMETER READINGS

Well # / Shot #	Date/Time	Main Time To Liquid Level (sec)	Main Depth to Liquid Level (ft)	Analysis Method	Depth To Downhole Marker	Well State	Gas Gravity (Sp.Gr.AIR)
MyWells\Seneca 38268/001 Casing	3/26/2012 8:50	3.522	2201.55	Depth Marker	553.2	Static	0.78
MyWells\Seneca 38268/001 Tubing	3/26/2012 8:51	4.245	2452.81	Acoustic Velocity	X	Static	0.84
MyWells\Seneca 38281/001	3/26/2012 10:29	4.042	2172.57	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/002	3/27/2012 9:17	4.036	2167.41	Depth Marker	602	Static	0.56
MyWells\Seneca 38281/003	3/27/2012 18:14	4.029	2165.59	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/004	3/28/2012 9:00	4.006	2153.22	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/005	3/28/2012 10:07	4.002	2151.07	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/006	3/28/2012 19:38	3.99	2144.63	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/007	3/29/2012 9:23	3.931	2118.59	Depth Marker	602	Static	0.89
MyWells\Seneca 38268/002 Casing	4/2/2012 14:17	3.424	2185.24	Depth Marker	553.2	Static	0.77
MyWells\Seneca 38268/012 Tubing	4/2/2012 14:45	4.051	2439.65	Acoustic Velocity	X	Static	0.78
MyWells\Seneca 38281/008	4/2/2012 15:13	3.875	2116.83	Depth Marker	602	Static	0.88

Injection Well # 38268 - Casing

Elapsed time (min)	Depth to Liquid Level (ft)
-1513	2201.55
8894	2185.24
Water level change	16.31

Injection Well # 38268 - Tubing

Elapsed time (min)	Depth to Liquid Level (ft)
-1512	2452.81
8922	2439.65
Water level change	13.16

Observation Well # 38281

Elapsed time (min)	Depth to Liquid Level (ft)
-1414	2172.57
-46	2167.41
491	2165.59
1377	2153.22
1444	2151.07
2015	2144.63
2840	2118.59
8950	2116.83
Water level change	55.74

APPENDIX D

Proposed Injection Well Records (#38282)

Well Construction Diagram

Proposed Injection Test Well

Seneca Well #38282
Highland Township
Elk County, PA
37-047-23885

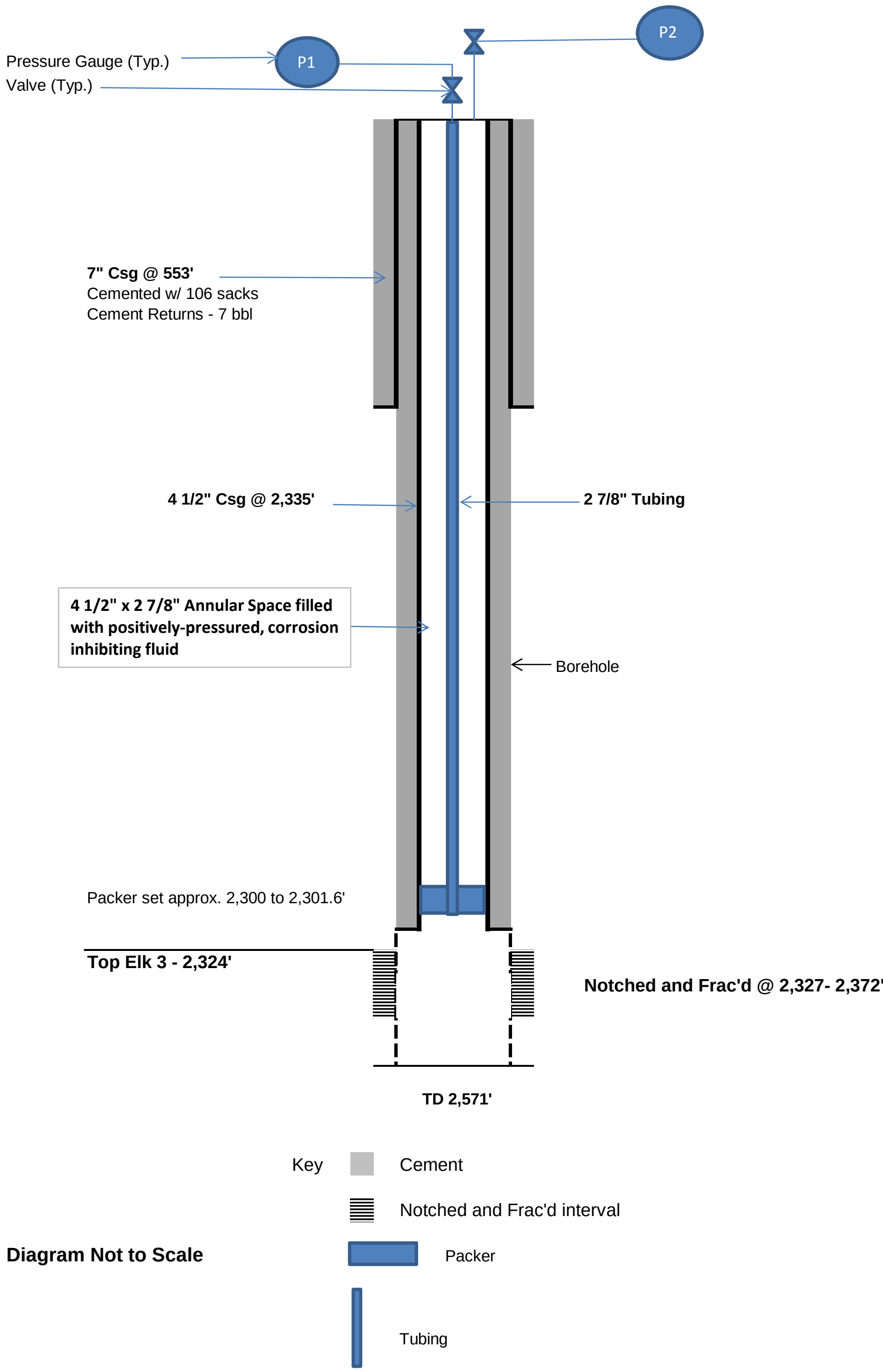


Diagram Not to Scale

5500-FM-OG0004 Rev 5/98

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

DEP USE ONLY	
Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

WELL RECORD AND COMPLETION REPORT

Well Operator SENECA RESOURCES CORPORATION	DEP ID# 72993	Well API # (Permit / Reg.) 37-047-32885	Project Number		Acres
Address 286 OLD 36 ROAD		Well Farm Name FEE-SRC Wt. 3771		Well # 38282	Serial #
City SIGEL	State PA / Zip Code 15860	County Mckean	Municipality Highland		
Phone 814-752-2291	Fax 814-752-6204	USGS 7.5 min. quadrangle map			

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type: ☐ Gas ☐ Oil ☒ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method: ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
01/25/08	01/29/08	2030	2565	2571

Casing and Tubing

Cement returned on surface casing? ☒ Yes ☐ No
Cement returned on coal protective casing? ☐ Yes ☐ No ☒ N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
12 ¼	9 5/8	26	T	40					01/25/08
8 ¾	7	17	T	553	105 sks Class A Cement			3 centralizers	01/26/08
					3% CaCl, ½# unicele/sk				
6 ¼	2 3/8	4.6	T	2448					03/06/08
	5/8		T	2425					03/06/08

COMPLETION REPORT

Perforation Record / Stimulation Record

Perf. Date	Interval Perforated From	To	Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			03/06/08	1644	Gel Water	9510	20/40 sks	140	20
				1649	Gel Water	7545	20/40 sks	100	20
				1652	Gel Water	10620	20/40 sks	160	20
				1655	Gel Water	7509	20/40 sks	100	20
				1714	Gel Water	7306	20/40 sks	100	20
				1722	Gel Water	7306	20/40 sks	100	20

Natural Open Flow Mcfd 2.0	Natural Rock Pressure	Hours	Days
After Treatment Open Flow Mcfd 500	After Treatment Rock Pressure	Hours	Days

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name Natural Oil and Gas	Name Universal Well Services	Name Schlumberger
Address 1410 W. Warren Road	Address PO Box 180	Address 95 Rutherford Run
City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701
Phone (814) 362-6890	Phone (814) 368-6175	Phone (814) 362-7441

COMPLETION REPORT API#37-047-32885

Perforation Record			Stimulation Record						
Date	Interval Perforated From	To	Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			03/06/08	1907	Gel Water	7520	20/40 Sand	100	20
				1930	Gel Water	7792	20/40 Sand	100	20
				2117	Gel Water	10184	20/40 Sand	140	17
				2327-2372	Gel Water	21621	20/40 Sand	420	22
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		

LOG OF FORMATIONS

Well API#: 37-047-32885

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

Well Operator's Signature: Guy A. Shrewy

Title: Superintendent / Prod. & Eng. Date:

DEP USE ONLY

Reviewed by: Date:

Comments:

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD. PENNSYLVAN
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL #	38282	PERMIT #	37-047-23885
SPUD DATE	1/25/2008	COUNTY	Elk
SPUD TIME	4:00 p.m.	TOWNSHIP	Highland
CONDUCTOR	40 ft.	LEASE	James City
CASING	561 ft.	TD DATE	1/29/2008
TOTAL DEPTH	2565 ft.	TD TIME	2:30 a.m.

PIPE TALLY

1	23.3 ft.	7	23.3 ft.	13	23.3 ft.	19	23.3 ft.	25	
2	23.3 ft.	8	23.3 ft.	14	23.3 ft.	20	23.3 ft.	26	
3	23.3 ft.	9	23.3 ft.	15	23.3 ft.	21	23.3 ft.	27	
4	23.3 ft.	10	23.3 ft.	16	23.3 ft.	22	23.3 ft.	28	
5	23.3 ft.	11	23.3 ft.	17	23.3 ft.	23	23.3 ft.	29	
6	23.3 ft.	12	23.3 ft.	18	23.3 ft.	24	23.3 ft.	30	

#JOINTS	24	CEMENT CO.	Universal
SACKS	105	RETURNS	2 barrel
PLUG DOWN	4:30 p.m.	CEMENT DATE	1/26/2008

OPERATOR: Seneca

LEASE NAME: James (

WELL # : 38282

PERMIT # : 37-047-23

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD. PENNSYLVANIA 16
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
45				645	11:27	14	RedRock
75	8:55		Shale	675	11:45	18	RedRock
105	9:08	13	Shale	705	11:56	11	Shale
135	9:17	9	Shale	735	12:12	16	
165	9:25	8	Shale/Sand	765	1:07		Shale
195	9:40	15	Sand	795	1:17	10	RedRock
225	9:48	8	Shale	825	1:27	10	Shale
255	10:00	12	Sand	855	1:37	10	RedRock
285	10:08	8	Shale	885	1:47	10	Shale
315	10:22	14		915	1:57	10	Shale
345	10:35	13	Sand	945	2:07	10	Shale
375	10:50	15	Sand	975	2:16	9	Shale
405	11:00	10	Sand	1005	2:27	11	Shale
435	11:10	10	Sand	1035	2:36	9	Shale
465	11:19	9	RedRock	1065	2:57		
495	11:28	9	RedRock	1095	3:21		
525	11:39	11	RedRock	1125	3:31	10	Shale
555	11:51	12	Sand	1155	3:42	11	Shale
585	12:00	9	RedRock	1185	3:53	11	Shale
615	11:13	13	RedRock	1215	4:04	11	Shale

COMMENTS:

OPERATOR: Seneca LEASE NAME: James C

WELL # : 38282 PERMIT # : 37-047-23

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD. PENNSYLVANIA 16
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
1245	4:13	9	Shale	1845	8:46	12	Shale
1275	4:23	10	Shale	1875	8:57	11	Shale
1305	4:33	10	Shale	1905	9:10	13	Shale/Sand
1335	4:45	12	RedRock	1935	9:23	13	Sand
1365	5:06	11	Sand	1965	9:40	17	Bit Problems
1395	5:18	12	Sand/Shale	1995	9:54	14	Shale
1425	5:29	11	Shale	2025	10:17	13	Shale
1455	5:41	12	Shale	2055	10:36	16	Shale
1485	5:52	11	Shale	2085	10:51	15	Shale
1515	6:04	12	Shale	2115	11:05	14	Shale
1545	6:15	11	Shale	2145	11:21	11	Shale
1575	6:27	12	Shale/Sand	2175	11:38	17	Shale
1605	6:50		Sand	2205	11:53	15	Shale
1635	7:02	12	Shale	2235	12:08	15	Shale
1665	7:14	12	Shale	2265	12:21	13	Shale
1695	7:25	11	Shale/Sand	2295	12:33	12	Sand
1725	7:40	15	Sand	2325	12:46	13	Shale
1755	8:07		Sand	2355	12:57	11	Shale
1785	8:22	15	Sand/Shale	2385	1:07	10	Shale
1815	8:34	12	Shale	2415	1:20	13	Shale

COMMENTS:

OPERATOR: Seneca

LEASE NAME: James (

WELL # : 38282

PERMIT # : 37-047-23

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD. PENNSYLVANIA 1(
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
2445	1:35	15	Sand				
2475	1:47	12	Sand/Shale				
2505	1:57	10	Shale				
2535	2:08	11	Shale				
2565	2:20	12	TD				

COMMENTS:

SENECA RESOURCES CORPORATION

FRAC PLAN : **Well # 38282** **Date:** 3-6-08

Start 5:30 Am End 3:45 PM

FIELD:	Kane(James City)Fee-SRC Wt3771	**T.D:**	2,571 ft.	**Surf. Csg:**	7 in.
TOWNSHIP:	HIGHLAND	**PBD:**	ft.	**Weight:**	17 # / ft
COUNTY, STATE:	MCKEAN	**Hole Size:**	6 1/4 in.	**Set @:**	553 ft.
SERVICE CO:	Keane	**BFOF:**	2 mcfd	**AFOF:**	mcfd

3 1/2", 9.5 #/ft pipe cap = 0.3652 gal/ft

Stage	Zone	---Job Settings ---	Sand Conc. (ppg)	Inc. Fluid Vol. (gal)	20/40 Sand Inc. (sks)	20/40 Sand Cum. (sks)	Cumul. "Clean" Vol. (gal)	Cumul. "Dirty" Vol. (gal)	---- Job Results ----
1	SPEECHLEY 6		0.5	0	0	0	0	0	BDP = 2130 psig
			1.0	1,000	10	10	1,000	1,046	ATP = 2402 psig
		H. NOTCH = 1,644.0	1.5	1,000	15	25	2,000	2,114	RATE = 20.0 bpm
		CORRECTED NOTCH =	2.0	5,750	115	140	7,750	8,388	ISIP = 1300 psig
			Flush	1,000			8,750	9,388	TTV = 9510 gal
NOTE: Formation Broke - Screened off - Re wash - High Treat - Frac Zone									
2	SPEECHLEY 6		0.5	0	0	0	0	0	BDP = 2090 psig
			1.0	1,000	10	10	1,000	1,046	ATP = 2042 psig
		H. NOTCH = 1,649.0	1.5	1,000	15	25	2,000	2,114	RATE = 20.0 bpm
		CORRECTED NOTCH =	2.0	3,750	75	100	5,750	6,206	ISIP = 1310 psig
			Flush	1,000			6,750	7,206	TTV = 7545 gal
NOTE: Broke with #1 pick up Above #1 + Treat 1+2 Together									
3	SPEECHLEY 6		0.5	0	0	0	0	0	BDP = 2500 psig
			1.0	1,000	10	10	1,000	1,046	ATP = 2116 psig
		H. NOTCH = 1,652.0	1.5	1,000	15	25	2,000	2,114	RATE = 20.0 bpm
		CORRECTED NOTCH =	2.0	6,750	135	160	8,750	9,480	ISIP = 1370 psig
			Flush	1,000			9,750	10,480	TTV = 10620 gal
NOTE: Good Break - Nice Treat									
4	SPEECHLEY 6		0.5	0	0	0	0	0	BDP = 3390 psig
			1.0	1,000	10	10	1,000	1,046	ATP = 2270 psig
		H. NOTCH = 1,655.0	1.5	1,000	15	25	2,000	2,114	RATE = 20.0 bpm
		CORRECTED NOTCH =	2.0	3,750	75	100	5,750	6,206	ISIP = ~~[illegible]~~ psig 1330
			Flush	1,000			6,750	7,206	TTV = 7509 gal
NOTE: Re wash - Frac Zone									
5	TIONA 1		0.5	0	0	0	0	0	BDP = 2330 psig
			1.0	1,000	10	10	1,000	1,046	ATP = 2100 psig
		H. NOTCH = 1,714.0	1.5	1,000	15	25	2,000	2,114	RATE = 20.0 bpm
		CORRECTED NOTCH =	2.0	3,750	75	100	5,750	6,206	ISIP = 1330 psig
			Flush	1,100			6,850	7,306	TTV = 7306 gal
NOTE: Had to work thru Mudring. Good Treat									

SENECA RESOURCES CORPORATION

FRAC PLAN : Well # 38282 **Date:**

					Start	End
FIELD:	Kane(James City)Fee-SRC Wt3771	**T.D:**	2,571 ft.		**Surf. Csg:**	7 in.
TOWNSHIP:	HIGHLAND	**PBD:**	ft.		**Weight:**	17 # / ft
COUNTY, STATE:	MCKEAN	**Hole Size:**	6 1/4 in.		**Set @:**	553 ft.
SERVICE CO:		**BFOF:**	2 mcfd		**AFOF:**	mcfd

3 1/2", 9.5 #/ft pipe cap = 0.3652 gal/ft

Stage	Zone	----Job Settings ----	Sand Conc. (ppg)	Inc. Fluid Vol. (gal)	20/40 Sand Inc. (sks)	20/40 Sand Cum. (sks)	Cumul. "Clean" Vol. (gal)	Cumul. "Dirty" Vol. (gal)	---- Job Results ----		
6	**COOPER 4**		0.5	0	0	0	0	0	BDP =	2410	psig
			1.0	1,000	10	10	1,000	1,046	ATP =	2270	psig
		H. NOTCH = 1,722.0	1.5	1,000	15	25	2,000	2,114	RATE =	20.0	bpm
		CORRECTED NOTCH =	2.0	3,750	75	100	5,750	6,206	ISIP =	1370	psig
			Flush	1,100			6,850	7,306	TTV =	7306	gal
	NOTE:	Good treat.									
7	**COOPER 6**		0.5	0	0	0	0	0	BDP =	2330	psig
			1.0	1,000	10	10	1,000	1,046	ATP =	2247	psig
		H. NOTCH = 1,907.0	1.5	1,000	15	25	2,000	2,114	RATE =	20.0	bpm
		CORRECTED NOTCH =	2.0	3,750	75	100	5,750	6,206	ISIP =	1420	psig
			Flush	1,100			6,850	7,306	TTV =	7522	gal
	NOTE:										
8	**COOPER 6**		0.5	0	0	0	0	0	BDP =	2630	psig
			1.0	1,000	10	10	1,000	1,046	ATP =	2705	psig
		H. NOTCH = 1,930.0	1.5	1,000	15	25	2,000	2,114	RATE =	20.0	bpm
		CORRECTED NOTCH =	2.0	3,750	75	100	5,750	6,206	ISIP =	1460	psig
			Flush	1,100			6,850	7,306	TTV =	7792	gal
	NOTE:										
9	**KANE 3**		0.5	0	0	0	0	0	BDP =	3320	psig
			1.0	1,000	10	10	1,000	1,046	ATP =	2942	psig
		H. NOTCH = 2,117.0	1.5	1,000	15	25	2,000	2,114	RATE =	17.2	bpm
		CORRECTED NOTCH =	2.0	5,750	115	140	7,750	8,388	ISIP =	1520	psig
			Flush	1,200			8,950	9,588	TTV =	10184	gal
	NOTE:										

SENECA RESOURCES CORPORATION

FRAC PLAN : Well # 38282 **Date:** Start End

FIELD:	Kane(James City)Fee-SRC Wt3771	**T.D:**	2,571 ft.	**Surf. Csg:**	7 in.
TOWNSHIP:	HIGHLAND	**PBD:**	ft.	**Weight:**	17 # / ft
COUNTY, STATE:	MCKEAN	**Hole Size:**	6 1/4 in.	**Set @:**	553 ft.
SERVICE CO:		**BFOF:**	2 mcfd	**AFOF:**	mcfd

3 1/2", 9.5 #/ft pipe cap = 0.3652 gal/ft

Stage	Zone	----Job Settings ----	Sand Conc. (ppg)	Inc. Fluid Vol. (gal)	20/40 Sand Inc. (sks)	20/40 Sand Cum. (sks)	Cumul. "Clean" Vol. (gal)	Cumul. "Dirty" Vol. (gal)	---- Job Results ----
10	ELK 3		1.0	1,000	10	10	1,000	1,046	BDP = 1600 psig
		H. NOTCH = 2,327.0	1.5	1,000	15	25	2,000	2,114	ATP = 1772 psig
		H. NOTCH = 2,331.0	2.0	7,750	155	180	9,750	10,571	RATE = 22.2 bpm
		H. NOTCH = 2,335.0	3.0	8,000	240	420	17,750	19,665	ISIP = 1580 psig
		H. NOTCH = 2,339.0	Flush	1,300			19,050	20,965	TTV = 21621 gal
		H. NOTCH = 2,345.0							
		H. NOTCH = 2,349.0							
		H. NOTCH = 2,356.0							
		H. NOTCH = 2,361.0							
		H. NOTCH = 2,367.0							
		H. NOTCH = 2,372.0							
NOTE:	*Frac together, max rate with equipment on location.. Run sand from 1-3#.*								
11	ELK 3		1.0	1,000	10	10	1,000	1,046	BDP = psig
	Skipped		1.5	1,000	15	25	2,000	2,114	ATP = psig
		H. NOTCH = 2,379.0	2.0	2,750	55	80	4,750	5,115	RATE = bpm
		H. NOTCH = 2,382.5	3.0	1,325	39.75	~~120~~	6,075	6,621	ISIP = psig
			Flush	1,300			7,375	7,921	TTV = gal
NOTE:	Check to see if already broke. CAme Around Treated with #10								

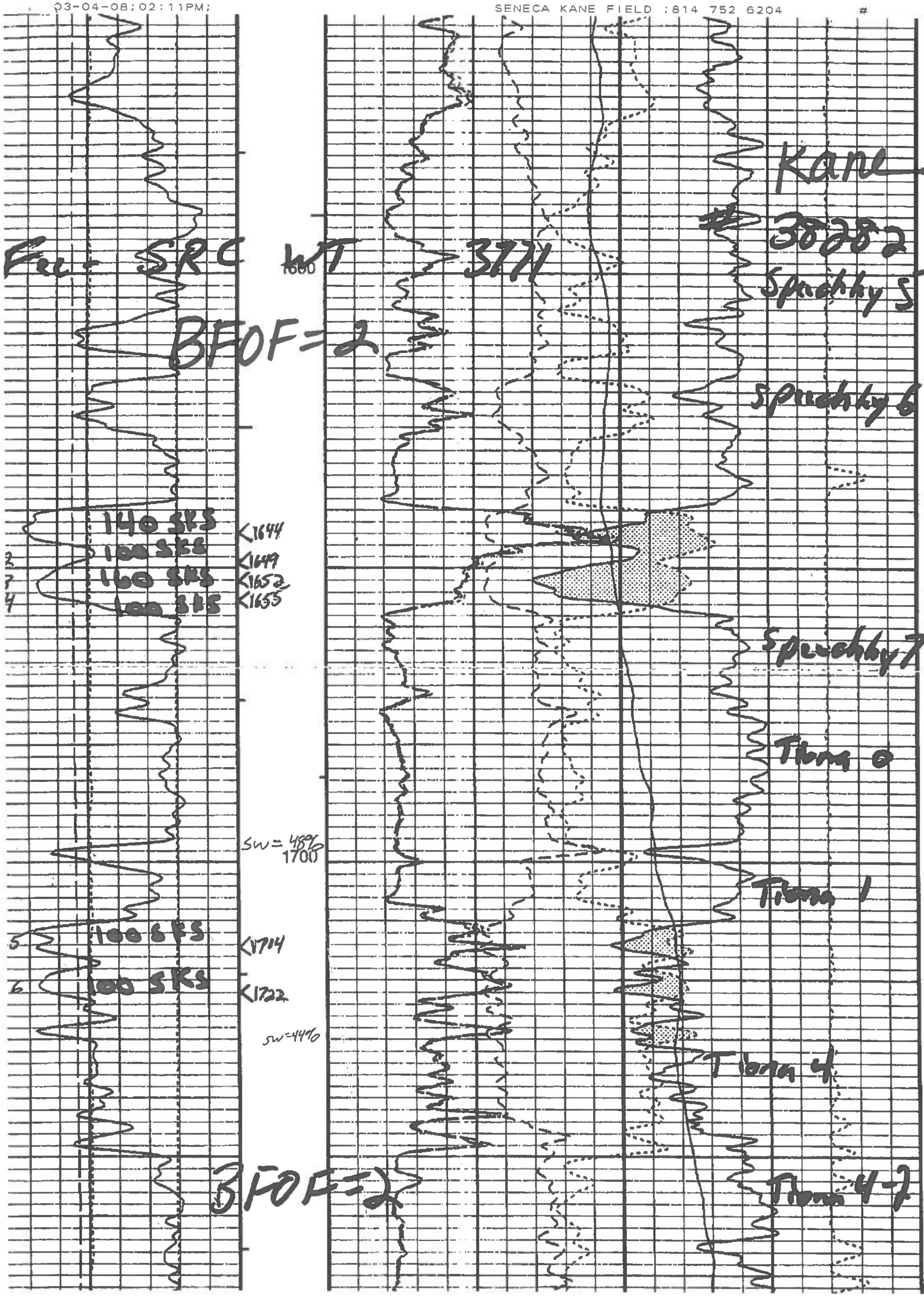
TOTAL SACKS = 1,580 sacks **JOB TOTAL FLUID =** 94,775 gallons 2,257 bbl

Rate = 18 - 20 BPM. Allow 5-min SI after each stage pumped, when possible. Do not run a foamer.

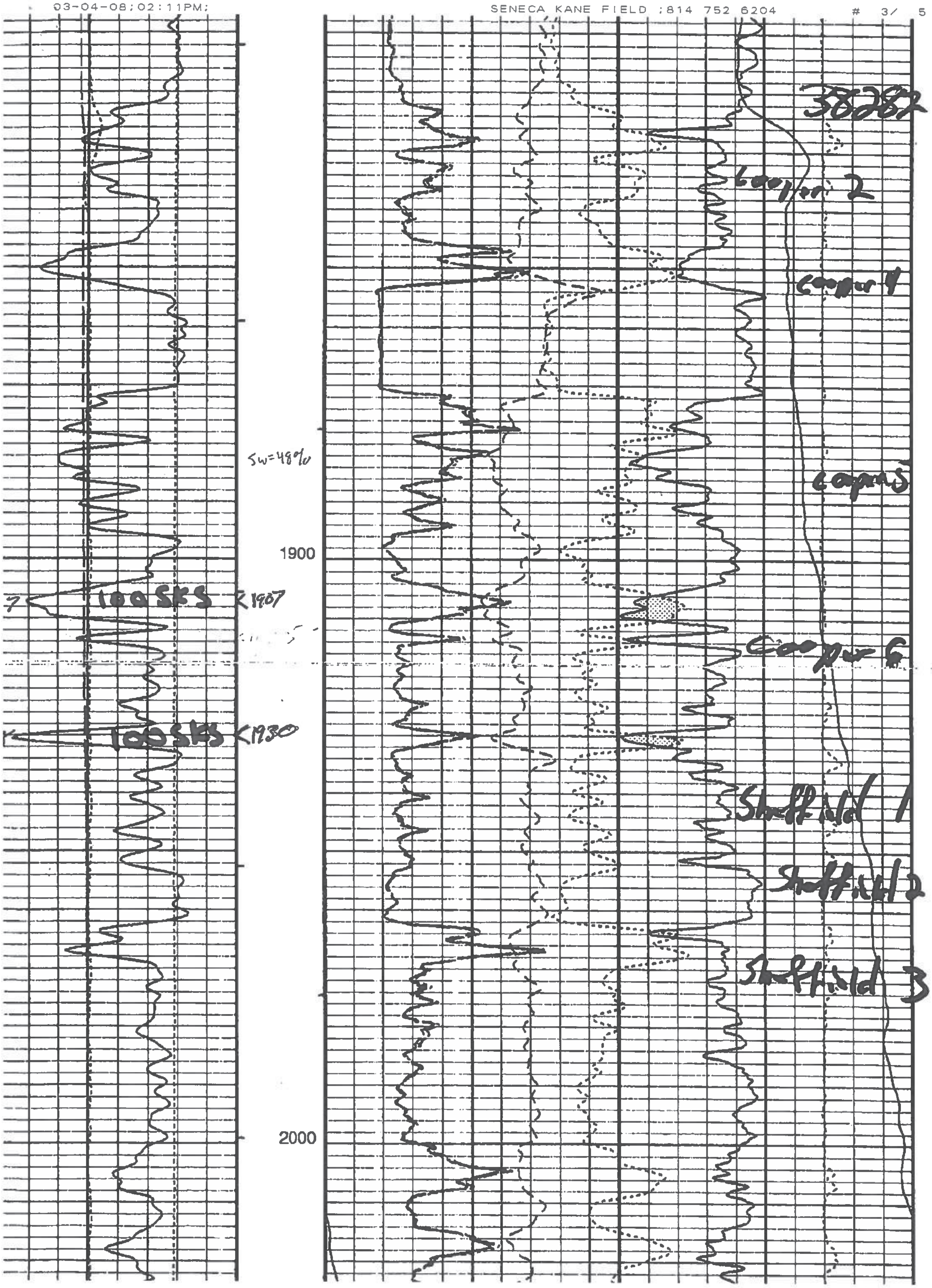
CHEMICALS:	Gel Agent	(#/M)	Gel Breaker	(gal/M)	Surf.	(gal/M)	Clay Control	(gal/M)	Iron Control	(gal/M)	Non Emulsifier
Universal	Unigel 5F	5	GB-L	0.1	Super Surf	—	Cla-Chek A	----	Iron-Sta II	—	
Appalachian	WGA-6	10	GBL-1	0.1	AFS-30	—	K-mate	—	—	—	
Superior	CW-3K SAS	6 0.5	OB-FE OB-FE 0.1	0.1	Super NE 100	—	Clay Treat pp	----	----	—	

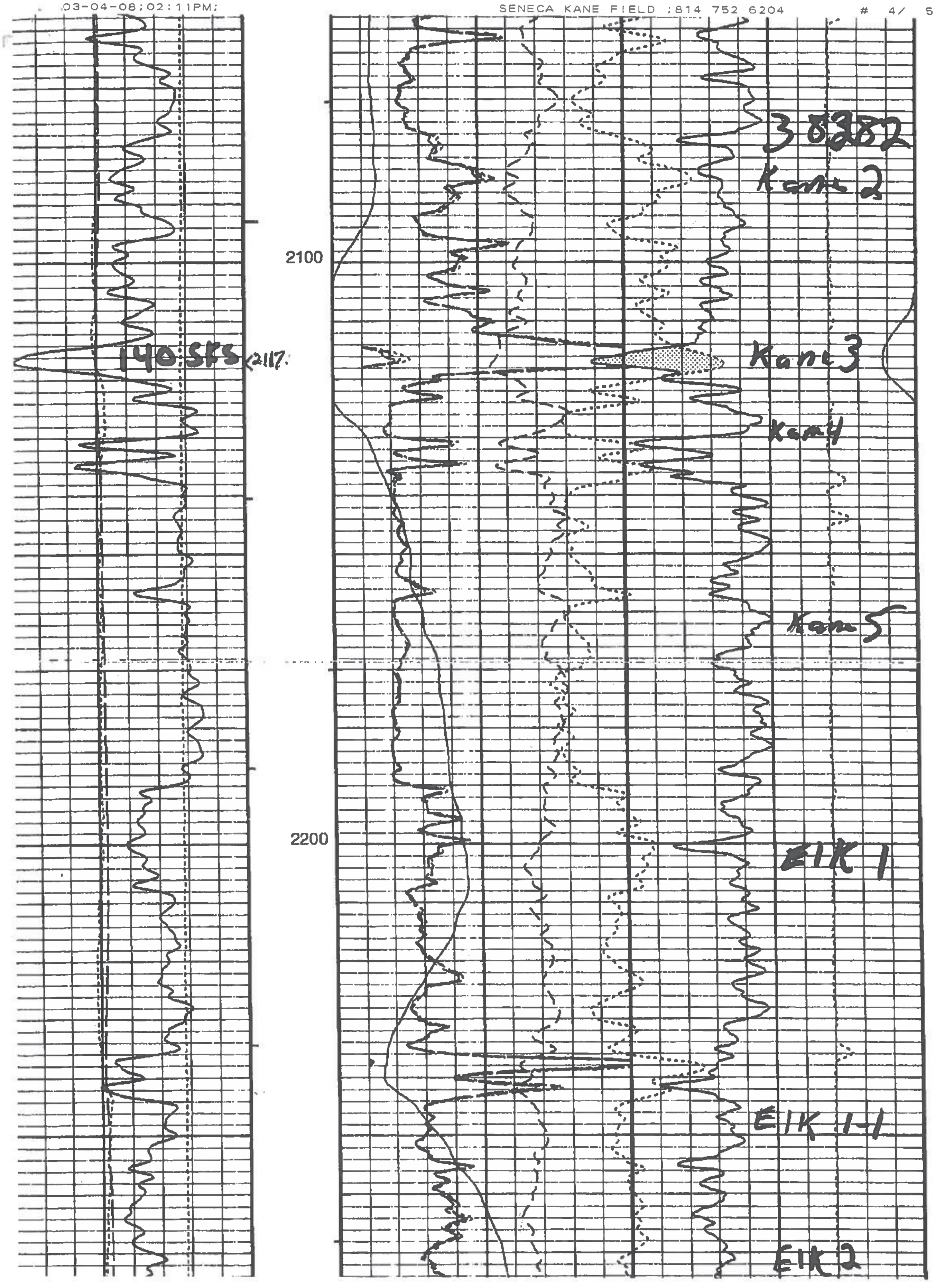
Post-Frac Results:

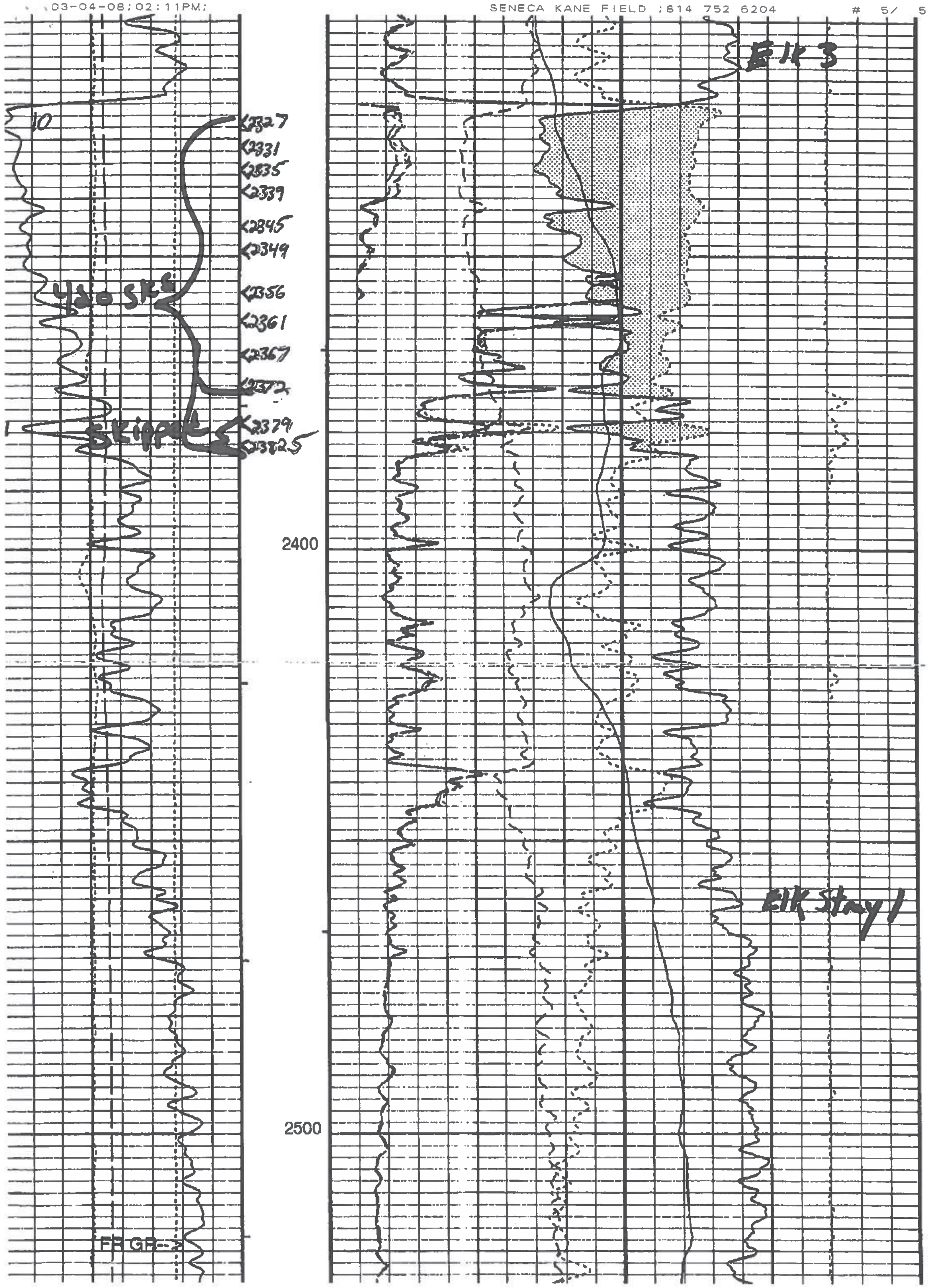
Packer Set @	
Tubing Set @	
Rod length	



Kane
38282
Fee - SRC WT 3771
1600
BFOF=2
Speechley 5
Speechley 6
140 SKS <1644
100 SKS <1649
160 SKS <1652
100 SKS <1655
Speechley 7
Tiona 0
SW=48%
1700
Tiona 1
100 SKS <1714
100 SKS <1722
SW=44%
Tiona 4
BFOF=2
Tiona 4-2


38282
Cooper 2
Cooper 4
Sw=48%
Cooper 5
1900
100 SKS <1907
Cooper 6
100 SKS <1930
Sheffield 1
Sheffield 2
Sheffield 3
2000


38282
Kane 2
2100
140 SFS 2117
Kane 3
Kane 4
Kane 5
2200
Elk 1
Elk 1-1
Elk 2


10
2327
2331
2335
2339
2345
2349
2356
2361
2367
2372
2379
2382.5
420 SKS
Skipper
1
2400
2500
Elk 3
Elk Stray 1
FR GR-->

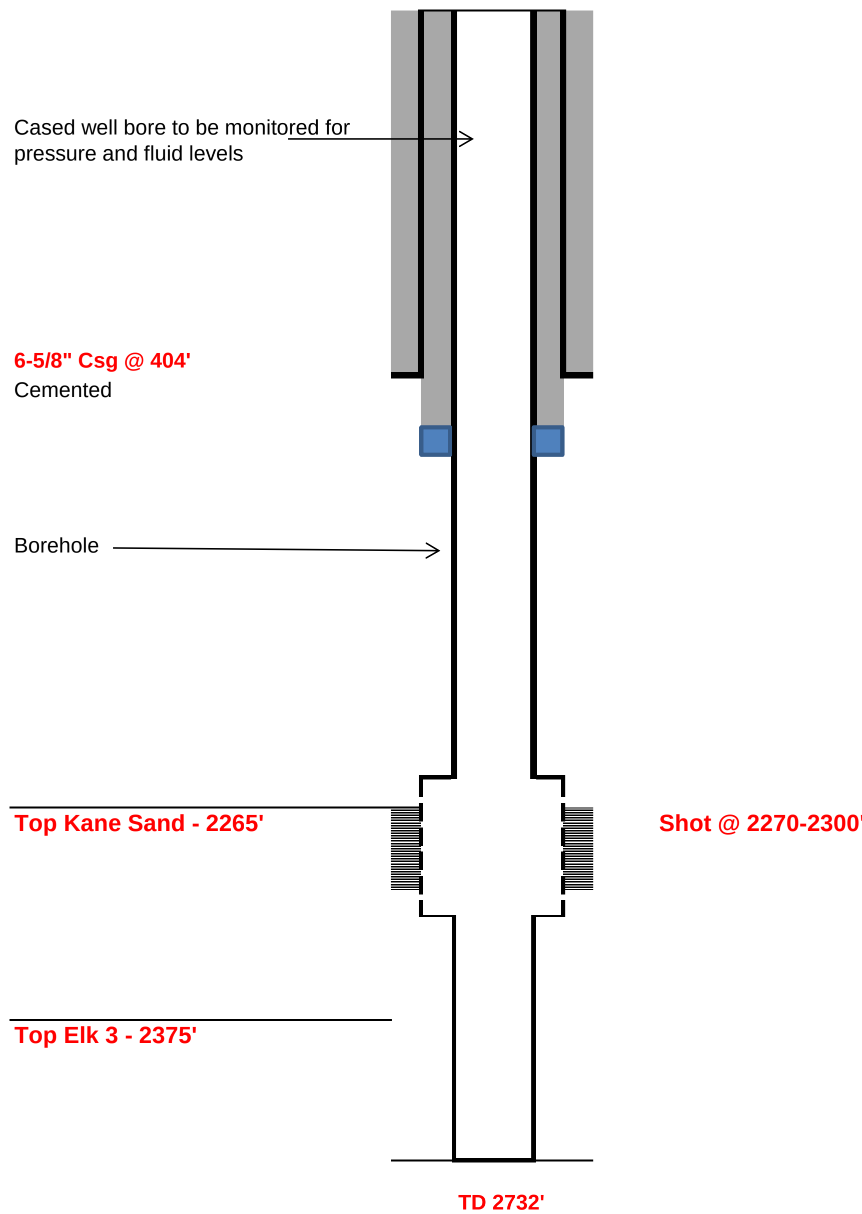
APPENDIX E

Monitoring Well Records (#04406)

Well Construction Diagram

Proposed Monitoring Well

Seneca Well #04406
Highland Township
Elk County, PA



Key
Cement
Completed Interval (shot)
Formation Packer

Diagram Not to Scale

January 21, 2013

Kane Field

TR.MK. REG. U.S. PAT. OFF.

The Mars Company lands
Comm. 12-30-42 Comp. 2-12-43
Vol. 49,578

Sand & Lime	35	65	water 65'
Sand & slate	65	209	
Lime	209	313	
Lime	329	337	water level
Red Rock	505	735	55'
Slate & Lime	735	764	
Pink Rock	764	800	
Pink Rock	910	947	
Lime	1084	1201	
Pink Rock	1201	1253	
Lime	1253	1278	
Lime	1436	1507	
Red Rock	1507	1515	
Clarendon	1582	1591	1582'-20,317
Sand	1650	1666	
Slate & Lime	1666	1816	
Sand	1816	1830	
Lime & slate	1830	2045	
Cooper	2045	2056	2050'-27,386
Lime	2150	2168	
Bradford	2172	2232	No gas or water
Kane Sand	2262	2324	2316'-52,008
Gas 2268,2291,2316'.			
Elk Sand	2375	2401	No water or
Lime & slate	2500	2710	gas
Total Depth		2732	

Form A-61 25570

UNITED NATURAL GAS COMPANY

Well No. 4406 Title No. 22-J Location Order No. 1990

Reason for Drilling Production Date Dec 15, 1942

Foreman C. R. Cartwright Field Kane

This Company will drill a well on

Lands The Mars Co. Acres 400

Warrant No. 3771 Lot No. — Township Highland

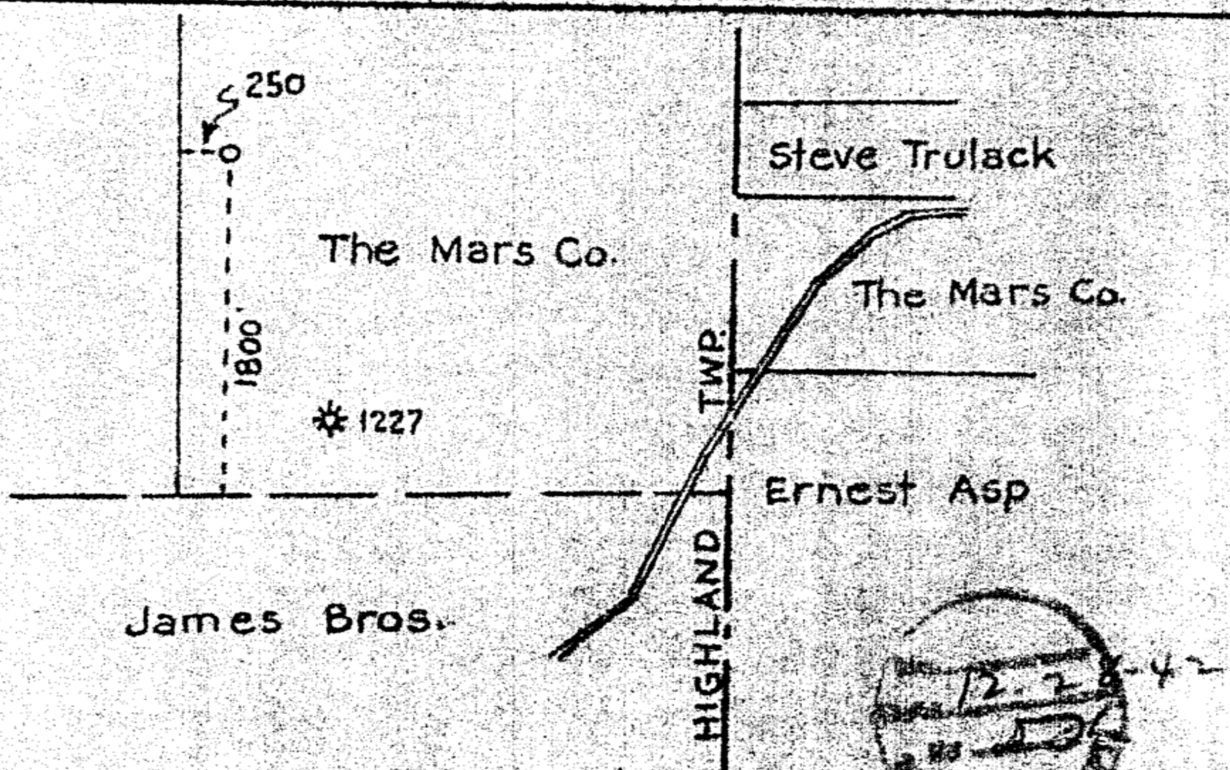
County Elk

CRE 12/17/42

Title Department

Superintendent President

Map 660 N. 19 S. E. 20 W. Sq. Mi. No. 2649



Reservation None rods feet around buildings

NOTE.—If conditions upon the ground prevent locating as above indicated the location as changed must be shown hereon, and all notices returned to this office with as little delay as possible.

Located on ground 12-22 1942 By D. Gorley

Noted 12-22 1942 C.R. Cartwright

Field Superintendent or Foreman

Located on Map. 19

Inv Map 962

6-43 RLA.

M-G 660 RE

This Agreement, made and entered into this........10th........day of December..............A. D. 1942..

by and between........Charles H. Smith........................, hereinafter referred to as the "Contractor," and UNITED ~~RIDGWAY~~ NATURAL GAS COMPANY, a Pennsylvania corporation doing business at Oil City, Pennsylvania, hereinafter referred to as the "Gas Company."

WHEREAS, The "Contractor" is a practical and experienced oil and gas well driller, familiar with the drilling conditions peculiar to the territory in the vicinity of the land upon which the "Gas Company" desires to drill a well as hereinafter indicated, and desires to undertake the drilling of the same, and

WHEREAS, The "Gas Company" is engaged in the business of producing and marketing natural gas and desires to contract with an experienced and practical oil and gas well driller for the drilling of such well,

NOW, THEREFORE, THIS AGREEMENT WITNESSETH, That for and in consideration of the premises and the covenants and agreements hereinafter contained, and the sum of One Dollar ($1.00) paid by each of the parties to the other, the receipt whereof is hereby acknowledged, the parties hereto do agree with each other as follows:

FIRST. The "Contractor" covenants and agrees to go upon the lands known as the..Mars Company 400 acres in......Highland..............Township,..............Elk..................County, and State of Pennsylvania, within...............ten.............(10) days after a well location has been made thereon by the "Gas Company" and drill a well at the said location for the purpose of discovering oil or gas for the "Gas Company" and to diligently and continuously prosecute the work of doing the same to completion.

SECOND. The "Contractor" covenants and agrees to furnish at his own expense...Drilling rig.................. all boilers and engines, steam pipes, water pipes and connections, as well as all fuel, water, material, tools, appliances, repairs to rigs, and all labor necessary or required for drilling, casing, tubing, piping, cleaning out, and completing said well promptly and in a good workmanlike manner, and the "Gas Company" covenants and agrees to furnish the casing, tubing, and packer to be used therein.

THIRD. The "Gas Company" agrees to pay, and the "Contractor" agrees to accept, for the drilling of the said well ..One and 30/100....................($1.30..) per foot ~~unless gas is purchased from the "Gas Company" for firing the boiler used in the said operations, in which event the rate will be ($.......) per foot~~, which said price will be full compensation for drilling, casing, tubing, packing, cleaning out, and completing said well if a producing well, or pulling and plugging if a dry hole; payment to be made within thirty (30) days from and after the completion of same.

FOURTH. The "Contractor" covenants and agrees to keep for the benefit of the "Gas Company" an accurate record of the drilling of said well, showing all the formations through which it passes, together with the actual depth and the thickness thereof measured with a steel line, and further that he will not impart to anyone information as to the drilling of said well or the discoveries made therein, nor will he permit any of his employees so to do.

FIFTH. It is understood and agreed that the "Contractor" is a contractor engaged in an independent business as set forth in Section 105, Article I, of the Workmen's Compensation Act of 1915; that, therefore, the term "Contractor" as used in Section 203, Article II, and Section 302 (b), Article III, of said Act, does not include him in the performance of his engagement under this contract.

SIXTH. If gas is purchased from the "Gas Company" for use as aforesaid, the "Contractor" agrees to pay the "Gas Company" for same at the rate of published tariff rate ~~cents~~ per thousand cubic feet as provided in the "Gas Company's" published Tariff, and the "Gas Company" agrees to make the necessary tap and install the meter for measuring said gas at a convenient point on its line, and will charge the "Contractor" for the said installation and work the sum of .Ten and No/100.Dollars ($10.00..), which sum the "Contractor" agrees to pay. If the "Contractor" so requests, the "Gas Company" will at the expense of the "Contractor" construct the line from the said meter to the boiler.

SEVENTH. The "Contractor" covenants and agrees to take care of at his own expense all sand pumpings, and other material, when necessary to prevent surface damage, and without extra charge to re-set the packer as many times as may be necessary in order to procure a tight job.

EIGHTH. If it is found necessary to drill a water well, the "Gas Company" agrees to pay and the "Contractor" agrees to accept the sum of...seventy-five.........(...75.) cents per drilling foot for same.

IT IS MUTUALLY COVENANTED AND AGREED as follows:

FIRST. That the well to be drilled hereunder shall be drilled to any depth desired by the "Gas Company" not exceeding .Three thousand....................(..3000..) feet; that upon the discovery of oil or gas in the said well at any time, the "Contractor" shall notify the "Gas Company," and shall discontinue drilling until further instructed by the "Gas Company"; and shall then resume or discontinue operations at the pleasure of the "Gas Company"; that rapid and continued progress in drilling said well is of the essence of this contract, and that the "Contractor" shall not be allowed more than thirty (30) days delay on account of a fishing job or fishing jobs, or for any other reason, but shall be required, upon the request of the "Gas Company" to move the rig and commence a new hole, without cost or expense to the "Gas Company" for the unfinished hole, removing the rig, loss of casing or drive pipe, or otherwise; that in event the said well shall be unproductive of oil or gas, or a dry hole, the "Contractor" shall make a reasonable effort to pull the casing, and shall plug the hole according to the laws of the State of Pennsylvania, the plug or plugs necessary for that purpose to be furnished by the "Gas Company"; that the "Contractor" shall have the right to remove his...Drilling rig.............................and all other machinery furnished by him as soon as said well is completed and accepted by the "Gas Company;" that the manner in which said well shall be cased, tubed, and packed by the "Contractor" shall be in accordance with the direction of the "Gas Company."

SECOND. In case said well shall be shot the "Contractor" shall clean out same for three (3) days free of cost to the "Gas Company", but shall thereafter receive from the "Gas Company"..Twenty and No/100.............($20.00...) per day for such work.

THIRD. No moneys or payments shall be or become due under this contract until and unless the said well is fully completed as contemplated by and under this contract.

Contractor is to build road to location over a route satisfactory to the Company. Permission to use existing road or the necessary right-of-way for new road, if necessary, will be obtained by the Company. Contractor is to clear location, cutting no more timber either at location or in road than is absolutely necessary.

(See Over)

OK
J.W.

FOURTH. That the "Contractor" shall make a thorough and careful inspection of the rig, casing, tubing, packer, and other material furnished by the "Gas Company" for said well before using the same and that any use made by him of the same shall be deemed as accepting them as sufficient for the purpose intended, and shall thereby relieve the "Gas Company" from any liability on account of any defects therein, and that upon the completion of said well the same shall be turned over to the "Gas Company" by the "Contractor" free and clear from all claims, demands, liens, and encumbrances of whatever kind or nature.

IN WITNESS WHEREOF, this agreement has been duly executed the day and year first above written.

Chas H. Smith..........(SEAL)

..............................(SEAL)

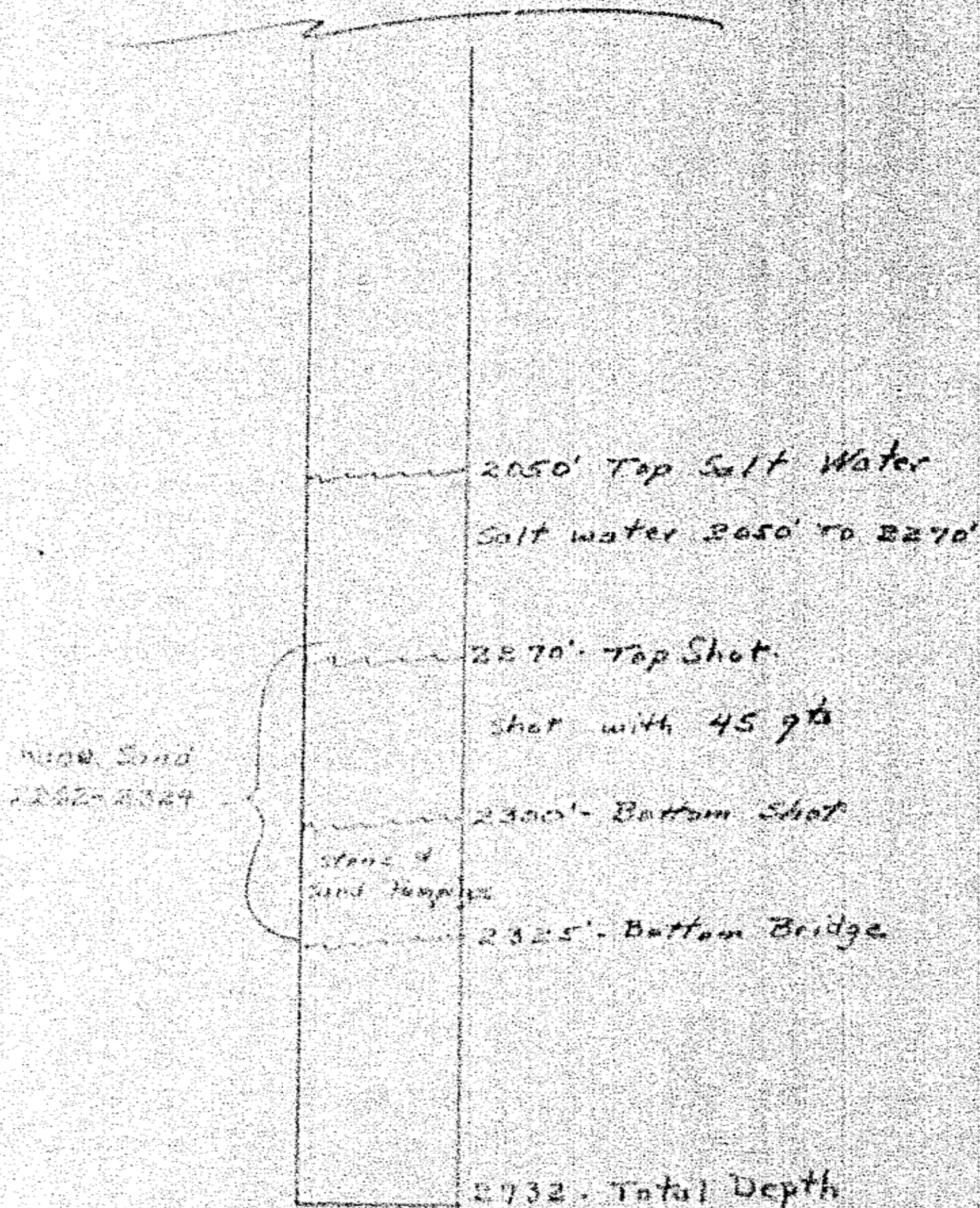
~~RIDGWAY NATURAL GAS COMPANY~~
UNITED NATURAL GAS COMPANY
By..........

(continued)
The amount of timber to be cut is to be approved by the Company.

Gas is to be used only for operating necessary machinery. Fuel for forge, boiler, lights (unless electric), stoves, etc. to be other than gas.

[illegible] at 370
[illegible] stake [illegible] located.
[illegible] " - Drilling at 1970'
[illegible] " - Sand 2172 to 2181'
Broken sand 2181 - 2209'
Good sand 2209 - 2224' Broken sand 2224 - 2232
Slate 2232 - 2262, Sand 2262 - 2304 Slate + sand 2304 - 2316
Sand 2316 - 2324' Slate 2324 - 2373.
O.F. at 2175 = 17,857 O.F. at 2209 = 17,325
" " 2265' = 38,398 " " 2271 = 45,711
" " 2342' = 52,008 Increase of gas at 2316 - 2324'
Water test at 2244' = dry.
" " 2383 = [illegible] O.F. at 2383 - 47,025
Shut down at 2380
[illegible] - [illegible] to 2730
[illegible] Drilling at 2875
Drilled to 2932 [illegible] sand [illegible] to 2932 Lime +
[illegible] formation [illegible] dry O.F. 38,398
Shot 2272 to 2300 with [illegible] qts, [illegible] to 2150
[illegible]
Shot as above. Flow immediately after shot 60,709
Water settled back + shut off flow. Bailed
to top of shot. O.F. [illegible] after shot - 14,713
C.O. to bottom [illegible], well not [illegible]
O.F. 49,578
Complete as a [illegible] well.
Completed [illegible] 13th

Well- 4406
Shooting Data



Field	Kane	Work Done	Drilled	Well No.	4406
Farm	The Mars Company	Twp.	Highland	Co. Elk	State Penna.
Ground / Derrick Floor Elevation		Commenced	December 30, 1942	Completed	February 12, 1943
No. Feet Derrick Floor To Ground Level	4'	Drilling Machine Name and Numbers	Standard Rig.		

2.

PRODUCTION TESTS

Date of Test	Nature of Test	Inches ~~Mercury~~ Water	Orifice Size		Volume Cu. Ft.	Depth When Tested	Rock Pressure Hrs. Shut in	R. P.
	Before Cleaning Out			Casing				
	Before Cleaning Out			Tubing				
	Before Drilling Deeper			Casing				
2/8/43	Before Shot	2.4"	1"	Casing	38,398 cf	2732'		
2A. 2/12/43	Completion	4.0"	1"	Casing	49,578 cf	2732'		
none	Completion	none		Tubing	none			

Casing Pressure 1 min. 1 2 min. 1½ 3 min. 2 4 min. 2½ 5 min. 3 10 min. 5½ 15 min. 8 30 min. 14 1 hr. 23

Tubing Pressure 1 min. none 2 min. 3 min. 4 min. 5 min. 10 min. 15 min. 30 min. 1 hr.

3.

RECORD OF EQUIPMENT IN WELL

	Drive Pipe	Casing	Casing	Tubing	Tubing	Anchor	Liner	Pumping Tubing	Anchor	Rods	Wire Line
Size	8¼"		6¼"	none	none	none	none	none	none	none	none
Amount	35'		404'								
No. of Joints	2		20								
Kind-Iron, Steel, etc.	Iron		Iron								
Condition	New		New								
Coating Material	None		None								
Weight per Foot	24#		13#								

R. & L. Nipple Size none Set at

Swage or Sub. Nipple none Top at

Liner: Size Top none Bottom

Packer Style	Name	Size	Set At
None			

Siphon pipe size none Diameter of Jet Depth of Jet Depth of water inlet

No. of sacks cement used none Size of pipe cemented From To

4.

NEW WELL

Amount of gas used as fuel 100,000 cu. ft.

Depth of well 2732' At $ 1.30 Per. Foot

Depth of water well none At $ Per. Foot

Reamed from to none At $ Per. Foot

Contractor C. H. Smith

5.

CLEANING OUT OR DRILLING DEEPER

Amount of gas used as fuel Cu. Ft.

Cleaning out cost (Excluding Equipment)

Drilling Deeper cost (Excluding Equipment)

Driller

Helper

6.

DRILLING RECORD

Producing Sand	Depth Top	Depth Bottom	Depth Where Flows Occur	QUANTITY, GAS, OIL, WATER
Clarendon Sand	1582'	1591'	1582'	20,317 cf
Cooper Sand	2045'	2056'	2050'	27,386 cf
Bradford Sand	2172'	2232'	x	No gas or water
Kane Sand	2262'	2324'	2268-2291-2316	52,008 cf
Elk Sand	2375'	2401'	x	No gas or water
Total depth		2732'		

7. Shot with 45 Qts. Top of shot 2270 Bottom of shot 2300 Tamped to 2050 with salt water

Well shot by Pringle Powder Co. Company. Capacity of shot hole x

Shooting Remarks Well did not cave much after shot.

8.

To what depth was well filled before cleaning out Original Depth Present Depth { Increased Volume / Result of work completed Cu. Ft.

Fluid test after completion Gals. Oil well dry Water Hours Average line pressure during test

9. Remarks:

Nothing left in hole to prevent drilling deeper.
Flow before drilling Clarendon Sand----- 0 cf.
Flow before drilling Cooper Sand-------- 14,361 cf.
Flow before drilling Kane Sand---------- 17,325 cf.
Well bridged at 2325' and filled up to 2300' with stone and sand pumpings. Shot with 45 qts. After shot well cleaned out for 10--8 hour tours and cleaned out to bottom at 2732'.

Date record is submitted Form U-243 covering above repairs date No.

Supt. Geological Land M

FORMATION	DEPTH TOP	DEPTH BOTTOM	GAS	OIL	WATER	S.L.M.	REMARKS
Clay	0	35					
Sand & lime	35	65					35' of $8\frac{1}{4}$"
Sand & slate	65	209					water at 65'
Lime	209	313					
Slate	313	329					
Lime	329	337					water level 55'
Slate	337	505					404' of $6\frac{1}{4}$"
Red rock	505	735					
Slate & lime	735	764					
Pink rock	764	800					
Slate	800	910					24 hr test showed
Pink rock	910	947					casing O.K.
Slate	947	1084					
Lime	1084	1201				1158'	---cable 1153'
Pink rock	1201	1253					
Lime	1253	1278					
Slate	1278	1436					
Lime	1436	1507					
Red rock	1507	1515					
Slate & shells	1515	1582				1582'	---cable 1583'
Clarendon Sand	1582	1591	20,317 cf at 1582'				
Slate	1591	1650					
Sand	1650	1666					
Slate & lime	1666	1816'					
Sand	1816	1830					
Lime & slate	1830	2045				1951'	---cable 1952'
Cooper Sand	2045	2056	27,386 cf at 2050'				
Slate	2056	2150				2056'	---cable 2056'
Lime	2150	2168					
Slate	2168	2172					
Bradford Sand	2172	2232	no gas or water			2175'	---cable 2175'
Slate	2232	2262					
Kane Sand	2262	2324	52,008 cf at 2316'				gas at 2268, 2291, 2316.
Slate & shells	2324	2375					
Elk Sand	2375	2401	no water or gas.				
Slate & shells	2401	2500					
Lime and slate.	2500	2710					
Slate	2710	2732					
Total depth		2732				2728'	---calbe 2731'

Mim. P-86

REPORT OF COMPLETION OF NEW WELL

Well No. 4406 United Natural Gas Company

Kane Field

Chas. H. Smith Contractor

Total Depth of Well (steel line measurement) 2732'

Amount of 15" hole..............10" hole.. 35'

Depth of Water Well........................ none

Total number of feet of hole reamed......... none

Was well shot?............................... yes

Number of days cleaning out after shot, including the three (3) free days.... 10 days

Date well was completed..................... 2/12/43

Was well completed in accordance with contract and in a manner satisfactory to you? yes

Do you approve payment for drilling?........ yes

Remarks:-

2/12/43
Date

C.R. Cartwright
Signature of Foreman

This form to be mailed to J. G. Montgomery, Jr. 308 Seneca St., Oil City, Pa., immediately upon completion of the well.

Inv. approved
2/15/43

JGM

PRESENT STATUS OF WELL EQUIPMENT

Date: February 12, 1943 — Well No. 4406
Field: Lane — Company: United Natural Gas — Individual Well Status No. 1
Lands: The Mars Company — Warrant: 3771 — Township: Highland — County: Elk — State: Penna.
Fluid removed by: bailing — Open Flow Test, Volume Casing: 49,578 cf — Tubing: xxx
Conductor: pipe — Size: 8¼" — Number of Feet: 35' — D.T. No. 29 — Month: Feb. 1943
Casing, No. Joints: 20 — Size: 6¼" — Number of Feet: 404' — D.T. No. 29 — Month: Feb. 1943
Tubing, No. Joints: none — Size — Number of Feet — D.T. No. — Month
Tubing, No. Joints: none — Size — Number of Feet — D.T. No. — Month
Tubing, No. Joints: none — Size — Number of Feet — D.T. No. — Month
Anchor, No. Joints: none — Size — Number of Feet — D.T. No. — Month
Rods or Wire Line: none — Size — Number of Feet — D.T. No. — Mo.
Packer, Style: none — Make — Size — Set At — D.T. No. — Mo.
Packer, Style: none — Make — Size — Set At — D.T. No. — Mo.
Liners, Size and Length: none — Top Set At — Bottom Set At
Other Material: none
Other Material, D.T. References: none
Remarks: New well drilled — Present Depth of Well: 2732'

OPERATION
Casing
Tubing

PART 2

DATA CONCERNING THE CHANGING OF PIPE AT THIS OPERATION

"A"

PIPE REMOVED

Size	Total Amount	Good Size	Good Amt.	Fair Size	Fair Amt.	Poor Size	Poor Amt.	Worthless Size	Worthless Amt.	Mfg'rs. Name	Name of Coating	Years since last Pipe Change	Was Pipe New When Installed	ORIGINAL Reason for Working on Well
							none							

"B"

DESCRIPTION OF PIPE NOT FIT FOR REINSTALLATION

GRADE	Weight Per Ft.	IRON Size	IRON Amt.	STEEL Size	STEEL Amt.	Location of Defective Pipe in Hole	Mfg'rs. Name	Name of Coating	Depth of Failure	CAUSE
Poor										
Poor						none				
Worthless										
Worthless										

"C"

PIPE INSTALLED

GRADE	Weight Per Ft.	IRON Size	IRON Amt.	STEEL Size	STEEL Amt.	Location in Hole—Top IRON	Location in Hole—Top STEEL	Mfg'rs. Name	Name of Coating	Years Pipe was in Stock	Well in which pipe had been used	No. of Years pipe was used	What repairs made before reinstallation
New	24#	8¼"	35'			top to	35'	Byers	xx	1	xx	xx	xx
New	13#	6¼"	404'			top to	404'	Byers	xx	1	xx	xx	xx
Good													
Good													
Fair													
Fair													

"D" Amount of Syphon Pipe Installed — Size — Depth to Jet — Depth to Water Inlet
"E" Number of Sacks Cement Used — Size Pipe Cemented — From — To
Remarks:

C R Cartwright

WELL No. 4406

Field Kane Date 2/12/43

Individual Status Notice No. 1

Work Completed new well drilled

Method of Handling Pipe

standard rig.

Estimated Cost, after Completion

" " Materials

" " Labor $3691.60 (contract only)

GENERAL OFFICE ONLY

G. O. Cost

Age of Casing Removed

Life of Casing Junked

Percent Good and Fair

Yearly Depreciation Rate, Good and Fair

Yearly Depreciation Rate, Junked

4406

United Natural Gas Company

RD#2, Kane, XXXXX, Pa. February 13, 1943

Mr. J. G. Montgomery, Jr.,

Oil City, Pennsylvania.

Subject:

Dear Sir:

With reference to your circular letter dated October 10, 1939 concerning shooting of wells, following is information on well #4406 which was shot February 8, 1943:-

Well was shot with 45 quarts and set off with a squibb. Shot between 2270' and 2300'. Steel measuring line used for all measurements of bridge, etc. Shot tamped to 2050 with salt water. Flow before shot 38,398 cf. Flow one hour after shot was 89,913 cf. Well shot February 8th and cleaned out to February 12th. Flow at completion of well 49,578 cf. Attached is sketch of well and location of shot.

Very truly yours,

C R Cartwright

CRC/RoP
Attch: 1

WELL NO. 4906

UNITED NATURAL GAS COMPANY

MERGED 7/1/74 TO

NATIONAL FUEL GAS SUPPLY CORPORATION

APPENDIX F

Monitoring Well Records (#04384)

Well Construction Diagram

Proposed Monitoring Well

Seneca Well #04384
Highland Township
Elk County, PA

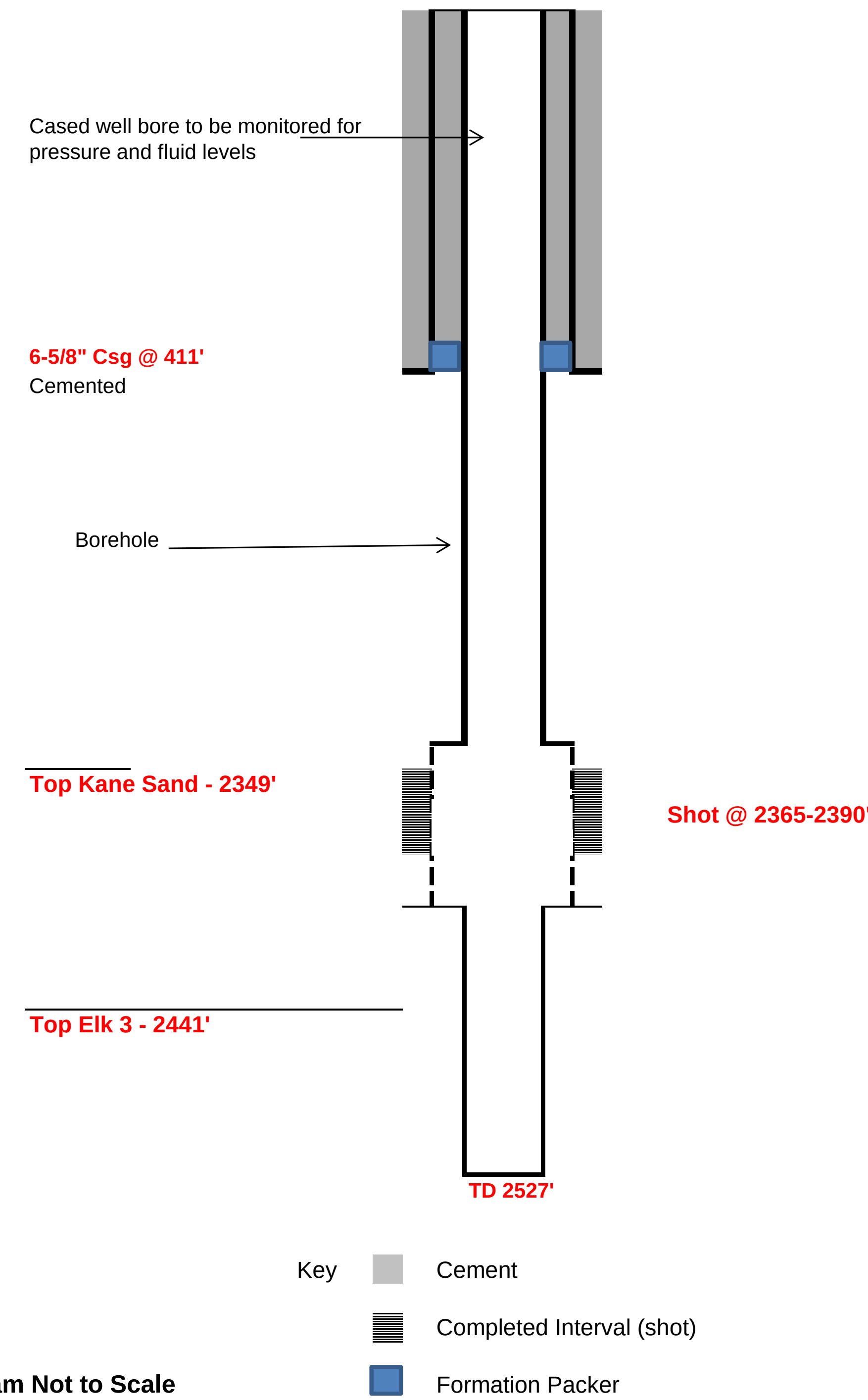


Diagram Not to Scale

January 21, 2013

The Mars Company lands
Comm. 11-4-42 Comp. 12-10-42
Vol. 33,267 R.P. 13#-1 hr.

Sand	161	177	water at 162'
Sand	325	375	
Lime & Slate	375	562	water level
Red Rock	562	821	220'
Red Rock	851	900	
Slate & lime	985	1090	
Lime	1090	1291	
Pink Rock	1291	1336	
Red Rock	1336	1344	
Pink Sand	1407	1437	
Lime	1450	1666	
Clarendon	1666	1682	1677'-7,950
			1686'-8,248
Lime	1707	1821	
Sand	1891	1907	
Lime	1907	2148	2216'-7,795
Slate & Lime	2148	2275	
Bradford	2275	2321	2320'-8,820
3 hr. water test at 2331'. Well dry.			
Kane	2349	2392	2392'-21,218
Sand & Lime	2392	2441	2433'-23,716
Elk Sand	2441	2449	2444'-25,624
Slate & sand	2449	2482	2460'-24,878
Slate	2482	2527	2527'-22,080
Total Depth		2527	

Well shot with 75 qts. from 2365 to 2390'. Bridged at 2435'

UNITED NATURAL GAS COMPANY

Well No. 4384 Title No. 22-J Location Order No. 1968.

Reason for Drilling Production Date Oct 13, 1942

Foreman C.R. Cartwright Field Kane

This Company will drill a well on

Lands The Mars Co. Acres 400

Warrant No. 3771 Lot No. — ~~Township~~ Highland

County Elk

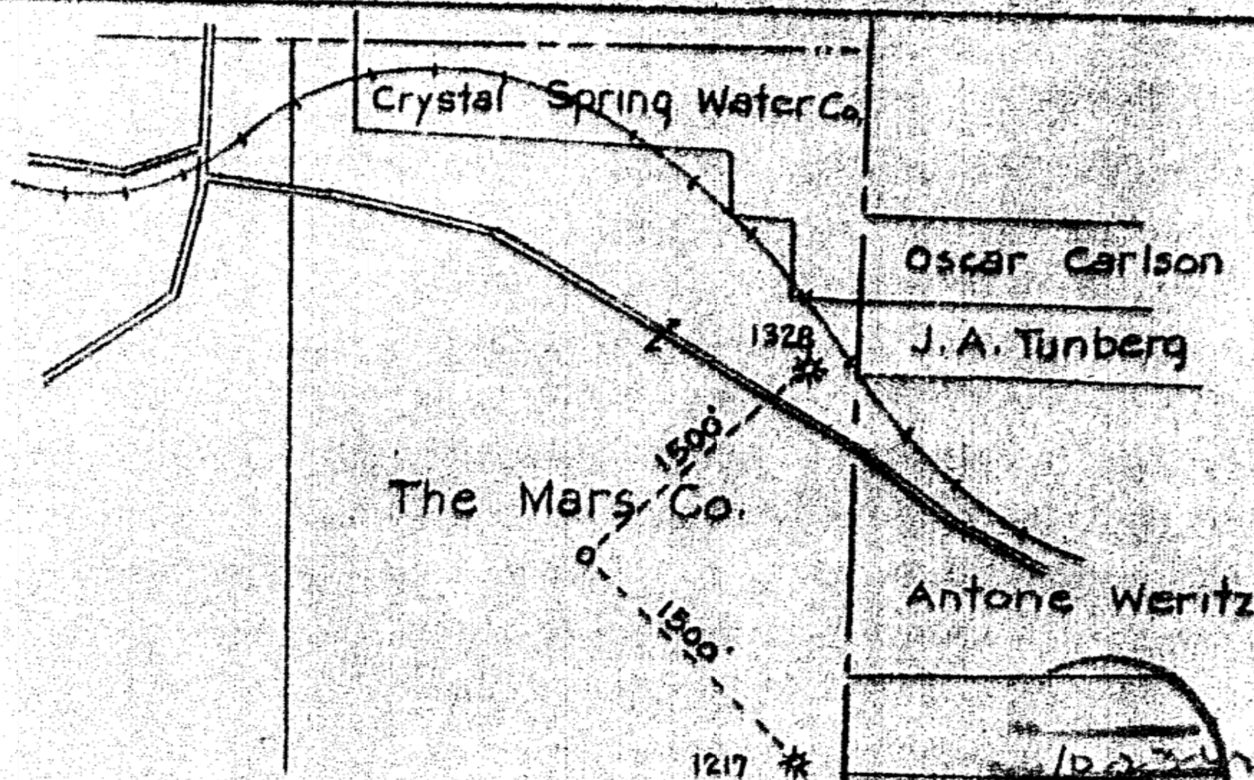
10/14/42 [signature]
C.R.E.

[signature] Title Department

[signature] Superintendent

[signature] President

Map 660 N. 19 S. E. 20 W. Sq. Mi. No. 2649



Reservation None rods feet around buildings

NOTE.—If conditions upon the ground prevent locating as above indicated the location as changed must be shown hereon, and all notices returned to this office with as little delay as possible.

Located on ground 10/19/42 19 By Russell Craig.

Noted 10/19/42 19 C R Cartwright
Field Superintendent or Foreman

Located on Map 19

Loc. Map #960 10-29-42

8M-G-660-7E

UNITED NATURAL GAS CO

October 16, 1942

Mr. C.R. Cartwright, Foreman - Kane
United Natural Gas Company
R.D.#2, Kane, Pennsylvania

Dear Sir:

Enclosed herewith please find location order No. 1968 for proposed well No. 4984 to be located on The Mars Company 400 acres, Highland Township, Elk County, Title 22-J. Please date, sign, and return this order to us promptly.

We are enclosing drilling agreement in duplicate. Please obtain contractor's signature on both copies and mail to this office at once.

Please familiarize yourself with the conditions of this contract so that you will know what is expected of the contractor and see that the terms are fulfilled.

Very truly yours,

COPY ORIGINAL SIGNED J.G.MONTGOMERY, JR

JGM:MM
Encl-2

by and between [illegible], hereinafter referred to as the "Contractor," and United Natural Gas Company a Pennsylvania corporation doing business at Oil City, Pennsylvania, hereinafter referred to as the "Gas Company."

WHEREAS, The "Contractor" is a practical and experienced oil and gas well driller, familiar with the drilling conditions peculiar to the territory in the vicinity of the land upon which the "Gas Company" desires to drill a well as hereinafter indicated, and desires to undertake the drilling of the same, and

WHEREAS, The "Gas Company" is engaged in the business of producing and marketing natural gas and desires to contract with an experienced and practical oil and gas well driller for the drilling of such well,

NOW, THEREFORE, THIS AGREEMENT WITNESSETH, That for and in consideration of the premises and the covenants and agreements hereinafter contained, and the sum of One Dollar ($1.00) paid by each of the parties to the other, the receipt whereof is hereby acknowledged, the parties hereto do agree with each other as follows:

FIRST. The "Contractor" covenants and agrees to go upon the lands known as the The Mars Company 400 acres in Highland Township, Elk County, and State of Pennsylvania, within ten (10) days after a well location has been made thereon by the "Gas Company" and drill a well at the said location for the purpose of discovering oil or gas for the "Gas Company" and to diligently and continuously prosecute the work of doing the same to completion.

SECOND. The "Contractor" covenants and agrees to furnish at his own expense Drilling rig all boilers and engines, steam pipes, water pipes and connections, as well as all fuel, water, material, tools, appliances, repairs to rigs, and all labor necessary or required for drilling, casing, tubing, piping, cleaning out, and completing said well promptly and in a good workmanlike manner, and the "Gas Company" covenants and agrees to furnish the casing, tubing, and packer to be used therein.

THIRD. The "Gas Company" agrees to pay, and the "Contractor" agrees to accept, for the drilling of the said well One and 30/100.................... ($1.30) per foot ~~unless gas is purchased from the "Gas Company" for firing the boiler used in the said operations, in which event the rate will be~~ ($......) per foot, which said price will be full compensation for drilling, casing, tubing, packing, cleaning out, and completing said well if a producing well, or pulling and plugging if a dry hole; payment to be made within thirty (30) days from and after the completion of same.

FOURTH. The "Contractor" covenants and agrees to keep for the benefit of the "Gas Company" an accurate record of the drilling of said well, showing all the formations through which it passes, together with the actual depth and the thickness thereof measured with a steel line, and further that he will not impart to anyone information as to the drilling of said well or the discoveries made therein, nor will he permit any of his employees so to do.

FIFTH. It is understood and agreed that the "Contractor" is a contractor engaged in an independent business as set forth in Section 105, Article I, of the Workmen's Compensation Act of 1915; that, therefore, the term "Contractor" as used in Section 203, Article II, and Section 302 (b), Article III, of said Act, does not include him in the performance of his engagement under this contract.

SIXTH. If gas is purchased from the "Gas Company" for use as aforesaid, the "Contractor" agrees to pay the "Gas Company" for same at the rate of published tariff rate per thousand cubic feet as provided in the "Gas Company's" published Tariff, and the "Gas Company" agrees to make the necessary tap and install the meter for measuring said gas at a convenient point on its line, and will charge the "Contractor" for the said installation and work the sum of Ten and No/100.. Dollars ($10.00), which sum the "Contractor" agrees to pay. If the "Contractor" so requests, the "Gas Company" will at the expense of the "Contractor" construct the line from the said meter to the boiler.

SEVENTH. The "Contractor" covenants and agrees to take care of at his own expense all sand pumpings, and other material, when necessary to prevent surface damage, and without extra charge to re-set the packer as many times as may be necessary in order to procure a tight job.

EIGHTH. If it is found necessary to drill a water well, the "Gas Company" agrees to pay and the "Contractor" agrees to accept the sum of seventy-five (75) cents per drilling foot for same.

IT IS MUTUALLY COVENANTED AND AGREED as follows:

FIRST. That the well to be drilled hereunder shall be drilled to any depth desired by the "Gas Company" not exceeding Three thousand................ (3000) feet; that upon the discovery of oil or gas in the said well at any time, the "Contractor" shall notify the "Gas Company," and shall discontinue drilling until further instructed by the "Gas Company"; and shall then resume or discontinue operations at the pleasure of the "Gas Company"; that rapid and continued progress in drilling said well is of the essence of this contract, and that the "Contractor" shall not be allowed more than thirty (30) days delay on account of a fishing job or fishing jobs, or for any other reason, but shall be required, upon the request of the "Gas Company" to move the rig and commence a new hole, without cost or expense to the "Gas Company" for the unfinished hole, removing the rig, loss of casing or drive pipe, or otherwise; that in event the said well shall be unproductive of oil or gas, or a dry hole, the "Contractor" shall make a reasonable effort to pull the casing, and shall plug the hole according to the laws of the State of Pennsylvania, the plug or plugs necessary for that purpose to be furnished by the "Gas Company"; that the "Contractor" shall have the right to remove his Drilling rig and all other machinery furnished by him as soon as said well is completed and accepted by the "Gas Company;" that the manner in which said well shall be cased, tubed, and packed by the "Contractor" shall be in accordance with the direction of the "Gas Company."

SECOND. In case said well shall be shot the "Contractor" shall clean out same for three (3) days free of cost to the "Gas Company", but shall thereafter receive from the "Gas Company" Twenty and No/100............ ($20.00) per day for such work.

THIRD. No moneys or payments shall be or become due under this contract until and unless the said well is fully completed as contemplated by and under this contract.

Contractor is to build road to location over a route satisfactory to the Company. Permission to use existing road or the necessary right-of-way for new road, if necessary, will be obtained by the Company. Contractor is to clear location, cutting no more timber either at location or in road than is absolutely necessary. (See Over)

FOURTH. That the "Contractor" shall make a thorough and careful inspection of the rig, casing, tubing, packer, and other material furnished by the "Gas Company" for said well before using the same and that any use made by him of the same shall be deemed as accepting them as sufficient for the purpose intended, and shall thereby relieve the "Gas Company" from any liability on account of any defects therein, and that upon the completion of said well the same shall be turned over to the "Gas Company" by the "Contractor" free and clear from all claims, demands, liens, and encumbrances of whatever kind or nature.

IN WITNESS WHEREOF, this agreement has been duly executed the day and year first above written.

Chas. H. Smith (SEAL)

(SEAL)

UNITED NATURAL GAS COMPANY

(continued)
The amount of timber to be cut is to be approved by the Company.

Gas is to be used only for operating necessary machinery. Fuel for forge, boiler, lights (unless electric), stoves, etc., to be other than gas.

Field Kane Work Done New Well drilled Well No. 4384

Farm The Mars Company Twp. Highland Co. Elk State Penn'a

For assistance in Accessing this document, please contact: R3_UIC_Mailbox@epa.gov

Ground / Derrick Floor Elevation Commenced 11-4-42 Completed 12-10-42

No. Feet Derrick Floor To Ground Level 2'10" Drilling Machine Name and Numbers Standard rig

2

PRODUCTION TESTS

Date of Test	Nature of Test	Inches Mercury Water	Inches Orifice Size		Volume Cu. Ft.	Depth When Tested	Rock Pressure Hrs. Shut in	Rock Pressure R. P.
	Before Cleaning Out			Casing				
	Before Cleaning Out			Tubing				
	Before Drilling Deeper			Casing				
11-26-42	Before Shot	4"	5/8"	Casing	22,080 cf	2527'		
2A 12-10-42	Completion	1.8"	1"	Casing	33,267 c.f.	2407'	1hr.	13#
	Completion			Tubing				

Casing Pressure 1 min. 1 2 min. 1½ 3 min. 1¾ 4 min. 2 5 min. 2½ 10 min. 4 15 min. 5 30 min. 8 1 hr. 13

Tubing Pressure 1 min. 2 min. 3 min. 4 min. 5 min. 10 min. 15 min. 30 min. 1 hr.

3

RECORD OF EQUIPMENT IN WELL

	Drive Pipe	Casing	Casing	Tubing	Tubing	Anchor	Liner	Pumping Tubing	Anchor	Rods	Wire Line
Size	8¼"	6¼"		none				none			
Amount	29'6"	411'									
No. of Joints	2	20									
Kind-Iron, Steel, etc.	iron	iron									
Condition	1	1									
Coating Material	none	none									
Weight per Foot	24#	13#									

R. & L. Nipple Size Set at

Swage or Sub. Nipple Top at

Liner: Size Top Bottom

Packer Style	Name	Size	Set At
none			

Siphon pipe size Diameter of Jet Depth of Jet Depth of water inlet

No. of sacks cement used Size of pipe cemented From To

4

NEW WELL

Amount of gas used as fuel 106,000 cu. ft.

Depth of well 2527' At $1.30 Per. Foot

Depth of water well none At $ Per. Foot

Reamed from to none At $ Per. Foot

Contractor C. H. Smith

5.

CLEANING OUT OR DRILLING DEEPER

Amount of gas used as fuel Cu. Ft.

Cleaning out cost (Excluding Equipment)

Drilling Deeper cost (Excluding Equipment)

Driller

Helper

6

DRILLING RECORD

Producing Sand	Depth Top	Depth Bottom	Depth Where Flows Occur	QUANTITY, GAS, OIL, WATER
Clarendon Sand	1666'	1682'	1677'	7,950 c.f.
Bradford Sand	2275'	2321'	2320'	8,820 c.f.
Kane Sand	2349'	2392'	2358-2392'	24,501 c.f.
Elk Sand	2441'	2449'	2444'	25,624 c.f.
Total depth		2527'		

7. Shot with 75 Qts. Top of shot 2365' Bottom of shot 2390' Tamped to 2100' with salt water

Well shot by Pringle Powder Co. Company. Capacity of shot hole xx

Shooting Remarks Sand was broken and well caved badly after shot.

8. To what depth was well filled before cleaning out Original Depth Present Depth Increased Volume / Result of work completed Cu. Ft.

Fluid test after completion Gals. Oil Water Hours Average line pressure during test

Well does not make any water in 3-hr. test.

9. Remarks:

Nothing left in hole to prevent drilling deeper.

Flow before drilling Clarendon Sand-- 0 c.f.

Flow before drilling Bradford Sand--7,795 c.f. at 2216' and 7,143 c.f. at 2302'

Flow before drilling Kane Sand-- 8,820 c.f.

Flow before drilling Elk Sand--23,716 c.f.

Well bridged at 2435' & filled up to 2390' with stone and sand pumpings. Shot with 75 qts. After shot well cleaned out to depth of 2408' & well completed at that depth. Well was drilled to 2527'. Cleaned Out for 10 days after well was shot.

Date record is submitted Form U-243 covering above repairs date No.

FORMATION	DEPTH TOP	DEPTH BOTTOM	GAS	OIL	WATER	S.L.M.	REMARKS
Mud	0	28					
Slate	28	161					29'6" of 8¼" drive pip
Sand	161	177					
Slate & Shells	177	325					Water at 162'
Sand	325	375					
Lime & Slate	375	562					
Red Rock	562	821					Water level 220'
Slate & shells	821	851					411' of 6¼" casing
Red Rock	851	900					
Slate 900	900	985				902'--cable 900'	
Slate & lime	985	1090					
Lime	1090	1291					
Pink Rock	1291	1336					
Red Rock	1336	1344					
Slate	1344	1407					
Pink Sand	1407	1437					
Slate & shells	1437	1450					
Lime	1450	1666					
Clarendon Sand	1666	1682	1677'---7,950 c.f.			1677'--cable 1674'	
Slate	1682	1707	1686'---8,248 c.f.				
Lime	1707	1821					Put Jars on 1737'
Slate	1821	1891					
Sand	1891	1907					
Lime	1907	2148	2216'--7795 c.f.				
Slate & lime	2148	2275					
Bradford Sand	2275	2321	2320'---8,820 c.f.			2293'--cable 2290'	3 hr. water test at 2331'. Well dry.
Slate	2321	2349					
Kane Sand	2349	2392	2392'---21,218 c.f.			2358'--cable 2356'	
Sand & lime	2392	2441	2433'---23,716 c.f.				
Elk Sand	2441	2449	2444'---25,624 c.f.				
Slate & sand	2449	2482	2460'---24,878 c.f.				
Slate	2482	2527	2527'---22,080 c.f.			2527--cable 2528'	
Total depth ----------------		2527'	Well shot with 75 qts. from 2365' to 2390'				Bridged at 2435'.

Carr
4384

1942
Oct [illegible] Located 10/14
[illegible] at [illegible]
[illegible]

19 " Drilling at 1800'
[illegible] Sand 2275 - 2325' O.F. at 2331' - 8,820
at 2331' - Made 3 hr. water test. No water
[illegible] Sand 2348' - 2392' O.F. at 2358' = 5,832
O.F. at 2375' = 16,772
O.F. at 2384 = 21,208
O.F. at 2400' = 24,591
Possibility of more gas 2440 - 2485 Drill unless advise
Drilled [illegible] sand 2441 to 2447'
O.F. at 2433' = 23,716
O.F. at 2444' = 25,677
O.F. at 2460' = 24,818 To drill [illegible] of [illegible]
26 " Shot from 2365' to 2390' with 75 qts. Tamp to 2400 with S.O. Remove tamping as soon as possible
[illegible] " Shot as above.
O.F. 10 min. after shot = 39,960 Water bailed out
O.F. = 119,642
C.O. in shot hole 12' caving in hole O.F. - 38,393
in shot hole

11/1 10 " Turned into line today O.F. 33,267
5 min press = 2½#
10 " " = 4#
15 " " = 5# Was drilled to 2527
30 " " = 8# Now bridged at 2407
60 " " = 13# Will start taking dummy

12/24/42 Note Nov. /42 Shot 2365 - 2390 O.F. before 22,680 O.F. after shot 119,642
([illegible]) O.F. 24 hrs after 33,008
Have cleaned out 9 days - 24 hr. days
and only 17 ft below bottom of shot.
Present volume 33,267.
No water before drilling [illegible] Sand.
Suggest completing at present depth.

12-9-42 - by JEM - will dry up & complete

PRESENT STATUS OF WELL EQUIPMENT

Date 12-17-42

Well No. 4384

Field Kane

United Natural Gas Company.

Individual Well Status No. 1

Lands The Mars Company Warrant 3771 Township Highland County Elk State Penn'a.

Fluid removed by Bailing Open Flow Test, Volume Casing 33,267 c.f. Tubing x

Conductor pipe Size $8\frac{1}{4}$" Number of Feet 29'6" D.T. No. 23-27603 Month Dec. 1942

Casing, No. Joints 20 Size $6\frac{1}{4}$" Number of Feet 411' D.T. No. 23-27603 Month Dec. 1942

Tubing, No. Joints none Size Number of Feet D.T. No. Month

Tubing, No. Joints Size Number of Feet D.T. No. Month

Tubing, No. Joints Size Number of Feet D.T. No. Month

Anchor, No. Joints Size Number of Feet D.T. No. Month

Rods or Wire Line Size Number of Feet D.T. No. Mo.

Packer, Style Make Size Set At D.T. No. Mo.

Packer, Style Make Size Set At D.T. No. Mo.

Liners, Size and Length Top Set At Bottom Set At

Other Material

Other Material, D.T. References

Remarks: Well bridged at 2435' for shooting. Cleaned out to 2408' present Present Depth of Well 2527' original

OPERATION

Casing

Tubing

PART 2

DATA CONCERNING THE CHANGING OF PIPE AT THIS OPERATION

"A"

PIPE REMOVED

Size	Total Amount	Good Size	Good Amt.	Fair Size	Fair Amt.	Poor Size	Poor Amt.	Worthless Size	Worthless Amt.	Mfg'rs. Name	Name of Coating	Years since last Pipe Change	Was Pipe New When Installed	ORIGINAL Reason for Working on Well
										none				

"B"

DESCRIPTION OF PIPE NOT FIT FOR REINSTALLATION

GRADE	Weight Per Ft.	IRON Size	IRON Amt.	STEEL Size	STEEL Amt.	Location of Defective Pipe in Hole	Mfg'rs. Name	Name of Coating	Depth of Failure	CAUSE
Poor						none				
Poor										
Worthless										
Worthless										

"C"

PIPE INSTALLED

GRADE	Weight Per Ft.	IRON Size	IRON Amt.	STEEL Size	STEEL Amt.	Location in Hole—Top IRON	Location in Hole—Top STEEL	Mfg'rs. Name	Name of Coating	Years Pipe was in Stock	Well in which pipe had been used	No. of Years pipe was used	What repairs made before reinstallation
New	24#	$8\frac{1}{4}$"	29'6"			top to 29'6"		Byers	none	one	none	none	none
New	13#	$6\frac{1}{4}$"	411'			top to 411'		Byers	none	one	none	none	none
Good													
Good													
Fair													
Fair													

"D" Amount of Syphon Pipe Installed Size Depth to Jet Depth to Water Inlet

"E" Number of Sacks Cement Used Size Pipe Cemented From To

Remarks:

WELL No. 4384

Field Kane Date 12-17-42

Individual Status Notice No. 1

Work Completed New well drilled

Method of Handling Pipe

Standard rig

Estimated Cost, after Completion

" " Materials

" " Labor $3,865.10 (contract or

GENERAL OFFICE ONLY

G. O. Cost

Age of Casing Removed

Life of Casing Junked

Percent Good and Fair

Yearly Depreciation Rate, Good and Fair

Yearly Depreciation Rate, Junked

United Natural Gas Co

Mr. J. G. Montgomery, Jr.,
Oil City, Pennsylvania.

RD#2, Kane, ~~XXXXX~~, Pa. January 7, 1943.

Subject:

Dear Sir:

With reference to your circular letter dated October 10, 1939 concerning shooting of wells, following is information on well #4384 which was shot November 27, 1942:-

Well was shot with 75 qts and set off with a squibb. Shot between 2365' and 2390'. Steel measuring line used for all measurements of bridge, etc. Shot tamped to 2100' with salt water. Flow before shot 22,080 cf. Flow two hours after shot 119,642 cf. Well shot Nov.27th and cleaned out to Dec.9th. Flow at completion of well 33,267 cf. Attached is sketch of well and location of shot.

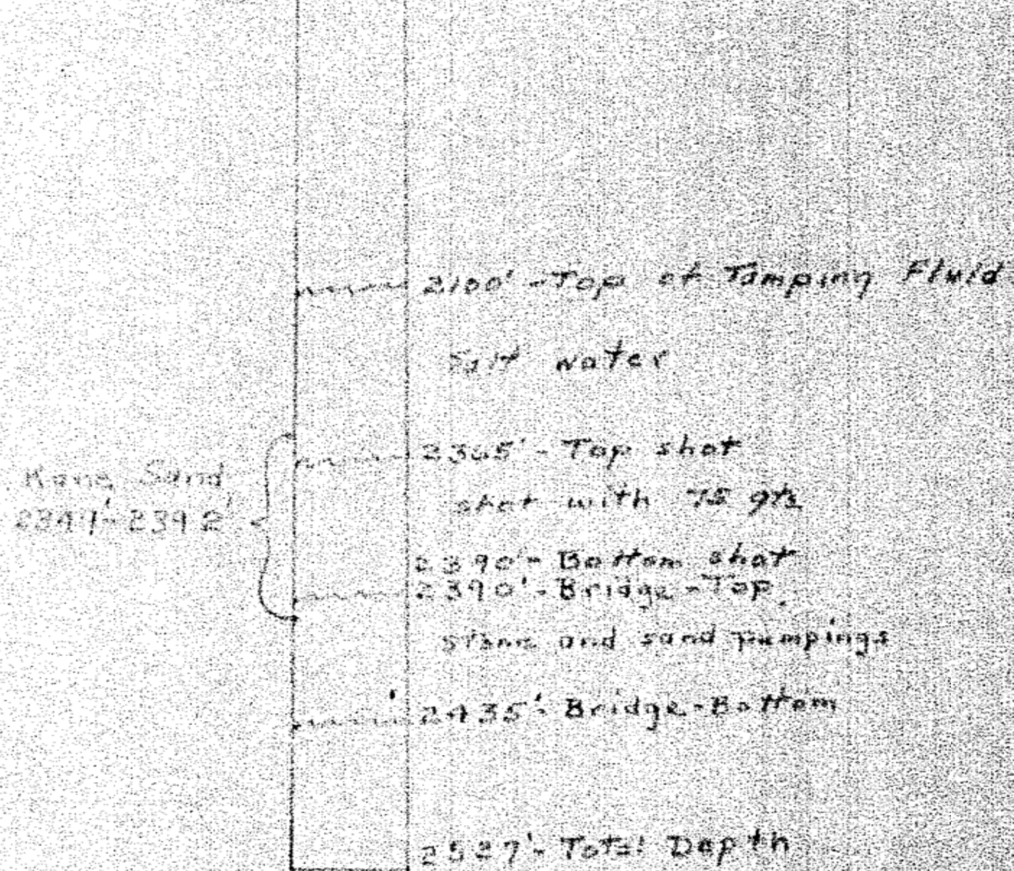
Very truly yours,

C. R. Cartwright

CRC/ROP
Attch: 1

Sketch of Shot at well #4384.

[illegible] 1942



WELL NO. #384

UNITED NATURAL GAS COMPANY

MERGED 7/1/74 TO

NATIONAL FUEL GAS SUPPLY CORPORATION

APPENDIX G

Typical Brine Laboratory Analysis

Date	W.O. #	Type Of Fluid	From	To	Well Hole	Secific Gravity	Weight (lb/gal)	pH	Conductivity
FO5323									
01/09/12	26757	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.15	9.6	5.87	212
01/08/12	18693	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
N5963									
01/07/12	18497	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.15	9.6	5.82	207
01/07/12	30558	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5314									
12/21/11	22010	Flowback	Collins Pine Pad G frac tanks	James City Pad A	Frac Tanks	1.13	9.4	7.51	184.1
12/21/11	22015	Flowback	Collins Pine Pad G frac tanks	James City Pad A	Frac Tanks				
FO5327									
01/06/12	18689	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.13	9.45	6.26	191
01/05/12	26756	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5324									
01/07/12	18691	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.16	9.65	5.77	210.2
01/07/12	18497	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5315									
01/11/12	18376	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.11	9.2	6.01	158.3
01/11/12	18696	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
01/09/12	26757	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5215									
01/09/12	18500	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.125	9.35	5.94	183.9
FO5289									
01/05/12	30553	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.135	9.45	5.92	193.6
01/05/12	30554	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
01/05/12	18684	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
01/08/12	15104	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5322									
01/08/12	18693	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.15	9.6	5.96	205.2
01/08/12	18499	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5316									
nothing						1.13	9.4	5.93	189.4
N5234									
12/20/11		Flowback	Collins Pine Pad G	James City Pad A		1.15	9.6	5.92	200.3

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Acidity to pH=8.3	BH	03/01	n/a	269	mg/l as CaCO3	n/a	SM2310B	2
Alkalinity to pH=4.5	BH	03/03	n/a	22	mg/l as CaCO3	n/a	SM2320B	20
Biological Oxygen Demand 05	CJ	02/29	9:44 AM	59.1	mg/l	n/a	SM5210B	2.0
Chemical Oxygen Demand	AJD	02/29	n/a	1162.5	mg/l	D	SM5220 D	500.0
Hydrogen Sulfide	SM	02/28	n/a	ND	mg/l	n/a	Hach	0.0
Ammonia as N / Distilled	BM	02/29	n/a	194.68	mg/l	n/a	SM4500NH3B & D	9.59
Bromide	BM	03/06	n/a	1910.00	mg/l	D	D1246-99	100.00
Chloride	KL	03/08	n/a	136446.00	mg/l	D	SM4500ClD	5.00
Dissolved Oxygen	SM	02/28	n/a	4.0	mg/l	n/a	SM4500 O-G	2.0
Kjeldahl Nitrogen as N	ZTR	03/14	n/a	320.8	mg/l	n/a	SM4500Norg-C,D	59.4
pH (SM)	BH	03/03	n/a	5.89	SU	R	SM 4500H-B	0.01
Sulfate ASTM	ZTR	03/13	n/a	ND	mg/l	D	D516-02	10
Total Nitrate + Nitrite as N	SR	03/01	n/a	0.08	mg/l	n/a	SM4500NO3E	0.05
Aluminum - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Arsenic-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Barium - ICP	BE	03/13	n/a	371.700	mg/l	D	200.7/6010	0.500
Beryllium - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Boron	ZTR	02/29	n/a	2.8	mg/l	D	SM 4500B-B	1.0
Cadmium - ICP	BE	03/14	n/a	ND	mg/l	D	200.7/6010	0.500
Calcium - ICP	BE	03/13	n/a	20307.000	mg/l	D	200.7/6010	50.000

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: Gabel J Tgh

Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Chromium - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Cobalt - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Copper - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Hardness	BE	03/13	n/a	58691	mg/l	n/a	SM2340B	1
Iron - ICP	BE	03/13	n/a	59.800	mg/l	D	200.7/6010	1.000
Iron,Dissolved-ICP	BE	03/13	n/a	26.600	mg/l	D	200.7/6010	1.000
Lead-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Lithium - ICP	BE	03/13	n/a	98.200	mg/l	D	200.7/6010	50.000
Magnesium-ICP	BE	03/13	n/a	1939.000	mg/l	D	200.7/6010	50.000
Manganese - ICP	BE	03/13	n/a	9.100	mg/l	D	200.7/6010	0.500
Mercury	SS	03/09	n/a	ND	mg/l	n/a	245.1	0.0010
Molybedenum - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Nickel - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Selenium-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Silver-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Sodium - ICP	BE	03/15	n/a	35620.000	mg/l	D	200.7/6010	250.000
Strontium - ICP	BE	03/15	n/a	3242.500	mg/l	D	200.7/6010	5.000
Zinc - ICP	BE	03/13	n/a	0.800	mg/l	D	200.7/6010	0.500
Detergents, MBAS	LAW	02/29	8:30 AM	1.110	mg/l	n/a	SM5540C	0.200
Ethylene Glycol	EAC	03/01	n/a	ND	ug/L	D	SW846 8015B	2500

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: ______________________
Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Oil and Grease - HEM	SGT	03/05	n/a	125.5	mg/l	n/a	1664A	5.0
Phenolics, as Phenol	SR	02/29	n/a	ND	mg/l	D	420.1	0.050
pH- Field	SM	02/28	n/a	5.76	SU	n/a	SM 4500H-B	0.00
Specific Conductance	BH	03/03	n/a	176784	umhos/cm	n/a	SM 2510B	1
Total Dissolved Solids (TDS)	LMB	02/29	n/a	212500	mg/l	n/a	SM2540C	25
tal Suspended Solids	LMB	02/29	n/a	238	mg/l	n/a	SM2540D	5
1) Benzene	RO	03/03	n/a	4.64	ug/L	n/a	624/8260B	1.00
47) Toluene	RO	03/03	n/a	4.00	ug/L	n/a	624/8260B	1.00

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: [signature]

Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08934
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/2/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Radium 226	Bnchmrk	03/21	n/a	*	pCi/L	n/a	RAD-CTDHS	0.000
Radium 228	Bnchmrk	03/13	n/a	*	pCi/L	n/a	RAD-CTDHS	0.000
Thorium	Bnchmrk	03/23	n/a	*	pCi/L	n/a	RAD-CTDHS	-1.000
Uranium	Bnchmrk	03/23	n/a	*	pCi/L	n/a	RAD-CTDHS	-1.000

Comments: Radiologicals done by Benchmark Analytical, PADEP Lab ID: 39-00401

ND=Not Detected

DEP Certification #s 32-00382

Approved By: [signature]
Laboratory Supervisor

LAB ID: 39-00401 *CV

BENCHMARK ANALYTICS, INC.
4777 Saucon Creek Road
Center Valley, PA 18034-9004

PHONE (610) 974-8100
FAX (610) 974-8104

SEND DATA TO:

NAME: Jean M. Cole
COMPANY: Environmental Service Laboratories, Inc
ADDRESS: 1803 Philadelphia St
Indiana, PA 15701

PHONE: (724) 463-8378
FAX: (724) 465-4209

WO#: 12030411
PAGE: 1 of 7
PO#:
PWS ID#

TEST REPORT

12 08934-09155-09160-09166-09172-09190-09193

RECEIVED FOR LAB BY: GMD DATE: 03/05/2012 9:45

SAMPLE: **12 08934** Lab ID: 12030411-001A Grab
SAMPLED BY: Client Sample Time 02/28/2012 11:45

Test	Result	Uncert.	MDA	Units		Method	MCL	Analysis Start	Analysis End	Analyst *
Radium, Combined (Ra226 + Ra228)	5396			pCi/L	N	Calculation		03/26/12 10:38		BH-CV
Radium-226	4690	± 139.80	194.00	pCi/L		EPA 903.0		03/07/12 17:10	03/21/12	BH-CV
Carrier Recovery	108			%		EPA 903.0		03/07/12 17:10	03/21/12	BH-CV

SAMPLE: **12 08934** Lab ID: 12030411-001B Grab
SAMPLED BY: Client Sample Time 02/28/2012 11:45

Test	Result	Uncert.	MDA	Units	Method	MCL	Analysis Start	Analysis End	Analyst *
Radium-228	706.1	± 110.10	137.70	pCi/L	EPA 904.0		03/08/12 8:30	03/13/12	NLB-CV
Carrier Recovery	118			%	EPA 904.0		03/08/12 8:30	03/13/12	NLB-CV

REMARKS:
Where the analytical method has been performed under NELAP certification, the analysis has met all of the requirements of NELAP unless otherwise noted on the Analytical Report.
* CV = Benchmark Analytics, Inc. Center Valley, PA; SA = Benchmark Analytics, Inc. Sayre, PA
[illegible] Analyte detected in the associated Method Blank
N Parameter is not NELAC certified

MANAGER [signature] DATE: 3/27/2012

LAB ID: 39-00401 *CV
LAB ID: 08-00380 *SA

Benchmark Analytics, Inc.

4777 Saucon Creek Road
Center Valley, PA 18034

Work Order: 12030411

Phone: (610) 974-8100
Fax: (610) 974-8104

SEND DATA TO:

NAME: Jean M. Cole
COMPANY: Environmental Service Laboratories, Inc
ADDRESS: 1803 Philadelphia St
Indiana, PA 15701

WO#: 12030411
PAGE: 1 of 2
PO#:
PWS ID#

PHONE: (724) 463-8378
FAX: (724) 465-4209

TEST REPORT

12 08934-09155-09160-09166-09172-09190-09193

RECEIVED FOR LAB BY: GMD DATE: 03/05/2012 9:45

SAMPLE: **12 08934** Lab ID: 12030411-001C Grab
SAMPLED BY: Client Sample Time: 02/28/2012 11:45

Test	Result	Method	Req Limit	Analysis Start	Analysis End	Analyst *
Thorium	< 12.50 µg/L	EPA 200.8		03/15/12 10:40	03/23/12	JRA-CV
Uranium	< 0.63 µg/L	EPA 200.8	30	03/15/12 10:40	03/23/12	JRA-CV
Uranium	< 0.43 pCi/L	EPA 200.8		03/15/12 10:40	03/23/12	JRA-CV

REMARKS:

Where the analytical method has been performed under NELAP certification, the analysis has met all of the requirements of NELAP unless otherwise noted on the Analytical Report.
* CV = Benchmark Analytics, Inc. Center Valley, PA; SA = Benchmark Analytics, Inc. Sayre, PA

MANAGER Cli Mel DATE: 3/27/2012

ENVIRONMENTAL SERVICE LABORATORIES, INC.

HEADQUARTERS: X
1803 Philadelphia St.
Indiana, PA 15701
(724) 463-TEST
(724) 465-4209

SOUTHERN DIVISION:
1276 Bentleyville Road
Van Voorhis, PA 15366
(724) 258-TEST
(724) 258-8376

FOR INTERNAL LABORATORY USE ONLY

SAMPLE REQUEST & CHAIN OF CUSTODY

Sample Identification	ESL#	Composite Date on/off	Composite Time on/off	Grab Date	Grab Time	Matrix	# of Containers	Container Type / Preservative	Analysis Requested
James SWD	12 08933			22812	1145	FIELD	FIELD	FIELD	pH 5.76 Hydrogen Sulfide Ø, DO 4.03
						WW	1 ✓	Plastic Liter none	pH, SC, Chloride, Sulfate, Alkalinity, Acidity, Bromide
						WW	2 ✓	Plastic Liter none	TSS, TDS, Dissolved Iron, Boron, BOD, MBAS Surfactants
						WW	1 ✓	Plastic Liter HNO_3	Al, As, Ba, Be, Cd, Cr, Co, Cu, Fe, Pb, Mg, Mn, Hg, Ni, Se, Ag, Sr, Zn, Li, Na, Ca, Mo, Hardness pH<2
						WW	1 ✓	Plastic Liter H_2SO_4	Nitrate-Nitrite, TKN, Ammonia, COD pH<2
	12 08934					WW	3 ✓	Plastic Liter HNO_3	Radium 226, Radium 228 Thorium, Uranium pH<2
						WW	1 ✓	Amber Glass L HCl	Oil & Grease pH<2
						WW	1 ✓	Amber Glass L H_2SO_4	Total Phenolics pH<2
						WW	2 ✓	Amber VOA Vials none	Ethylene Glycol
	2-28-12					WW	2 ✓	Amber VOA Vials HCl	Benzene, Toluene
TRIP BLANK	12 ~~08935~~					Water	2	Amber VOA Vials HCl	Benzene, Toluene

THE UNDERSIGNED PURCHASER HEREBY AGREES TO PAY SERVICE CHARGES ON ACCOUNTS OVER 31 DAYS OLD.
1. THESE SERVICE CHARGES WILL ACCRUE AT THE RATE OF 1 1/2% PER MONTH (18% PER ANNUM OR THE MAXIMUM ALLOWED BY LAW.)
2. THE UNDERSIGNED PURCHASER AGREES TO PAY, IN THE EVENT HIS ACCOUNT BECOMES DELINQUENT AND IS TURNED OVER TO ANY ATTORNEY FOR COLLECTION, REASONABLE ATTORNEY'S FEES PLUS ALL COURT AND ATTENDANT COLLECTION COSTS.

Project Notes: **26R Waste Profile**

Sampled By: (Signature) [signature] Date/ Time 22812 1145

Relinquished By: (Signature) [signature] Date/ Time 22812 1410 — Received By: (Signature) [signature] Date/ Time 2-28-12 1419

Relinquished By: (Signature) Date/ Time — Received By: (Signature) Date/ Time

Relinquished By: (Signature) Date/ Time — Received By: (Signature) 2-28-12 Date/ Time

PRESERVATION Y / N CONTAINER Y / N TEMP 6°C Y / N / NA

Company/Name: **Seneca Resources**
Address: 51 Zents Boulevard, Brookville, PA 15825
Contact Person: Ms. Marisa Dollinger
Phone: (814) 849-4555
Fax: (814) 849-4795
Email: DollingerM@srcx.com

E.9

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 40681
		Sample Type:	Waste Water
		Sample Source:	Grab
Sample Start Date:	8/16/2012 11:00 AM	**Sampler:**	CLIENT (Client)
Receipt Date:	8/17/2012 2:50 PM	**Client Sample ID:**	James City
Report Date:	8/27/2012		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Total Organic Carbon	ZTR	08/20	n/a	5.49	mg/l	n/a	SM5310C	0.50

Comments:

ND=Not Detected

Note: DEP Certification #s 32-00382

Approved By:
Laboratory Supervisor

ENVIRONMENTAL SERVICE LABORATORIES, INC.

HEADQUARTERS: [X]
1803 Philadelphia St.
Indiana, PA 15701
(724) 463-TEST
(724) 465-4209

SOUTHERN DIVISION: [ ]
1276 Bentleyville Road
Van Voorhis, PA 15366
(724) 258-TEST
(724) 258-8376

FOR INTERNAL LABORATORY USE ONLY

SAMPLE REQUEST & CHAIN OF CUSTODY

RUSH due 8/20/12

Sample Identification	ESL#	Sample Type: Composite Date on/off	Composite Time on/off	Grab Date	Grab Time	Matrix	# of Containers	Container Type Preservative	Analysis Requested
James City	12 40681			8/16/12	11:00	WW	1	Amber Glass 250ml H3PO4	TOC ✓pH<2

THE UNDERSIGNED PURCHASER HEREBY AGREES TO PAY SERVICE CHARGES ON ACCOUNTS OVER 31 DAYS OLD.
1. THESE SERVICE CHARGES WILL ACCRUE AT THE RATE OF 1 1/2% PER MONTH (18% PER ANNUM OR THE MAXIMUM ALLOWED BY LAW.)
2. THE UNDERSIGNED PURCHASER AGREES TO PAY, IN THE EVENT HIS ACCOUNT BECOMES DELINQUENT AND IS TURNED OVER TO ANY ATTORNEY FOR COLLECTION, REASONABLE ATTORNEY'S FEES PLUS ALL COURT AND ATTENDANT COLLECTION COSTS.

Project Notes:

Client — 8-16-12 1100
Sampled By: (Signature) — Date/ Time

Pete Kostelle — ~~8-16-12~~ 8-17-12 0840
Relinquished By: (Signature) — Date/ Time
Received By: (Signature) — Date/ Time

Pete Kostelle — 8-17-12 1450
Relinquished By: (Signature) — Date/ Time

[signature] — 8/17/12 1459
Received By: (Signature) — Date/ Time

Relinquished By: (Signature) — Date/ Time
Received By: (Signature) — Date/ Time

PRESERVATION Y / N CONTAINER Y / N TEMP ≤ 4°C Y / N / NA

Company/Name: Seneca Resources
Address: 51 Zents Boulevard, Brookville, PA 15825
Contact Person: Mr. Doug Kepler
Phone: (814) 849-4555
Fax: (814) 849-4795
Email: KeplerD@srcx.com

APPENDIX H

Typical Corrosion Inhibitor

For assistance in Accessing this document, please contact: R3_UIC_Mailbox@epa.gov

AQUACLEAR
PRODUCT INFORMATION

Corrosion Inhibitor SticksT

WHAT ARE CORROSION INHIBITOR STICKST?

Corrosion Inhibitor SticksT are water soluble or oil soluble sticks that contain a blend of Imidazolines which have excellent filming characteristics and low emulsion tendencies. This unique blend gives effective corrosion control for most oil field corrosion problems.

CORROSION INHIBITOR STICK™ USES

Corrosion Inhibitor Sticks ™ are primarily used to control common corrosion problems found in producing oil and gas well systems. They can be used to treat hard to reach 'dead' areas such as the annulus space above the packer, rat-hole, or the bottom of water supply tanks.

ADVANTAGES OF CORROSION INHIBITOR STICKST

Corrosion Inhibitor SticksT can provide corrosion control throughout the entire production system. Regular usage will help control corrosion at the point they begin - down-hole.

They are available in two different formulations (oil soluble and water dispersable) or (water soluble and oil dispersable). The oil soluble type is soluble in oil, condensate and wet gas and can slowly disperse inhibitor into the water phase. The water soluble type is soluble in water and can slowly disperse inhibitor into the oil phase.

Corrosion Inhibitor SticksT can effectively inhibit corrosion in wells that produce both water and distillate or oil phases. In this case, it may be desirable to treat the well with both types of sticks by first dropping water soluble sticks and allowing them to fall through the oil into the water, thus dissolving and releasing inhibitor in

TREATMENT DETERMINATION

The number of Corrosion Inhibitor SticksT used is based on the volume of total fluid produced (oil or condensate plus water). Field experience indicates that for most corrosive environments the best results are achieved by using a larger initial slug treatment (80 PPM daily) until the problem is under control then reduce to smaller periodic treatments (40 PPM daily) thereafter. EXAMPLE: An initial slug treatment of 80 PPM would require 0.64 lbs of Corrosion Inhibitor Stick™ per 24 BBL (1000 gallons) of total fluid produced.

COR. INH. STICK™ SIZES	STICKS PER BBL
SENIOR (1 5/8 " x 18")	**1 per 58 bbls**
JUNIOR (1 3/8 " x 16 ")	**1 per 40 bbls**
JUNIOR (1 1/4" x 15")	**1 per 29 bbls**
THRIFTY (1" x 15")	**1 per 18 bbls**
MIDGET (5/8" x 15")	**1 per 7 bbls**

NOTE: To successfully control any corrosion problem, the inhibitor insertion into the fluid stream must be constant. For intermittent treatment or extreme corrosive environments increase the number of sticks accordingly.

THE MOST COMMON PROCEDURE for producing wells is to shut-in well and drop sticks through lubricator. Leave well shut until sticks fall to the bottom. The time in minutes for the sticks to fall to the bottom (assuming well is shut-in with fluid at surface) is equal to the depth divided by 100. (Time, min. = Depth, ft / 100).

FOR WATER INJECTION SYSTEMS drop the sticks into the water supply tank to inhibit more of the system.

the water column). Then drop the oil soluble sticks which will "FLOAT" at where the oil and water contact thus slowly dissolving and releasing inhibitor in the oil column.

The sticks are economical when compared to conventional corrosion control operations and therefore save investment in pumps, drums of chemical, and equipment maintenance.

Corrosion Inhibitor SticksT may be used in wells with bottom hole temperatures (BHT) of up to 375 degrees Fahrenheit.

PRODUCTION SPECIFICATIONS

OIL SOLUBLE: The stick will dissolve in 20 to 120 minutes (in moving diesel) depending on temperature, salt content, and relative fluid motion. The stick will melt at 135 degrees Fahrenheit and the specific gravity is 0.95.

WATER SOLUBLE: The stick will dissolve in 12 to 24 hours (in 60,00 PPMmoving brine water) depending on temperature, salt content, and relative fluid motion. The stick will melt at 125 degrees Fahrenheit and the specific gravity is 1.10.

PRODUCT PACKAGING

SENIOR	1.55 lb/stick	24/case	31/pail	48/chest
JUNIOR(1)	1.20 lb/stick	36/case	n/a	72/chest
JUNIOR(2)	0.76 lb/stick	36/case	52/pail	72/chest
THRIFTY	0.49 lb/stick	49/case	72/pail	98/chest
MIDGET	0.19 lb/stick	108/case	204/pail	216/chest

WHERE TO BUY

All good oil field supply stores carry Aqua-Clear, Inc. Corrosion Inhibitor Sticks™, but you can also buy direct from us.

Ordering Information

Should you wish to speak to a sales representative about any of our products, you can call or email Tommy Halloran Jr., Ronald "Buster" Wilson, or Russell Cook directly:

Tommy Halloran Jr.
W 304-343-4792
H 304-345-5152
C 304-546-8526
tom@aquaclear-inc.com

Ronald "Buster" Wilson
W 304-546-8518
H 304-965-7996
Fax 304-965-2713
buster@aquaclear-inc.com

Russell Cook
W 304-546-2940
H 304-842-7050
Fax 304-842-7050
russell@aquaclear-inc.com

APPENDIX I

Contractor Estimate for Plugging and Abandonment of Proposed Injection Well #38282

ALCO Well Services, Inc.
314 Interstate Parkway
Bradford, PA 16701
814-598-2566

Sent via electronic mail to SmithJ@srcx.com
SwansonL2@srcx.com

April 4th, 2016

Ms. Jamie Smith
Sr. Coordinator, Completions
Seneca Resource, Inc.
51 Zents Boulevard
Brookville, PA 15825

Dear Jamie:

On behalf of ALCO Well Services, Inc., we appreciate the opportunity to present ALCO's cost estimate for the plugging of Seneca **Well #38282**.

After reviewing the specifications provided and based on the assumptions outlined below, ALCO's estimated turnkey fee for plugging **Well #38282** is **$22,300.**

This quotation is valid until June 30th, 2016 and the assumptions are as follows:

1. Cement between 9 5/8" casing and 7" casing must be visible at surface.[1]
2. The projected amount of cement and gel required to plug the well is based on PA DEP regulations and has a direct correlation to the depths indicated on the Well information provided to us by your office.

The quotation breaks down as follows:

Category	Unit	Total
Site Preparation/Restoration	Lump Sum	$ 1,800
Mobilization/Demobilization	Lump Sum	$ 1,750
Plugging Rig[2]	Hourly	$ 8,800
Cement Services	Per Sack	$ 6,750
Gravel and Non-Cement Mat'l	Lump Sum	$ 750
Water	Lump Sum	$ 1,200
Disposal	Bbl	$ 1,250

[1] If cement is not visible between 9 5/8" and 7" casing, a bond log must be run to find top of cement. 7" pipe must be shot off. These fees are estimated to be $2750.00 if required plus one additional rig day at $2200.00.
[2] Plugging Rig hourly rate of $275 includes one operator and 2 laborers. 4 days of rig time is estimated for completion of this project.

Total		**$ 22,300**

In the event you have questions or concerns about this quotation, feel free to contact me at 814-598-2566. Again, we thank you for the opportunity to submit this quotation.

Sincerely,

Margaret M. Copeland
President ALCO Well Services, Inc.
mcopeland@alcowell.com

APPENDIX J

EPA Plugging and Abandonment Plan (EPA Form 7520-14)

OMB No. 2040-0042 Approval Expires 12/31/2018

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Seneca Well #38282 Highland Township, Elk County, PA	Seneca Resources Corporation 5800 Corporate Blvd, Suite 300, Pittsburgh, PA 15237

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State	County	Permit Number
PA	Elk	37-047-32885

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name

WELL ACTIVITY

- [ ] CLASS I
- [x] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
9 5/8"	26		40'	12.25"
7"	17		553'cemented to surface	8.75"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	6.25"	6.25"					
Depth to Bottom of Tubing or Drill Pipe (ft	2500'	700'					
Sacks of Cement To Be Used (each plug)	173	18					
Slurry Volume To Be Pumped (cu. ft.)	204	21.3					
Calculated Top of Plug (ft.)	1544	600'					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6					
Type Cement or Other Material (Class III)	Class A	Class A					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
Surface casing seat at 553'	Total depth 2565'		

Estimated Cost to Plug Wells

$

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Amanda Verzey Geologist	Amanda Verzey	5/1/2016

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

APPENDIX K

Seneca Resources Corporation's Chief Financial Officers Financial Responsibility Letter to USEPA

National Fuel

David P. Bauer
Treasurer

May 3, 2016

Mr. Shawn M. Garvin
Regional Administrator
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103-2029

Dear Mr. Garvin:

I am the Principal Financial Officer of National Fuel Gas Company, located at 6363 Main St., Williamsville, NY 14221. This letter is in support of this firm's use of the financial test to demonstrate financial assurance, as specified in subpart F of 40 CFR Part 144.

1. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is demonstrated through the financial test specified in Subpart F of 40 CFR Part 144. The current plugging and abandonment cost estimate covered by the test is shown for each injection well: NONE.

2. This firm guarantees, through the corporate guarantee specified in Subpart F of 40 CFR Part 144, the plugging and abandonment of the following injection wells owned or operated by subsidiaries of this firm, specifically Seneca Resources Corporation, located at 5800 Corporate Drive, Suite 300, Pittsburgh, PA 15237. The current cost estimate for plugging and abandonment so guaranteed is shown for each injection well:
API# 37-047-23835 $22,300
API# 37-047-23885 $22,300.

3. In states where EPA is not administering the financial requirements of Subpart F of 40 CFR Part 144, this firm, as owner or operator or guarantor, is demonstrating financial assurance for the plugging and abandonment of the following injection wells through the use of a test equivalent or substantially equivalent to the financial test specified in Subpart F of 40 CFR Part 144. The current plugging and abandonment cost estimate covered by such a test is shown for each injection well: NONE.

4. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is not demonstrated either to EPA or a state through the financial test or any other financial assurance mechanism specified in Subpart F of 40 CFR Part 144 or equivalent or substantially equivalent state mechanisms. The current plugging and abandonment cost estimate not covered by such financial assurance is shown for each injection well: NONE.

This firm is required to file a Form 10K with the Securities and Exchange Commission (SEC) for the latest fiscal year. The fiscal year of this firm ends on September 30. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended September 30, 2015. The name and address of the accounting firm auditing these financial statements is: PricewaterhouseCoopers LLP, located at 726 Exchange Street, Suite 1010, Buffalo, NY 14210. The dollar amounts stated below are in thousands of dollars.

Alternative I 1. (a) Current plugging and abandonment cost	$45
(b) Sum of the Company's financial responsibilities under 40 CFR Parts 264 and 265, Subpart H, currently met using the Financial Test or Corporate Guarantee	$0
(c) Total of lines A and B	$45
*2. Total liabilities [if any portion of the plugging and abandonment cost is included in total liabilities, you may deduct the amount of that portion from this line and add that amount to lines 3 and 4]	$4,676,699
*3. Tangible net worth	$1,168,195
*4. Net worth	$2,025,440
*5. Current assets	$513,001
*6. Current liabilities	$446,140
*7. Net working capital [line 5 minus line 6]	$66,861
*8. The sum of net income plus depreciation, depletion and amortization	$(43,269)
*9. Total assets in U.S. (required only if less than 90% of firm's assets are located in U.S.)	

	Yes	No
10. Is line 3 at least $10 million?	Yes	
11. Is line 3 at least 6 times line 1(c)?	Yes	
12. Is line 7 at least 6 times line 1(c)?	Yes	
*13. Are at least 90% of firm's assets located in the U.S.? If not, complete line 14.	Yes	
14. Is line 9 at least 6 times line 1(c)?		
15. Is line 2 divided by line 4 less than 2.0?		No
16. Is line 8 divided by line 2 greater than 0.1?		No
17. Is line 5 divided by line 6 greater than 1.5?		No

Alternative II 1. (a) Current plugging and abandonment cost	$45
(b) Sum of the Company's financial responsibilities under 40 CFR Parts 264 and 265, Subpart H, currently met using the financial test or corporate guarantee	$0
(c) total of lines a and b	$45
2. Current bond rating of most recent issuance of this firm and name of rating service	MOODY'S (BAA2) FITCH (BBB+) S&P (BBB)

3. Date of issuance of bond	JUNE 22, 2015	
4. Date of maturity of bond	JULY 15, 2025	
*5. Tangible net worth [if any portion of the plugging and abandonment cost estimate is included in "total liabilities" on your firm's financial statements, you may add the amount of that portion to this line]	$1,168,195	
*6. Total assets in U.S. (required only if less than 90% of firm's assets are located in U.S.)		
	Yes	No
7. Is line 5 at least $10 million?	Yes	
8. Is line 5 at least 6 times line 1(c)?	Yes	
*9. Are at least 90% of the firm's assets located in the U.S.? If not, complete line 10	Yes	
10. Is line 6 at least 6 times line 1(c)?	Yes	

I hereby certify that the wording of this letter is identical to the wording specified in 40 CFR 144.70(F) as such regulations were constituted on the date shown immediately below.

David P Bauer

DAVID P BAUER

TREASURER AND PRINCIPAL FINANCIAL OFFICER

MAY 3, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended September 30, 2015

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to
Commission File Number 1-3880

National Fuel Gas Company

(Exact name of registrant as specified in its charter)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6363 Main Street Williamsville, New York	**14221**
(Address of principal executive offices)	*(Zip Code)*

(716) 857-7000
Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $1.00 per share, and Common Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $4,935,145,000 as of March 31, 2015.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2015: 84,633,992 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2016 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2015, are incorporated by reference into Part III of this report.

Glossary of Terms

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation National Fuel Gas Distribution Corporation
Empire Empire Pipeline, Inc.
Midstream Corporation National Fuel Gas Midstream Corporation
National Fuel National Fuel Gas Company
NFR National Fuel Resources, Inc.
Registrant National Fuel Gas Company
Seneca Seneca Resources Corporation
Supply Corporation National Fuel Gas Supply Corporation

Regulatory Agencies

CFTC Commodity Futures Trading Commission
EPA United States Environmental Protection Agency
FASB Financial Accounting Standards Board
FERC Federal Energy Regulatory Commission
NYDEC New York State Department of Environmental Conservation
NYPSC State of New York Public Service Commission
PaDEP Pennsylvania Department of Environmental Protection
PaPUC Pennsylvania Public Utility Commission
PHMSA Pipeline and Hazardous Materials Safety Administration
SEC Securities and Exchange Commission

Other

Bbl Barrel (of oil)
Bcf Billion cubic feet (of natural gas)
Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.
Capital expenditure Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.
Degree day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.
Development costs Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.
Development well A well drilled to a known producing formation in a previously discovered field.
Dodd-Frank Act Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.
Exploration costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
FERC 7(c) application An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
Exploratory well A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.
Firm transportation and/or storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP Accounting principles generally accepted in the United States of America
Goodwill An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
ICE Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Interruptible transportation and/or storage The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LDC Local distribution company
LIBOR London Interbank Offered Rate
LIFO Last-in, first-out
Marcellus Shale A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl Thousand barrels (of oil)
Mcf Thousand cubic feet (of natural gas)
MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations
MDth Thousand decatherms (of natural gas)
MMBtu Million British thermal units (heating value of one dekatherm of natural gas)
MMcf Million cubic feet (of natural gas)
MMcfe Million cubic feet equivalent
NEPA National Environmental Policy Act of 1969, as amended
NGA The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.

PCB Polychlorinated Biphenyl
Precedent Agreement An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called "conditions precedent") happen, usually within a specified time.
Proved developed reserves Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make those reserves productive.
PRP Potentially responsible party
Reliable technology Technology that a company may use to establish reserves estimates and categories that has been proven empirically to lead to correct conclusions.
Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Restructuring Generally referring to partial "deregulation" of the pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or "unbundling") of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.
Revenue decoupling mechanism A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P Standard & Poor's Ratings Service
SAR Stock appreciation right
Service Agreement The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Spot gas purchases The purchase of natural gas on a short-term basis.
Stock acquisitions Investments in corporations.
Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
VEBA Voluntary Employees' Beneficiary Association
WNC Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

For the Fiscal Year Ended September 30, 2015

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PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. Except as otherwise indicated below, the Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to "the Company" in this report means the Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company's fiscal year ended September 30 of that year unless otherwise noted.

The Company is a diversified energy company engaged principally in the production, gathering, transportation, distribution and marketing of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being used for, and benefiting from, the production and transportation of natural gas from the Marcellus Shale basin. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Marcellus Shale to markets in Canada and the eastern United States. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments: Exploration and Production, Pipeline and Storage, Gathering, Utility, and Energy Marketing.

1. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and production of, natural gas and oil reserves in California and in the Appalachian region of the United States. At September 30, 2015, Seneca had U.S. proved developed and undeveloped reserves of 33,722 Mbbl of oil and 2,142,128 MMcf of natural gas.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, and Empire Pipeline, Inc. (Empire), a New York corporation. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and eastward to Ellisburg and Leidy, Pennsylvania, and (ii) 27 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields owned and operated jointly with other interstate gas pipeline companies. Empire, an interstate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns the Empire Pipeline, a 249-mile pipeline system comprising three principal components: a 157-mile pipeline that extends from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York; a 76-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York (the Empire Connector), and a 16-mile pipeline extension from Corning into Tioga County, Pennsylvania (the Tioga County Extension).

3. The Gathering segment operations are carried out by wholly-owned subsidiaries of National Fuel Gas Midstream Corporation (Midstream Corporation), a Pennsylvania corporation. Through these subsidiaries, Midstream Corporation builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region.

4. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation (Distribution Corporation), a New York corporation. Distribution Corporation sells natural gas or provides natural gas transportation services to approximately 739,975 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

5. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation, which markets natural gas to industrial, wholesale, commercial, public authority and residential

customers primarily in western and central New York and northwestern Pennsylvania, offering competitively priced natural gas for its customers.

Financial information about each of the Company's business segments can be found in Item 7, MD&A and also in Item 8 at Note J — Business Segment Information.

The following business is not included in any of the five reported business segments:

- Seneca's Northeast Division, which markets timber from Appalachian land holdings. At September 30, 2015, the Company owned approximately 93,000 acres of timber property and managed approximately 3,000 additional acres of timber cutting rights.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2015.

Rates and Regulation

The Utility segment's rates, services and other matters are regulated by the NYPSC with respect to services provided within New York and by the PaPUC with respect to services provided within Pennsylvania. For additional discussion of the Utility segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters are regulated by the FERC. For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The discussion under Item 8 at Note C — Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

In addition, the Company and its subsidiaries are subject to the same federal, state and local (including foreign) regulations on various subjects, including environmental matters, to which other companies doing similar business in the same locations are subject.

The Exploration and Production Segment

The Exploration and Production segment incurred a net loss in 2015. This represented 146.8% of the Company's 2015 net loss.

Additional discussion of the Exploration and Production segment appears below in this Item 1 under the headings "Sources and Availability of Raw Materials" and "Competition: The Exploration and Production Segment," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Pipeline and Storage Segment

The Pipeline and Storage segment contributed net income in 2015. This net income partially offset the Company's 2015 net loss by 21.2%.

Supply Corporation's firm transportation capacity is subject to change as the market identifies different transportation paths and receipt/delivery point combinations. At the end of fiscal year 2015, Supply Corporation had firm transportation service agreements for approximately 2,754 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,115 MDth per day or 41% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 171 MDth per day or 6%. The remaining 1,468 MDth or 53% is subject to firm contracts with nonaffiliated customers. Contracted transportation capacity with both affiliated and unaffiliated shippers is expected to increase 12% in 2016.

Supply Corporation had service agreements for all of its firm storage capacity, totaling 68,042 MDth, at the end of 2015. The Utility segment has contracted for 28,491 MDth or 42% of the total firm storage capacity, and the Energy Marketing segment accounts for another 3,097 MDth or 4%. Nonaffiliated customers have contracted for the remaining 36,454 MDth or 54%. Supply Corporation expects 2% of its contracts for firm storage capacity will expire or terminate and be available for remarketing in 2016.

At the end of 2015, Empire had service agreements in place for firm transportation capacity totaling up to approximately 1,057 MDth per day, with 88% of that capacity contracted as long-term, full-year deals. The Utility segment accounted for 3% of Empire's firm contracted capacity, with the remaining 97% subject to contracts with nonaffiliated customers. None of the long-term contracts will expire or terminate in 2016.

The majority of Supply Corporation's transportation and storage contracts, and the majority of Empire's transportation contracts, allow either party to terminate the contract upon six or twelve months' notice effective at the end of the primary term, and include "evergreen" language that allows for annual term extension(s).

Additional discussion of the Pipeline and Storage segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Pipeline and Storage Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Gathering Segment

The Gathering segment contributed net income in 2015. This net income partially offset the Company's 2015 net loss by 8.4%.

Additional discussion of the Gathering segment appears below under the headings "Sources and Availability of Raw Materials" and "Competition: The Gathering Segment," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Utility Segment

The Utility segment contributed net income in 2015. This net income partially offset the Company's 2015 net loss by 16.7%.

Additional discussion of the Utility segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Utility Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Energy Marketing Segment

The Energy Marketing segment contributed net income in 2015. This net income partially offset the Company's 2015 net loss by 2.0%.

Additional discussion of the Energy Marketing segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Energy Marketing Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss in 2015. This represented 1.5% of the Company's 2015 net loss.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

The Exploration and Production segment seeks to discover and produce raw materials (natural gas, oil and hydrocarbon liquids) as further described in this report in Item 7, MD&A and Item 8 at Note J — Business Segment Information and Note M — Supplementary Information for Oil and Gas Producing Activities.

The Pipeline and Storage segment transports and stores natural gas owned by its customers, whose gas originates in the southwestern, mid-continent and Appalachian regions of the United States as well as in Canada. Additional discussion of proposed pipeline projects appears below under “Competition: The Pipeline and Storage Segment” and in Item 7, MD&A.

The Gathering segment gathers, processes and transports natural gas that is produced by Seneca in the Appalachian region of the United States. Additional discussion of proposed gathering projects appears below in Item 7, MD&A.

Natural gas is the principal raw material for the Utility segment. In 2015, the Utility segment purchased 66.5 Bcf of gas for delivery to its customers. Gas purchased from producers and suppliers in the United States under firm contracts (seasonal and longer) accounted for 56% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 44% of the Utility segment’s 2015 purchases. Purchases from DTE Energy Trading, Inc. (18%), South Jersey Resources Group, LLC (15%), J. Aron & Company (11%) and Statoil Natural Gas, LLC (9%) accounted for 53% of the Utility’s 2015 gas purchases. No other producer or supplier provided the Utility segment with more than 9% of its gas requirements in 2015.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2015, this segment purchased 47.4 Bcf of gas, including 46.8 Bcf for delivery to its customers. The remaining 0.6 Bcf largely represents gas used in operations. The gas purchased by the Energy Marketing segment originates primarily in either the Appalachian or mid-continent regions of the United States.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy, such as fuel oil and electricity. Management believes that the environmental advantages of natural gas have enhanced its competitive position relative to other fuels.

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this “Competition” heading, do not compete with the Company to any significant extent.

Competition: The Exploration and Production Segment

The Exploration and Production segment competes with other oil and natural gas producers and marketers with respect to sales of oil and natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas producers with respect to exploration and development prospects and mineral leaseholds.

To compete in this environment, Seneca originates and acts as operator on certain of its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks market niches based on size, operating expertise and financial criteria.

Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position, as described below. Most of Supply Corporation’s facilities are in or near areas overlying the Marcellus and Utica Shale production areas in Pennsylvania. Its facilities are also located adjacent to the Canadian border at the Niagara River (Niagara) and the northeastern United States, and provide part of the traditional link between gas-consuming regions of the eastern United States and gas-producing regions of Canada and the southwestern, southern and other continental regions of the United States. While costlier natural gas pricing at Niagara has decreased the importation and transportation of gas from that receipt point, new productive areas in the Appalachian region related to the development of the Marcellus Shale formation have increased transportation services from that region. Supply Corporation has developed and placed into service a number of pipeline expansion projects to receive natural gas produced from the Marcellus Shale and transport it to key markets of Canada and the northeastern United States, and most recently to long-haul pipelines moving gas into the U.S. Midwest and even back to the gulf coast. For further discussion of these projects, refer to Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters."

Empire competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation of Appalachian-sourced gas as well as gas received at the Niagara River at Chippawa. Empire's location provides it the opportunity to compete for an increased share of the gas transportation markets. As noted above, the Empire Connector project expanded Empire's natural gas pipeline and enables Empire to serve new markets in New York and elsewhere in the Northeast. In November 2011, Empire also completed its Tioga County Extension project, which stretches approximately 16 miles south from its existing interconnection with Millennium Pipeline at Corning, New York, into Tioga County, Pennsylvania. Like Supply Corporation, Empire's expanded system facilitates transportation of Marcellus Shale gas to key markets of Canada and the northeastern United States.

Competition: The Gathering Segment

The Gathering segment provides gathering services for Seneca's production and competes with other companies that gather and process natural gas in the Appalachian region.

Competition: The Utility Segment

With respect to gas commodity service, in New York and Pennsylvania, both of which have implemented "unbundling" policies that allow customers to choose their gas commodity supplier, Distribution Corporation has retained a substantial majority of small sales customers. In New York, approximately 22%, and in Pennsylvania, approximately 15%, of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In contrast, almost all large-volume load is served by unregulated retail marketers. However, retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, utility cost of service is recovered through rates and charges for gas delivery service, not gas commodity service. Over the longer run, it is possible that rate design changes resulting from further customer migration to marketer service could expose utility companies such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

Competition for transportation service to large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories without use of the utility's facilities (i.e., bypass). In addition, competition continues with fuel oil suppliers.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible, high quality services. The Utility segment continues to develop or promote new uses of natural gas as well as new services, rates and contracts.

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy supply. Competition in this area is well developed with regard to price and services from local, regional and national marketers.

Seasonality

Variations in weather conditions can materially affect the volume of natural gas delivered by the Utility segment, as virtually all of its residential and commercial customers use natural gas for space heating. The effect that this has on Utility segment margins in New York is mitigated by a WNC, which covers the eight-month period from October through May. Weather that is warmer than normal results in an upward adjustment to customers' current bills, while weather that is colder than normal results in a downward adjustment, so that in either case projected operating costs calculated at normal temperatures will be recovered.

Volumes transported and stored by Supply Corporation and volumes transported by Empire may vary materially depending on weather, without materially affecting the revenues of those companies. Supply Corporation's and Empire's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

Variations in weather conditions materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations have a corresponding impact on revenues within this segment.

Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note I — Commitments and Contingencies.

Miscellaneous

The Company and its wholly owned or majority-owned subsidiaries had a total of 2,125 full-time employees at September 30, 2015.

The Company has agreements in place with collective bargaining units in New York and Pennsylvania. Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2017. Agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2018 and May 2018.

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's internet website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company's internet website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

Executive Officers of the Company as of November 15, 2015(1)

Name and Age (as of November 15, 2015)	Current Company Positions and Other Material Business Experience During Past Five Years
Ronald J. Tanski (63)	Chief Executive Officer of the Company since April 2013 and President of the Company since July 2010. Mr. Tanski previously served as Chief Operating Officer of the Company from July 2010 through March 2013.
Matthew D. Cabell (57)	Senior Vice President of the Company since July 2010 and President of Seneca since December 2006.
Anna Marie Cellino (62)	President of Distribution Corporation since July 2008.
John R. Pustulka (63)	President of Supply Corporation since July 2010.
David P. Bauer (46)	Treasurer and Principal Financial Officer of the Company since July 2010; Treasurer of Seneca since April 2015; Treasurer of Distribution Corporation since April 2015; Treasurer of Midstream Corporation since April 2013; Treasurer of Supply Corporation since June 2007; and Treasurer of Empire since June 2007. Mr. Bauer previously served as Assistant Treasurer of Distribution Corporation from April 2004 through March 2015.
Karen M. Camiolo (56)	Controller and Principal Accounting Officer of the Company since April 2004; Vice President of Distribution Corporation since April 2015; Controller of Midstream Corporation since April 2013; Controller of Empire since June 2007; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Carl M. Carlotti (60)	Senior Vice President of Distribution Corporation since January 2008.
Paula M. Ciprich (55)	Senior Vice President of the Company since April 2015; Secretary of the Company since July 2008; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008.
Donna L. DeCarolis (56)	Vice President Business Development of the Company since October 2007.
James D. Ramsdell (60)	Senior Vice President and Chief Safety Officer of the Company since May 2011. Mr. Ramsdell previously served as Senior Vice President of Distribution Corporation from July 2001 to May 2011.

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served or currently serve as officers or directors of other subsidiaries of the Company.

Item 1A *Risk Factors*

As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends and other cash flow from the subsidiaries. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

The Company is dependent on capital and credit markets to successfully execute its business strategies.

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt on favorable terms. These difficulties could adversely affect the Company's growth strategies, operations and financial performance. The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures. Under the Company’s 1974 indenture, the Company has been precluded since October 1, 2015 from issuing incremental long-term debt as a result of the impairments (i.e.,write-downs) of its oil and gas properties recognized during the nine months ended June 30, 2015. Given those impairments and the impairment recognized for the quarter ended September 30, 2015, the Company will be precluded from issuing incremental long-term debt through September 2016. If the Company experiences additional significant impairments of its oil and gas properties in the first or subsequent quarters of fiscal 2016, the Company expects to continue to be precluded from issuing incremental long-term debt into the first or subsequent quarters of fiscal 2017. The 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt.

In addition, the Company's short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and the ability of the Company to issue commercial paper are affected by its debt credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings. A downgrade in the Company's credit ratings could increase borrowing costs and negatively impact the availability of capital from banks, commercial paper purchasers and other sources.

The Company may be adversely affected by economic conditions and their impact on our suppliers and customers.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect the Company’s revenues and cash flows or restrict its future growth. Economic conditions in the Company’s utility service territories and energy marketing territories also impact its collections of accounts receivable. All of the Company’s segments are exposed to risks associated with the creditworthiness or performance of key suppliers and customers, many of which may be adversely affected by volatile conditions in the financial markets. These conditions could result in financial instability or other adverse effects at any of our suppliers or customers. For example, counterparties to the Company’s commodity hedging arrangements or commodity sales contracts might not be able to perform their obligations under these arrangements or contracts. Customers of the Company’s Utility and Energy Marketing segments may have particular trouble paying their bills during periods of declining economic activity or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. Similarly, if reductions were to occur in funding of the federal

Low Income Home Energy Assistance Program, bad debt expense could increase and earnings could decrease. In addition, oil and gas exploration and production companies that are customers of the Company's Pipeline and Storage segment may decide not to renew contracts for the same transportation capacity during periods of reduced production due to persistent low commodity prices. Any of these events could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

The Company's credit ratings may not reflect all the risks of an investment in its securities.

The Company's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. The Company's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this Form 10-K.

The Company's need to comply with comprehensive, complex, and the sometimes unpredictable enforcement of government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

While the Company generally refers to its Utility segment and its Pipeline and Storage segment as its "regulated segments," there are many governmental regulations that have an impact on almost every aspect of the Company's businesses. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may increase the Company's costs or affect its business in ways that the Company cannot predict.

In the Company's Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is required in a rate proceeding to reduce the rates it charges its utility customers, or to the extent Distribution Corporation is unable to obtain approval for rate increases from these regulators, particularly when necessary to cover increased costs (including costs that may be incurred in connection with governmental investigations or proceedings or mandated infrastructure inspection, maintenance or replacement programs), earnings may decrease.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have established competitive markets in which customers may purchase gas commodity from unregulated marketers, in addition to utility companies. Retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation because in both jurisdictions it recovers its cost of service through delivery rates and charges, and not through any mark-up on the gas commodity purchased by its customers. Over the longer run, however, rate design changes resulting from further customer migration to marketer service ("unbundling") can expose utilities such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

Both the NYPSC and the PaPUC have, from time-to-time, instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for the installation of high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a "revenue decoupling mechanism" that renders Distribution Corporation's New York division financially indifferent to the effects of conservation. In Pennsylvania, the PaPUC has not directed Distribution Corporation to implement conservation program. If the NYPSC were to revoke the revenue decoupling mechanism in a future proceeding or the PaPUC were to adopt a conservation program without revenue decoupling mechanism or other changes in rate design, reduced customer usage could decrease revenues, forcing Distribution Corporation to file for rate relief. If Distribution Corporation were unable to obtain adequate rate relief, its financial condition, results of operations and cash flows would be adversely affected.

In New York, aggressive generic statewide programs created under the label of efficiency or conservation continue to generate a sizable utility funding requirement for state agencies that administer those programs. Although utilities are authorized to recover the cost of efficiency and conservation program funding through special rates and surcharges, the resulting upward pressure on customer rates, coupled with increased assessments and taxes, could affect future tolerance for traditional utility rate increases, especially if natural gas commodity costs were to increase.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries, including Seneca, Distribution Corporation and NFR. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to adjust those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to adjust the rates it charges its natural gas transportation and/or storage customers, or if either Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. The FERC also possesses significant penalty authority with respect to violations of the laws and regulations it administers. Supply Corporation, Empire and, to the extent subject to FERC jurisdiction, the Company's other subsidiaries are subject to the FERC's penalty authority. In addition, the FERC exercises jurisdiction over the construction and operation of facilities used in interstate gas transmission. Also, decisions of Canadian regulators such as the National Energy Board and the Ontario Energy Board could affect the viability and profitability of Supply Corporation and Empire projects designed to transport gas from between Canada and the U.S.

The Company is also subject to the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA), which issues regulations and conducts evaluations pursuant to various laws including the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. This legislation increased civil penalties for pipeline safety violations and addressed matters such as pipeline damage prevention, automatic and remote-controlled shut-off valves, excess flow valves, pipeline integrity management, documentation and testing of maximum allowable operating pressure, and reporting of pipeline accidents. In addition, PHMSA is considering issuing new rules or amendments to existing rules regarding, among other things, pipeline safety, the use of plastic pipe in natural gas systems, expanded use of excess flow valves for natural gas utilities, pipeline incident notifications, operator qualifications and pipeline flow reversals. Unrelated to these safety initiatives, the EPA in April 2010 issued an Advance Notice of Proposed Rulemaking reassessing its regulations governing the use and distribution in commerce of PCBs. The EPA had projected that it would issue a Notice of Proposed Rulemaking by April 2013, but it has not done so. If as a result of these or similar new laws or regulations the Company incurs material costs that it is unable to recover fully through rates or otherwise offset, the Company's financial condition, results of operations, and cash flows would be adversely affected.

In the Company 's Exploration and Production segment, various aspects of Seneca's operations are subject to regulation by, among others, the EPA, the U.S. Fish and Wildlife Service, the U.S. Forestry Service, the Bureau of Land Management, the PaDEP, the Pennsylvania Department of Conservation and Natural Resources, the Division of Oil, Gas and Geothermal Resources of the California Department of Conservation, the California Department of Fish and Wildlife, and in some areas, locally adopted ordinances. Administrative proceedings or increased regulation by these or other agencies could lead to operational delays or restrictions and increased expense for Seneca.

The nature of the Company's operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.

The Company's operations in its various reporting segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; geological formations with abnormal pressures; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, the Company's facilities, machinery, and equipment may be subject to sabotage. Any of these events could cause a loss of hydrocarbons, environmental pollution, claims for personal injury, death, property damage or business interruption, or governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that the Company executes with contractors provide for the division of responsibilities between the contractor and the Company, and the Company seeks to obtain an indemnification from the contractor for certain of these risks. The Company is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes the Company is required to indemnify others.

Insurance or indemnification agreements, when obtained, may not adequately protect the Company against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to the Company. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Hazards and risks faced by the Company, and insurance and indemnification obtained or provided by the Company, may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against the Company or be resolved on unfavorable terms, the result of which could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

Environmental regulation significantly affects the Company's business.

The Company's business operations are subject to federal, state, and local laws and regulations relating to environmental protection. These laws and regulations concern the generation, storage, transportation, disposal, emission or discharge of pollutants, contaminants, hazardous substances and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. For example, currently applicable environmental laws and regulations restrict the types, quantities and concentrations of materials that can be released into the environment in connection with regulated activities, limit or prohibit activities in certain protected areas, and may require the Company to investigate and/or remediate contamination at certain current and former properties regardless of whether such contamination resulted from the Company's actions or whether such actions were in compliance with applicable laws and regulations at the time they were taken. Moreover, spills or releases of regulated substances or the discovery of currently unknown contamination could expose the Company to material losses, expenditures and environmental, health and safety liabilities. Such liabilities could include penalties, sanctions or claims for damages to persons, property or natural resources brought on behalf of the government or private litigants that could cause the Company to incur substantial costs or uninsured losses.

In addition, the Company must obtain, maintain and comply with numerous permits, leases, approvals, consents and certificates from various governmental authorities before commencing regulated activities. In connection with such activities, the Company may need to make significant capital and operating expenditures to detect, repair and/or control air emissions, to control water discharges or to perform certain corrective actions to meet the conditions of the permits issued pursuant to applicable environmental laws and regulations. Any failure to comply with applicable environmental laws and regulations and the terms and conditions of its environmental permits and authorizations could result in the assessment of significant administrative, civil and/or criminal penalties, the imposition of investigatory or remedial obligations and corrective actions, the revocation of required permits, or the issuance of injunctions limiting or prohibiting certain of the Company's operations.

Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company's business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local laws or regulations, the Company's costs could increase if environmental laws and regulations change.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Under the Federal Clean Air Act, the EPA requires that new stationary sources of significant greenhouse gas emissions or major modifications of existing facilities obtain permits covering such emissions. The EPA recently proposed, and is expected to finalize, regulations that will set methane emissions standards for new oil and natural gas emission sources. In addition, the EPA issued draft guidelines for voluntarily reducing emissions from existing equipment and processes in the oil and natural gas industry. Although the EPA's proposed rules are primarily directed at new or modified oil and gas emission sources, it is possible that existing sources eventually may be subject to similar regulations. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. The Company currently complies with California cap-and-trade guidelines, which increases the Company's cost of environmental compliance in its Exploration and Production segment operations. Legislation or regulation that restricts greenhouse gas emissions could increase the Company's cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas initiatives could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

Third parties may attempt to breach the Company's network security, which could disrupt the Company's operations and adversely affect its financial results.

The Company's information technology systems are subject to attempts by others to gain unauthorized access through the Internet, or to otherwise introduce malicious software. These attempts might be the result of industrial or other espionage, or actions by hackers seeking to harm the Company, its services or customers. Attempts to breach the Company's network security may result in disruption of the Company's business operations and services, delays in production, theft of sensitive and valuable data, damage to our physical systems, and reputational harm. Significant expenditures may be required to remedy breaches, including restoration of customer service and enhancement of information technology systems. The Company seeks to prevent, detect and investigate these security incidents, but in some cases the Company might be unaware of an incident or its magnitude and effects. The Company has experienced attempts to breach its network security, and although the scope of such incidents is sometimes unknown, they could prove to be material to the Company. These security incidents may have an adverse impact on the Company's operations, earnings and financial condition.

Delays or changes in plans or costs with respect to Company projects, including delays in obtaining necessary approvals, permits or orders, could delay anticipated project completion and may result in reduced earnings.

Construction of the Pipeline and Storage segment's planned pipelines and storage facilities, as well as the expansion of existing facilities, is subject to various regulatory, environmental, political, legal, economic and other development risks, including the ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on acceptable terms. Existing or potential third party opposition, such as opposition from landowner and environmental groups, which are beyond our control, could interfere significantly with or delay the Company's receipt of such approvals or permits, which could materially affect the anticipated construction of a project. In addition, third parties could impede the Gathering segment's acquisition, expansion or renewal of rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project construction may prevent a planned project from going into service when anticipated, which could cause a delay in the receipt of revenues from those facilities. A significant construction delay in a material project, whatever the cause, may result in reduced earnings and could have a material adverse impact on anticipated operating results.

The Company could be adversely affected by the disallowance of purchased gas costs incurred by the Utility segment.

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. There is a risk of disallowance of full recovery of these costs if regulators determine that Distribution Corporation was imprudent in making its gas purchases. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings.

Changes in interest rates may affect the Company's ability to finance capital expenditures and to refinance maturing debt.

The Company's ability to cost-effectively finance capital expenditures and to refinance maturing debt will depend in part upon interest rates. The direction in which interest rates may move is uncertain. Declining interest rates have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. In addition, the Company's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company's authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company's ability to earn its authorized rate of return may be adversely impacted.

Fluctuations in oil and natural gas prices could adversely affect revenues, cash flows and profitability.

Operations in the Company's Exploration and Production segment are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, natural disasters, the supply and price of foreign oil and natural gas, the level of consumer product demand, national and worldwide economic conditions, economic disruptions caused by terrorist activities, acts of war or major accidents, political conditions in foreign countries, the price and availability of alternative fuels, the proximity to, and availability of, capacity on transportation facilities, regional levels of supply and demand, energy conservation measures, and government regulations, such as regulation of greenhouse gas emissions and natural gas transportation, royalties, and price controls. The Company sells most of the oil and natural gas that it produces at current market and/or indexed prices rather than through fixed-price contracts, although as discussed below, the Company frequently hedges the price of a significant portion of its future production in the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in oil and natural gas prices could restrict its ability to continue the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

The natural gas the Company produces is priced in local markets where production occurs, and price is therefore affected by local or regional supply and demand factors as well as other local market dynamics such as regional pipeline capacity. Currently, the prices the Company receives for its natural gas production are generally lower than the relevant benchmark prices, such as NYMEX, that are used for commodity trading purposes. The difference between the benchmark price and the price the Company receives is called a differential. The Company may be unable to accurately predict natural gas differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as pipeline takeaway capacity and specifications, localized storage capacity, disruptions in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Insufficient pipeline or storage capacity, or a lack of demand or surplus of supply in any given operating area may cause the differential to widen in that area compared to other natural gas producing areas. Increases in the differential could lead to production curtailments or otherwise have a material adverse effect on the Company's revenues, cash flows and results of operations.

In the Company's Pipeline and Storage segment, significant changes in the price differential between equivalent quantities of natural gas at different geographic locations could adversely impact the Company. For example, if the price of natural gas at a particular receipt point on the Company's pipeline system increases relative to the price of natural gas at other locations, then the volume of natural gas received by the Company at the relatively more expensive receipt point may decrease, or the price the Company charges to transport that natural gas may decrease. Changes in price differentials can cause shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. In some cases, shippers may decide not to renew transportation contracts due to changes in price differentials. While much of the impact of lower volumes under existing contracts would be offset by the straight fixed-variable rate design utilized by Supply Corporation and Empire, this rate design does not protect Supply Corporation or Empire where shippers do not contract for expiring capacity at the same quantity and rate. If contract renewals were to decrease, revenues and earnings in the Pipeline and Storage segment may decrease. Significant changes in the price differential between futures contracts for natural gas having different delivery dates could also adversely impact the Company. For example, if the prices of natural gas futures contracts for winter deliveries to locations served by the Pipeline and Storage segment decline relative to the prices of such contracts for summer deliveries (as a result, for instance, of increased production of natural gas within the Pipeline and Storage segment's geographic area or other factors), then demand for the Company's natural gas storage services driven by that price differential could decrease. Such changes in price differential could also affect the Energy Marketing segment's ability to offset its natural gas storage costs through hedging transactions. These changes could adversely affect revenues, cash flows and results of operations.

The Company has significant transactions involving price hedging of its oil and natural gas production as well as its fixed price purchase and sale commitments.

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and natural gas production for certain periods of time, the Company's Exploration and Production segment regularly enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may at any time cover as much as approximately 80% of the Company's expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit the Company's ability to benefit from increases in commodity prices. In addition, the Energy Marketing segment enters into certain hedging arrangements, primarily with respect to its fixed price purchase and sales commitments and its gas stored underground.

Under applicable accounting rules currently in effect, the Company's hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines into which hedged natural gas production is delivered and the reference price established in the hedging arrangements, assumptions regarding the levels of production that will be achieved and, with regard to fixed price commitments, assumptions regarding the creditworthiness of certain customers and their forecasted consumption of natural gas. Depending on market conditions for natural gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. For example, in the Exploration and Production segment, where the Company uses short positions (i.e. positions that pay off in the event of commodity price decline) to hedge forecasted sales, gains would occur to the extent that natural gas and crude oil hedge prices exceed market prices for the Company's natural gas and crude oil production, and losses would occur to the extent that market prices for the Company's natural gas and crude oil production exceed hedge prices.

Use of energy commodity price hedges also exposes the Company to the risk of non-performance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements. In addition, the Company enters into certain commodity price hedges that are cleared through the NYMEX or ICE by futures commission merchants. Under NYMEX and ICE rules, the Company is required to post collateral in connection with such hedges, with such collateral being held by its futures commission merchants. The Company is exposed to the risk of loss of such collateral from occurrences such as financial failure of its futures commission merchants, or misappropriation or mishandling of clients' funds or other similar actions by its futures commission merchants. In addition, the Company is exposed to potential hedging ineffectiveness in the event of a failure by one of its futures commission merchants or contract counterparties.

It is the Company's policy that the use of commodity derivatives contracts comply with various restrictions in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production, and in the Energy Marketing segment, commodity derivatives with respect to fixed price purchase and sales commitments must be matched against commitments reasonably certain to be fulfilled. The Company maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and natural gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

The Dodd-Frank Act increased federal oversight and regulation of the over-the-counter derivatives markets and certain entities that participate in those markets. The act requires the CFTC, the SEC and various banking regulators to promulgate rules and regulations implementing the act. Although regulators have issued certain regulations, other rules that may be relevant to the Company have yet to be finalized. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company's derivative hedging transactions. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. In addition, while the Company expects to be exempt from the Dodd-Frank Act's requirement that swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company's ability to monetize or restructure existing derivative contracts; and increase the Company's exposure to less creditworthy counterparties, all of which could increase the Company's business costs.

You should not place undue reliance on reserve information because such information represents estimates.

This Form 10-K contains estimates of the Company's proved oil and natural gas reserves and the future net cash flows from those reserves that were prepared by the Company's petroleum engineers and audited by independent petroleum engineers. Petroleum engineers consider many factors and make assumptions in estimating oil and natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning oil and natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Lower oil and natural gas prices generally cause estimates of proved reserves to be lower. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to the Company's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of the Company's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable oil and natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from the Company's proved reserves is the current market value of the Company's estimated oil and natural gas reserves. In accordance with SEC requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on a 12-month average of historical prices for oil and natural gas (based on first day of the month prices and adjusted for hedging) and on costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of the Company's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company's reserve estimates in the future. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the production and operating costs incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The amount and timing of actual future oil and natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce the Company's earnings.

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company's Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce the Company's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and natural gas can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is significant and often uncertain, and new wells may not be productive or the Company may not recover all or any portion of its investment. Production can also be delayed or made uneconomic if there is insufficient gathering, processing and transportation capacity available at an economic price to get that production to a location where it can be profitably sold. Without continued successful exploitation or acquisition activities, the Company's reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot make assurances that it will be able to find or acquire additional reserves at acceptable costs.

Financial accounting requirements regarding exploration and production activities are expected to negatively affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses a 12-month historical average price for oil and natural gas (based on first day of the month prices and adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. For the fiscal year ended September 30, 2015, the Company recognized pre-tax impairment charges on its oil and natural gas properties of $1.1 billion. Given the potential that oil and natural gas prices could stay at low levels in future months, and the expected loss of significantly higher prices from the 12-month historical average that will be used in the ceiling test at December 31, 2015, the Company expects to experience an additional significant ceiling test impairment in that quarter (the first quarter of fiscal 2016). Depending upon the movement of oil and natural gas prices, it is possible that the Company may experience additional impairment charges in the second or subsequent quarters of fiscal 2016 as well.

Increased regulation of exploration and production activities, including hydraulic fracturing, could adversely impact the Company.

Due to the burgeoning Marcellus Shale natural gas play in the northeast United States, together with the fiscal difficulties faced by state governments in New York and Pennsylvania, various state legislative and regulatory initiatives regarding the exploration and production business have been proposed. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, abandonment and monitoring of wells, the protection of water supplies and restrictions on water use and water rights, hydraulic fracturing operations, surface owners' rights and damage compensation, the spacing of wells, use and disposal of potentially hazardous materials, and environmental and safety issues regarding natural gas pipelines. New permitting fees and/or severance taxes for oil and gas production are also possible. Additionally, legislative initiatives in the U.S. Congress and regulatory studies, proceedings or rule-making initiatives at federal or state agencies focused on the hydraulic fracturing process and related operations could result in additional permitting, compliance, reporting and disclosure requirements. For example, the EPA has adopted regulations that establish emission performance standards for hydraulic fracturing operations as well as natural gas gathering and transmission operations. Other EPA initiatives could expand water quality and hazardous waste regulation of hydraulic fracturing and related operations. The Bureau of Land Management finalized its hydraulic fracturing rules which set standards for such operations on federal lands. In California, legislation regarding well stimulation, including hydraulic fracturing, has been adopted. The law mandates technical standards for well construction, hydraulic fracturing water management, groundwater monitoring, seismicity monitoring during hydraulic fracturing operations and public disclosure of hydraulic fracturing fluid constituents. These and any other new state or federal legislative or regulatory measures could lead to operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risks of litigation for the Company.

The increasing costs of certain employee and retiree benefits could adversely affect the Company's results.

The Company's earnings and cash flow may be impacted by the amount of income or expense it expends or records for employee benefit plans. This is particularly true for pension and other post-retirement benefit plans, which are dependent on actual plan asset returns and factors used to determine the value and current costs of plan benefit obligations. In addition, if medical costs rise at a rate faster than the general inflation rate, the Company might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension, other post-retirement and medical benefits could have an adverse effect on the Company's financial results.

Significant shareholders or potential shareholders may attempt to effect changes at the Company or acquire control over the Company, which could adversely affect the Company's results of operations and financial condition.

Shareholders of the Company may from time to time engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes or acquire control over the Company. Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company's operations and diverting the attention of the Company's Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company's results of operations and financial condition.

Item 1B ***Unresolved Staff Comments***

None.

Item 2 ***Properties***

General Information on Facilities

The net investment of the Company in property, plant and equipment was $5.3 billion at September 30, 2015. The Exploration and Production segment comprises 39.9% of this investment, and is primarily located in California and in the Appalachian region of the United States. Approximately 51.4% of the Company's investment in net property, plant and equipment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and northwestern Pennsylvania. The Gathering segment comprises 7.5% of the Company's investment in net property, plant and equipment, and is located in northwestern Pennsylvania. The remaining net investment in property, plant and equipment consisted of the All Other category and Corporate operations (1.2%). During the past five years, the Company has made additions to property, plant and equipment in order to expand its exploration and production operations in the Appalachian region of the United States and to expand and improve transmission facilities for transportation customers in New York and Pennsylvania. Net property, plant and equipment has increased $1.9 billion, or 54.5%, since September 30, 2010. As part of its strategy to focus its exploration and production activities within the Appalachian region of the United States, specifically within the Marcellus Shale, the Company sold its off-shore oil and natural gas properties in the Gulf of Mexico in April 2011. The net property, plant and equipment associated with these properties was $55.4 million. The Company also sold on-shore oil and natural gas properties in its West Coast region in May 2011 with net property, plant and equipment of $8.1 million.

The Exploration and Production segment had a net investment in property, plant and equipment of $2.1 billion at September 30, 2015.

The Pipeline and Storage segment had a net investment of $1.4 billion in property, plant and equipment at September 30, 2015. Transmission pipeline represents 35% of this segment's total net investment and includes 2,340 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 16% of this segment's total net investment and consist of 31 storage fields operating at a combined working gas level of 73.4 Bcf, four of which are jointly owned and operated with other interstate gas pipeline companies, and 427 miles of pipeline. Net investment in storage facilities includes $83.2 million of gas stored underground-noncurrent, representing the cost of the gas utilized to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 34 compressor stations with 148,717 installed compressor horsepower that represent 20% of this segment's total net investment in property, plant and equipment.

The Gathering segment had a net investment of $0.4 billion in property, plant and equipment at September 30, 2015. Gathering lines and related compressors comprise substantially all of this segment's total net investment, including 82 miles of lines utilized to move Appalachian production (including Marcellus Shale) to various transmission pipeline receipt points. The Gathering segment has 4 compressor stations with 34,500 installed compressor horsepower.

The Utility segment had a net investment in property, plant and equipment of $1.4 billion at September 30, 2015. The net investment in its gas distribution network (including 14,816 miles of distribution pipeline) and its service connections to customers represent approximately 48% and 34%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2015.

The Pipeline and Storage segments' facilities provided the capacity to meet Supply Corporation's 2015 peak day sendout for transportation service of 2,384 MMcf, which occurred on January 7, 2015. Withdrawals from storage of 622.3 MMcf provided approximately 26% of the requirements on that day.

Company maps are included in Exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California and the Appalachian region of the United States. The Company has been increasing its emphasis in the Appalachian region, primarily in the Marcellus Shale, and sold its off-shore oil and natural gas properties in the Gulf of Mexico during 2011, as mentioned above. Further discussion of oil and gas producing activities is included in Item 8, Note M - Supplementary Information for Oil and Gas Producing Activities. Note M sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2015, 2014 and 2013 reserves shown in Note M are valued using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. The reserves were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note M discusses the qualifications of the Company's reservoir engineers, internal controls over the reserve estimation process and audit of the reserve estimates and changes in proved developed and undeveloped oil and natural gas reserves year over year.

Seneca's proved developed and undeveloped natural gas reserves increased from 1,683 Bcf at September 30, 2014 to 2,142 Bcf at September 30, 2015. This increase is attributed to extensions and discoveries of 633 Bcf, partially offset by production of 140 Bcf and negative revisions of previous estimates of 34 Bcf. Total downward gas revisions of 34 Bcf were primarily a result of negative revisions due to lower gas prices of 38 Bcf primarily in the Marcellus Shale and Upper Devonian reservoirs, coupled with the removal of 38 Bcf of PUD reserves in the Marcellus Shale in Tioga County as the Company has no near term plans to develop these reserves as it is employing capital elsewhere. Partially offsetting these negative revisions were a 16 Bcf upward revision to Marcellus PUD reserves transferred to proved developed reserves and a 26 Bcf upward revision to remaining Marcellus PUD reserves.

Seneca's proved developed and undeveloped oil reserves decreased from 38,477 Mbbl at September 30, 2014 to 33,722 Mbbl at September 30, 2015. Extensions and discoveries of 533 Mbbl were exceeded by production of 3,034 Mbbl, primarily occurring in the West Coast region, and downward revisions of previous estimates of 2,254 Mbbl. Downward revisions of 2,254 Mbbl were primarily a result of lower oil prices (1,861 Mbbl) as well as removing 279 Mbbl of PUD reserves at the North Lost Hills field in the Tulare reservoir as the Company has no near term plans to develop these reserves as it is employing capital elsewhere. On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 1,914 Bcfe at September 30, 2014 to 2,344 Bcfe at September 30, 2015. Total revisions of previous estimates was a decrease of 48 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 1,300 Bcf at September 30, 2013 to 1,683 Bcf at September 30, 2014. This increase was attributed to extensions and discoveries of 447 Bcf, acquisitions of 34 Bcf (both primarily Marcellus Shale) and positive revisions of previous estimates of 45 Bcf which were partially offset by production of 142 Bcf. Upward performance revisions of 45 Bcf were primarily performance revisions in the Marcellus Shale and included a 20 Bcf upward revision to Marcellus PUD reserves transferred to proved developed reserves and a 13 Bcf upward revision to remaining Marcellus PUD reserves.

Seneca's proved developed and undeveloped oil reserves decreased from 41,598 Mbbl at September 30, 2013 to 38,477 Mbbl at September 30, 2014. Extensions and discoveries of 1,539 Mbbl were exceeded by production of 3,036 Mbbl primarily occurring in the West Coast region (3,005 Mbbl), and downward revisions of previous estimates of 1,694 Mbbl. Downward revisions were primarily a result of removing 1,501 Mbbl of proved undeveloped reserves at the Midway Sunset field in the Tulare reservoir as the Company has no near term plans to develop these reserves as it is employing its capital elsewhere. On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 1,549 Bcfe at September 30, 2013 to 1,914 Bcfe at September 30, 2014. Total revisions of previous estimates was an increase of 35 Bcfe.

At September 30, 2015, the Company's Exploration and Production segment had delivery commitments of 2,134 Bcfe (mostly natural gas as commitments for crude oil, gasoline, butane and propane was insignificant). The Company expects to meet those commitments through proved reserves, including the future development of reserves that are currently classified as proved undeveloped reserves, the growth of proved gas reserves (which has averaged 30 percent over the past two years through the development of Seneca's large Appalachian acreage position) and (if necessary) from the purchase of natural gas and crude oil at index-related prices.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

Production

	For The Year Ended September 30		
	2015	2014	2013
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 2.48 (1)	$ 3.55 (1)	$ 3.49 (1)
Average Sales Price per Barrel of Oil	$ 57.44	$ 96.34	$ 96.48
Average Sales Price per Mcf of Gas (after hedging)	$ 3.35	$ 3.49	$ 4.00
Average Sales Price per Barrel of Oil (after hedging)	$ 57.44	$ 96.34	$ 96.48
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.81 (1)	$ 0.74 (1)	$ 0.67 (1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	374 (1)	382 (1)	276 (1)
West Coast Region			
Average Sales Price per Mcf of Gas	$ 4.11	$ 6.75	$ 6.61
Average Sales Price per Barrel of Oil	$ 51.37	$ 98.25	$ 103.14
Average Sales Price per Mcf of Gas (after hedging)	$ 4.52	$ 6.65	$ 7.12
Average Sales Price per Barrel of Oil (after hedging)	$ 70.49	$ 95.54	$ 98.23
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 2.69	$ 2.96	$ 2.61
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	58	58	55
Total Company			
Average Sales Price per Mcf of Gas	$ 2.51	$ 3.62	$ 3.58
Average Sales Price per Barrel of Oil	$ 51.43	$ 98.23	$ 103.07
Average Sales Price per Mcf of Gas (after hedging)	$ 3.38	$ 3.56	$ 4.10
Average Sales Price per Barrel of Oil (after hedging)	$ 70.36	$ 95.55	$ 98.21
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.06	$ 1.03	$ 0.99
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	432	440	331

(1) The Marcellus Shale fields (which exceed 15% of total reserves at September 30, 2015, 2014 and 2013) contributed 357 MMcfe, 361 MMcfe and 258 MMcfe of daily production in 2015, 2014 and 2013, respectively. The average sales price (per Mcfe) was $2.48 ($3.35 after hedging) in 2015, $3.53 ($3.47 after hedging) in 2014 and $3.49 ($4.04 after hedging) in 2013. The average lifting costs (per Mcfe) were $0.79 in 2015, $0.72 in 2014 and $0.64 in 2013.

Productive Wells

	Appalachian Region		West Coast Region		Total Company	
At September 30, 2015	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	2,871	1	—	2,093	2,871	2,094
Productive Wells — Net	2,802	1	—	2,046	2,802	2,047

Developed and Undeveloped Acreage

At September 30, 2015	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	554,352	24,130	578,482
— Net	544,780	20,604	565,384
Undeveloped Acreage			
— Gross	370,812	14,127	384,939
— Net	353,713	7,263	360,976
Total Developed and Undeveloped Acreage			
— Gross	925,164	38,257	963,421
— Net	898,493	27,867	926,360

As of September 30, 2015, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 10,684 acres in 2016 (8,083 net acres), 12,441 acres in 2017 (8,723 net acres), 2,154 acres in 2018 (1,621 net acres) and 50,989 acres thereafter (46,845 net acres). The remaining 308,671 gross acres (295,704 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2016, 2017 and 2018, Seneca has 88 Bcfe of proved undeveloped gas reserves, with 54 Bcfe subject to lease expirations in 2016 and 34 Bcfe subject to lease expirations in 2017. This total represents approximately 11% of Seneca's proved undeveloped reserves in the Marcellus Shale. Seneca intends to develop these reserves prior to the expiration of the leases and/or extend/renew as part of its management approved development plan.

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	2015	2014	2013	2015	2014	2013
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	3.000	4.832	—	—	—	1.000
— Development	49.000	53.000	39.500	2.000	2.000	2.500
West Coast Region						
Net Wells Completed						
— Exploratory	—	1.533	0.625	—	—	—
— Development	45.000	84.720	74.996	1.000	1.000	—
Total Company						
Net Wells Completed						
— Exploratory	3.000	6.365	0.625	—	—	1.000
— Development	94.000	137.720	114.496	3.000	3.000	2.500

Present Activities

At September 30, 2015	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	100.000	—	100.000
— Net	85.500	—	85.500

(1) Includes wells awaiting completion.

Item 3 ***Legal Proceedings***

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note I — Commitments and Contingencies.

Item 4 ***Mine Safety Disclosures***

Not Applicable.

PART II

Item 5 ***Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 8 at Note E — Capitalization and Short-Term Borrowings, and at Note L — Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2015, the Company issued a total of 4,200 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company, 600 shares to each such director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended September 30, 2015. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

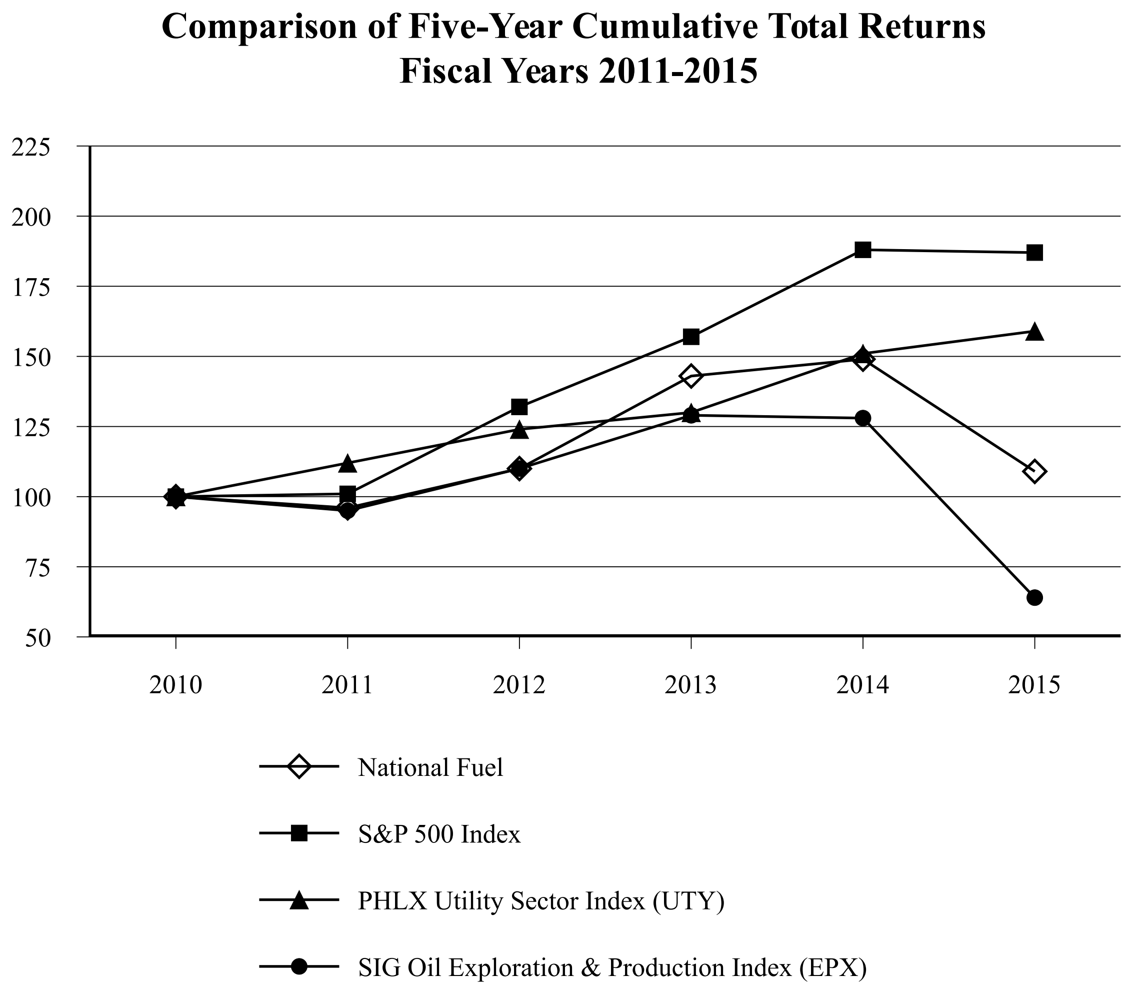
Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)
July 1-31, 2015	—	N/A	—	6,971,019
Aug. 1-31, 2015	267	$ 51.97	—	6,971,019
Sept. 1-30, 2015	—	N/A	—	6,971,019
Total	267	$ 51.97	—	6,971,019

(a) Represents shares of common stock of the Company tendered to the Company by holders of stock options, SARs, restricted stock units or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended September 30, 2015, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

(b) In September 2008, the Company's Board of Directors authorized the repurchase of eight million shares of the Company's common stock. The repurchase program has no expiration date. The Company, however, stopped repurchasing shares after September 17, 2008. Since that time, the Company has increased its emphasis on Marcellus Shale development and pipeline expansion. As such, the Company does not anticipate repurchasing any shares in the near future.

Performance Graph

The following graph compares the Company's common stock performance with the performance of the S&P 500 Index, the PHLX Utility Sector Index and the SIG Oil Exploration & Production Index for the period September 30, 2010 through September 30, 2015. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2010 and that all dividends were reinvested.



	2010	2011	2012	2013	2014	2015
National Fuel	$100	$96	$110	$143	$149	$109
S&P 500 Index	$100	$101	$132	$157	$188	$187
PHLX Utility Sector Index (UTY)	$100	$112	$124	$130	$151	$159
SIG Oil Exploration & Production Index (EPX)	$100	$95	$110	$129	$128	$64

Source: Bloomberg

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

Item 6 ***Selected Financial Data***

	Year Ended September 30				
	2015	2014	2013	2012	2011
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues	$1,760,913	$2,113,081	$1,829,551	$1,626,853	$1,778,842
Operating Expenses:					
Purchased Gas	349,984	605,838	460,432	415,589	628,732
Operation and Maintenance	470,003	463,078	442,090	401,397	400,519
Property, Franchise and Other Taxes	89,564	90,711	82,431	90,288	81,902
Depreciation, Depletion and Amortization	336,158	383,781	326,760	271,530	226,527
Impairment of Oil and Gas Producing Properties	1,126,257	—	—	—	—
	2,371,966	1,543,408	1,311,713	1,178,804	1,337,680
Operating Income (Loss)	(611,053)	569,673	517,838	448,049	441,162
Other Income (Expense):					
Gain on Sale of Unconsolidated Subsidiaries	—	—	—	—	50,879
Other Income	8,039	9,461	4,697	5,133	5,947
Interest Income	3,922	4,170	4,335	3,689	2,916
Interest Expense on Long-Term Debt	(95,916)	(90,194)	(90,273)	(82,002)	(73,567)
Other Interest Expense	(3,555)	(4,083)	(3,838)	(4,238)	(4,554)
Income (Loss) Before Income Taxes	(698,563)	489,027	432,759	370,631	422,783
Income Tax Expense (Benefit)	(319,136)	189,614	172,758	150,554	164,381
Net Income (Loss) Available for Common Stock	$ (379,427)	$ 299,413	$ 260,001	$ 220,077	$ 258,402
Per Common Share Data					
Basic Earnings (Loss) per Common Share	$ (4.50)	$ 3.57	$ 3.11	$ 2.65	$ 3.13
Diluted Earnings (Loss) per Common Share	$ (4.50)	$ 3.52	$ 3.08	$ 2.63	$ 3.09
Dividends Declared	$ 1.56	$ 1.52	$ 1.48	$ 1.44	$ 1.40
Dividends Paid	$ 1.55	$ 1.51	$ 1.47	$ 1.43	$ 1.39
Dividend Rate at Year-End	$ 1.58	$ 1.54	$ 1.50	$ 1.46	$ 1.42
At September 30:					
Number of Registered Shareholders	12,147	12,654	13,215	13,800	14,355

	Year Ended September 30				
	2015	2014	2013	2012	2011
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Exploration and Production	$2,126,265	$2,897,744	$2,600,448	$2,273,030	$1,753,194
Pipeline and Storage	1,387,516	1,187,924	1,074,079	1,069,070	954,554
Gathering	400,409	292,793	161,111	110,269	31,962
Utility	1,351,504	1,297,179	1,246,943	1,217,431	1,189,030
Energy Marketing	1,989	2,070	2,002	1,530	850
All Other	60,404	61,236	62,554	63,245	65,266
Corporate	3,808	4,145	4,589	5,228	5,668
Total Net Plant	$5,331,895	$5,743,091	$5,151,726	$4,739,803	$4,000,524
Total Assets	$6,702,139	$6,728,040	$6,204,977	$5,925,694	$5,215,358
Capitalization					
Comprehensive Shareholders' Equity	$2,025,440	$2,410,683	$2,194,729	$1,960,095	$1,891,885
Long-Term Debt, Net of Unamortized Discount and Debt Issuance Costs	2,084,009	1,637,443	1,635,630	1,139,552	893,274
Total Capitalization	$4,109,449	$4,048,126	$3,830,359	$3,099,647	$2,785,159

Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

OVERVIEW

The Company is a diversified energy company engaged principally in the production, gathering, transportation, distribution and marketing of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Marcellus Shale basin. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Marcellus Shale to markets in Canada and the eastern United States. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments. Refer to Item 1, Business, for a more detailed description of each of the segments. This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;

2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"

3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity;"

4. Off-Balance Sheet Arrangements;

5. Contractual Obligations; and

6. Other Matters, including: (a) 2015 and projected 2016 funding for the Company's pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate and regulatory matters in the Company's New York, Pennsylvania and FERC-regulated jurisdictions; (d) environmental matters; and (e) new authoritative accounting and financial reporting guidance.

The information in MD&A should be read in conjunction with the Company's financial statements in Item 8 of this report.

For the year ended September 30, 2015 compared to the year ended September 30, 2014, the Company experienced a loss of $379.4 million. The loss is driven largely by impairment charges of $1.1 billion ($650.2 million after-tax) recorded in the Exploration and Production segment during the year ended September 30, 2015. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. Due to significant declines in crude oil and natural gas commodity prices, the book value of the Company's oil and gas properties exceeded the ceiling at March 31, 2015, June 30, 2015 and September 30, 2015, resulting in the impairment charges mentioned above. The Company expects that the book value of its oil and gas properties will also exceed the ceiling at December 31, 2015, resulting in an additional impairment charge. For further discussion of the ceiling test and a sensitivity analysis concerning changes in crude oil and natural gas commodity prices and their impact on the ceiling test, refer to the Critical Accounting Estimates section below. For further discussion of the Company's earnings, refer to the Results of Operations section below.

The Company continues to develop its natural gas reserves in the Marcellus Shale, a Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York. The Company controls the natural gas interests associated with approximately 790,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 1,624 Bcf at September 30, 2014 to 2,093 Bcf at September 30, 2015. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the year ended September 30, 2015, the Company's Exploration and Production segment had capital expenditures of $500.2 million in the Appalachian region, of which $458.6 million was spent towards the development of the Marcellus Shale. The amount spent towards the development of the Marcellus Shale represented approximately 46% of the Company's capital expenditures for the year ended September 30, 2015. The Company's fiscal 2016 estimated capital expenditures in the Exploration and Production segment's Appalachian region are expected to be approximately $380 million. Forecasted production in the Exploration and Production segment's Appalachian region for fiscal 2016 is expected to be in the range of 141 to 211 Bcfe, up from actual Appalachia production of 137 Bcfe in fiscal 2015.

To facilitate the flow of natural gas from the Marcellus Shale, the Company continues to expand its gathering and pipeline infrastructure in the Gathering segment and the Pipeline and Storage segment. For the year ended September 30, 2015, the Gathering segment had capital expenditures of $118.2 million and its estimated capital expenditures in fiscal 2016 are expected to be approximately $140 million. The Pipeline and Storage segment's capital expenditures for the year ended September 30, 2015 were $230.2 million and its estimated capital expenditures in fiscal 2016 are expected to be approximately $525 million. The amount spent towards the development of gathering and pipeline infrastructure in fiscal 2015 represented approximately 35% of the Company's capital expenditures.

The well stimulation technology referred to as hydraulic fracturing used in conjunction with horizontal drilling continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. The potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. Please refer to the Risk Factors section above for further discussion.

From a capital resources perspective, in June 2015, the Company issued $450.0 million of 5.20% notes due in July 2025. The notes were issued to enhance the Company's liquidity position and reduce short-term debt. Under the Company's existing indenture covenants, given the significant impairments recorded during the year ended September 30, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness during fiscal 2016. If the Company experiences additional significant impairments of its oil and gas properties in the first or subsequent quarters of fiscal 2016, the Company expects to continue to be precluded from issuing incremental long-term debt into the first or subsequent quarters of fiscal 2017. However, the Company expects that it could borrow under its credit facilities. In addition, the 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt. On September 30, 2015, the Company entered into a Second Amended and Restated Credit Agreement (the "Credit Agreement") that amends and restates a five-year, $750 million unsecured committed revolving credit facility obtained by the Company in December 2014. The Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019, plus a $500.0 million 364-day unsecured committed revolving credit facility through September 29, 2016. With respect to borrowings under the multi-year facility, the Company is permitted (but not required) to elect a maturity date that is 364 days after the date of borrowing. The Credit Agreement includes an option for the Company to request increases in the aggregate multi-year commitments to an amount not to exceed $850.0 million, subject to certain terms and conditions.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this accounting methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full cost method of accounting (on a units-of-production basis). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. The book value of the Company's oil and gas properties exceeded the ceiling at September 30, 2015 as well as June 30, 2015 and March 31, 2015, resulting in cumulative impairment charges of $1.1 billion ($650.2 million after-tax) for 2015. The 12-month average of the first day of the month price for crude oil for each month during 2015, based on posted Midway Sunset prices, was $54.54 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2015, based on the quoted Henry Hub spot price for natural gas, was $3.06 per MMBtu. (Note — Because actual pricing of the Company's various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for 2015.) If natural gas average prices used in the ceiling test calculation at September 30, 2015 had been $0.25 per MMBtu lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $378.1 million (after-tax), which would have resulted in an additional impairment charge of $137.3 million (after-tax) at September 30, 2015. If crude oil average prices used in the ceiling test calculation at September 30, 2015 had been $5 per Bbl lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $281.6 million (after-tax), which would have resulted in an additional impairment charge of $40.8 million (after-tax) at September 30, 2015. If both natural gas and crude oil average prices used in the ceiling test calculation at September 30, 2015 were lower by $0.25 per MMBtu and $5 per Bbl, respectively, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $418.9 million (after-tax), which would have resulted in an additional impairment charge of $178.1 million (after-tax) at September 30, 2015. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation including, among others, changes in reserve quantities and future cost estimates. Looking ahead, the first day of the month Midway Sunset price for crude oil in October 2015 was $39.67 per Bbl. The first day of the month Henry Hub spot price for natural gas in October 2015 was $2.48 per MMBtu. Given these October prices, the potential that prices could stay at this level in future months, and the expected loss of significantly higher oil and gas prices from the 12-month average that will be used in the ceiling test at December 31, 2015, the Company expects to experience an additional significant ceiling test impairment in that quarter (the first quarter of fiscal 2016). Depending upon the movement of oil and natural gas prices, it is possible that the Company may experience additional impairment charges in the second or subsequent quarters of fiscal 2016 as well.

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. As discussed above, fluctuations in or subtractions from proved reserves and significant fluctuations in oil and gas prices have an impact on the amount of the ceiling at any point in time.

In accordance with the current authoritative guidance for asset retirement obligations, the Company records an asset retirement obligation for plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and capitalizes such costs in property, plant and equipment (i.e. the full cost pool). Under the current authoritative guidance for asset retirement obligations, since plugging and abandonment costs are already included in the full cost pool, the units-of-production depletion calculation excludes from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, the future cash outflows associated with plugging and abandoning wells are excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to the FASB authoritative guidance regarding accounting for certain types of regulations, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting principles for certain types of rate-regulated activities provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note C — Regulatory Matters.

Accounting for Derivative Financial Instruments. The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil in its Exploration and Production and Energy Marketing segments. These instruments are categorized as price swap agreements and futures contracts. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company primarily accounts for these instruments as effective cash flow hedges or fair value hedges. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. These instruments are accounted for as cash flow hedges. Gains or losses associated with the derivative financial instruments that are accounted for as cash flow or fair value hedges are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that such derivative financial instruments would ever be deemed to be ineffective based on effectiveness testing, mark-to-market gains or losses from such derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction. Refer to the "Market Risk Sensitive Instruments" section below for further discussion of the Company's derivative financial instruments and refer to Item 8 at Note F— Fair Value Measurements for discussion of the determination of fair value for derivative financial instruments.

Pension and Other Post-Retirement Benefits. The amounts reported in the Company's financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. The Company utilizes the Mercer Yield Curve Above Mean Model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. In determining the spot rates, the model will exclude coupon interest rates that are in the lower 50th percentile based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience, including deviations between actual versus expected return on plan assets, could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company. However, the Company expects to recover a substantial portion of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization, subject to applicable accounting requirements for rate-regulated activities, as discussed above under "Regulation."

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company's pension and other post-retirement benefits and could impact the Company's equity. For example, the discount rate used to determine benefit obligations of the Company's other post-retirement benefits changed from 4.25% in 2014 to 4.50% in 2015. The change in the discount rate from 2014 to 2015 reduced the accumulated post-retirement benefit obligation by $14.3 million. While the discount rate used to determine benefit obligations of the Retirement Plan did not change from 2014 to 2015, the discount rate was changed from 4.75% in 2013 to 4.25% in 2014. The change in the discount rate from 2013 to 2014 increased the Retirement Plan projected benefit obligation by $53.7 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. For 2015, the actual return on plan assets was lower than the expected return, which resulted in a decrease to the funded status of the Retirement Plan ($73.0 million) as well as a decrease to the funded status of the VEBA trusts and 401(h) accounts ($33.6 million). The actual versus expected benefit payments for 2015 caused a decrease of $2.6 million to the accumulated post-retirement benefit obligation. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 7 years for the Retirement Plan and 6 years for those eligible for other post-retirement benefits. For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year, and to Item 8 at Note H — Retirement Plan and Other Post Retirement Benefits.

RESULTS OF OPERATIONS

EARNINGS

2015 Compared with 2014

The Company experienced a loss of $379.4 million in 2015 compared with earnings of $299.4 million in 2014. The decrease in earnings is primarily the result of a loss recognized in the Exploration and Production segment. Lower earnings in the Gathering segment and Utility segment, as well as losses in the Corporate category and All Other category, also contributed to the decrease. Higher earnings in the Pipeline and Storage segment and the Energy Marketing segment partially offset these decreases. In the discussion that follows, all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings were impacted by the following events in 2015 and 2014:

2015 Events

- Non-cash impairment charges of $1.1 billion ($650.2 million after tax) recorded during 2015 for the Exploration and Production segment's oil and gas producing properties.

- A $5.2 million reversal of stock-based compensation expense related to performance based restricted stock units since performance conditions, which do not include any market conditions, are not expected to be met. The $5.2 million was allocated across each of the segments as well as the All Other and Corporate category.

2014 Event

- A $3.6 million death benefit gain on life insurance proceeds recorded in the Corporate category.

2014 Compared with 2013

The Company's earnings were $299.4 million in 2014 compared with earnings of $260.0 million in 2013. The increase in earnings of $39.4 million is primarily a result of higher earnings in the Exploration and Production segment, Pipeline and Storage segment, Gathering segment and Energy Marketing segment. Lower earnings in the Utility segment and a higher loss in the Corporate category slightly offset these increases. Earnings were impacted by the 2014 event discussed above and the following event in 2013:

2013 Event

- A $4.9 million refund provision recorded in the Utility segment related to various issues raised in Distribution Corporation's rate proceeding in New York.

Earnings (Loss) by Segment

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Exploration and Production	$ (556,974)	$ 121,569	$ 115,391
Pipeline and Storage	80,354	77,559	63,245
Gathering	31,849	32,709	13,321
Utility	63,271	64,059	65,686
Energy Marketing	7,766	6,631	4,589
Total Reported Segments	(373,734)	302,527	262,232
All Other	(2)	1,160	894
Corporate	(5,691)	(4,274)	(3,125)
Total Consolidated	$ (379,427)	$ 299,413	$ 260,001

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Gas (after Hedging)	$ 471,657	$ 506,491	$ 424,735
Oil (after Hedging)	213,488	290,030	278,005
Gas Processing Plant	2,891	4,831	4,502
Other	5,405	2,744	(4,305)
Operating Revenues	$ 693,441	$ 804,096	$ 702,937

Production

	Year Ended September 30		
	2015	2014	2013
Gas Production *(MMcf)*			
Appalachia	136,404	139,097	100,633
West Coast	3,159	3,210	3,060
Total Production	139,563	142,307	103,693
Oil Production *(Mbbl)*			
Appalachia	30	31	28
West Coast	3,004	3,005	2,803
Total Production	3,034	3,036	2,831

Average Prices

	Year Ended September 30		
	2015	2014	2013
Average Gas Price/Mcf			
Appalachia	$ 2.48	$ 3.55	$ 3.49
West Coast	$ 4.11	$ 6.75	$ 6.61
Weighted Average	$ 2.51	$ 3.62	$ 3.58
Weighted Average After Hedging(1)	$ 3.38	$ 3.56	$ 4.10
Average Oil Price/Barrel (Bbl)			
Appalachia	$ 57.44	$ 96.34	$ 96.48
West Coast	$ 51.37	$ 98.25	$ 103.14
Weighted Average	$ 51.43	$ 98.23	$ 103.07
Weighted Average After Hedging(1)	$ 70.36	$ 95.55	$ 98.21

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note G — Financial Instruments in Item 8 of this report.

2015 Compared with 2014

Operating revenues for the Exploration and Production segment decreased $110.7 million in 2015 as compared with 2014. Gas production revenue after hedging decreased $34.8 million primarily due to a $0.18 per Mcf decrease in the weighted average price of gas after hedging and a decrease in production due to temporary pricing-related curtailments. Oil production revenue after hedging decreased $76.5 million due to a $25.19 per Bbl decrease in the weighted average price of oil after hedging as production was largely flat. In addition, processing plant revenue decreased $1.9 million, largely due to a decrease in the price of natural gas liquids and other price and volume fluctuations. Partially offsetting these decreases was a $2.7 million increase in other revenue. This was largely due to a $3.7 million positive variance in mark-to-market adjustments related to hedging ineffectiveness and the reversal of a gas imbalance liability ($0.6 million) related to offshore properties no longer owned by the Exploration and Production segment, partially offset by the impact from the receipt of settlement proceeds in fiscal 2014 related to former insurance policies ($1.9 million) that did not recur in the current year.

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows. Refer to the tables above for production and price information.

2014 Compared with 2013

Operating revenues for the Exploration and Production segment increased $101.2 million in 2014 as compared with 2013. Gas production revenue after hedging increased $81.8 million primarily due to production increases in the Appalachian division. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, primarily in Lycoming County, Pennsylvania. This was partially offset by a $0.54 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging increased $12.0 million due to an increase in production, which was partially offset by a $2.66 per Bbl decrease in the weighted average price of oil after hedging. The increase in crude oil production was largely due to increased development in the East Coalinga, Sespe and South Midway Sunset fields in California. The increase in other revenue ($7.0 million) was largely due to a $3.6 million positive variance in mark-to-market charges related to hedging ineffectiveness, settlement proceeds received in 2014 related to former insurance policies ($1.9 million) and the non-recurrence of a royalty adjustment (including interest) recorded in 2013 ($1.8 million).

Earnings

2015 Compared with 2014

The Exploration and Production segment’s loss for 2015 was $557.0 million, compared with earnings of $121.6 million for 2014, a decrease of $678.6 million. The main drivers of the decrease were the aforementioned impairment charge ($650.2 million), lower crude oil prices after hedging ($49.7 million), lower natural gas prices after hedging ($16.3 million), lower natural gas production ($6.3 million), the impact of the non-recurrence of settlement proceeds on former insurance policies recorded in the prior year ($1.3 million), higher interest expense ($2.9 million), higher production costs ($1.5 million) and higher operating expenses ($1.4 million). The increase in production costs was largely attributable to higher transportation costs associated with production volumes transported by Midstream Corporation. The increase in interest expense was largely due to the Exploration and Production segment's share of the Company's $450 million long-term debt issuance in June 2015. The increase in operating expenses was largely due to an increase in professional services and personnel costs, partially offset by a reversal of stock-based compensation expense for certain performance based restricted stock unit awards since performance conditions are not expected to be met. These decreases in earnings were partially offset by the impact of lower depletion expense ($36.7 million), lower income tax expense ($11.8 million) and the impact of mark-to-market adjustments ($2.4 million). The decrease in depletion expense is due to the impact of impairment charges recognized in the second and third quarters of 2015, a decrease in production due to pricing-related curtailments discussed above, and an increase in reserves achieved with lower finding and development costs per Mcfe (due to increased operating efficiencies). The decrease in income tax expense was largely due to an increase in firm transportation of natural gas to Canadian delivery points, which decreased the effective tax rate used in the calculation of deferred tax expense ($3.0 million) combined with other deferred tax adjustments that reduced Seneca's deferred income tax liability by $6.2 million. The decrease in income taxes was partially offset by the non-recurrence of a favorable settlement with a taxing authority that occurred in fiscal 2014.

2014 Compared with 2013

The Exploration and Production segment’s earnings for 2014 were $121.6 million, compared with earnings of $115.4 million for 2013, an increase of $6.2 million. The main drivers of the increase were higher natural gas production ($102.8 million), higher crude oil production ($13.1 million) and lower income taxes ($11.2 million). In addition, the earnings impact of the increase in other revenues ($4.6 million) also contributed to the increase in earnings, as discussed above. The decrease in income taxes was largely due to an increase in firm transportation of natural gas to Canadian delivery points, which decreased the effective tax rate used in the calculation of deferred tax expense. These earnings increases were partially offset by the earnings impact of higher depletion expense ($34.3 million), lower natural gas prices after hedging ($49.7 million), higher production costs ($30.1 million), higher general, administrative and other expense ($2.7 million), higher interest expense ($1.6 million), higher property and other taxes ($2.3 million) and lower crude oil prices after hedging ($5.3 million). The increase in depletion expense is primarily due to increased Appalachian natural gas production (primarily in the Marcellus Shale formation). The increase in production costs was largely attributable to higher transportation costs. The increase in general, administrative and other expense was largely due to an increase in personnel costs and the accrual of plugging and abandonment costs associated with offshore properties no longer owned by the Exploration and Production segment. The increase in interest expense was attributable to an increase in the weighted average amount of debt due to the Exploration and Production segment's share of the Company's $500 million long-term debt issuance in February 2013.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Firm Transportation	$ 214,611	$ 207,892	$ 190,470
Interruptible Transportation	2,971	2,666	2,152
	217,582	210,558	192,622
Firm Storage Service	70,732	69,878	70,555
Interruptible Storage Service	3	13	5
	70,735	69,891	70,560
Other	3,023	3,959	4,426
	$ 291,340	$ 284,408	$ 267,608

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2015	2014	2013
Firm Transportation	737,206	731,271	575,805
Interruptible Transportation	12,874	4,724	3,997
	750,080	735,995	579,802

2015 Compared with 2014

Operating revenues for the Pipeline and Storage segment increased $6.9 million in 2015 as compared with 2014. The increase was primarily due to an increase in transportation revenues of $7.0 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation's Mercer Expansion Project, which was placed in service in November 2014. The addition of new firm contracts for transportation service on Supply Corporation's system also contributed to the increase in transportation revenues.

Transportation volume increased by 14.1 Bcf in 2015 as compared with 2014. The increase in transportation volume primarily reflects the results of the ongoing pricing basis differentials in the Appalachian region in which customers are flowing more natural gas to higher priced markets. The addition of a new contract for interruptible transportation also contributed to the increase in transportation volume. Volume fluctuations, other than those caused by the addition or deletion of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

2014 Compared with 2013

Operating revenues for the Pipeline and Storage segment increased $16.8 million in 2014 as compared with 2013. The increase was primarily due to an increase in transportation revenues of $17.9 million slightly offset by a decrease in storage revenues of $0.7 million. The increase in transportation revenues was largely due to demand and commodity charges on new contracts for transportation service on Supply Corporation's Northern Access expansion project, which was placed fully in service in January 2013, Supply Corporation's Line N 2012 Expansion Project, which was placed fully in service in November 2012 and Supply Corporation's Line N 2013 Project, which was placed in service in November 2013. In addition, the increase in transportation revenues was due to additional demand charges associated with the full-ramp up of a transportation contract for an anchor shipper on Empire's Tioga County Extension Project as well as additional commodity charges associated with that contract due to higher throughput flowing through a secondary receipt point. These projects provide pipeline capacity for Marcellus Shale production. Also contributing to the increase in transportation revenues was additional non-expansion revenue as a result of new short-term contracts for both Empire and Supply Corporation and new contracts for transportation service from an Open Season Supply Corporation held near the end of fiscal 2013. Partially offsetting these increases was a decrease in storage revenues due to a decline in demand charges as a result of contract restructuring.

Transportation volume increased by 156.2 Bcf in 2014 as compared with 2013. The large increase in transportation volume primarily reflects the impact of the above mentioned expansion projects being placed in service and new contracts for transportation service. The increase was enhanced by weather that was significantly colder than the prior year and colder than normal.

Earnings

2015 Compared with 2014

The Pipeline and Storage segment’s earnings in 2015 were $80.4 million, an increase of $2.8 million when compared with earnings of $77.6 million in 2014. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $4.6 million, as discussed above, combined with an increase in the allowance for funds used during construction (equity component) of $2.5 million. The increase in the allowance for funds used during construction is mainly due to capital costs incurred during the year ended September 30, 2015 related to various expansion projects currently under construction. These earnings increases were partially offset by higher operating expenses ($2.0 million), an increase in depreciation expense ($1.0 million), an increase in property taxes ($0.9 million) and higher interest expense ($0.8 million). The increase in operating expenses primarily reflects an increase in compressor maintenance costs, an increase in expense related to the reserve for preliminary project costs, an increase in regulatory commission expense and increased personnel costs offset partially by the reversal of stock-based compensation expense for certain performance based restricted stock unit awards since performance conditions are not expected to be met. The increase in depreciation expense was attributable to incremental depreciation expense related to projects that were placed in service within the last year. The increase in property taxes was attributable to various expansion projects constructed over the last few years. The increase in interest expense was largely due to Supply Corporation's share of the Company's $450 million long-term debt issuance in June 2015.

2014 Compared with 2013

The Pipeline and Storage segment’s earnings in 2014 were $77.6 million, an increase of $14.4 million when compared with earnings of $63.2 million in 2013. The increase in earnings was primarily due to the earnings impact of higher transportation revenues of $11.7 million, as discussed above, combined with lower operating expenses ($6.3 million). The decrease in operating expenses primarily reflected lower pension and other post-retirement benefit costs and a decrease in the reserve for preliminary project costs offset partially by higher pipeline integrity program expenses. These earnings increases were partially offset by an increase in depreciation expense ($1.0 million), higher property taxes ($0.9 million), a decrease in the allowance for funds used during construction (equity component) of $0.4 million, higher income taxes ($0.5 million) and the earnings impact of lower storage revenue ($0.4 million), as discussed above. The increase in depreciation expense was attributable to incremental depreciation expense related to the projects that were placed in service during fiscal 2014. The increase in property taxes was primarily due to the addition of new plant. The decrease in the allowance for funds used during construction was mainly due to Supply Corporation’s Line N 2012 Expansion Project and Supply Corporation’s Northern Access expansion project, which were under construction in the first quarter of fiscal 2013 and were placed in service during fiscal 2013. The increase in income taxes was a result of higher state taxes combined with a reduction in benefits associated with the tax sharing agreement with affiliated companies.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Gathering	$ 76,709	$ 69,937	$ 33,815
Processing and Other Revenues	497	673	966
	$ 77,206	$ 70,610	$ 34,781

Gathering Volume — (MMcf)

	Year Ended September 30		
	2015	2014	2013
Gathered Volume	139,629	138,726	93,449

2015 Compared with 2014

Operating revenues for the Gathering segment increased $6.6 million in 2015 as compared with 2014. This increase was due to an increase in gathering revenues driven by higher gathering rates coupled with a 0.9 Bcf increase in gathered volume. The overall increase in gathered volume was largely due to a 15.4 Bcf increase in gathered volume on Midstream Corporation's Clermont Gathering System (Clermont), which was placed in service in July 2014, and a 1.6 Bcf increase in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run) where the increase in production during the first two quarters of the fiscal year more than offset the impact of low natural gas price related production curtailments experienced in the last two quarters of the fiscal year. The increases in gathered volume were largely offset by a 14.8 Bcf decrease in gathered volume on Midstream Corporation's Covington Gathering System (Covington), a 1.0 Bcf decrease in gathered volume on Midstream Corporation's Mt. Jewett Gathering System (Mt. Jewett) and a 0.3 Bcf decrease in gathered volume on Midstream Corporation's Tionesta Gathering System (Tionesta). Most of these decreases in gathered volume are attributable to a decrease in Seneca's Marcellus Shale production largely due to the impact of low natural gas prices, which caused Seneca to curtail production.

2014 Compared with 2013

Operating revenues for the Gathering segment increased $35.8 million in 2014 as compared with 2013. This increase was largely due to an increase in gathering revenues driven by a 45.3 Bcf increase in gathered volume combined with higher gathering rates. The overall increase in gathered volume was largely due to a 40.7 Bcf increase in gathered volume on Trout Run and a 4.5 Bcf increase in gathered volume on Clermont. Most of the increase in gathered volume was attributable to an increase in Seneca's Marcellus Shale production, primarily in Lycoming County, Pennsylvania.

Earnings

2015 Compared with 2014

The Gathering segment's earnings in 2015 were $31.8 million, a decrease of $0.9 million when compared with earnings of $32.7 million in 2014. The decrease in earnings is mainly due to the earnings impact of higher depreciation expense ($3.1 million), higher operating expenses ($1.1 million) and higher income tax expense ($1.0 million). These earnings increases were partially offset by higher gathering revenues ($4.4 million). The growth of Trout Run and Clermont is primarily responsible for the revenue and operating expense variations. During the quarter ended March 31, 2015, the Company recorded long-lived asset impairment charges ($1.0 million) related to its gathering facilities at Tionesta. This impairment, combined with greater plant balances, led to an increase in depreciation expense. The increase in income tax expense is due to higher state income taxes and the impact of the provision-to-return adjustments.

2014 Compared with 2013

The Gathering segment's earnings in 2014 were $32.7 million, an increase of $19.4 million when compared with earnings of $13.3 million in 2013. The increase in earnings was mainly due to the earnings impact of higher gathering revenues ($23.5 million) and lower interest expense ($0.4 million). These earnings increases were partially offset by higher income tax expense ($1.9 million), higher depreciation expense ($1.4 million) and higher operating expenses ($1.0 million). The significant growth of Trout Run was primarily responsible for the revenue, depreciation expense and operating expense variations. The increase in income tax expense was largely due to higher state taxes. The decrease in interest expense was largely due to an increase in capitalized interest, which more than offset the impact of an increase in the weighted average amount of debt due to the Gathering segment's share of the $500 million long-term debt issuance in February 2013.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Retail Revenues:			
Residential	$ 480,163	$ 590,080	$ 513,654
Commercial	61,099	78,036	66,602
Industrial	2,655	3,692	6,096
	543,917	671,808	586,352
Off-System Sales	11,773	19,712	25,020
Transportation	142,289	150,158	135,273
Other	18,288	7,940	(306)
	$ 716,267	$ 849,618	$ 746,339

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2015	2014	2013
Retail Sales:			
Residential	59,600	60,101	52,753
Commercial	8,710	8,834	7,486
Industrial	337	393	947
	68,647	69,328	61,186
Off-System Sales	3,787	4,564	6,717
Transportation	78,749	80,949	69,149
	151,183	154,841	137,052

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Percent (Warmer) Colder Than Prior Year
2015(1)	Buffalo	6,617	6,968	5.3 %	(1.7)%
	Erie	6,147	6,586	7.1 %	(2.3)%
2014(2)	Buffalo	6,617	7,087	7.1 %	15.4 %
	Erie	6,147	6,742	9.7 %	14.5 %
2013(3)	Buffalo	6,617	6,139	(7.2)%	15.9 %
	Erie	6,147	5,888	(4.2)%	17.8 %

(1) Percents compare actual 2015 degree days to normal degree days and actual 2015 degree days to actual 2014 degree days.
(2) Percents compare actual 2014 degree days to normal degree days and actual 2014 degree days to actual 2013 degree days.
(3) Percents compare actual 2013 degree days to normal degree days and actual 2013 degree days to actual 2012 degree days.

2015 Compared with 2014

Operating revenues for the Utility segment decreased $133.4 million in 2015 compared with 2014. This decrease largely resulted from a $127.9 million decrease in retail gas sales revenues. In addition, there was a $7.9 million decrease in off-system sales and a $7.9 million decrease in transportation revenues. These were partially offset by a $10.3 million increase in other operating revenues. The increase in other operating revenues was largely due to a regulatory adjustment recorded during 2015 to recognize an under-collection from customers of a New York State regulatory assessment, a 2015 reversal of a portion of a 2014 accrual for an estimated sharing refund provision in New York, and an increase in capacity release revenues. As a result of a colder than normal calendar 2013/2014 winter season, the demand for pipeline capacity increased as pipeline capacity release contracts for Distribution Corporation's calendar 2014/2015 winter season were being executed. This increase in demand resulted in higher capacity release rates for Distribution Corporation in 2015 compared to 2014, thus resulting in higher capacity release revenues.

The $127.9 million decrease in retail gas sales revenues was largely a result of a decrease in the cost of gas sold (per Mcf) coupled with lower volumes due to slightly warmer weather than the prior year. The $7.9 million decrease in transportation revenues was primarily due to a 2.2 Bcf decrease in transportation throughput due to slightly warmer weather than the prior year. The $7.9 million decrease in off-system sales is due to lower volumes as market conditions reduced the opportunity for off-system gas sales.

2014 Compared with 2013

Operating revenues for the Utility segment increased $103.3 million in 2014 compared with 2013. This increase largely resulted from an $85.5 million increase in retail gas sales revenues and a $14.9 million increase in transportation revenue. In addition, there was an $8.2 million increase in other operating revenues. These were partially offset by a $5.3 million decrease in off-system sales (due to lower volume). The decrease in off-system sales volume was due to the Utility segment's greater utilization of pipeline capacity in order to reliably meet the increased demand for its retail gas brought on by colder weather experienced during the winter of fiscal 2014. Due to profit sharing with retail customers, the margins resulting from off-system sales were minimal.

The $85.5 million increase in retail gas sales revenues was largely a function of higher volume (8.1 Bcf) due to colder weather. The $14.9 million increase in transportation revenues was primarily due to an 11.8 Bcf increase in transportation throughput, largely the result of colder weather compared to the prior period and the migration of customers from retail sales to transportation services. The $8.2 million increase in other operating revenues was largely due to the non-recurrence of a $7.5 million refund provision recorded during fiscal 2013 related to various issues raised in a New York rate proceeding. During 2014, the Utility segment recorded an earnings share adjustment pursuant to the settlement resulting from that rate proceeding ($2.5 million reduction to revenues). However, this was largely offset by a 2014 true-up of regulatory asset balances associated with insurance proceeds on site remediation claims ($2.3 million).

Purchased Gas

The cost of purchased gas is the Company's single largest operating expense. Annual variations in purchased gas costs are attributed directly to changes in gas sales volume, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $307.7 million, $446.9 million and $362.3 million of Purchased Gas expense during 2015, 2014 and 2013, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation is not allowed to profit from fluctuations in gas costs. Purchased gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation's purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Distribution Corporation contracts for long-term firm transportation capacity with Supply Corporation, Empire and seven other upstream pipeline companies, and for storage service with Supply Corporation and two other upstream companies. Distribution Corporation utilizes long-term and spot gas supply contracts with various producers and marketers to satisfy purchase requirements. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2015 Compared with 2014

The Utility segment's earnings in 2015 were $63.3 million, a decrease of $0.8 million when compared with earnings of $64.1 million in 2014. The decrease in earnings is largely attributable to an increase in operating expenses ($5.8 million), an increase in depreciation expense ($1.3 million) and the impact of slightly warmer weather in fiscal 2015 compared to fiscal 2014 ($0.6 million). The increase in operating expenses is largely attributable to costs associated with the planned replacement of the Utility segment's legacy mainframe systems, partially offset by the reversal of stock-based compensation expense for certain performance based restricted stock unit awards since performance conditions are not expected to be met. The increase in depreciation expense is due to an increase in plant balances in fiscal 2015 compared to fiscal 2014. These earnings decreases were partially offset by a $6.2 million increase in regulatory adjustments (discussed above) and a $0.9 million increase in capacity release revenues (discussed above).

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For 2015, the WNC reduced earnings by approximately $2.5 million as the weather was colder than normal. In 2014, the WNC reduced earnings by approximately $3.0 million as the weather was colder than normal.

2014 Compared with 2013

The Utility segment's earnings in 2014 were $64.1 million, a decrease of $1.6 million when compared with earnings of $65.7 million in 2013. The decrease in earnings was largely attributable to an increase in operating expenses ($9.1 million), an increase in income tax expense ($2.4 million), the impact of an earnings sharing adjustment ($1.6 million) and an increase in property and other taxes ($0.8 million). The increase in operating expenses was largely attributable to increased costs associated with defined benefit and defined contribution retirement plans as a result of a recent settlement with the NYPSC and an increase in bad debt expense. The increase in income tax expense was largely due to higher state income taxes and the reversal of tax expense that occurred in 2013 (as a result of a favorable tax settlement), which did not recur in 2014. The increase in property and other taxes was largely due to increases in FICA, school, town and county taxes. These earnings decreases were partially offset by the impact of colder weather in Pennsylvania ($5.8 million), the positive earnings impact of the non-recurrence of the refund provision recorded in fiscal 2013 ($4.9 million), a true-up of regulatory asset balances associated with a NYPSC settlement concerning insurance proceeds on site remediation claims ($1.5 million) and the earnings impact of lower interest expense ($0.9 million). The decrease in interest expense was due to a decrease in the weighted average amount of debt outstanding due to the Utility segment's share of the Company's $250 million of notes that matured in March 2013.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Natural Gas (after Hedging)	$ 160,651	$ 273,099	$ 213,324
Other	55	53	50
	$ 160,706	$ 273,152	$ 213,374

Energy Marketing Volume

	Year Ended September 30		
	2015	2014	2013
Natural Gas — (MMcf)	46,752	52,694	46,875

2015 Compared with 2014

Operating revenues for the Energy Marketing segment decreased $112.4 million in 2015 as compared with 2014. The decrease is primarily due to a decline in gas sales revenue due to a lower average price of natural gas period over period and a decrease in volume sold to retail customers.

2014 Compared with 2013

Operating revenues for the Energy Marketing segment increased $59.8 million in 2014 as compared with 2013. The increase reflects an increase in gas sales revenue due to a higher average price of natural gas period over period and an increase in volume sold to retail customers as a result of colder weather. Effective with the first quarter of 2014, the Energy Marketing segment began recording unbilled revenue. Operating revenues for the year ended September 30, 2014 include an $8.5 million accrual for unbilled revenue while operating revenues for the year ended September 30, 2013 do not include such an accrual. The volume associated with unbilled revenue at September 30, 2014 was 2,122 MMcf.

Earnings

2015 Compared with 2014

The Energy Marketing segment's earnings in 2015 were $7.8 million, an increase of $1.2 million when compared with earnings of $6.6 million in 2014. This increase in earnings was largely attributable to higher margin of $1.4 million. The increase in margin largely reflects a reduction in pipeline capacity reservation charges due to the turn back of certain storage and transportation capacity, higher average margins per Mcf, and an increase in the benefit the Energy Marketing segment realized from its contracts for storage capacity. These increases were partially offset by slightly lower margin associated with unbilled revenue. The Energy Marketing segment began recording unbilled revenue and related gas costs during the quarter ended December 31, 2013. Prior to that quarter, Energy Marketing segment revenues and related purchased gas costs had been recorded when billed, resulting in a one-month lag. As a result of eliminating the one-month lag, revenues and related gas costs for the year ended September 30, 2014 reflected thirteen months of activity whereas the revenue and related gas costs for the year ended September 30, 2015 reflect twelve months of activity.

2014 Compared with 2013

The Energy Marketing segment's earnings in 2014 were $6.6 million, an increase of $2.0 million when compared with earnings of $4.6 million in 2013. This increase in earnings was largely attributable to higher margin of $2.2 million, which primarily reflects the positive impact on margin from the increase in volume sold to retail customers due to colder weather during 2014 combined with improved average margin per Mcf. These earnings increases were partially offset by a decline in the benefit the Energy Marketing segment realized from its contracts for storage capacity. To a lesser extent, margin was also positively impacted by the recording of unbilled revenues and related gas costs at September 30, 2014. The impact of this change for the year ended September 30, 2014 was to increase operating revenues and margin by $8.5 million and $0.6 million, respectively. Management has determined that the impact of not recording unbilled revenue and related gas costs was immaterial in all prior periods.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Seneca's Northeast Division and corporate operations. Seneca's Northeast Division markets timber from its New York and Pennsylvania land holdings.

Earnings

2015 Compared with 2014

All Other and Corporate operations recorded a loss of $5.7 million in 2015, which was $2.6 million higher than the loss of $3.1 million in 2014. The increase in loss is primarily due to the non-recurrence of a $3.6 million death benefit gain on life insurance proceeds recognized during the quarter ended March 31, 2014, which was recorded in Other Income. A $0.8 million decrease in margin from the sale of standing timber (including certain timber stumpage tracts by Seneca's land and timber division) decreased earnings further. These decreases were offset partially by lower income tax expense of $1.2 million (primarily due to consolidated tax sharing) and lower operating expenses of $1.1 million (largely due to the reversal of stock-based compensation expense for certain performance based restricted stock unit awards since performance conditions are not expected to be met).

2014 Compared with 2013

All Other and Corporate operations recorded a loss of $3.1 million in 2014, which was $0.9 million higher than the loss of $2.2 million in 2013. The increase in loss was primarily due to higher income tax expense of $4.7 million (primarily due to consolidated tax sharing and an adjustment for an intercompany deferred tax reallocation recorded in 2013 that did not recur in 2014) and higher property, franchise and other taxes of $0.7 million (largely due to a reduction in franchise taxes recorded in 2013 that did not recur in 2014). These increases were offset partially by a $3.6 million death benefit gain on life insurance policies that was recorded in 2014. In addition, earnings were increased by an increase in income from unconsolidated subsidiaries of $0.4 million.

INTEREST CHARGES

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Interest on long-term debt increased $5.7 million in 2015 as compared to 2014. This increase is due to additional long-term debt that was issued in fiscal 2015. The Company issued $450 million of 5.20% notes in June 2015. This was partially offset by the impact of an increase in capitalized interest (mostly in Midstream Corporation), which decreased interest expense for the year ended September 30, 2015 as compared to the year ended September 30, 2014.

Interest on long-term debt decreased $0.1 million in 2014 as compared to 2013. This decrease is due to an increase in capitalized interest (mostly in Midstream Corporation) for the year ended September 30, 2014 as compared to the year ended September 30, 2013. This was partially offset by the impact of a higher average amount of long-term debt outstanding (partially offset by a decrease in the weighted average interest on such debt). The Company issued $500 million of 3.75% notes in February 2013 and repaid $250 million of 5.25% notes that matured in March 2013.

CAPITAL RESOURCES AND LIQUIDITY

The primary sources and uses of cash during the last three years are summarized in the following condensed statement of cash flows:

	Year Ended September 30		
	2015	2014	2013
		(Millions)	
Provided by Operating Activities	$ 853.6	$ 909.4	$ 738.6
Capital Expenditures	(1,018.2)	(914.4)	(703.5)
Other Investing Activities	(6.6)	6.0	(2.5)
Reduction of Long-Term Debt	—	—	(250.0)
Change in Notes Payable to Banks and Commercial Paper	(85.6)	85.6	(171.0)
Net Proceeds from Issuance of Long-Term Debt	444.6	—	495.4
Net Proceeds from Issuance of Common Stock	10.5	7.5	5.4
Dividends Paid on Common Stock	(130.7)	(126.7)	(122.7)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	9.1	4.6	0.7
Net Increase (Decrease) in Cash and Temporary Cash Investments	$ 76.7	$ (28.0)	$ (9.6)

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes and stock-based compensation.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by the straight fixed-variable rate design used by Supply Corporation and Empire.

Cash provided by operating activities in the Exploration and Production segment may vary from year to year as a result of changes in the commodity prices of natural gas and crude oil as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $853.6 million in 2015, a decrease of $55.8 million compared with the $909.4 million provided by operating activities in 2014. The decrease in cash provided by operating activities reflects lower cash provided by operating activities in the Exploration and Production segment. The decrease is partially offset by the increase in cash provided by operating activities in the Utility segment, Pipeline and Storage segment and Gathering segment. The decrease in the Exploration and Production segment is primarily due to lower cash receipts from crude oil and natural gas production as a result of lower crude oil and natural gas prices. The increase in the Utility segment is primarily due to the timing of gas cost recovery and the timing of receivable collections. The increase in the Gathering segment is primarily a result of an increase in Seneca's Marcellus Shale production, which has resulted in higher gathering revenues at the Trout Run and Clermont gathering systems. Lastly, the increase in the Pipeline and Storage segment is due to higher cash receipts from transportation revenues as a result of expansion projects coming on-line.

Net cash provided by operating activities totaled $909.4 million in 2014, an increase of $170.8 million compared with the $738.6 million provided by operating activities in 2013. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Exploration and Production segment, Gathering segment and Corporate category. The increase in the Exploration and Production segment is primarily due to higher cash receipts from natural gas production in the Appalachian region, specifically development in the Marcellus Shale formation. The increase in the Gathering segment is due to an increase in gathering revenues from Midstream Corporation's Trout Run Gathering System and Midstream Corporation's Clermont Gathering System. Lastly, the increase in the Corporate category is primarily due to the receipt of life insurance proceeds.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets, including non-cash capital expenditures, totaled $1.0 billion, $969.9 million and $717.1 million in 2015, 2014 and 2013, respectively. The table below presents these expenditures:

	Year Ended September 30		
	2015	2014	2013
		(Millions)	
Exploration and Production:			
Capital Expenditures	$ 557.3 (1)	$ 602.7 (2)	$ 533.1 (3)
Pipeline and Storage:			
Capital Expenditures	230.2 (1)	139.8 (2)	56.1 (3)
Gathering:			
Capital Expenditures	118.2 (1)	137.8 (2)	54.8 (3)
Utility:			
Capital Expenditures	94.4 (1)	88.8 (2)	72.0 (3)
All Other and Corporate:			
Capital Expenditures	0.4	0.8	1.1
Total Expenditures	$1,000.5	$ 969.9	$ 717.1

(1) 2015 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $46.2 million, $33.9 million, $22.4 million and $16.5 million, respectively, of non-cash capital expenditures.

(2) 2014 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $80.1 million, $28.1 million, $20.1 million and $8.3 million, respectively, of non-cash capital expenditures.

(3) 2013 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $58.5 million, $5.6 million, $6.7 million and $10.3 million, respectively, of non-cash capital expenditures.

Exploration and Production

In 2015, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $500.2 million for the Appalachian region (including $458.6 million in the Marcellus Shale area) and $57.1 million for the West Coast region. These amounts included approximately $161.8 million spent to develop proved undeveloped reserves.

In 2014, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $519.9 million for the Appalachian region (including $502.9 million in the Marcellus Shale area) and $82.8 million for the West Coast region. These amounts included approximately $179.9 million spent to develop proved undeveloped reserves.

In 2013, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $428.5 million for the Appalachian region (including $393.3 million in the Marcellus Shale area) and $104.6 million for the West Coast region. These amounts included approximately $148.5 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The majority of the Pipeline and Storage segment's capital expenditures for 2015 were mainly for expenditures related to Supply Corporation's Westside Expansion and Modernization Project ($63.0 million), Empire and Supply Corporation's Tuscarora Lateral Project ($53.7 million), Supply Corporation's Northern Access 2015 Project ($40.4 million), Supply Corporation's Northern Access 2016 Project ($5.9 million) and Supply Corporation's Mercer Expansion Project ($5.4 million), as discussed below. In addition, the Pipeline and Storage segment capital expenditures for 2015 also include additions, improvements and replacements to this segment's transmission and gas storage systems.

The majority of the Pipeline and Storage segment's capital expenditures for 2014 were related to additions, improvements, and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for 2014 included expenditures related to Supply Corporation's Mercer Expansion Project ($27.0 million), Supply Corporation's Northern Access 2015 project ($11.1 million) and Supply Corporation's Westside Expansion and Modernization Project ($4.8 million), as discussed below.

The majority of the Pipeline and Storage segment's capital expenditures for 2013 were related to additions, improvements, and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for 2013 included expenditures for the construction of Supply Corporation's Northern Access expansion project ($14.5 million), Supply Corporation's Line N 2012 Expansion Project ($4.2 million), Supply Corporation's Line N 2013 Project ($2.8 million) and Supply Corporation's Mercer Expansion Project ($0.7 million).

Gathering

The majority of the Gathering segment's capital expenditures for 2015 were for the construction of Midstream Corporation's Clermont Gathering System ($117.3 million), as discussed below.

The majority of the Gathering segment's capital expenditures for 2014 were for the construction of Midstream Corporation's Clermont Gathering System ($95.2 million) and to build compressor stations on Midstream Corporation's Trout Run Gathering System ($32.9 million). In addition, the Gathering segment capital expenditures for 2014 included expenditures for the expansion of Midstream Corporation's Covington Gathering System in Tioga County, Pennsylvania ($4.6 million).

The majority of the Gathering segment's capital expenditures for 2013 were related to the expansion of Midstream Corporation's Trout Run Gathering System ($48.0 million).

Utility

The majority of the Utility segment's capital expenditures for 2015, 2014 and 2013 were made for replacement of mains and main extensions and for the replacement of service lines. The capital expenditures for 2015, 2014 and 2013 included $18.4 million, $15.6 million and $9.1 million, respectively, related to the replacement of the Utility segment's customer information system, as discussed below.

Estimated Capital Expenditures

The Company's estimated capital expenditures for the next three years are:

	Year Ended September 30		
	2016	2017	2018
		(Millions)	
Exploration and Production(1)	$ 425	$ 490	$ 520
Pipeline and Storage	525	280	120
Gathering	140	85	55
Utility	100	95	90
All Other	—	—	—
	$ 1,190	$ 950	$ 785

(1) Includes estimated expenditures for the years ended September 30, 2016, 2017 and 2018 of approximately $166 million, $185 million and $114 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting.

Exploration and Production

Estimated capital expenditures in 2016 for the Exploration and Production segment include approximately $380 million for the Appalachian region and $45 million for the West Coast region.

Estimated capital expenditures in 2017 for the Exploration and Production segment include approximately $430 million for the Appalachian region and $60 million for the West Coast region.

Estimated capital expenditures in 2018 for the Exploration and Production segment include approximately $445 million for the Appalachian region and $75 million for the West Coast region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2016 through 2018 are expected to include: construction of new pipeline and compressor stations to support expansion projects, the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations. Expansion projects are discussed below.

In light of the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, the amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of September 30, 2015, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $7.7 million.

Supply Corporation and Empire are moving forward with, or have recently completed, several projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to on-system markets, and markets beyond the Supply Corporation and Empire pipeline systems. Projects where the Company has begun to make significant investments of preliminary survey and investigation costs and/or where shipper agreements have been executed are described below.

In 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to a new interconnection with Tennessee Gas Pipeline ("TGP") at Mercer, Pennsylvania, a pooling point recently established at Tennessee's Station 219 ("Mercer Expansion Project"). Supply Corporation executed a service agreement with Range Resources ("Range") for 105,000 Dth per day, all of the project capacity, for service which began November 1, 2014. The cost estimate is $34.2 million, of which $30.1 million is for expansion and $4.1 million is for replacement. Supply Corporation constructed the required 3,550 horsepower of compression at Mercer, and replaced 2.08 miles of 24" pipeline, both under its FERC blanket certificate authorization. As of September 30, 2015, approximately $33.1 million has been spent on the Mercer Expansion Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2015.

On January 18, 2013, Supply Corporation concluded an Open Season to further increase its capacity to move gas north and south on its Line N system to Texas Eastern Transmission, LP ("TETCO") at Holbrook and TGP at Mercer ("Westside Expansion and Modernization Project"). Supply Corporation received its FERC 7(c) certificate on March 2, 2015 and executed two service agreements (Range and Seneca) for all 175,000 Dth per day of project capacity. Partial service for Range began on September 8, 2015 with full service beginning for Range on October 16, 2015 and for Seneca on November 1, 2015. The Westside Expansion and Modernization Project facilities include the replacement of approximately 23.3 miles of 20" pipe with 24" pipe and the addition of 3,550 horsepower of compression at Mercer. The cost estimate is $86.0 million, of which $44.9 million is related to expansion and the remainder is for replacement. As of September 30, 2015, approximately $67.9 million has been capitalized as Construction Work in Progress for the Westside Expansion and Modernization Project. The remaining expenditures are expected to be spent in fiscal 2016 and are included as Pipeline and Storage estimated capital expenditures in the table above.

Supply Corporation and TGP have jointly developed a project that combines expansions on both pipeline systems, providing a seamless transportation path from TGP's 300 Line in the Marcellus fairway to the TransCanada Pipeline delivery point at Niagara. Supply Corporation has offered 140,000 Dth per day of capacity on its system to TGP under a lease, from its Ellisburg Station for redelivery to TGP in East Eden, New York ("Northern Access 2015"). The project provides Seneca Resources, TGP's anchor shipper, with an outlet to premium Dawn-indexed markets in Canada, for Seneca Resources' Clermont Area Marcellus production. The Northern Access 2015 project involves the construction of a new 15,400 horsepower compressor station in Hinsdale, New York and a 7,700 horsepower addition to its compressor station in Concord, New York, for service that commenced on an interim basis for 40,000 Dth per day on November 1, 2015, and is expected to be fully operational by December 1, 2015. Supply Corporation and TGP received their FERC 7(c) certificates on February 27, 2015 and have executed the Capacity Lease agreement. The cost estimate for the Northern Access 2015 project is $67.5 million. As of September 30, 2015, approximately $51.5 million has been capitalized as Construction Work in Progress for the Northern Access 2015 project. The remaining expenditures expected to be spent are included in Pipeline and Storage estimated capital expenditures in the table above.

Supply Corporation and Empire have been working with Seneca Resources to develop a project which would move significant prospective Marcellus production from Seneca Resources' Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa ("Northern Access 2016"). Similar to the goal of the Northern Access 2015 project, the separate and distinct Northern Access 2016 project would provide an outlet to premium Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast, all with a target in-service date in late calendar year 2016. The Northern Access 2016 project involves the construction of approximately 98.5 miles of largely 24” pipeline and approximately 27,500 horsepower of compression on the two systems. The preliminary cost estimate for the Northern Access 2016 project is $455 million. Supply Corporation, Empire and Seneca Resources executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa and 140,000 Dth per day of firm transportation capacity to a new interconnection with TGP's 200 Line on this project. On July 24, 2014, Supply Corporation and Empire initiated the FERC NEPA Pre-filing process on this project and both parties filed a joint FERC 7(b) and 7(c) application in early March 2015 and amended that application on November 2, 2015. As of September 30, 2015, approximately $15.1 million has been spent on the Northern Access 2016 project, including $9.2 million that has been spent to study the project. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and this $9.2 million of project costs has been reestablished as a Deferred Charge on the Consolidated Balance Sheet. The remaining $5.9 million spent on the project has been capitalized as Construction Work in Progress. The remainder of the preliminary cost estimate expected to be spent on this project is included as Pipeline and Storage estimated capital expenditures in the table above.

On November 21, 2014, Supply Corporation concluded an Open Season for an expansion of its Line D pipeline (“Line D Expansion”) that is intended to allow growing on-system markets to avail themselves of economical gas supply on the TGP 300 line, at an existing interconnect at Lamont, Pennsylvania, and provide increased capacity into the Erie, Pennsylvania market area. Following negotiations with prospective shippers, Supply Corporation executed five precedent agreements for a total of 77,500 Dth per day for terms of ten years. The project involves construction of a new 4,152 horsepower Keelor Compressor Station and modifications to the Roystone and Bowen compressor stations at an estimated capital cost of approximately $23 million. The project will also provide system modernization benefits. Supply Corporation plans to seek authorization for this project under its FERC blanket certificate. The target in-service date is November 1, 2016. As of September 30, 2015, less than $0.1 million has been spent to study the Line D Expansion project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2015.

On August 12, 2013, Empire concluded an Open Season, offering for the first time no-notice transportation and storage services to new and existing shippers on the Empire pipeline system. Empire and Rochester Gas & Electric (“RG&E”), Empire’s largest LDC connected market, executed a precedent agreement to convert all 172,500 Dth per day of its standard firm transportation services to no-notice service, including 3.3 Bcf of no-notice storage service. The new services will provide RG&E with a superior flexible delivery service with daily and seasonal load balancing capabilities and greater access to Marcellus supplies. In addition, Empire executed a precedent agreement with New York State Electric and Gas for 14,816 Dth per day of transportation capacity and a third agreement with Distribution Corporation for the remaining 34,500 Dth per day of project capacity, providing both LDCs with increased access to Marcellus supplies. Empire has constructed a 17.2 mile, 12" and 16" pipeline and an interconnection between Empire’s pipeline system and Supply Corporation’s system at Tuscarora, New York. Empire is also modifying its Oakfield compressor station and Supply Corporation is constructing approximately 1,380 horsepower of compression at its Tuscarora compressor station (“Tuscarora Lateral Project”). Supply Corporation concluded an Open Season and has awarded to Empire the necessary storage services under a lease agreement. Empire and Supply Corporation began the FERC pre-filing process on April 12, 2013, and both companies filed their FERC 7(c) applications in March 2014. Empire and Supply Corporation received a FERC certificate on March 10, 2015. Both parties have executed the Capacity Lease, Empire executed service agreements with all three of its project shippers, and service began November 1, 2015. The cost estimate for the Tuscarora Lateral Project is $60.0 million. As of September 30, 2015, approximately $55.5 million has been capitalized as Construction Work in Progress for the Tuscarora Lateral Project. The remaining expenditures are expected to be spent in fiscal 2016 and are included in Pipeline and Storage estimated capital expenditures in the table above.

Empire is developing an expansion of its system, and began an Open Season, that would allow for the transportation of approximately 300,000 Dth per day of additional Marcellus supplies from Millennium Pipeline at Corning, from Supply Corporation at Tuscarora, or from new interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line (“Empire North Project”). The preliminary cost estimate for the Empire North Project is at least $150 million depending on requested receipt points. As of September 30, 2015, approximately $0.3 million has been spent to study this project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2015.

Gathering

The majority of the Gathering segment capital expenditures in 2016 through 2018 are expected to be for construction and expansion of gathering systems, as discussed below.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The preliminary cost estimate for the continued buildout is anticipated to be in the range of $250 million to $500 million. As of September 30, 2015, approximately $216.5 million has been spent on the Clermont Gathering System, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2015.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, continues to develop its Trout Run Gathering System in Lycoming County, Pennsylvania. The Trout Run Gathering System was initially placed in service in May 2012. The current system consists of approximately 40 miles of backbone and in-field gathering pipelines and two compressor stations. Estimated capital expenditures in 2016 through 2018 include anticipated expenditures in the range of $20 million to $50 million for the continued expansion of the Trout Run Gathering System. As of September 30, 2015, the Company has spent approximately $162.7 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2015.

Utility

Capital expenditures for the Utility segment in 2016 through 2018 are expected to be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment. Estimated capital expenditures in the Utility segment for 2016 through 2018 also include amounts for the planned replacement of the Utility segment's legacy mainframe systems. This includes estimated capital expenditures in 2016 of $13.6 million related to the replacement of the customer information system, which is scheduled to be placed in service in the spring of 2016. Estimated capital expenditures for the replacement of other legacy mainframe systems amount to $1.5 million for 2016, $2.1 million for 2017 and $0.4 million for 2018.

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. In addition, the Company issued additional long-term debt in June 2015 to enhance its liquidity position, including the reduction of short-term debt. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term debt as necessary during fiscal 2016 to help meet its capital expenditures needs. The level of short-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells. As disclosed above, the Company is precluded from issuing new long-term debt throughout fiscal 2016 as a means of financing projects.

The Company continuously evaluates capital expenditures and potential investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, natural gas storage facilities and the expansion of natural gas transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market conditions.

FINANCING CASH FLOW

Consolidated short-term debt decreased $85.6 million when comparing the balance sheet at September 30, 2015 to the balance sheet at September 30, 2014. The maximum amount of short-term debt outstanding during the year ended September 30, 2015 was $260.8 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At September 30, 2015, the Company did not have any outstanding commercial paper or short-term notes payable to banks.

On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement with a syndicate of 14 banks. The agreement replaced the Company's previous $750.0 million committed credit facility with a substantially similar facility totaling $750.0 million. On September 30, 2015, the Company entered into a Second Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of the same 14 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019, plus a $500.0 million 364-day unsecured committed revolving credit facility through September 29, 2016. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines.

The total amount available to be issued under the Company’s commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through December 5, 2019. At September 30, 2015, the Company’s debt to capitalization ratio (as calculated under the facility) was .51. The constraints specified in the Credit Agreement would have permitted an additional $1.67 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company’s debt to capitalization ratio exceeded .65.

If a downgrade in any of the Company’s credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources, including cash provided by operations.

The Credit Agreement contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2015, the Company did not have any debt outstanding under the Credit Agreement.

On June 25, 2015, the Company issued $450.0 million of 5.20% notes due July 15, 2025. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $444.6 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including the reduction of short-term debt.

On February 15, 2013, the Company issued $500.0 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used to refund the $250.0 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.

None of the Company’s long-term debt at September 30, 2015 and 2014 had a maturity date within the following twelve-month period.

The Company’s embedded cost of long-term debt was 5.53% and 5.61% at September 30, 2015 and September 30, 2014, respectively. Refer to “Interest Rate Risk” in this Item for a more detailed breakdown of the Company’s embedded cost of long-term debt.

Under the Company’s existing indenture covenants, at September 30, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness during fiscal 2016 as a result of impairments of its oil and gas properties recognized during the year ended September 30, 2015, as discussed above. The 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt. If the Company experiences additional significant impairments of its oil and gas properties in the first or subsequent quarters of fiscal 2016, the Company, under its 1974 indenture, expects to continue to be precluded from issuing incremental long-term debt into the first or subsequent quarters of fiscal 2017. However, the Company expects that it could borrow under its credit facilities. The Company's present liquidity position is believed to be adequate to satisfy known demands. Please refer to the Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.

The Company’s 1974 indenture pursuant to which $99.0 million (or 4.7%) of the Company’s long-term debt (as of September 30, 2015) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company’s consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $44.8 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2015, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2016	2017	2018	2019	2020	Thereafter	Total
				(Millions)			
Long-Term Debt, including interest expense(1)	$ 115.3	$ 115.3	$ 406.4	$ 336.7	$ 74.0	$ 1,761.4	$ 2,809.1
Operating Lease Obligations	$ 25.7	$ 6.0	$ 4.7	$ 4.5	$ 3.3	$ 0.6	$ 44.8
Purchase Obligations:							
Gas Purchase Contracts(2)	$ 127.1	$ 6.0	$ 1.3	$ —	$ —	$ —	$ 134.4
Transportation and Storage Contracts(3)	$ 58.0	$ 83.4	$ 83.6	$ 92.6	$ 73.5	$ 762.5	$ 1,153.6
Hydraulic Fracturing and Fuel Obligations	$ 104.7	$ 25.0	$ —	$ —	$ —	$ —	$ 129.7
Pipeline, Compressor and Gathering Projects	$ 96.6	$ 0.2	$ —	$ —	$ —	$ —	$ 96.8
Mainframe Replacement Project	$ 21.4	$ —	$ —	$ —	$ —	$ —	$ 21.4
Other	$ 18.3	$ 11.8	$ 7.0	$ 6.7	$ 5.8	$ 9.6	$ 59.2

(1) Refer to Note E — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense.

(2) Gas prices are variable based on the NYMEX prices adjusted for basis.

(3) Transportation service contractual obligations include the following precedent agreements executed by the Exploration and Production segment for transportation of Appalachian gas: $10.8 million for 2016, $35.2 million for 2017, $34.3 million for 2018, $45.0 million for 2019, $46.9 million for 2020 and $718.7 million thereafter.

The Company has other long-term obligations recorded on its Consolidated Balance Sheets that are not reflected in the table above. Such long-term obligations include pension and other post-retirement liabilities, asset retirement obligations, deferred income tax liabilities, various regulatory liabilities, derivative financial instrument liabilities and other deferred credits (the majority of which consist of liabilities for non-qualified benefit plans, deferred compensation liabilities, environmental liabilities and workers compensation liabilities).

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading "Critical Accounting Estimates —Accounting for Derivative Financial Instruments"); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the Consolidated Balance Sheets as a current liability; and (iii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note I — Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan). The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2015, the Company contributed $36.2 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2016 will be in the range of $5.0 million to $10.0 million. The Company expects that all subsidiaries having employees covered by the Retirement Plan will make contributions to the Retirement Plan. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through short-term borrowings or cash from operations.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and 401(h) accounts. During 2015, the Company contributed $2.0 million to its VEBA trusts and 401(h) accounts. The Company anticipates that the annual contribution to its VEBA trusts and 401(h) accounts in 2016 will be in the range of $2.0 million to $5.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company uses various derivative financial instruments (derivatives), including price swap agreements and futures contracts, as part of the Company's overall energy commodity price risk management strategy in its Exploration and Production and Energy Marketing segments. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2015 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as "swap dealers" and "major swap participants," (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC's enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company's derivative hedging transactions. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. In addition, while the Company expects to be exempt from the Dodd-Frank Act's requirement that certain swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, documentation, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company's ability to monetize or restructure existing derivative contracts; and increase the Company's exposure to less creditworthy counterparties, all of which could increase the Company's business costs. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

In accordance with the authoritative guidance for fair value measurements, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative net assets relate to crude oil swap agreements used to hedge forecasted sales at a specific location (southern California). The Company's internal model that is used to calculate fair value applies a historical basis differential (between the sales locations and NYMEX) to a forward NYMEX curve because there is not a forward curve specific to this sales location. The Company does not believe that the fair value recorded would be significantly different from what it expects to receive upon settlement.

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net assets (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 derivative net assets amount to $1.8 million at September 30, 2015 and represent 0.4% of the Total Net Assets shown in Item 8 at Note F — Fair Value Measurements at September 30, 2015.

The increase in the net fair value asset of the Level 3 positions from October 1, 2014 to September 30, 2015, as shown in Item 8 at Note F, was attributable to a decrease in the commodity price of crude oil (at the aforementioned sales location) relative to the swap prices during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at September 30, 2015.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2015, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2015. At September 30, 2015, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2020.

Natural Gas Price Swap Agreements

	Expected Maturity Dates					
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Notional Quantities (Equivalent Bcf)	79.6	62.5	22.1	11.0	1.9	177.1
Weighted Average Fixed Rate (per Mcf)	$ 4.10	$ 4.17	$ 3.78	$ 3.56	$ 3.67	$ 4.05
Weighted Average Variable Rate (per Mcf)	$ 2.67	$ 2.97	$ 3.25	$ 3.26	$ 3.30	$ 2.89

Of the total Bcf above, 2.2 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $3.81 per Mcf. The remaining 174.9 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $4.05 per Mcf.

Crude Oil Price Swap Agreements

	2016	2017	2018	Total
Notional Quantities (Equivalent Bbls)	1,425,000	696,000	75,000	2,196,000
Weighted Average Fixed Rate (per Bbl)	$ 88.24	$ 75.22	$ 91.00	$ 84.21
Weighted Average Variable Rate (per Bbl)	$ 50.47	$ 54.51	$ 58.77	$ 52.03

At September 30, 2015, the Company would have received from its respective counterparties an aggregate of approximately $202.3 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have received from its respective counterparties an aggregate of approximately $69.8 million to terminate the crude oil price swap agreements outstanding at September 30, 2015.

At September 30, 2014, the Company had natural gas price swap agreements covering 205.7 Bcf at a weighted average fixed rate of $4.33 per Mcf. The Company also had crude oil price swap agreements covering 3,285,000 Bbls at a weighted average fixed rate of $93.93 per Bbl.

The following table discloses the net contract volume purchased (sold), weighted average contract prices and weighted average settlement prices by expected maturity date for futures contracts used to manage natural gas price risk. At September 30, 2015, the Company did not hold any futures contracts with maturity dates extending beyond 2019 (the futures contracts maturing in 2019 were insignificant).

Futures Contracts

	Expected Maturity Dates			
	2016	2017	2018	Total
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	8.3	2.0	1.1	11.4
Weighted Average Contract Price (per Mcf)	$ 3.84	$ 3.98	$ 3.77	$ 3.87
Weighted Average Settlement Price (per Mcf)	$ 4.27	$ 4.15	$ 4.25	$ 4.24

At September 30, 2015, the Company had long (purchased) contracts covering 17.8 Bcf of gas extending through 2018 at a weighted average contract price of $3.81 per Mcf and a weighted average settlement price of $2.95 per Mcf. Of this amount, 15.6 Bcf is accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with certain residential, commercial, industrial, public authority and wholesale customers. The remaining 2.2 Bcf is accounted for as cash flow hedges used to hedge against rising prices related to anticipated gas purchases for potential injections into storage. The Company would have paid $15.3 million to terminate these contracts at September 30, 2015.

At September 30, 2015, the Company had short (sold) contracts covering 6.4 Bcf of gas extending through 2018 at a weighted average contract price of $4.03 per Mcf and a weighted average settlement price of $3.04 per Mcf. Of this amount, 6.3 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Company's Energy Marketing segment. The remaining 0.1 Bcf is accounted for as fair value hedges, the majority of which are used to hedge against falling prices, a risk to which the Energy Marketing segment is exposed due to the fixed price gas purchase commitments that it enters into with certain natural gas suppliers. The Company would have received $6.4 million to terminate these contracts at September 30, 2015.

At September 30, 2014, the Company had long (purchased) contracts covering 18.1 Bcf of gas extending through 2018 at a weighted average contract price of \$4.30 per Mcf and a weighted average settlement price of \$4.23 per Mcf.

At September 30, 2014, the Company had short (sold) contracts covering 7.7 Bcf of gas extending through 2018 at a weighted average contract price of \$4.64 per Mcf and a weighted average settlement price of \$4.46 per Mcf.

Foreign Exchange Risk

The Company uses foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. All of these transactions are forecasted.

The following table discloses foreign exchange contract information by expected maturity dates. The Company receives a fixed price in exchange for paying a variable price as noted in the Canadian to U.S. dollar forward exchange rates. Notional amounts (Canadian dollars) are used to calculate the contractual payments to be exchanged under contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2015. At September 30, 2015, the Company had not entered into any foreign currency exchange contracts extending beyond 2020.

	Expected Maturity Dates					
	2016	2017	2018	2019	2020	Total
Notional Quantities (Canadian Dollar)	\$ 10.0	\$ 12.0	\$ 12.0	\$ 12.0	\$ 12.0	\$ 58.0
Weighted Average Fixed Rate (\$Cdn/\$US)	\$ 1.25	\$ 1.25	\$ 1.24	\$ 1.23	\$ 1.22	\$ 1.23
Weighted Average Variable Rate (\$Cdn/\$US)	\$ 1.30	\$ 1.30	\$ 1.29	\$ 1.29	\$ 1.28	\$ 1.28

At September 20, 2015, absent other positions with the same counterparties, the Company would have paid its respective counterparties an aggregate of \$3.0 million to terminate foreign exchange contracts.

Refer to Item 8 at Note G — Financial Instruments for a discussion of the Company's exposure to credit risk related to its derivative financial instruments.

Interest Rate Risk

The fair value of long-term fixed rate debt is \$2.1 billion at September 30, 2015. This fair value amount is not intended to reflect principal amounts that the Company will ultimately be required to pay. The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt:

	Principal Amounts by Expected Maturity Dates						
	2016	2017	2018	2019	2020	Thereafter	Total
				(Dollars in millions)			
Long-Term Fixed Rate Debt	\$ —	\$ —	\$ 300.0	\$ 250.0	\$ —	\$1,549.0	\$2,099.0
Weighted Average Interest Rate Paid	—	—	6.5%	8.8%	—	4.8%	5.5%

RATE AND REGULATORY MATTERS

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states' respective public utility commissions and typically are changed only when approved through a procedure known as a "rate case." Although neither division has a rate case on file, see below for a description of other rate proceedings affecting the New York division. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs.

Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated "supply charge" on the customer bill.

New York Jurisdiction

Customer delivery rates charged by Distribution Corporation's New York division were established in a rate order issued on December 21, 2007 by the NYPSC. In connection with an efficiency and conservation program, the rate order approved a revenue decoupling mechanism. The revenue decoupling mechanism "decouples" revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation.

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an "earnings sharing mechanism" ("ESM"). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation's pipeline replacement spending by $8.2 million per year of the agreement. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million ($4.9 million after-tax) refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014. All significant terms of the agreement, including existing rates, continue in effect beyond September 30, 2015 until modified by the NYPSC. The agreement also states that nothing in the agreement precludes the parties from meeting to discuss extending the agreement on mutually acceptable terms, and presenting such extension to the NYPSC for approval. On May 22, 2015, Distribution Corporation filed with the NYPSC a Notice of Impending Settlement Discussions stating that settlement discussions would be scheduled in the near future, and that such discussions might include, among other things, the possible extension of the agreement on mutually acceptable terms. Distribution Corporation is currently involved in such settlement discussions.

Pennsylvania Jurisdiction

Distribution Corporation's current delivery charges in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007.

Pipeline and Storage

On September 29, 2015, Supply Corporation filed a rate case settlement at the FERC that would, upon approval, extend the Company's current FERC-approved rate case settlement with a required rate case filing at the latest by December 31, 2019 and prohibit any party from seeking to initiate a rate case proceeding before September 30, 2017. Prior to this settlement, Supply Corporation had been otherwise required by its current rate settlement to make a general rate filing no later than January 1, 2016. The settlement extension provides for, among other things, the following: Supply Corporation will reduce its maximum reservation, capacity, demand and deliverability rates by 2% on November 1, 2015 and by an additional 2% on November 1, 2016. Supply Corporation will also adopt a mechanism that allows it to recover, as a surcharge, certain pipeline safety and greenhouse gas costs it may incur as a result of new rules and regulations. FERC approved the settlement extension on November 13, 2015.

Empire does not have a rate case currently on file with the FERC, and is not subject to any requirement to make a future general rate filing. Empire is also not barred from filing a general rate case at any time.

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory requirements.

For further discussion of the Company's environmental exposures, refer to Item 8 at Note I — Commitments and Contingencies under the heading "Environmental Matters."

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which restrict emissions associated with oil and natural gas drilling. In 2015, the EPA proposed new rules regulating methane and volatile organic compound emissions from new or modified oil and gas emissions sources. If adopted as proposed, these new rules would impose more stringent leak detection and repair requirements, and would further address reporting and control of methane and volatile organic compound emissions. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. The Company currently complies with California cap-and-trade guidelines, which increases the Company's cost of environmental compliance in its Exploration and Production segment operations. Legislation or regulation that restricts carbon emissions could increase the Company's cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

For discussion of the recently issued authoritative accounting and financial reporting guidance, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading "New Authoritative Accounting and Financial Reporting Guidance."

EFFECTS OF INFLATION

Although the rate of inflation has been relatively low over the past few years, the Company's operations remain sensitive to increases in the rate of inflation because of its capital spending and the regulated nature of a significant portion of its business.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

2. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;

3. Changes in the price of natural gas or oil;

4. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions;

5. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;

6. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;

7. Changes in price differential between similar quantities of natural gas or oil at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;

8. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;

9. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;

10. Uncertainty of oil and gas reserve estimates;

11. Significant differences between the Company's projected and actual production levels for natural gas or oil;

12. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;

13. Changes in demographic patterns and weather conditions;

14. Changes in the availability, price or accounting treatment of derivative financial instruments;
15. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services;
16. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
17. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
18. Significant differences between the Company's projected and actual capital expenditures and operating expenses;
19. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;
20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or
21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

Item 8 *Financial Statements and Supplementary Data*

Index to Financial Statements

Financial Statements and Financial Statement Schedule:

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Supplementary Data

Supplementary data that is included in Note K — Quarterly Financial Data (unaudited) and Note M — Supplementary Information for Oil and Gas Producing Activities (unaudited), appears under this Item, and reference is made thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of National Fuel Gas Company:

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2015, based on criteria established in *Internal Control - Integrated Framework 2013* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PRICEWATERHOUSECOOPERS LLP

Buffalo, New York
November 20, 2015

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2015	2014	2013
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 1,760,913	$ 2,113,081	$ 1,829,551
Operating Expenses			
Purchased Gas	349,984	605,838	460,432
Operation and Maintenance	470,003	463,078	442,090
Property, Franchise and Other Taxes	89,564	90,711	82,431
Depreciation, Depletion and Amortization	336,158	383,781	326,760
Impairment of Oil and Gas Producing Properties	1,126,257	—	—
	2,371,966	1,543,408	1,311,713
Operating Income (Loss)	(611,053)	569,673	517,838
Other Income (Expense):			
Other Income	8,039	9,461	4,697
Interest Income	3,922	4,170	4,335
Interest Expense on Long-Term Debt	(95,916)	(90,194)	(90,273)
Other Interest Expense	(3,555)	(4,083)	(3,838)
Income (Loss) Before Income Taxes	(698,563)	489,027	432,759
Income Tax Expense (Benefit)	(319,136)	189,614	172,758
Net Income (Loss) Available for Common Stock	(379,427)	299,413	260,001
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,614,361	1,442,617	1,306,284
	1,234,934	1,742,030	1,566,285
Dividends on Common Stock	(131,734)	(127,669)	(123,668)
Balance at End of Year	$ 1,103,200	$ 1,614,361	$ 1,442,617
Earnings Per Common Share:			
Basic:			
Net Income (Loss) Available for Common Stock	$ (4.50)	$ 3.57	$ 3.11
Diluted:			
Net Income (Loss) Available for Common Stock	$ (4.50)	$ 3.52	$ 3.08
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	84,387,755	83,929,989	83,518,857
Used in Diluted Calculation	84,387,755	84,952,347	84,341,220

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2015	2014	2013
	(Thousands of dollars)		
Net Income (Loss) Available for Common Stock	$ (379,427)	$ 299,413	$ 260,001
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(31,538)	(8,280)	55,940
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	9,217	9,203	15,282
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(3,234)	3,863	5,041
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	381,018	5,334	91,790
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	(591)	(662)	—
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(184,953)	17,647	(36,029)
Other Comprehensive Income (Loss), Before Tax	169,919	27,105	132,024
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(11,922)	(2,720)	21,304
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	3,375	3,370	5,650
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(1,195)	1,398	1,847
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	160,872	529	38,236
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	(217)	(242)	—
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(78,345)	9,515	(14,799)
Income Taxes — Net	72,568	11,850	52,238
Other Comprehensive Income	97,351	15,255	79,786
Comprehensive Income (Loss)	$ (282,076)	$ 314,668	$ 339,787

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30	
	2015	2014
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 9,261,323	$ 8,245,791
Less — Accumulated Depreciation, Depletion and Amortization	3,929,428	2,502,700
	5,331,895	5,743,091
Current Assets		
Cash and Temporary Cash Investments	113,596	36,886
Hedging Collateral Deposits	11,124	2,734
Receivables — Net of Allowance for Uncollectible Accounts of $29,029 and $31,811, Respectively	105,004	149,735
Unbilled Revenue	20,746	25,663
Gas Stored Underground	34,252	39,422
Materials and Supplies — at average cost	30,414	27,817
Other Current Assets	60,665	54,752
Deferred Income Taxes	137,200	40,323
	513,001	377,332
Other Assets		
Recoverable Future Taxes	168,214	163,485
Unamortized Debt Expense	2,218	2,747
Other Regulatory Assets	278,227	224,436
Deferred Charges	15,129	14,212
Other Investments	92,990	86,788
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	24,459	36,512
Fair Value of Derivative Financial Instruments	270,363	72,606
Other	167	1,355
	857,243	607,617
Total Assets	$ 6,702,139	$ 6,728,040
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 84,594,383 Shares and 84,157,220 Shares, Respectively	$ 84,594	$ 84,157
Paid In Capital	744,274	716,144
Earnings Reinvested in the Business	1,103,200	1,614,361
Accumulated Other Comprehensive Income (Loss)	93,372	(3,979)
Total Comprehensive Shareholders' Equity	2,025,440	2,410,683
Long-Term Debt, Net of Unamortized Discount and Debt Issuance Costs	2,084,009	1,637,443
Total Capitalization	4,109,449	4,048,126
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	85,600
Current Portion of Long-Term Debt	—	—
Accounts Payable	180,388	136,674
Amounts Payable to Customers	56,778	33,745
Dividends Payable	33,415	32,400
Interest Payable on Long-Term Debt	36,200	29,960
Customer Advances	16,236	19,005
Customer Security Deposits	16,490	15,761
Other Accruals and Current Liabilities	96,557	136,672
Fair Value of Derivative Financial Instruments	10,076	759
	446,140	490,576
Deferred Credits		
Deferred Income Taxes	1,275,162	1,456,283
Taxes Refundable to Customers	89,448	91,736
Unamortized Investment Tax Credit	731	1,145
Cost of Removal Regulatory Liability	184,907	173,199
Other Regulatory Liabilities	108,617	81,152
Pension and Other Post-Retirement Liabilities	202,807	134,202
Asset Retirement Obligations	156,805	117,713
Other Deferred Credits	128,073	133,908
	2,146,550	2,189,338
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 6,702,139	$ 6,728,040

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2015	2014	2013
	(Thousands of dollars)		
Operating Activities			
Net Income (Loss) Available for Common Stock	$ (379,427)	$ 299,413	$ 260,001
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Impairment of Oil and Gas Producing Properties	1,126,257	—	—
Depreciation, Depletion and Amortization	336,158	383,781	326,760
Deferred Income Taxes	(357,587)	142,415	167,887
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(9,064)	(4,641)	(675)
Stock-Based Compensation	3,208	11,763	12,446
Other	9,823	14,063	14,965
Change in:			
Hedging Collateral Deposits	(8,390)	(1,640)	(730)
Receivables and Unbilled Revenue	51,638	(22,781)	(17,135)
Gas Stored Underground and Materials and Supplies	3,438	13,285	(3,016)
Unrecovered Purchased Gas Costs	—	12,408	(12,408)
Other Current Assets	3,150	(3,630)	(109)
Accounts Payable	34,687	15,149	8,303
Amounts Payable to Customers	23,033	20,917	(7,136)
Customer Advances	(2,769)	(2,954)	(2,096)
Customer Security Deposits	729	(422)	(1,759)
Other Accruals and Current Liabilities	(7,173)	6,872	666
Other Assets	2,696	18,513	(5,757)
Other Liabilities	23,173	6,879	(1,635)
Net Cash Provided by Operating Activities	853,580	909,390	738,572
Investing Activities			
Capital Expenditures	(1,018,179)	(914,417)	(703,461)
Other	(6,611)	5,982	(2,522)
Net Cash Used in Investing Activities	(1,024,790)	(908,435)	(705,983)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	(85,600)	85,600	(171,000)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	9,064	4,641	675
Net Proceeds from Issuance of Long-Term Debt	444,635	—	495,415
Reduction of Long-Term Debt	—	—	(250,000)
Net Proceeds from Issuance of Common Stock	10,540	7,474	5,395
Dividends Paid on Common Stock	(130,719)	(126,642)	(122,710)
Net Cash Provided By (Used in) Financing Activities	247,920	(28,927)	(42,225)
Net Increase (Decrease) in Cash and Temporary Cash Investments	76,710	(27,972)	(9,636)
Cash and Temporary Cash Investments At Beginning of Year	36,886	64,858	74,494
Cash and Temporary Cash Investments At End of Year	$ 113,596	$ 36,886	$ 64,858
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 90,747	$ 91,927	$ 91,215
Income Taxes	$ 18,657	$ 40,944	$ 13,187
Non-Cash Investing Activities:			
Non-Cash Capital Expenditures	$ 118,959	$ 136,628	$ 81,138

See Notes to Consolidated Financial Statements

Note A — Summary of Significant Accounting Policies

Principles of Consolidation

The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassification

Due to the adoption of the authoritative guidance regarding the presentation of debt issuance costs, certain prior year amounts have been reclassified to conform with current year presentation. The Company reclassified debt issuance costs related to long-term debt previously shown as Unamortized Debt Expense as a direct deduction from the carrying value of Long-Term Debt on the Consolidated Balance Sheet.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note C — Regulatory Matters for further discussion.

Revenue Recognition

The Company's Exploration and Production segment records revenue based on entitlement, which means that revenue is recorded based on the actual amount of gas or oil that is delivered to a pipeline and the Company's ownership interest in the producing well. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance.

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services. Revenue from reservation charges on firm contracted capacity is recognized through equal monthly charges over the contract period regardless of the amount of gas that is transported or stored. Commodity charges on firm contracted capacity and interruptible contracts are recognized as revenue when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage field. The point of delivery into the pipeline or injection or withdrawal from storage is the point at which ownership and risk of loss transfers to the buyer of such transportation and storage services.

In the Company's Gathering segment, revenue is recorded at the point at which gathered volumes are delivered into interstate pipelines.

The Company's Utility segment records revenue for gas sales and transportation in the period that gas is delivered to customers. This includes the recording of receivables for gas delivered but not yet billed to customers based on the Company's estimate of the amount of gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets.

The Company's Energy Marketing segment records revenue for gas sales in the period that gas is delivered to customers. This includes the recording of receivables for gas delivered but not yet billed to customers based on the Company's estimate of the amount of gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance is determined based on historical experience, the age and other specific information about customer accounts. Account balances are charged off against the allowance twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

Regulatory Mechanisms

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note C — Regulatory Matters for further discussion.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNC, which covers the eight-month period from October through May. The WNC is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is warmer than normal results in a surcharge being added to customers' current bills, while weather that is colder than normal results in a refund being credited to customers' current bills. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

The impact of weather normalized usage per customer account in the Utility segment's New York rate jurisdiction is tempered by a revenue decoupling mechanism. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. Weather normalized usage per account that exceeds the average weather normalized usage per customer account results in a refund being credited to customers' bills. Weather normalized usage per account that is below the average weather normalized usage per account results in a surcharge being added to customers' bills. The surcharge or credit is calculated over a twelve-month period ending December 31st, and applied to customer bills annually, beginning March 1st.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation and Empire bill their customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation or Empire.

Property, Plant and Equipment

In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For further discussion of capitalized costs, refer to Note M — Supplementary Information for Oil and Gas Producing Activities.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. The book value of the oil and gas properties exceeded the ceiling at September 30, 2015 as well as at June 30, 2015 and March 31, 2015. As such, the Company recognized pre-tax impairment charges of $1.1 billion for the year ended September 30, 2015. Deferred income tax benefits of $476.1 million related to the impairment charges were also recognized for the year ended September 30, 2015. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2015, 2014, and 2013, estimated future net cash flows were increased by $194.5 million, decreased by $33.6 million and increased by $71.6 million, respectively.

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

Depreciation, Depletion and Amortization

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved oil and gas properties is excluded from this computation. In the All Other category, for timber properties, depletion, determined on a property by property basis, is charged to operations based on the actual amount of timber cut in relation to the total amount of recoverable timber. For all other property, plant and equipment, depreciation and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

	As of September 30	
	2015	2014
	(Thousands)	
Exploration and Production	$ 4,556,096	$ 3,995,200
Pipeline and Storage	1,710,947	1,609,593
Gathering	307,274	239,507
Utility	1,888,489	1,833,104
Energy Marketing	3,494	3,366
All Other and Corporate	109,193	108,986
	$ 8,575,493	$ 7,789,756

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2015	2014	2013
Exploration and Production, per Mcfe(1)	$ 1.52	$ 1.85	$ 2.02
Pipeline and Storage	2.4%	2.4%	2.5%
Gathering	4.0%	3.3%	3.7%
Utility	2.6%	2.6%	2.6%
Energy Marketing	6.1%	5.8%	3.9%
All Other and Corporate	1.4%	0.9%	1.3%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note M — Supplementary Information for Oil and Gas Producing Activities, depletion of oil and gas producing properties amounted to $1.49, $1.82 and $1.98 per Mcfe of production in 2015, 2014 and 2013, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2015 and 2014 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2015, 2014 and 2013, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

Financial Instruments

Unrealized gains or losses from the Company's investments in an equity mutual fund and the stock of an insurance company (securities available for sale) are recorded as a component of accumulated other comprehensive income (loss). Reference is made to Note G — Financial Instruments for further discussion.

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil and to manage a portion of the risk of currency fluctuations associated with transportation costs denominated in Canadian currency. These instruments include price swap agreements and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note F — Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues, purchased gas expense or operation and maintenance expense on the Consolidated Statements of Income. Reference is made to Note G - Financial Instruments for further discussion concerning cash flow hedges.

For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets representing the change in fair value of the asset or firm commitment that is being hedged (see Other Current Assets section in this footnote). The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the

Consolidated Statements of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm commitment that is being hedged. Reference is made to Note G - Financial Instruments for further discussion concerning fair value hedges.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) and changes for the year ended September 30, 2015, net of related tax effect, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Gains and Losses on Securities Available for Sale	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Year Ended September 30, 2015				
Balance at October 1, 2014	$ 43,659	$ 8,382	$ (56,020)	$ (3,979)
Other Comprehensive Gains and Losses Before Reclassifications	220,146	(2,039)	(19,616)	198,491
Amounts Reclassified From Other Comprehensive Income	(106,608)	(374)	5,842	(101,140)
Balance at September 30, 2015	$ 157,197	$ 5,969	$ (69,794)	$ 93,372
Year Ended September 30, 2014				
Balance at October 1, 2013	$ 30,722	$ 6,337	$ (56,293)	$ (19,234)
Other Comprehensive Gains and Losses Before Reclassifications	4,805	2,465	(5,560)	1,710
Amounts Reclassified From Other Comprehensive Loss	8,132	(420)	5,833	13,545
Balance at September 30, 2014	$ 43,659	$ 8,382	$ (56,020)	$ (3,979)

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company's pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service (cost) credit was ($1.5 million) and $0.2 million at September 30, 2015 and 2014, respectively. The total amount for accumulated losses was $68.3 million and $56.2 million at September 30, 2015 and 2014, respectively.

Reclassifications Out of Accumulated Other Comprehensive Income (Loss)

The details about the reclassification adjustments out of accumulated other comprehensive income (loss) for the year ended September 30, 2015 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) for the Year Ended September 30,		Affected Line Item in the Statement Where Net Income (Loss) is Presented
	2015	2014	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	$180,069	($14,880)	Operating Revenues
Commodity Contracts	4,884	(2,767)	Purchased Gas
Gains (Losses) on Securities Available for Sale	591	662	Other Income
Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans:			
Prior Service Credit	109	131	(1)
Net Actuarial Loss	(9,326)	(9,334)	(1)
	176,327	(26,188)	Total Before Income Tax
	(75,187)	12,643	Income Tax Expense
	$101,140	($13,545)	Net of Tax

(1) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost. Refer to Note H — Retirement Plan and Other Post-Retirement Benefits for additional details.

Gas Stored Underground — Current

In the Utility segment, gas stored underground — current in the amount of $26.8 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2015, including transportation costs, the current cost of replacing this inventory of gas stored underground — current exceeded the amount stated on a LIFO basis by approximately $13.8 million at September 30, 2015. All other gas stored underground — current, which is in the Energy Marketing segment, is carried at an average cost method, subject to lower of cost or market adjustments.

Unamortized Debt Expense

Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment. At September 30, 2015, the remaining weighted average amortization period for such costs was approximately 4 years.

Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return. State tax returns are filed on a combined or separate basis depending on the applicable laws in the jurisdictions where tax returns are filed.

Investment tax credit, prior to its repeal in 1986, was deferred and is being amortized over the estimated useful lives of the related property, as required by regulatory authorities having jurisdiction.

The Company reports a liability or a reduction of deferred tax assets for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. When applicable, the Company recognizes interest relating to uncertain tax positions in Other Interest Expense and penalties in Other Income.

Consolidated Statement of Cash Flows

For purposes of the Consolidated Statement of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of generally three months or less to be cash equivalents.

Hedging Collateral Deposits

This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instrument liability or asset balances.

Other Current Assets

The components of the Company's Other Current Assets are as follows:

	Year Ended September 30	
	2015	2014
	(Thousands)	
Prepayments	$ 10,743	$ 10,079
Prepaid Property and Other Taxes	13,709	13,743
Federal Income Taxes Receivable	—	8,211
Fair Values of Firm Commitments	15,775	—
Regulatory Assets	20,438	22,719
	$ 60,665	$ 54,752

Other Accruals and Current Liabilities

The components of the Company's Other Accruals and Current Liabilities are as follows:

	Year Ended September 30	
	2015	2014
	(Thousands)	
Accrued Capital Expenditures	$ 53,652	$ 80,348
Regulatory Liabilities	5,346	18,072
Federal Income Taxes Payable	5,686	—
State Income Taxes Payable	1,170	5,798
Other	30,703	32,454
	$ 96,557	$ 136,672

Customer Advances

The Company's Utility and Energy Marketing segments have balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2015 and 2014, customers in the balanced billing programs had advanced excess funds of $16.2 million and $19.0 million, respectively.

Customer Security Deposits

The Company, in its Utility, Pipeline and Storage, and Energy Marketing segments, often times requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2015 and 2014, the Company had received customer security deposits amounting to $16.5 million and $15.8 million, respectively.

Earnings Per Common Share

Basic earnings per common share is computed by dividing income or loss by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options, SARs, restricted stock units and performance shares. As the Company recognized a net loss in 2015, the aforementioned securities, amounting to 709,063 securities, were not recognized in the diluted earnings per share calculation for 2015. For 2014 and 2013, the diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2014 and 2013, 1,007 securities and 181,418 securities were excluded as being antidilutive, respectively.

Stock-Based Compensation

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, SARs, restricted stock, restricted stock units, performance units or performance shares. The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments. Stock options and SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or SAR is exercisable less than one year or more than ten years after the date of each grant. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with stock options and SARs.

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company's stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant. Restricted stock units also are subject to restrictions on vesting and transferability. Restricted stock units, both performance and non-performance based, represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. The performance based and non-performance based restricted stock units do not entitle the participants to dividend and voting rights. The accounting for performance based and non-performance based restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period. For performance shares based on a return on capital goal, the fair value at the date of grant of the performance shares is determined by multiplying the expected number of performance shares to be issued by the market value of Company common stock on the date of grant reduced by the present value of forgone dividends. For performance shares based on a total shareholder return goal, the Company uses the Monte Carlo simulation technique to estimate the fair value price at the date of grant.

Refer to Note E — Capitalization and Short-Term Borrowings under the heading “Stock Option and Stock Award Plans” for additional disclosures related to stock-based compensation awards for all plans.

New Authoritative Accounting and Financial Reporting Guidance

In May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The original effective date of this authoritative guidance was as of the Company's first quarter of fiscal 2018. However, the FASB has delayed the effective date of the new revenue standard by one year, and the guidance will now be effective as of the Company's first quarter of fiscal 2019. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements and disclosures.

In June 2014, the FASB issued authoritative guidance regarding accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the employee has completed the requisite service period. This authoritative guidance requires that such performance targets that affect vesting be treated as performance conditions, meaning that the performance target should not be factored in the calculation of the award at the grant date. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2017, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

In April 2015, the FASB issued authoritative guidance regarding the presentation of debt issuance costs. The authoritative guidance requires that all costs incurred to issue debt be presented in the balance sheet as a direct deduction from the carrying value of the debt. The Company early adopted this guidance at September 30, 2015 on a retrospective basis.

In July 2015, the FASB issued authoritative guidance simplifying inventory measurement by requiring companies to value inventory at the lower of cost and net realizable value. The authoritative guidance applies to all inventory other than inventory that is measured using last-in, first-out or the retail inventory method. The intention of this authoritative guidance is to eliminate some diversity in practice. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

Note B — Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the authoritative guidance that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. An asset retirement obligation is defined as a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within the control of the Company. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. The Company estimates the fair value of its asset retirement obligations based on the discounting of expected cash flows using various estimates, assumptions and judgments regarding certain factors such as the existence of a legal obligation for an asset retirement obligation; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements as the inputs used to measure the fair value are unobservable.

The Company has recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool).

In addition to the asset retirement obligation recorded in the Exploration and Production segment, the Company has recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. The Company has also recorded asset retirement obligations for certain costs connected with the retirement of the distribution mains and services components of the pipeline system in the Utility segment, with the transmission mains and other components in the pipeline system in the Pipeline and Storage segment and with gathering lines and other components in the Gathering segment. These retirement costs within the distribution, transmission and gathering systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

A reconciliation of the Company's asset retirement obligations are shown below:

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Balance at Beginning of Year	$ 117,713	$ 119,511	$ 119,246
Liabilities Incurred and Revisions of Estimates	38,150	(2,496)	(4,796)
Liabilities Settled	(6,825)	(6,955)	(1,744)
Accretion Expense	7,767	7,653	6,805
Balance at End of Year	$ 156,805	$ 117,713	$ 119,511

Note C — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2015	2014
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note H)	$ 202,781	$ 164,804
Post-Retirement Benefit Costs(2) (Note H)	34,217	17,128
Recoverable Future Taxes (Note D)	168,214	163,485
Environmental Site Remediation Costs(2) (Note I)	24,606	25,645
NYPSC Assessment(3)	13,916	12,730
Asset Retirement Obligations(2) (Note B)	12,250	12,006
Unamortized Debt Expense (Note A)	2,218	2,747
Other(4)	10,895	14,842
Total Regulatory Assets	469,097	413,387
Less: Amounts Included in Other Current Assets	(20,438)	(22,719)
Total Long-Term Regulatory Assets	$ 448,659	$ 390,668

	At September 30	
	2015	2014
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$ 184,907	$ 173,199
Taxes Refundable to Customers (Note D)	89,448	91,736
Post-Retirement Benefit Costs (Note H)	60,013	53,650
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	56,778	33,745
Off-System Sales and Capacity Release Credits(5)	21,027	12,805
Other(6)	32,923	32,769
Total Regulatory Liabilities	445,096	397,904
Less: Amounts included in Current and Accrued Liabilities	(62,124)	(51,817)
Total Long-Term Regulatory Liabilities	$ 382,972	$ 346,087

(1) The Company recovers the cost of its regulatory assets but generally does not earn a return on them. There are a few exceptions to this rule. For example, the Company does earn a return on Unrecovered Purchased Gas Costs and, in the New York jurisdiction of its Utility segment, earns a return, within certain parameters, on the excess of cumulative funding to the pension plan over the cumulative amount collected in rates.

(2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.

(3) Amounts are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2015 and September 30, 2014 since such amounts are expected to be recovered from ratepayers in the next 12 months.

(4) $6,522 and $9,989 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2015 and 2014, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $4,373 and $4,853 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2015 and 2014, respectively.

(5) The September 30, 2015 amount is included in Other Regulatory Liabilities on the Consolidated Balance Sheet at September 30, 2015. The September 30, 2014 amount is included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet at September 30, 2014 since such amount is expected to be passed back to ratepayers in the next 12 months.

(6) $5,346 and $5,267 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2015 and 2014, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $27,577 and $27,502 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2015 and 2014, respectively.

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheets and included in income of the period in which the discontinuance of regulatory accounting treatment occurs.

Cost of Removal Regulatory Liability

In the Company's Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note B — Asset Retirement Obligations. Rather, they are classified as a regulatory liability in recognition of the fact that the Company has collected dollars from the customer that will be used in the future to fund asset retirement costs.

NYPSC Assessment

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the allowed utility assessment from the then current rate of one-third of one percent to one percent of a utility's in-state gross operating revenue, together with a temporary surcharge (expiring March 31, 2014) equal, as applied, to an additional one percent of the utility's in-state gross operating revenue. Pursuant to a New York State budget agreement in 2014, the temporary increase in the assessment will be phased out over a three year period ending July 1, 2017. The NYPSC, in a generic proceeding initiated for the purpose of implementing the amended law, has authorized the recovery, through rates, of the full cost of the increased assessment. The assessment is currently being applied to customer bills in the Utility segment's New York jurisdiction.

NYPSC Rate Proceeding

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an "earnings sharing mechanism" ("ESM"). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% would be allocated to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation's pipeline replacement spending by $8.2 million per year of the agreement. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014. All significant terms of the agreement, including existing rates, continue in effect beyond September 30, 2015 until modified by the NYPSC. The agreement also states that nothing in the agreement precludes the parties from meeting to discuss extending the agreement on mutually acceptable terms, and presenting such extension to the NYPSC for approval. On May 22, 2015, Distribution Corporation filed with the NYPSC a Notice of Impending Settlement Discussions stating that settlement discussions would be scheduled in the near future, and that such discussions might include, among other things, the possible extension of the agreement on mutually acceptable terms. Distribution Corporation is currently involved in such settlement discussions.

FERC Rate Proceeding

On September 29, 2015, Supply Corporation filed a rate case settlement at the FERC that would, upon approval, extend the Company's current FERC-approved rate case settlement with a required rate case filing at the latest by December 31, 2019 and prohibit any party from seeking to initiate a rate case proceeding before September 30, 2017. Prior to this settlement, Supply Corporation had been otherwise required by its current rate settlement to make a general rate filing no later than January 1, 2016. The settlement extension provides for, among other things, the following: Supply Corporation will reduce its maximum reservation, capacity, demand and deliverability rates by 2% on November 1, 2015 and by an additional 2% on November 1, 2016. Supply Corporation will also adopt a mechanism that allows it to recover, as a surcharge, certain pipeline safety and greenhouse gas costs it may incur as a result of new rules and regulations. FERC approved the settlement extension on November 13, 2015.

Off-System Sales and Capacity Release Credits

The Company, in its Utility segment, has entered into off-system sales and capacity release transactions. Most of the margins on such transactions are returned to the customer with only a small percentage being retained by the Company. The amount owed to the customer has been deferred as a regulatory liability.

Note D — Income Taxes

The components of federal and state income taxes included in the Consolidated Statements of Income are as follows:

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Current Income Taxes —			
Federal	$ 25,064	$ 34,579	$ (632)
State	13,387	12,620	5,503
Deferred Income Taxes —			
Federal	(244,336)	116,143	130,318
State	(113,251)	26,272	37,569
	(319,136)	189,614	172,758
Deferred Investment Tax Credit	(414)	(434)	(426)
Total Income Taxes	$ (319,550)	$ 189,180	$ 172,332
Presented as Follows:			
Other Income	$ (414)	$ (434)	$ (426)
Income Tax Expense (Benefit)	(319,136)	189,614	172,758
Total Income Taxes	$ (319,550)	$ 189,180	$ 172,332

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income (loss) before income taxes. The following is a reconciliation of this difference:

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
U.S. Income (Loss) Before Income Taxes	$ (698,977)	$ 488,593	$ 432,333
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 35%	$ (244,642)	$ 171,008	$ 151,317
State Income Taxes (Benefit)	(64,912)	25,280	27,997
Miscellaneous	(9,996)	(7,108)	(6,982)
Total Income Taxes	$ (319,550)	$ 189,180	$ 172,332

Significant components of the Company's deferred tax liabilities and assets were as follows:

	At September 30	
	2015	2014
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,291,718	$ 1,614,515
Pension and Other Post-Retirement Benefit Costs	141,032	113,248
Unrealized Hedging Gains	118,522	37,051
Other	51,230	50,884
Total Deferred Tax Liabilities	1,602,502	1,815,698
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(168,451)	(124,452)
Tax Loss and Credit Carryforwards	(185,681)	(171,423)
Other	(110,408)	(103,863)
Total Deferred Tax Assets	(464,540)	(399,738)
Total Net Deferred Income Taxes	$ 1,137,962	$ 1,415,960
Presented as Follows:		
Deferred Tax Liability/(Asset) — Current	$ (137,200)	$ (40,323)
Deferred Tax Liability — Non-Current	1,275,162	1,456,283
Total Net Deferred Income Taxes	$ 1,137,962	$ 1,415,960

As a result of certain realization requirements of the authoritative guidance on stock-based compensation, the table of deferred tax liabilities and assets shown above does not include certain deferred tax assets that arose directly from excess tax deductions related to stock-based compensation. Tax benefits of $9.1 million, $4.6 million and $0.7 million relating to the excess stock-based compensation deductions were recorded in Paid in Capital during the years ended September 30, 2015, September 30, 2014 and September 30, 2013, respectively. Cumulative tax benefits of $32.8 million and $34.2 million remain as of September 30, 2015 and September 30, 2014, respectively, and will be recorded in Paid in Capital in future years when such tax benefits are realized.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $89.4 million and $91.7 million at September 30, 2015 and 2014, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $168.2 million and $163.5 million at September 30, 2015 and 2014, respectively. Included in the above are regulatory liabilities and assets relating to the tax accounting method change noted below. The amounts are as follows: regulatory liabilities of $52.6 million as of September 30, 2015 and 2014 and regulatory assets of $88.7 million and $85.3 million as of September 30, 2015 and 2014, respectively.

The following is a reconciliation of the change in unrecognized tax benefits:

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
Balance at Beginning of Year	$ 3,147	$ 2,001	$ 11,170
Additions for Tax Positions Related to Current Year	—	—	700
Additions for Tax Positions of Prior Years	2,504	2,447	164
Reductions for Tax Positions of Prior Years	(566)	(1,301)	(10,033)
Balance at End of Year	$ 5,085	$ 3,147	$ 2,001

As a result of certain examinations in progress (discussed below), the Company anticipates the balance of unrecognized tax benefits could be reduced during the next 12 months. As of September 30, 2015, the entire balance of unrecognized tax benefits would favorably impact the effective tax rate, if recognized.

The IRS is currently conducting examinations of the Company for fiscal 2015 and fiscal 2014 in accordance with the Compliance Assurance Process (“CAP”). The CAP audit employs a real time review of the Company’s books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. The federal statute of limitations remains open for fiscal 2009 and later years. During fiscal 2009, consent was received from the IRS National Office approving the Company’s application to change its tax method of accounting for certain capitalized costs relating to its utility property. While local IRS examiners issued no-change reports for fiscal 2009 through 2013, the IRS has reserved the right to re-examine these years, pending the anticipated issuance of IRS guidance addressing the issue for natural gas utilities.

The Company is also subject to various routine state income tax examinations. The Company’s principal subsidiaries operate mainly in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return.

As of September 30, 2015, the Company has a federal net operating loss (NOL) carryover of $343 million, which expires in varying amounts between 2023 and 2033, and a minimum tax credit carryforward of $54 million, that has no expiration date. Approximately $7.3 million of the NOL carryforward is subject to certain annual limitations, and $87 million is attributable to excess tax deductions related to stock-based compensation as discussed above. In addition, the Company has state NOL carryovers in Pennsylvania, California and New York of $333 million, $207 million and $96 million, respectively, which begin to expire in varying amounts between 2025 and 2035.

During fiscal 2014, legislation was enacted reducing the corporate tax rate in New York from 7.1% to 6.5%, effective for tax years beginning after January 1, 2016. As a result, a deferred tax benefit of approximately $2.8 million was recorded in the accompanying financial statements.

Note E — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock					
	Shares	Amount	Paid In Capital	Earnings Reinvested in the Business		Accumulated Other Comprehensive Income (Loss)
	(Thousands, except per share amounts)					
Balance at September 30, 2012	83,330	$83,330	$ 669,501	$1,306,284		$ (99,020)
Net Income Available for Common Stock				260,001		
Dividends Declared on Common Stock ($1.48 Per Share)				(123,668)		
Other Comprehensive Income, Net of Tax						79,786
Share-Based Payment Expense(2)			11,537			
Common Stock Issued Under Stock and Benefit Plans(1)	332	332	6,646			
Balance at September 30, 2013	83,662	83,662	687,684	1,442,617		(19,234)
Net Income Available for Common Stock				299,413		
Dividends Declared on Common Stock ($1.52 Per Share)				(127,669)		
Other Comprehensive Income, Net of Tax						15,255
Share-Based Payment Expense(2)			10,654			
Common Stock Issued Under Stock and Benefit Plans(1)	495	495	17,806			
Balance at September 30, 2014	84,157	84,157	716,144	1,614,361		(3,979)
Net Income (Loss) Available for Common Stock				(379,427)		
Dividends Declared on Common Stock ($1.56 Per Share)				(131,734)		
Other Comprehensive Income, Net of Tax						97,351
Share-Based Payment Expense(2)			2,207			
Common Stock Issued Under Stock and Benefit Plans(1)	437	437	25,923			
Balance at September 30, 2015	84,594	$84,594	$ 744,274	$1,103,200	(3)	$ 93,372

(1) Paid in Capital includes tax benefits of $9.1 million, $4.6 million and $0.7 million for September 30, 2015, 2014 and 2013, respectively, related to stock-based compensation.

(2) Paid in Capital includes compensation costs associated with stock option, SARs, performance share and/or restricted stock awards. The expense is included within Net Income Available For Common Stock, net of tax benefits.

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2015, $959.0 million of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company’s common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2015, the Company issued 124,214 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 92,887 original issue shares of common stock for the Company's 401(k) plans.

During 2015, the Company issued 206,523 original issue shares of common stock as a result of stock option and SARs exercises and 48,490 original issue shares of common stock for restricted stock units that vested. Holders of stock options, SARs, restricted share awards or restricted stock units will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2015, 50,467 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company’s 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors’ services during the fiscal year. Under this program, the Company issued 15,516 original issue shares of common stock during 2015.

Shareholder Rights Plan

In 1996, the Company’s Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended several times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective December 4, 2008, a copy of which was included as an exhibit to the Form 8-K filed by the Company on December 4, 2008.

Pursuant to the Plan, the holders of the Company’s common stock have one right (Right) for each of their shares. Each Right is initially evidenced by the Company’s common stock certificates representing the outstanding shares of common stock.

The Rights have anti-takeover effects because they will cause substantial dilution of the Company’s common stock if a person (an Acquiring Person) attempts to acquire the Company on terms not approved by the Board of Directors.

The Rights become exercisable upon the occurrence of a Distribution Date as described below, but after a Distribution Date, Rights that are owned by an Acquiring Person will be null and void. At any time following a Distribution Date, each holder of a Right may exercise its right to receive, upon payment of an amount calculated under the Rights Agreement, common stock of the Company (or, under certain circumstances, other securities or assets of the Company) having a value equal to two times the amount paid to exercise the Right. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

A Distribution Date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company’s common stock or other voting stock (including Synthetic Long Positions as defined in the Plan) having 10% or more of the total voting power of the Company’s common stock and other voting stock or (ii) ten days after the commencement or announcement by a person or group of an intention to make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial ownership of the Company's common stock or other voting stock having 10% or more of the total voting power of the Company's common stock and other voting stock.

In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company's stock as described above, each holder of a Right will have the right to receive, upon exercise of the Right, common stock of the acquiring company having a value equal to two times the amount paid to exercise the Right. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company's assets or earning power is sold or transferred.

At any time prior to the end of the business day on the tenth day following the Distribution Date, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company's full Board of Directors. Also, at any time following the Distribution Date, 75% of the Company's full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2018, unless earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration date.

Stock Option and Stock Award Plans

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, SARs, restricted stock, restricted stock units, performance units or performance shares.

Stock-based compensation expense for the years ended September 30, 2015, 2014 and 2013 was approximately $2.1 million, $10.5 million, and $11.5 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2015, 2014 and 2013 was approximately $0.9 million, $4.3 million and $4.6 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Stock-based compensation of $0.1 million, $0.1 million and less than $0.1 million was capitalized under these rules during the years ended September 30, 2015, 2014 and 2013, respectively.

The Company realized excess tax benefits related to stock-based compensation of $7.7 million, $3.1 million, and $3.6 million for the fiscal years ended September 30, 2015, 2014 and 2013, respectively. These amounts are recorded in Paid in Capital when they meet the realization requirements of the authoritative guidance on stock-based compensation.

Stock Options

Transactions involving option shares for all plans are summarized as follows:

	Number of Shares Subject to Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value
				(In thousands)
Outstanding at September 30, 2014	482,000	$ 36.71		
Granted in 2015	—	$ —		
Exercised in 2015	(175,500)	$ 34.94		
Forfeited in 2015	—	$ —		
Outstanding at September 30, 2015	306,500	$ 37.73	0.94	$ 3,754
Option shares exercisable at September 30, 2015	306,500	$ 37.73	0.94	$ 3,754
Option shares available for future grant at September 30, 2015(1)	3,184,675			

(1) Includes shares available for SARs, restricted stock and performance share grants.

The total intrinsic value of stock options exercised during the years ended September 30, 2015, 2014 and 2013 totaled approximately $5.1 million, $13.7 million, and $11.6 million, respectively. For 2015, 2014 and 2013, the amount of cash received by the Company from the exercise of such stock options was approximately $5.6 million, $7.4 million, and $2.6 million, respectively. The Company last granted stock options in fiscal 2007 and all outstanding stock options have been fully vested since fiscal 2010.

SARs

Transactions involving SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value
				(In thousands)
Outstanding at September 30, 2014	1,793,482	$ 48.11		
Granted in 2015	—	$ —		
Exercised in 2015	(60,698)	$ 31.29		
Forfeited in 2015	—	$ —		
Outstanding at September 30, 2015	1,732,784	$ 48.70	4.98	$ 2,224
SARs exercisable at September 30, 2015	1,614,702	$ 48.36	4.82	$ 2,621

The Company did not grant any SARs during the year ended September 30, 2014. The Company granted 412,970 SARs during the year ended September 30, 2013 with a weighted average grant date fair value of $10.66 per share. The SARs granted in 2013 may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. The Company's SARs include both performance based and non-performance based SARs, but the performance conditions associated with the performance based SARs at the time of grant have all been subsequently met. The SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for SARs is the same as the accounting for stock options. The SARs granted during the year ended September 30, 2013 vest and become exercisable annually in one-third increments. The weighted average grant date fair value of the SARs granted during the year ended September 30, 2013 was estimated on the date of grant using the same accounting treatment that is applied for stock options.

The total intrinsic value of SARs exercised during the years ended September 30, 2015, 2014 and 2013 totaled approximately $2.0 million, $8.4 million, and $0.8 million, respectively. For the years ended September 30, 2015, 2014 and 2013, 157,386 SARs, 323,188 SARs and 287,168 SARs, respectively, became fully vested. The total fair value of the SARs that became vested during each of the years ended September 30, 2015, 2014 and 2013 was approximately $1.7 million, $3.8 million and $3.6 million, respectively. As of September 30, 2015, unrecognized compensation expense related to SARs totaled approximately $0.1 million, which will be recognized over a weighted average period of 6 months.

The fair value of SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the SARs. The expected life is based on historical experience and the expected volatility is based on historical daily stock price returns. For SARs grants during the year ended September 30, 2013, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following weighted average assumptions were used in estimating the fair value of SARs at the date of grant:

	Year Ended September 30		
	2015	2014	2013
Risk-Free Interest Rate	N/A	N/A	1.55%
Expected Life (Years)	N/A	N/A	8.25
Expected Volatility	N/A	N/A	25.61%
Expected Dividend Yield (Quarterly)	N/A	N/A	0.69%

Restricted Share Awards

Transactions involving restricted share awards for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Outstanding at September 30, 2014	89,518	$ 49.05
Granted in 2015	—	$ —
Vested in 2015	(29,518)	$ 52.14
Forfeited in 2015	—	$ —
Outstanding at September 30, 2015	60,000	$ 47.53

The Company did not grant any restricted share awards (non-vested stock as defined by the current accounting literature) during the years ended September 30, 2014 and 2013. As of September 30, 2015, unrecognized compensation expense related to restricted share awards totaled approximately $0.9 million, which will be recognized over a weighted average period of 2.4 years.

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2015 will lapse as follows: 2016 — 5,000 shares; 2018 — 35,000 shares; and 2021 — 20,000 shares.

Restricted Stock Units

Transactions involving non-performance based restricted stock units for all plans are summarized as follows:

	Number of Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2014	204,519	$ 56.36
Granted in 2015	88,899	$ 64.04
Vested in 2015	(48,490)	$ 57.17
Forfeited in 2015	(7,980)	$ 57.38
Outstanding at September 30, 2015	236,948	$ 59.04

The Company also granted 82,151 and 44,200 non-performance based restricted stock units during the years ended September 30, 2014 and 2013, respectively. The weighted average fair value of such non-performance based restricted stock units granted in 2014 and 2013 was $65.24 per share and $51.11 per share, respectively. As of September 30, 2015, unrecognized compensation expense related to non-performance based restricted stock units totaled approximately $5.7 million, which will be recognized over a weighted average period of 1.6 years.

Vesting restrictions for the non-performance based restricted stock units outstanding at September 30, 2015 will lapse as follows: 2016 — 77,837 units; 2017 — 76,156 units; 2018 — 50,600 units; 2019 — 21,245 units; and 2020 - 11,110 units.

Transactions involving performance based restricted stock units for all plans are summarized as follows:

	Number of Performance Based Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2014	233,876	$ 49.61
Granted in 2015	—	$ —
Vested in 2015	—	$ —
Forfeited in 2015	(389)	$ 48.49
Outstanding at September 30, 2015	233,487	$ 49.61

The Company granted 255,604 performance based restricted stock units during the year ended September 30, 2013 with a weighted average grant date fair value of $49.51 per share. The Company did not grant any performance based restricted stock units during the year ended September 30, 2014. The performance based restricted stock units granted during the year ended September 30, 2013 must meet a performance condition over the performance cycle of October 1, 2012 to September 30, 2015. The performance condition over the performance cycle, generally stated, is the Company’s total return on capital as compared to the same metric for companies in the Natural Gas Distribution and Integrated Natural Gas Companies group as calculated and reported in the Monthly Utility Reports of AUS, Inc., a leading industry consultant. The number of performance based restricted stock units that will vest will depend upon the Company’s performance relative to the report group and not upon the absolute level of return achieved by the Company. Based on the significant loss that the Company experienced during 2015, management believes that the performance conditions associated with the outstanding performance based restricted stock units will not be met. Accordingly, the cumulative stock-based compensation expense of approximately $8.0 million associated with these restricted stock units was reversed during 2015, and there is no unrecognized compensation expense related to such performance based restricted stock units at September 30, 2015. These restricted stock units are not expected to vest in 2016, which is when the vesting restrictions are scheduled to lapse.

Performance Shares

Transactions involving performance shares for all plans are summarized as follows:

	Number of Performance Shares	Weighted Average Fair Value per Award
Outstanding at September 30, 2014	98,466	$ 67.16
Granted in 2015	107,044	$ 65.26
Vested in 2015	—	$ —
Forfeited in 2015	(768)	$ 67.16
Outstanding at September 30, 2015	204,742	$ 66.17

The Company granted 116,090 performance shares during the year ended September 30, 2014 with a weighted average grant date fair value of $67.16 per share. The Company did not grant any performance shares during the year ended September 30, 2013. As of September 30, 2015, unrecognized compensation expense related to performance shares totaled approximately $7.0 million, which will be recognized over a weighted average period of 1.3 years. Vesting restrictions for the outstanding performance shares at September 30, 2015 will lapse as follows: 2017 - 97,698 shares; and 2018 - 107,044 shares.

Half of the performance shares granted during the year ended September 30, 2015 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2014 to September 30, 2017. In addition, half of the performance shares granted during the year ended September 30, 2014 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2013 to September 30, 2016. The performance goals over their respective performance cycles for these performance shares granted during 2015 and 2014 is the Company’s total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee (“Report Group”). Total return on capital for a given company means the average of the Report Group companies’ returns on capital for each twelve month period corresponding to each of the Company’s fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these performance shares that will vest and be paid will depend upon the Company’s performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of these performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award.

The other half of the performance shares granted during the year ended September 30, 2015 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2014 to September 30, 2017. In addition, the other half of the performance shares granted during the year ended September 30, 2014 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2013 to September 30, 2016. The performance goals over their respective performance cycles for these total shareholder return performance shares ("TSR performance shares") granted during 2015 and 2014 is the Company’s three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company’s securities at each ex-dividend date) in the Bloomberg database. The number of these TSR performance shares that will vest and be paid will depend upon the Company’s performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value price at the date of grant for the TSR performance shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of TSR performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award. In calculating fair value of the award, the risk-free interest rate is based on the yield of a Treasury Note with a term commensurate with the remaining term of the TSR performance shares. The remaining term is based on the remainder of the performance cycle as of the date of grant. The expected volatility is based on historical daily stock price returns. For the TSR performance shares, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following assumptions were used in estimating the fair value of the TSR performance shares at the date of grant:

	Year Ended September 30		
	2015	2014	2013
Risk-Free Interest Rate	1.01%	0.62%	N/A
Remaining Term at Date of Grant (Years)	2.78	2.78	N/A
Expected Volatility	20.1%	28.3%	N/A
Expected Dividend Yield (Quarterly)	N/A	N/A	N/A

Redeemable Preferred Stock

As of September 30, 2015, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30	
	2015	2014
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$ 99,000	$ 99,000
Notes(1)(3):		
3.75% to 8.75% due April 2018 to July 2025	2,000,000	1,550,000
Total Long-Term Debt	2,099,000	1,649,000
Less Unamortized Discount and Debt Issuance Costs	14,991	11,557
Less Current Portion(2)	—	—
	$ 2,084,009	$ 1,637,443

(1) The Medium-Term Notes and Notes are unsecured.

(2) None of the Company's long-term debt at September 30, 2015 and 2014 will mature within the following twelve-month period.

(3) The holders of these notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade.

On June 25, 2015, the Company issued $450.0 million of 5.20% notes due July 15, 2025. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $444.6 million. The proceeds of this debt issuance were used for general corporate purposes, including the reduction of short-term debt.

As of September 30, 2015, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: zero in 2016 and 2017, $300.0 million in 2018, $250.0 million in 2019, zero in 2020 and $1,549.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement with a syndicate of 14 banks. The agreement replaced the Company's previous $750.0 million syndicated committed credit facility with a substantially similar facility totaling $750.0 million. On September 30, 2015, the Company entered into a Second Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of the same 14 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019, plus a $500.0 million 364-day unsecured committed revolving credit facility through September 29, 2016. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. The total amount available to be issued under the Company’s commercial paper program is $500.0 million. At September 30, 2015, the commercial paper program was backed by the Credit Agreement.

The Company did not have any outstanding commercial paper at September 30, 2015. At September 30, 2014, the Company had outstanding commercial paper of $85.6 million with a weighted average interest rate on the commercial paper of 0.31%. The Company did not have any short-term notes payable to banks at September 30, 2015 and 2014.

Debt Restrictions

The Credit Agreement provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through December 5, 2019. At September 30, 2015, the Company’s debt to capitalization ratio (as calculated under the facility) was .51. The constraints specified in the Credit Agreement would have permitted an additional $1.67 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company’s debt to capitalization ratio exceeded .65.

If a downgrade in any of the Company’s credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources, including cash provided by operations.

The Credit Agreement contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2015, the Company had no debt outstanding under the Credit Agreement.

Under the Company’s existing indenture covenants, at September 30, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness during fiscal 2016 as a result of impairments of its oil and gas properties recognized during the year ended September 30, 2015. The 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt. If the Company experiences additional significant impairments of its oil and gas properties in the first or subsequent quarters of fiscal 2016, the Company, under its 1974 indenture, expects to continue to be precluded from issuing incremental long-term debt into the first or subsequent quarters of fiscal 2017. However, the Company expects that it could borrow under its credit facilities. The Company's present liquidity position is believed to be adequate to satisfy known demands.

The Company's 1974 indenture pursuant to which $99.0 million (or 4.7%) of the Company's long-term debt (as of September 30, 2015) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

Note F — Fair Value Measurements

The FASB authoritative guidance regarding fair value measurements establishes a fair-value hierarchy and prioritizes the inputs used in valuation techniques that measure fair value. Those inputs are prioritized into three levels. Level 1 inputs are unadjusted quoted prices in active markets for assets or liabilities that the Company can access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly at the measurement date. Level 3 inputs are unobservable inputs for the asset or liability at the measurement date. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of September 30, 2015 and 2014. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps combines gas and oil swaps because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At Fair Value as of September 30, 2015				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 92,196	$ —	$ —	$ —	$ 92,196
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	6,373	—	—	(6,373)	—
Over the Counter Swaps — Gas and Oil	—	272,335	1,791	(808)	273,318
Foreign Currency Contracts	—	—	—	(2,955)	(2,955)
Other Investments:					
Balanced Equity Mutual Fund	34,884	—	—	—	34,884
Fixed Income Mutual Funds	8,004	—	—	—	8,004
Common Stock — Financial Services Industry	4,318	—	—	—	4,318
Other Common Stock	450	—	—	—	450
Hedging Collateral Deposits	11,124	—	—	—	11,124
Total	$ 157,349	$ 272,335	$ 1,791	$ (10,136)	$ 421,339
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	$ 15,276	$ —	$ —	$ (6,373)	$ 8,903
Over the Counter Swaps — Gas and Oil	—	1,981	—	(808)	1,173
Foreign Currency Contracts	—	2,955	—	(2,955)	—
Total	$ 15,276	$ 4,936	$ —	$ (10,136)	$ 10,076
Total Net Assets/(Liabilities)	$ 142,073	$ 267,399	$ 1,791	$ —	$ 411,263

Recurring Fair Value Measures	At Fair Value as of September 30, 2014				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 23,794	$ —	$ —	$ —	$ 23,794
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	2,725	—	—	(1,987)	738
Over the Counter Swaps — Gas and Oil	—	75,951	1,368	(5,451)	71,868
Other Investments:					
Balanced Equity Mutual Fund	35,331	—	—	—	35,331
Common Stock — Financial Services Industry	6,629	—	—	—	6,629
Other Common Stock	455	—	—	—	455
Hedging Collateral Deposits	2,734	—	—	—	2,734
Total	$ 71,668	$ 75,951	$ 1,368	$ (7,438)	$ 141,549
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	$ 2,674	$ —	$ —	$ (1,987)	$ 687
Over the Counter Swaps — Gas and Oil	—	5,523	—	(5,451)	72
Total	$ 2,674	$ 5,523	$ —	$ (7,438)	$ 759
Total Net Assets/(Liabilities)	$ 68,994	$ 70,428	$ 1,368	$ —	$ 140,790

(1) Netting Adjustments represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties. The net asset or net liability for each counterparty is recorded as an asset or liability on the Company's balance sheet.

Derivative Financial Instruments

At September 30, 2015 and 2014, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX and ICE futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $11.1 million (at September 30, 2015) and $2.7 million (at September 30, 2014), which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at September 30, 2015 and 2014 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments, the majority of the crude oil price swap agreements used in the Company's Exploration and Production segment and foreign currency contracts used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The fair value of the Level 2 foreign currency contracts is determined using the market approach based on observable market transactions of forward Canadian currency rates. The derivative financial instruments reported in Level 3 consist of a portion of the crude oil price swap agreements used in the Company's Exploration and Production segment at September 30, 2015 and 2014. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The significant unobservable input used in the fair value measurement of a portion of the Company's over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in the value of the derivative financial instruments. At September 30, 2015, it was assumed that Midway Sunset oil was 91.8% of NYMEX. This is based on a historical twelve month average of Midway Sunset oil sales verses NYMEX settlements. During this twelve-month period, the price of Midway Sunset oil ranged from 87.8% to 94.6% of NYMEX. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement calculation had been 10 percentage points higher, the fair value of the Level 3 crude oil price swap agreements asset would have been approximately $0.2 million lower at September 30, 2015. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement had been 10 percentage points lower, the fair value measurement of the Level 3 crude oil price swap agreements asset would have been approximately $0.2 million higher at September 30, 2015. These calculated amounts are based solely on basis differential changes and do not take into account any other changes to the fair value measurement calculation.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2015, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the years ended September 30, 2015 and September 30, 2014, respectively. For the years ended September 30, 2015 and September 30, 2014, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/

Losses Realized and Included in Earnings column of the tables below (amounts in parentheses indicate credits in the derivative asset/liability accounts).

Fair Value Measurements Using Unobservable Inputs (Level 3)

		Total Gains/Losses			
	October 1, 2014	(Gains)/Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2015
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$ 1,368	$ (12,738) (1)	$ 13,161	$ —	$ 1,791

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2015.
(2) Derivative Financial Instruments are shown on a net basis.

		Total Gains/Losses			
	October 1, 2013	(Gains)/Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2014
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$ (5,190)	$ 2,217 (1)	$ 4,341	$ —	$ 1,368

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2014.
(2) Derivative Financial Instruments are shown on a net basis.

Note G — Financial Instruments

Long-Term Debt

The fair market value of the Company's debt, as presented in the table below, was determined using a discounted cash flow model, which incorporates the Company's credit ratings and current market conditions in determining the yield, and subsequently, the fair market value of the debt. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows:

	At September 30			
	2015 Carrying Amount	2015 Fair Value	2014 Carrying Amount	2014 Fair Value
		(Thousands)		
Long-Term Debt	$ 2,084,009	$ 2,129,558	$ 1,637,443	$ 1,775,715

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company's Consolidated Balance Sheets approximate fair value. The fair value of long-term debt was calculated using observable inputs (U.S.

Treasuries/LIBOR for the risk-free component and company specific credit spread information — generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

Any temporary cash investments, notes payable to banks and commercial paper are stated at cost. Temporary cash investments are considered Level 1, while notes payable to banks and commercial paper are considered to be Level 2. Given the short-term nature of the notes payable to banks and commercial paper, the Company believes cost is a reasonable approximation of fair value.

Other Investments

Investments in life insurance are stated at their cash surrender values or net present value as discussed below. Investments in an equity mutual fund and the stock of an insurance company (marketable equity securities), as discussed below, are stated at fair value based on quoted market prices.

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity and fixed income securities. The values of the insurance contracts amounted to $45.3 million and $44.4 million at September 30, 2015 and 2014, respectively. The fair value of the equity mutual fund was $34.9 million and $35.3 million at September 30, 2015 and 2014, respectively. The gross unrealized gain on this equity mutual fund was $6.5 million at September 30, 2015 and $8.4 million at September 30, 2014. The fair value of the fixed income mutual fund was $8.0 million at September 30, 2015. The fair value of the stock of an insurance company was $4.3 million and $6.6 million at September 30, 2015 and 2014, respectively. The gross unrealized gain on this stock was $2.6 million and $4.5 million at September 30, 2015 and 2014, respectively. The insurance contracts and marketable equity and fixed income securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company's combined cash flow and fair value hedges does not typically exceed 5 years. The Exploration and Production segment holds the majority of the Company's derivative financial instruments. The derivative financial instruments held by the Energy Marketing segment are not considered to be material to the Company.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at September 30, 2015 and September 30, 2014. Substantially all of the derivative financial instruments reported on those line items relate to commodity contracts and a small portion relates to foreign currency contracts.

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of September 30, 2015, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	180.5	Bcf (short positions)
Natural Gas	2.8	Bcf (long positions)
Crude Oil	2,196,000	Bbls (short positions)

As of September 30, 2015, the Company was hedging a total of $58.0 million of forecasted transportation costs denominated in Canadian dollars with swaps on forward currency rates (long positions). Settlements will begin in fiscal 2016.

As of September 30, 2015, the Company had $272.2 million ($157.2 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $168.1 million ($97.1 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transactions are recorded in earnings.

Refer to Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2015 and 2014 (Dollar Amounts in Thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Year Ended September 30,	
	2015	2014		2015	2014		2015	2014
Commodity Contracts	$ 377,957	$ 9,763	Operating Revenue	$180,069	$(14,880)	Operating Revenue	$ 3,563	$ 624
Commodity Contracts	$ 6,016	$ (4,429)	Purchased Gas	$ 4,884	$ (2,767)	Not Applicable	$ —	$ —
Foreign Currency Contracts	$ (2,955)	$ —	Not Applicable	$ —	$ —	Not Applicable	$ —	$ —
Total	$ 381,018	$ 5,334		$184,953	$(17,647)		$ 3,563	$ 624

Fair Value Hedges

The Company utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of certain natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company's financial statements. As of September 30, 2015, the Company's Energy Marketing segment had fair value hedges covering approximately 17.9 Bcf of mostly fixed price sales commitments. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Derivatives in Fair Value Hedging Relationships	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2015	Amount of Gain or (Loss) on Hedged Item Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2015
		(In thousands)	
Commodity Contracts	Operating Revenues	$ (13,944)	$ 13,944
Commodity Contracts	Purchased Gas	(18)	18
		$ (13,962)	**$ 13,962**

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with sixteen counterparties of which fifteen are in a net gain position. On average, the Company had $18.0 million of credit exposure per counterparty in a gain position at September 30, 2015. The maximum credit exposure per counterparty in a gain position at September 30, 2015 was $50.5 million. The Company's gain position on such derivative financial instruments for certain counterparties exceeded the established thresholds at which the counterparties would be required to post collateral. At September 30, 2015, collateral deposits of $29.7 million were posted. These collateral deposits are recorded as a component of Accounts Payable on the Consolidated Balance Sheet.

As of September 30, 2015, thirteen of the sixteen counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At September 30, 2015, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $174.6 million according to the Company's internal model (discussed in Note F — Fair Value Measurements). For its over-the-counter swap agreements, no hedging collateral deposits were required to be posted by the Company at September 30, 2015.

For its exchange traded futures contracts, the Company was required to post $11.1 million in hedging collateral deposits as of September 30, 2015. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company's requirement to post hedging collateral deposits and the Company's right to receive hedging collateral deposits is based on the fair value determined by the Company's counterparties, which may differ from the Company's assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note A under Hedging Collateral Deposits.

Note H — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan). The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were $2.3 million, $1.9 million and $1.2 million for the years ended September 30, 2015, 2014 and 2013, respectively. Costs associated with the Company's contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were $5.8 million, $5.2 million, and $4.4 million for the years ended September 30, 2015, 2014 and 2013, respectively.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The other post-retirement benefits cover certain non-collectively bargained employees hired before January 1, 2003 and certain collectively bargained employees hired before October 31, 2003.

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established VEBA trusts for its other post-retirement benefits. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' other post-retirement benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its other post-retirement benefits. They are separate accounts within the Retirement Plan trust used to pay retiree medical benefits for the associated participants in the Retirement Plan. Although these accounts are in the Retirement Plan trust, for funding status purposes as shown below, the 401(h) accounts are included in Fair Value of Assets under Other Post-Retirement Benefits. Contributions are tax-deductible when made, subject to limitations contained in the Internal Revenue Code and regulations.

The expected return on Retirement Plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is the market value as of the measurement date adjusted for variances between actual returns and expected returns (from previous years) that have not been reflected in net periodic benefit costs. The expected return on other post-retirement benefit assets (i.e. the VEBA trusts and 401(h) accounts), which is a component of net periodic benefit cost shown in the tables below, is applied to the fair value of assets as of the measurement date.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal years 2015, 2014 and 2013.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2015	2014	2013	2015	2014	2013
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 999,499	$ 946,305	$1,070,744	$465,583	$460,634	$ 561,263
Service Cost	12,047	11,987	15,846	2,693	2,939	4,705
Interest Cost	41,217	43,574	36,498	19,285	21,308	19,212
Plan Participants' Contributions	—	—	—	2,242	2,265	2,141
Retiree Drug Subsidy Receipts	—	—	—	1,338	1,419	1,526
Amendments(1)	7,752	—	—	—	—	—
Actuarial (Gain) Loss	23,426	53,887	(121,631)	(1,575)	1,087	(104,455)
Benefits Paid	(57,751)	(56,254)	(55,152)	(24,579)	(24,069)	(23,758)
Benefit Obligation at End of Period	$1,026,190	$ 999,499	$ 946,305	$464,987	$465,583	$ 460,634
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 869,791	$ 799,307	$ 701,676	$497,601	$472,392	$ 414,134
Actual Return on Plan Assets	(13,370)	93,238	98,783	534	44,898	61,715
Employer Contributions	36,200	33,500	54,000	2,161	2,115	18,160
Plan Participants' Contributions	—	—	—	2,242	2,265	2,141
Benefits Paid	(57,751)	(56,254)	(55,152)	(24,579)	(24,069)	(23,758)
Fair Value of Assets at End of Period	$ 834,870	$ 869,791	$ 799,307	$477,959	$497,601	$ 472,392
Net Amount Recognized at End of Period (Funded Status)	$ (191,320)	$ (129,708)	$ (146,998)	$ 12,972	$ 32,018	$ 11,758
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$ (191,320)	$ (129,708)	$ (146,998)	$ (11,487)	$ (4,494)	$ (11,016)
Non-Current Assets	—	—	—	24,459	36,512	22,774
Net Amount Recognized at End of Period	$ (191,320)	$ (129,708)	$ (146,998)	$ 12,972	$ 32,018	$ 11,758
Accumulated Benefit Obligation	$ 968,984	$ 940,068	$ 886,942	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	4.25%	4.25%	4.75%	4.50%	4.25%	4.75%
Rate of Compensation Increase	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2015	2014	2013	2015	2014	2013
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 12,047	$ 11,987	$ 15,846	$ 2,693	$ 2,939	$ 4,705
Interest Cost	41,217	43,574	36,498	19,285	21,308	19,212
Expected Return on Plan Assets	(59,615)	(59,974)	(57,346)	(34,089)	(37,424)	(32,872)
Amortization of Prior Service Cost (Credit)	183	210	238	(1,913)	(2,138)	(2,138)
Amortization of Transition Amount	—	—	—	—	—	8
Recognition of Actuarial Loss(2)	36,129	36,007	52,776	4,148	2,645	20,892
Net Amortization and Deferral for Regulatory Purposes	7,739	8,151	(10,406)	20,322	23,263	11,844
Net Periodic Benefit Cost	$ 37,700	$ 39,955	$ 37,606	$ 10,446	$ 10,593	$ 21,651
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	4.25%	4.75%	3.50%	4.25%	4.75%	3.50%
Expected Return on Plan Assets	7.50%	8.00%	8.00%	7.00%	8.00%	8.00%
Rate of Compensation Increase	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

(1) In fiscal 2015, the Company passed an amendment which updated the mortality table used in the Retirement Plan's definition of "actuarially equivalent" effective July 1, 2015. This increased the benefit obligation of the Retirement Plan.

(2) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

The Net Periodic Benefit Cost in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under the existing authoritative guidance as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets and liabilities) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In addition to the Retirement Plan discussed above, the Company also has Non-Qualified benefit plans that cover a group of management employees designated by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with these plans were $7.0 million, $7.5 million and $9.6 million in 2015, 2014 and 2013, respectively. The accumulated benefit obligations for the plans were $66.0 million, $65.7 million and $57.2 million at September 30, 2015, 2014 and 2013, respectively. The projected benefit obligations for the plans were $85.8 million, $85.5 million and $77.1 million at September 30, 2015, 2014 and 2013, respectively. At September 30, 2015, $4.5 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining $81.3 million is recorded in Other Deferred

Credits on the Consolidated Balance Sheets. At September 30, 2014, $6.6 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $78.9 million was recorded in Other Deferred Credits on the Consolidated Balance Sheets. At September 30, 2013, the projected benefit obligations are recorded in Other Deferred Credits on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 3.50%, 3.50% and 3.75% as of September 30, 2015, 2014 and 2013, respectively and the weighted average rate of compensation increase for these plans were 7.75%, 7.50% and 7.75% as of September 30, 2015, 2014 and 2013, respectively.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2015, the changes in such amounts during 2015, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2016 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plans
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	$ (287,180)	$ (59,914)	$ (24,929)
Prior Service (Cost) Credit	(8,425)	5,027	—
Net Amount Recognized	$ (295,605)	$ (54,887)	$ (24,929)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2015(1)			
Increase in Actuarial Loss, excluding amortization(2)	$ (96,412)	$ (31,980)	$ (4,321)
Change due to Amortization of Actuarial Loss	36,129	4,148	2,925
Prior Service (Cost) Credit	(7,569)	(1,913)	—
Net Change	$ (67,852)	$ (29,745)	$ (1,396)
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	$ (32,248)	$ (5,530)	$ (3,295)
Prior Service (Cost) Credit	(1,234)	912	—
Net Amount Expected to be Recognized	$ (33,482)	$ (4,618)	$ (3,295)

(1) Amounts presented are shown before recognizing deferred taxes.

(2) Amounts presented include the impact of actuarial gains/losses related to return on assets, as well as the Actuarial (Gain) Loss amounts presented in the Change in Benefit Obligation.

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2015, the Company recorded a $76.7 million increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $22.3 million (pre-tax) decrease to Accumulated Other Comprehensive Income.

The effect of the mortality assumption change for the Retirement Plan in 2015 was to increase the projected benefit obligation of the Retirement Plan by $24.2 million. In 2015, other actuarial experience decreased the projected benefit obligation for the Retirement Plan by $0.8 million. The effect of the discount rate change for the Retirement Plan in 2014 was to increase the projected benefit obligation of the Retirement Plan by $53.7 million. The effect of the discount rate change for the Retirement Plan in 2013 was to decrease the projected benefit obligation of the Retirement Plan by $147.9 million.

The Company made cash contributions totaling $36.2 million to the Retirement Plan during the year ended September 30, 2015. The Company expects that the annual contribution to the Retirement Plan in 2016 will be in the range of $5.0 million to $10.0 million.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: $61.1 million in 2016; $62.1 million in 2017; $63.0 million in 2018; $63.7 million in 2019; $64.4 million in 2020; and $332.1 million in the five years thereafter.

The effect of the discount rate change in 2015 was to decrease the other post-retirement benefit obligation by $14.3 million. Other actuarial experience increased the other post-retirement benefit obligation in 2015 by $12.8 million primarily attributable to the change in mortality assumption.

The effect of the discount rate change in 2014 was to increase the other post-retirement benefit obligation by $26.4 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2014 by $25.3 million primarily attributable to a revision in assumed per-capita claims cost, premiums and participant contributions based on actual experience.

The effect of the discount rate change in 2013 was to decrease the other post-retirement benefit obligation by $75.9 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2013 by $28.6 million as the increase in obligation attributable to the change in mortality assumption was more than offset by the decrease in obligation attributable to a revision in assumed per-capita claims cost, premiums and participant contributions based on actual experience.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

The estimated gross other post-retirement benefit payments and gross amount of Medicare Part D prescription drug subsidy receipts are as follows (dollars in thousands):

	Benefit Payments	Subsidy Receipts
2016	$ 25,728	$ (1,786)
2017	$ 26,942	$ (1,935)
2018	$ 28,059	$ (2,094)
2019	$ 29,038	$ (2,259)
2020	$ 30,079	$ (2,405)
2021 through 2025	$ 161,958	$ (14,197)

Assumed health care cost trend rates as of September 30 were:

	2015	2014	2013
Rate of Medical Cost Increase for Pre Age 65 Participants	6.93% (1)	7.10% (1)	7.28% (1)
Rate of Medical Cost Increase for Post Age 65 Participants	6.68% (1)	6.73% (1)	6.78% (1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	7.17% (1)	7.47% (1)	7.78% (1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	6.68% (1)	6.73% (1)	6.78% (1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	6.65% (1)	6.79% (1)	7.03% (1)

(1) It was assumed that this rate would gradually decline to 4.5% by 2028.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2015 would increase by $53.9 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2015 by $2.9 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2015 would decrease by $45.2 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2015 by $2.4 million.

The Company made cash contributions totaling $2.0 million to its VEBA trusts and 401(h) accounts during the year ended September 30, 2015. In addition, the Company made direct payments of $0.2 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2015. The Company expects that the annual contribution to its VEBA trusts and 401(h) accounts in 2016 will be in the range of $2.0 million to $5.0 million.

Investment Valuation

The Retirement Plan assets and other post-retirement benefit assets are valued under the current fair value framework. See Note F — Fair Value Measurements for further discussion regarding the definition and levels of fair value hierarchy established by the authoritative guidance.

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2015 and 2014, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall, based on the lowest level input that is significant to the fair value measurement in its entirety (dollars in thousands):

	Total Fair Value Amounts at September 30, 2015	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$ 229,811	$ 170,166	$ 59,645	$ —
International Equities(2)	96,478	—	96,478	—
Global Equities(3)	112,802	—	112,802	—
Domestic Fixed Income(4)	303,508	1,539	301,969	—
International Fixed Income(5)	883	883	—	—
Global Fixed Income(6)	86,773	—	86,773	—
Hedge Fund Investments	26,490	—	—	26,490
Real Estate	4,724	—	—	4,724
Cash and Cash Equivalents	27,723	—	27,723	—
Total Retirement Plan Investments	889,192	172,588	685,390	31,214
401(h) Investments	(53,686)	(10,420)	(41,381)	(1,885)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 835,506	$ 162,168	$ 644,009	$ 29,329
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(636)			
Total Retirement Plan Assets	$ 834,870			

	Total Fair Value Amounts at September 30, 2014	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$ 268,649	$ 171,979	$ 96,670	$ —
International Equities(2)	80,957	1,969	78,988	—
Global Equities(3)	104,238	—	104,238	—
Domestic Fixed Income(4)	299,494	63,187	236,307	—
International Fixed Income(5)	1,240	508	732	—
Global Fixed Income(6)	93,704	—	93,704	—
Hedge Fund Investments	45,213	—	—	45,213
Real Estate	3,792	—	—	3,792
Cash and Cash Equivalents	33,544	—	33,544	—
Total Retirement Plan Investments	930,831	237,643	644,183	49,005
401(h) Investments	(54,921)	(14,105)	(37,907)	(2,909)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 875,910	$ 223,538	$ 606,276	$ 46,096
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(6,119)			
Total Retirement Plan Assets	$ 869,791			

(1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.
(2) International Equities include mostly collective trust funds and common stock.
(3) Global Equities are comprised of collective trust funds.

(4) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.
(5) International Fixed Income securities include mostly collective trust funds and exchange traded funds.
(6) Global Fixed Income securities are comprised of a collective trust fund.

	Total Fair Value Amounts at September 30, 2015	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds — Domestic Equities	$ 128,336	$ —	$ 128,336	$ —
Collective Trust Funds — International Equities	48,857	—	48,857	—
Exchange Traded Funds — Fixed Income	233,471	233,471	—	—
Cash Held in Collective Trust Funds	13,119	—	13,119	—
Total VEBA Trust Investments	423,783	233,471	190,312	—
401(h) Investments	53,686	10,420	41,381	1,885
Total Investments (including 401(h) Investments)	$ 477,469	$ 243,891	$ 231,693	$ 1,885
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	490			
Total Other Post-Retirement Benefit Assets	$ 477,959			

	Total Fair Value Amounts at September 30, 2014	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds — Domestic Equities	$ 148,219	$ —	$ 148,219	$ —
Collective Trust Funds — International Equities	54,881	—	54,881	—
Exchange Traded Funds — Fixed Income	236,513	236,513	—	—
Cash Held in Collective Trust Funds	6,412	—	6,412	—
Total VEBA Trust Investments	446,025	236,513	209,512	—
401(h) Investments	54,921	14,105	37,907	2,909
Total Investments (including 401(h) Investments)	$ 500,946	$ 250,618	$ 247,419	$ 2,909
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(3,345)			
Total Other Post-Retirement Benefit Assets	$ 497,601			

The fair values disclosed in the above tables may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). Note: For the years ended September 30, 2015 and September 30, 2014, there were no transfers from Level 1 to Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

	Retirement Plan Level 3 Assets (Thousands)			
	Hedge Funds	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2013	$ 42,027	$ 2,723	$ (2,606)	$ 42,144
Realized Gains/(Losses)	—	62	(4)	58
Unrealized Gains/(Losses)	3,186	(10)	(239)	2,937
Purchases	—	1,111	(65)	1,046
Sales	—	(94)	5	(89)
Balance at September 30, 2014	45,213	3,792	(2,909)	46,096
Realized Gains/(Losses)	2,284	—	(135)	2,149
Unrealized Gains/(Losses)	317	871	(103)	1,085
Purchases	—	82	(5)	77
Sales	(21,324)	(21)	1,267	(20,078)
Balance at September 30, 2015	$ 26,490	$ 4,724	$ (1,885)	$ 29,329

	Other Post-Retirement Benefit Level 3 Assets (Thousands)		
	VEBA Trust Investments		
	Real Estate	Including 401(h) Investments	Other Post-Retirement Benefit Investments
Balance at September 30, 2013	$ 55	$ 2,606	$ 2,661
Realized Gains/(Losses)	(40)	4	(36)
Unrealized Gains/(Losses)	—	239	239
Purchases	—	65	65
Sales	(15)	(5)	(20)
Balance at September 30, 2014	—	2,909	2,909
Realized Gains/(Losses)	—	135	135
Unrealized Gains/(Losses)	—	103	103
Purchases	—	5	5
Sales	—	(1,267)	(1,267)
Balance at September 30, 2015	$ —	$ 1,885	$ 1,885

The Company's assumption regarding the expected long-term rate of return on plan assets is 7.25% (Retirement Plan) and 6.75% (other post-retirement benefits), effective for fiscal 2016. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes projected capital market conditions and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). The target allocation for the Retirement Plan and the VEBA trusts (including 401(h) accounts) is 40-60% equity securities, 40-60% fixed income securities and 0-15% other. Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trusts, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

The discount rate used to present value the future benefit payment obligations of the Retirement Plan is 4.25% at September 30, 2015. The discount rate used to present value the future benefit payment obligations of the Company's other post-retirement benefits is 4.50% as of September 30, 2015. The discount rate used to present value the future benefit payment obligations of the Non-Qualified benefit plans is 3.50% as of September 30, 2015. The Company utilizes the Mercer Yield Curve Above Mean Model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. In determining the spot rates, the model will exclude coupon interest rates that are in the lower 50^{th} percentile based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities.

Note I — Commitments and Contingencies

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory requirements.

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2015, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $11.2 million. The main component of this liability is discussed below under "Former Manufactured Gas Plant Sites." This estimated liability has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2015. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 12 years. Other than as discussed below, the Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could could have an adverse financial impact on the Company.

Former Manufactured Gas Plant Sites

The Company has incurred investigation and/or clean-up costs at several former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing monitoring and long-term maintenance at two sites.

The most significant ongoing clean-up matter currently facing the Company is a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. As a result of this work, the Company submitted to the NYDEC a proposal to amend the NYDEC's Record of Decision remedy for the site. In April 2013, the NYDEC approved the Company's proposed amendment. Final remedial design work for the site has been completed, and remedial work has begun. An estimated minimum liability for remaining remediation of this site of $9.9 million has been recorded.

Other

The Company, in its Utility segment, Energy Marketing segment, and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The majority of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $185.1 million in 2016, $89.4 million in 2017, $84.9 million in 2018, $92.6 million in 2019, $73.5 million in 2020 and $762.5 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of compressors, drilling rigs, buildings, meters and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $25.7 million in 2016, $6.0 million in 2017, $4.7 million in 2018, $4.5 million in 2019, $3.3 million in 2020 and $0.6 million thereafter.

The Company, in its Pipeline and Storage segment and Gathering segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system expansion projects. As of September 30, 2015, the future contractual commitments related to the expansion projects are $96.6 million in 2016 and $0.2 million in 2017. There are no contractual commitments extending beyond 2017.

The Company, in its Exploration and Production segment, has entered into contractual obligations associated with hydraulic fracturing and fuel. The future contractual commitments are $104.7 million in 2016 and $25.0 million in 2017. There are no contractual commitments extending beyond 2017.

The Company, in its Utility segment, has entered into contractual obligations associated with the replacement of its legacy mainframe systems and has future contractual commitments of $21.4 million in 2016. There are no contractual commitments extending beyond 2016.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note C — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

Note J — Business Segment Information

The Company reports financial results for five segments: Exploration and Production, Pipeline and Storage, Gathering, Utility and Energy Marketing. The division of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California and the Appalachian region of the United States.

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR), exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports natural gas to major industrial companies, utilities (including Distribution Corporation) and power producers in New York State.

The Gathering segment is comprised of Midstream Corporation's operations. Midstream Corporation builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region and currently provides gathering services to Seneca.

The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The Energy Marketing segment is comprised of NFR's operations. NFR markets natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western and central New York and northwestern Pennsylvania, offering competitively priced natural gas for its customers.

The data presented in the tables below reflects financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. The Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. Energy Marketing segment revenues and related purchased gas costs for the year ended September 30, 2013 were recorded when billed, resulting in a one month lag. Starting in 2014, the Energy Marketing segment began recording unbilled revenue and related gas costs, recording \$8.5 million of unbilled revenue and \$0.6 million of related incremental margin (net of tax). The impact of not recording unbilled revenue and related costs was immaterial in all prior periods.

	Year Ended September 30, 2015								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$ 693,441	$ 203,089	$ 497	$ 700,761	$ 159,857	$ 1,757,645	$ 2,352	$ 916	$ 1,760,913
Intersegment Revenues	$ —	$ 88,251	$ 76,709	$ 15,506	$ 849	$ 181,315	$ —	$ (181,315)	$ —
Interest Income	$ 2,554	$ 474	$ 140	$ 2,220	$ 195	$ 5,583	$ 66	$ (1,727)	$ 3,922
Interest Expense	$ 46,726	$ 27,658	$ 1,627	$ 28,176	$ 27	$ 104,214	$ —	$ (4,743)	$ 99,471
Depreciation, Depletion and Amortization	$ 239,818	$ 38,178	$ 10,829	$ 45,616	$ 209	$ 334,650	$ 832	$ 676	$ 336,158
Income Tax Expense (Benefit)	$ (428,217)	$ 48,113	$ 24,721	$ 33,143	$ 4,547	$ (317,693)	$ 13	$ (1,456)	$ (319,136)
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ 1,126,257	$ —	$ —	$ —	$ —	$ 1,126,257	$ —	$ —	$ 1,126,257
Segment Profit: Net Income (Loss)	$ (556,974)	$ 80,354	$ 31,849	$ 63,271	$ 7,766	$ (373,734)	$ (2)	$ (5,691)	$ (379,427)
Expenditures for Additions to Long-Lived Assets	$ 557,313	$ 230,192	$ 118,166	$ 94,371	$ 128	$ 1,000,170	$ —	$ 339	$ 1,000,509
	At September 30, 2015								
	(Thousands)								
Segment Assets	$ 2,549,374	$1,597,173	$ 447,968	$1,960,158	$ 88,193	$ 6,642,866	$77,350	$ (18,077)	$ 6,702,139

	Year Ended September 30, 2014								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Elimination	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$ 804,096	$ 200,664	$ 673	$ 831,156	$ 271,993	$ 2,108,582	$ 3,532	$ 967	$ 2,113,081
Intersegment Revenues	$ —	$ 83,744	$ 69,937	$ 18,462	$ 1,159	$ 173,302	$ —	$ (173,302)	$ —
Interest Income	$ 1,909	$ 284	$ 120	$ 3,010	$ 173	$ 5,496	$ 106	$ (1,432)	$ 4,170
Interest Expense	$ 42,232	$ 26,428	$ 1,726	$ 27,693	$ 31	$ 98,110	$ 6	$ (3,839)	$ 94,277
Depreciation, Depletion and Amortization	$ 296,210	$ 36,642	$ 6,116	$ 43,594	$ 197	$ 382,759	$ 344	$ 678	$ 383,781
Income Tax Expense (Benefit)	$ 81,370	$ 47,100	$ 23,636	$ 33,918	$ 3,761	$ 189,785	$ 822	$ (993)	$ 189,614
Segment Profit: Net Income (Loss)	$ 121,569	$ 77,559	$ 32,709	$ 64,059	$ 6,631	$ 302,527	$ 1,160	$ (4,274)	$ 299,413
Expenditures for Additions to Long-Lived Assets	$ 602,705	$ 139,821	$ 137,799	$ 88,810	$ 264	$ 969,399	$ 274	$ 234	$ 969,907
	At September 30, 2014								
	(Thousands)								
Segment Assets	$ 3,100,514	$1,367,181	$ 326,662	$1,862,850	$ 76,238	$ 6,733,445	$86,460	$ (91,865)	$ 6,728,040

	Year Ended September 30, 2013								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$ 702,937	$ 178,184	$ 1,324	$ 730,319	$ 211,990	$ 1,824,754	$ 3,910	$ 887	$ 1,829,551
Intersegment Revenues	$ —	$ 89,424	$ 33,457	$ 16,020	$ 1,384	$ 140,285	$ —	$ (140,285)	$ —
Interest Income	$ 1,501	$ 193	$ 55	$ 3,417	$ 169	$ 5,335	$ 115	$ (1,115)	$ 4,335
Interest Expense	$ 39,745	$ 26,248	$ 2,283	$ 29,076	$ 36	$ 97,388	$ 2	$ (3,279)	$ 94,111
Depreciation, Depletion and Amortization	$ 243,431	$ 35,156	$ 3,945	$ 42,729	$ 123	$ 325,384	$ 577	$ 799	$ 326,760
Income Tax Expense (Benefit)	$ 95,317	$ 38,626	$ 10,287	$ 31,065	$ 2,450	$ 177,745	$ 529	$ (5,516)	$ 172,758
Segment Profit: Net Income (Loss)	$ 115,391	$ 63,245	$ 13,321	$ 65,686	$ 4,589	$ 262,232	$ 894	$ (3,125)	$ 260,001
Expenditures for Additions to Long-Lived Assets	$ 533,129	$ 56,144	$ 54,792	$ 71,970	$ 595	$ 716,630	$ 307	$ 160	$ 717,097
	At September 30, 2013								
	(Thousands)								
Segment Assets	$ 2,746,233	$1,246,027	$ 203,323	$1,870,587	$ 67,267	$ 6,133,437	$95,793	$ (24,253)	$ 6,204,977

(1) All Revenue from External Customers originated in the United States.

Geographic Information	At September 30		
	2015	2014	2013
	(Thousands)		
Long-Lived Assets:			
United States	$ 6,189,138	$ 6,350,708	$ 5,756,300

Note K — Quarterly Financial Data (unaudited)

In the opinion of management, the following quarterly information includes all adjustments necessary for a fair statement of the results of operations for such periods. Per common share amounts are calculated using the weighted average number of shares outstanding during each quarter. The total of all quarters may differ from the per common share amounts shown on the Consolidated Statements of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) Available for Common Stock	Earnings (Loss) per Common Share Basic	Diluted
	(Thousands, except per common share amounts)				
2015					
9/30/2015	$ 301,062	$ (326,731)	$ (187,703) (1)	$ (2.22)	$ (2.22)
6/30/2015	$ 339,815	$ (489,214)	$ (293,134) (2)	$ (3.47)	$ (3.44)
3/31/2015	$ 596,127	$ 44,331	$ 16,669 (3)	$ 0.20	$ 0.20
12/31/2014	$ 523,909	$ 160,561	$ 84,741	$ 1.01	$ 1.00
2014					
9/30/2014	$ 366,623	$ 102,004	$ 57,431	$ 0.68	$ 0.68
6/30/2014	$ 440,144	$ 127,013	$ 64,520	$ 0.77	$ 0.76
3/31/2014	$ 756,242	$ 180,075	$ 95,210 (4)	$ 1.14	$ 1.12
12/31/2013	$ 550,072	$ 160,581	$ 82,252	$ 0.98	$ 0.97

(1) Includes a non-cash $417.2 million impairment charge ($240.9 million after tax) associated with the Exploration and Production segment's oil and gas producing properties and a $8.0 million reversal of stock-based compensation expense ($5.2 million after tax) related to performance based restricted stock units.

(2) Includes a non-cash $588.7 million impairment charge ($339.8 million after tax) associated with the Exploration and Production segment's oil and gas producing properties.

(3) Includes a non-cash $120.3 million impairment charge ($69.5 million after tax) associated with the Exploration and Production segment's oil and gas producing properties.

(4) Includes $3.6 million of income associated with a death benefit gain on life insurance proceeds recorded in the Corporate category.

Note L — Market for Common Stock and Related Shareholder Matters (unaudited)

At September 30, 2015, there were 12,147 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note E — Capitalization and Short-Term Borrowings. The quarterly price ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2015 and 2014, are shown below:

Quarter Ended	Price Range High	Low	Dividends Declared
2015			
9/30/2015	$ 59.39	$ 48.61	$ 0.395
6/30/2015	$ 66.07	$ 58.83	$ 0.395
3/31/2015	$ 70.19	$ 57.73	$ 0.385
12/31/2014	$ 72.21	$ 64.31	$ 0.385
2014			
9/30/2014	$ 78.79	$ 65.29	$ 0.385
6/30/2014	$ 78.46	$ 68.50	$ 0.385
3/31/2014	$ 77.05	$ 68.12	$ 0.375
12/31/2013	$ 72.53	$ 65.23	$ 0.375

Note M — Supplementary Information for Oil and Gas Producing Activities (unaudited, except for Capitalized Costs Relating to Oil and Gas Producing Activities)

The Company follows authoritative guidance related to oil and gas exploration and production activities that aligns the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also follows. The SEC rules require companies to value their year-end reserves using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve month period prior to the end of the reporting period.

The following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2015	2014
	(Thousands)	
Proved Properties(1)	$ 4,473,721	$ 3,941,143
Unproved Properties	176,327	141,719
	4,650,048	4,082,862
Less — Accumulated Depreciation, Depletion and Amortization	2,572,348	1,211,610
	$ 2,077,700	$ 2,871,252

(1) Includes asset retirement costs of $113.3 million and $75.7 million at September 30, 2015 and 2014, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2020. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2016. Following is a summary of costs excluded from amortization at September 30, 2015:

	Total as of September 30, 2015	Year Costs Incurred			
		2015	2014	2013	Prior
	(Thousands)				
Acquisition Costs	$ 61,253	$ 2,777	$ 7,057	$ 905	$ 50,514
Development Costs	86,641	74,444	9,343	665	2,189
Exploration Costs	27,815	10,210	17,605	—	—
Capitalized Interest	618	303	315	—	—
	$ 176,327	$ 87,734	$ 34,320	$ 1,570	$ 52,703

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 1,767	$ 18,213	$ 7,575
Unproved	19,998	7,884	9,274
Exploration Costs(1)	53,222	71,850	49,483
Development Costs(2)	454,605	490,164	460,554
Asset Retirement Costs	37,595	(4,946)	37,546
	$ 567,187	$ 583,165	$ 564,432

(1) Amounts for 2015, 2014 and 2013 include capitalized interest of $0.4 million, $0.7 million and $0.4 million, respectively.

(2) Amounts for 2015, 2014 and 2013 include capitalized interest of $0.5 million, $0.7 million and $0.7 million, respectively.

For the years ended September 30, 2015, 2014 and 2013, the Company spent $161.8 million, $179.9 million and $148.5 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2015	2014	2013
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $1 for all years presented and transfers to operations of $1,946, $2,145 and $612, respectively)	$ 350,673	$ 515,080	$ 371,311
Oil, Condensate and Other Liquids	156,048	298,179	291,762
Total Operating Revenues(1)	506,721	813,259	663,073
Production/Lifting Costs	167,800	165,534	119,243
Franchise/Ad Valorem Taxes	20,167	20,765	17,200
Purchased Emission Allowance Expense	3,089	—	—
Accretion Expense	6,186	6,192	3,929
Depreciation, Depletion and Amortization ($1.49, $1.82 and $1.98 per Mcfe of production)	234,480	291,651	238,467
Impairment of Oil and Gas Producing Properties	1,126,257	—	—
Income Tax Expense	(444,393)	140,484	120,431
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$ (606,865)	$ 188,633	$ 163,803

(1) Exclusive of hedging gains and losses. See further discussion in Note G — Financial Instruments.

Reserve Quantity Information

The Company's proved oil and gas reserve estimates are prepared by the Company's reservoir engineers who meet the qualifications of Reserve Estimator per the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007. The Company maintains comprehensive internal reserve guidelines and a continuing education program designed to keep its staff up to date with current SEC regulations and guidance.

The Company's Vice President of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 25 years of Petroleum Engineering experience with both major and independent oil and gas companies. He has maintained oversight of the Company's reserve estimation process for the past twelve years. He is a member of the Society of Petroleum Evaluation Engineers and a Registered Professional Engineer in the State of Texas.

The Company maintains a system of internal controls over the reserve estimation process. Management reviews the price, heat content, lease operating cost and future investment assumptions used in the economic model that determines the reserves. The Vice President of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell and Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (consulting at NSAI since 2004 and with over 5 years of prior industry experience in petroleum engineering) and a professional geoscientist registered in the State of Texas (consulting at NSAI since 1998 with over 13 years of prior industry experience in petroleum geosciences). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2015 and did not identify any problems which would cause it to take exception to those estimates.

The reliable technologies that were utilized in estimating the reserves include wire line open-hole log data, performance data, log cross sections, core data, 2D and 3D seismic data and statistical analysis. The statistical method utilized production performance from both the Company's and competitors' wells. Geophysical data includes data from the Company's wells, published documents, state data-sites and 2D and 3D seismic data. This data was used to confirm continuity of the formation.

	Gas MMcf			
	U. S.			
	Appalachian Region		West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2012	925,411		63,023	988,434
Extensions and Discoveries	360,922	(1)	702	361,624
Revisions of Previous Estimates	53,038		112	53,150
Production	(100,633)	(2)	(3,060)	(103,693)
September 30, 2013	1,238,738		60,777	1,299,515
Extensions and Discoveries	446,821	(1)	—	446,821
Revisions of Previous Estimates	43,690		1,358	45,048
Production	(139,097)	(2)	(3,210)	(142,307)
Purchases of Minerals in Place	33,986		—	33,986
Sale of Minerals in Place	(76)		(103)	(179)
September 30, 2014	1,624,062		58,822	1,682,884
Extensions and Discoveries	633,360	(1)	—	633,360
Revisions of Previous Estimates	(28,124)		(6,317)	(34,441)
Production	(136,404)	(2)	(3,159)	(139,563)
Sale of Minerals in Place	(112)		—	(112)
September 30, 2015	2,092,782		49,346	2,142,128
Proved Developed Reserves:				
September 30, 2012	544,560		59,923	604,483
September 30, 2013	807,055		59,862	866,917
September 30, 2014	1,119,901		57,907	1,177,808
September 30, 2015	1,267,498		49,346	1,316,844
Proved Undeveloped Reserves:				
September 30, 2012	380,851		3,100	383,951
September 30, 2013	431,683		915	432,598
September 30, 2014	504,161		915	505,076
September 30, 2015	825,284		—	825,284

(1) Extensions and discoveries include 355 Bcf (during 2013), 442 Bcf (during 2014) and 598 Bcf (during 2015), of Marcellus Shale gas in the Appalachian Region.

(2) Production includes 93,999 MMcf (during 2013), 131,590 MMcf (during 2014) and 130,291 MMcf (during 2015), from Marcellus Shale fields (which exceed 15% of total reserves).

	Oil Mbbl		
	U. S.		
	Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
September 30, 2012	306	42,556	42,862
Extensions and Discoveries	—	2,443	2,443
Revisions of Previous Estimates	5	(881)	(876)
Production	(28)	(2,803)	(2,831)
September 30, 2013	283	41,315	41,598
Extensions and Discoveries	18	1,521	1,539
Revisions of Previous Estimates	(17)	(1,677)	(1,694)
Production	(31)	(3,005)	(3,036)
Purchases of Minerals in Place	—	83	83
Sales of Minerals in Place	—	(13)	(13)
September 30, 2014	253	38,224	38,477
Extensions and Discoveries	—	533	533
Revisions of Previous Estimates	(3)	(2,251)	(2,254)
Production	(30)	(3,004)	(3,034)
September 30, 2015	220	33,502	33,722
Proved Developed Reserves:			
September 30, 2012	306	38,138	38,444
September 30, 2013	283	38,082	38,365
September 30, 2014	253	37,002	37,255
September 30, 2015	220	33,150	33,370
Proved Undeveloped Reserves:			
September 30, 2012	—	4,418	4,418
September 30, 2013	—	3,233	3,233
September 30, 2014	—	1,222	1,222
September 30, 2015	—	352	352

The Company's proved undeveloped (PUD) reserves increased from 512 Bcfe at September 30, 2014 to 827 Bcfe at September 30, 2015. PUD reserves in the Marcellus Shale increased from 504 Bcfe at September 30, 2014 to 825 Bcfe at September 30, 2015. The Company's total PUD reserves were 35% of total proved reserves at September 30, 2015, up from 27% of total proved reserves at September 30, 2014.

The Company's PUD reserves increased from 452 Bcfe at September 30, 2013 to 512 Bcfe at September 30, 2014. PUD reserves in the Marcellus Shale increased from 432 Bcfe at September 30, 2013 to 504 Bcfe at September 30, 2014. The Company's total PUD reserves were 27% of total proved reserves at September 30, 2014, down from 29% of total proved reserves at September 30, 2013.

The increase in PUD reserves in 2015 of 315 Bcfe is a result of 496 Bcfe in new PUD reserve additions (494 Bcfe from the Marcellus Shale), 26 Bcfe in upward revisions to remaining PUD reserves, offset by 168 Bcfe in PUD conversions to developed reserves and 39 Bcfe in PUD reserves removed. The PUD reserves removed were primarily in the Marcellus Shale (37 Bcfe) in Tioga County, where the Company has no near term plans to develop these reserves as it is employing capital elsewhere. An additional 2 Bcfe (279 Mbbl) of PUD reserves were removed at the Midway Sunset field in the Tulare reservoir as the Company has no near term plans to develop these reserves as it is employing capital elsewhere.

The increase in PUD reserves in 2014 of 60 Bcfe is a result of 290 Bcfe in new PUD reserve additions (288 Bcfe from the Marcellus Shale), 20 Bcfe in PUD reserves acquired, 12 Bcfe in upward revisions to remaining PUD reserves, offset by 229 Bcfe in PUD conversions to developed reserves and 33 Bcfe in PUD reserves removed. The PUD reserves removed were primarily in the Marcellus Shale (24 Bcfe) in Seneca's non-operated joint venture in Clearfield County where the operator had previously drilled and cased the horizontal wells to total depth and does not appear now to have firm plans for their completion. An additional 9 Bcfe (1,501 Mbbl) of PUD reserves were removed at the Midway Sunset field in the Tulare reservoir as the Company has no near term plans to develop these reserves as it is employing capital elsewhere.

The Company invested $162 million during the year ended September 30, 2015 to convert 168 Bcfe (184 Bcfe including revisions) of PUD reserves to developed reserves. This represents 33% of the PUD reserves booked at September 30, 2014. The Company invested $180 million during the year ended September 30, 2014 to convert 229 Bcfe (248 Bcfe including revisions) of September 30, 2013 PUD reserves to proved developed reserves. This represented 51% of the PUD reserves booked at September 30, 2013. In 2016, the Company estimates that it will invest approximately $166 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting. Since that rule, and over the last five years, the Company developed 47% of its beginning year PUD reserves in fiscal 2011, 33% of its beginning year PUD reserves in fiscal 2012, 39% of its beginning year PUD reserves in fiscal 2013, 51% of its beginning year PUD reserves in fiscal 2014 and 33% of its beginning year PUD reserves in fiscal 2015.

At September 30, 2015, the Company does not have a material concentration of proved undeveloped reserves that have been on the books for more than five years at the corporate level, country level or field level. All of the Company's proved reserves are in the United States.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, in accordance with the SEC's final rule on Modernization of Oil and Gas Reporting, it is based on the unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
United States			
Future Cash Inflows	$ 6,916,775	$ 10,001,545	$ 8,943,942
Less:			
Future Production Costs	2,854,142	2,795,657	2,334,393
Future Development Costs	761,922	790,033	749,876
Future Income Tax Expense at Applicable Statutory Rate	1,117,433	2,434,370	2,113,101
Future Net Cash Flows	2,183,278	3,981,485	3,746,572
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	860,244	1,914,607	1,780,206
Standardized Measure of Discounted Future Net Cash Flows	$ 1,323,034	$ 2,066,878	$ 1,966,366

The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

	Year Ended September 30		
	2015	2014	2013
		(Thousands)	
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	$ 2,066,878	$ 1,966,366	$ 1,469,791
Sales, Net of Production Costs	(318,753)	(626,960)	(526,630)
Net Changes in Prices, Net of Production Costs	(1,752,843)	(38,723)	339,655
Extensions and Discoveries	266,159	381,008	390,255
Changes in Estimated Future Development Costs	164,510	68,731	6,117
Purchases of Minerals in Place	—	34,705	—
Sales of Minerals in Place	(1)	(691)	—
Previously Estimated Development Costs Incurred	161,833	179,502	148,535
Net Change in Income Taxes at Applicable Statutory Rate	545,442	(231,807)	(130,574)
Revisions of Previous Quantity Estimates	(16,573)	55,184	34,864
Accretion of Discount and Other	206,382	279,563	234,353
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 1,323,034	$ 2,066,878	$ 1,966,366

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions (2)	Balance at End of Period
Year Ended September 30, 2015					
Allowance for Uncollectible Accounts	$ 31,811	$ 9,316	$ 2,585	$ 14,683	$ 29,029
Year Ended September 30, 2014					
Allowance for Uncollectible Accounts	$ 27,144	$ 10,856	$ 3,241	$ 9,430	$ 31,811
Year Ended September 30, 2013					
Allowance for Uncollectible Accounts	$ 30,317	$ 5,568	$ 2,390	$ 11,131	$ 27,144

(1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.

(2) Amounts represent net accounts receivable written-off.

Item 9 *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2015.

Management's Annual Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2015. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework,* published in 2013. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2015.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2015. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2015 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B ***Other Information***

None.

PART III

Item 10 ***Directors, Executive Officers and Corporate Governance***

The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2019," "Directors Whose Terms Expire in 2018," "Directors Whose Terms Expire in 2017," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and has posted such Code of Business Conduct and Ethics on the Company's website, www.nationalfuelgas.com, together with certain other corporate governance documents. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees, and Corporate Governance Guidelines will be made available free of charge upon written request to Investor Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuelgas.com.

Item 11 ***Executive Compensation***

The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

Item 12 ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Equity Compensation Plan Information

The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading "Equity Compensation Plan Information" and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(b) Security Ownership of Management

The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(c) Changes in Control

None.

Item 13 ***Certain Relationships and Related Transactions, and Director Independence***

The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading "Director Independence" and is incorporated herein by reference.

Item 14 ***Principal Accountant Fees and Services***

The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading "Audit Fees" and is incorporated herein by reference.

PART IV

Item 15 ***Exhibits and Financial Statement Schedules***

(a)1. Financial Statements

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)2. Financial Statement Schedules

Financial statement schedules filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)3. Exhibits

All documents referenced below were filed pursuant to the Securities Exchange Act of 1934 by National Fuel Gas Company (File No. 1-3880), unless otherwise noted.

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:

Exhibit Number	Description of Exhibits
•	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2013)
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended June 12, 2014 (Exhibit 3.1, Form 8-K dated June 16, 2014)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999)
•	Officer’s Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008)
•	Officer’s Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009)
•	Officer’s Certificate establishing 4.90% Notes due 2021, dated December 1, 2011 (Exhibit 4.4, Form 8-K dated December 1, 2011)
•	Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2013)
•	Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York Mellon (formerly The Bank of New York), as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008)
•	Letter of Appointment of Wells Fargo Bank, National Association, as Successor Rights Agent, dated July 18, 2012 (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2012)
10	Material Contracts:
10.1	Second Amended and Restated Credit Agreement, dated as of September 30, 2015, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent.

Exhibit Number	Description of Exhibits
•	Amended and Restated Credit Agreement, dated as of January 6, 2012, among the Company, the Lenders Party Thereto, and JPMorgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2012)
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
•	Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008)
	Management Contracts and Compensatory Plans and Arrangements:
•	Amendment to the Director Services Agreement between the Company and David F. Smith, dated March 12, 2015 (Exhibit 10.1, Form 8-K dated March 16, 2015)
•	Director Services Agreement between the Company and David F. Smith, dated March 13, 2014 (Exhibit 10.1, Form 8-K dated March 18, 2014)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of David P. Bauer, Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2008)
•	Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006)
•	Description of September 17, 2009 restricted stock award (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2009)
•	Description of post-employment medical and prescription drug benefits (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2009)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006)
•	Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006)
•	Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)

Exhibit Number	Description of Exhibits
•	Form of Restricted Stock Award Notice under the National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2010)
•	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 8-K dated March 16, 2015)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2010)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
•	Form of Restricted Stock Unit Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2012)
•	Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2008)
•	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)
•	Description of performance goals under the Amended and Restated National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2012)
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective February 26, 2015 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2015)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)

Exhibit Number	Description of Exhibits
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)
•	Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997)
•	Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998)
•	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005)
•	National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007)
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999)
•	Life Insurance Premium Agreement, dated September 17, 2009, between the Company and David F. Smith (Exhibit 10.1, Form 8-K dated September 23, 2009)
•	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997)

Exhibit Number	Description of Exhibits
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010)
10.2	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated August 13, 2015
•	National Fuel Gas Company 2012 Performance Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2012)
•	Description of long-term performance incentives for the period October 1, 2011 to September 30, 2014 under the National Fuel Gas Company 2012 Performance Incentive Program (Item 5.02, Form 8-K dated March 13, 2012)
10.3	Amended and Restated National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan, dated September 18, 2015
•	Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006)
•	Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006)
•	Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006)
•	Description of 2014 performance goals under the National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2013)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2014)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2014)

Exhibit Number	Description of Exhibits
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2013)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2013)
•	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2013)
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2011 through 2015
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
99.2	Company Maps
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2015, 2014 and 2013, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2015, 2014 and 2013 (iii) the Consolidated Balance Sheets at September 30, 2015 and September 30, 2014, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2015, 2014 and 2013 and (v) the Notes to Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

National Fuel Gas Company
(Registrant)

By /s/ R. J. Tanski
R. J. Tanski
President and Chief Executive Officer

Date: November 20, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	
/s/ D. F. Smith D. F. Smith	Chairman of the Board and Director	Date: November 20, 2015
/s/ P. C. Ackerman P. C. Ackerman	Director	Date: November 20, 2015
/s/ D. C. Carroll D. C. Carroll	Director	Date: November 20, 2015
/s/ S. E. Ewing S. E. Ewing	Director	Date: November 20, 2015
/s/ J. N. Jaggers J. N. Jaggers	Director	Date: November 20, 2015
/s/ R. W. Jibson R. W. Jibson	Director	Date: November 20, 2015
/s/ C. G. Matthews C. G. Matthews	Director	Date: November 20, 2015
/s/ J. W. Shaw J. W. Shaw	Director	Date: November 20, 2015
/s/ R. J. Tanski R. J. Tanski	President, Chief Executive Officer and Director	Date: November 20, 2015
/s/ D. P. Bauer D. P. Bauer	Treasurer and Principal Financial Officer	Date: November 20, 2015
/s/ K. M. Camiolo K. M. Camiolo	Controller and Principal Accounting Officer	Date: November 20, 2015

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Amendment No. 1

Form 10-K/A

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended September 30, 2015

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to
Commission File Number 1-3880

National Fuel Gas Company

(Exact name of registrant as specified in its charter)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6363 Main Street Williamsville, New York	**14221**
(Address of principal executive offices)	*(Zip Code)*

(716) 857-7000

Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $1.00 per share, and Common Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $4,935,145,000 as of March 31, 2015.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2015: 84,633,992 shares.

For the Fiscal Year Ended September 30, 2015

CONTENTS

EXPLANATORY NOTE

The Company is filing this Amendment No. 1 on Form 10-K/A solely to include in its Form 10-K for the fiscal year ended September 30, 2015 ("2015 Form 10-K") an auditor's report on the financial statement schedule and to refile, without modification, the financial statement schedule, which was originally included in Item 8 of the Company's 2015 Form 10-K, in Item 15(a)2 to accompany the auditor's report.

PART IV

Item 15 ***Exhibits and Financial Statement Schedules***

(a)2. **Financial Statement Schedules**

Report of Independent Registered Public Accounting Firm on Financial Statement Schedule

To the Board of Directors and Shareholders of National Fuel Gas Company

Our audits of the consolidated financial statements and of the effectiveness of internal control over financial reporting referred to in our report dated November 20, 2015 appearing in the 2015 Annual Report on Form 10-K of National Fuel Gas Company also included an audit of the financial statement schedule listed in Item 15(a)2 of this Form 10-K/A. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/PricewaterhouseCoopers LLP
Buffalo, New York
November 20, 2015

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions (2)	Balance at End of Period
Year Ended September 30, 2015					
Allowance for Uncollectible Accounts	$ 31,811	$ 9,316	$ 2,585	$ 14,683	$ 29,029
Year Ended September 30, 2014					
Allowance for Uncollectible Accounts	$ 27,144	$ 10,856	$ 3,241	$ 9,430	$ 31,811
Year Ended September 30, 2013					
Allowance for Uncollectible Accounts	$ 30,317	$ 5,568	$ 2,390	$ 11,131	$ 27,144

(1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.
(2) Amounts represent net accounts receivable written-off.

(a)3. Exhibits

All documents referenced below were filed pursuant to the Securities Exchange Act of 1934 by National Fuel Gas Company (File No. 1-3880), unless otherwise noted.

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:
•	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2013)
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended June 12, 2014 (Exhibit 3.1, Form 8-K dated June 16, 2014)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999)
•	Officer’s Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008)
•	Officer’s Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009)
•	Officer’s Certificate establishing 4.90% Notes due 2021, dated December 1, 2011 (Exhibit 4.4, Form 8-K dated December 1, 2011)
•	Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2013)
•	Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York Mellon (formerly The Bank of New York), as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008)

- Letter of Appointment of Wells Fargo Bank, National Association, as Successor Rights Agent, dated July 18, 2012 (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2012)

10 Material Contracts:

- Second Amended and Restated Credit Agreement, dated as of September 30, 2015, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2015)
- Amended and Restated Credit Agreement, dated as of January 6, 2012, among the Company, the Lenders Party Thereto, and JPMorgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2012)
- Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
- Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008)

Management Contracts and Compensatory Plans and Arrangements:

- Amendment to the Director Services Agreement between the Company and David F. Smith, dated March 12, 2015 (Exhibit 10.1, Form 8-K dated March 16, 2015)
- Director Services Agreement between the Company and David F. Smith, dated March 13, 2014 (Exhibit 10.1, Form 8-K dated March 18, 2014)
- Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of David P. Bauer, Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
- Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2008)
- Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006)
- Description of September 17, 2009 restricted stock award (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2009)
- Description of post-employment medical and prescription drug benefits (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2009)
- National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
- Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005)
- Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006)
- Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006)
- Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006)
- Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008)

- Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008)
- Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)
- Form of Restricted Stock Award Notice under the National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2010)
- Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005)
- National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 8-K dated March 16, 2015)
- Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2010)
- Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
- Form of Restricted Stock Unit Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2012)
- Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2008)
- Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2011)
- National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)
- Description of performance goals under the Amended and Restated National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2012)
- National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
- Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective February 26, 2015 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2015)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)

- Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)
- Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
- Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)
- Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005)
- National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997)
- Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998)
- Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998)
- Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005)
- National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005)
- National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999)
- Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999)
- Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999)
- Life Insurance Premium Agreement, dated September 17, 2009, between the Company and David F. Smith (Exhibit 10.1, Form 8-K dated September 23, 2009)
- National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995)
- Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997)

- Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998)
- Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999)
- Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008)
- Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010)
- Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated August 13, 2015 (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2015)
- National Fuel Gas Company 2012 Performance Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2012)
- Description of long-term performance incentives for the period October 1, 2011 to September 30, 2014 under the National Fuel Gas Company 2012 Performance Incentive Program (Item 5.02, Form 8-K dated March 13, 2012)
- Amended and Restated National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan, dated September 18, 2015 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2015)
- Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006)
- Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006)
- Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006)
- Description of 2014 performance goals under the National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2013)
- Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2014)
- Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2014)

•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2013)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2013)
•	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2013)
12	Statements regarding Computation of Ratios:
•	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2011 through 2015 (Exhibit 12, Form 10-K for the fiscal year ended September 30, 2015)
21	Subsidiaries of the Registrant:
•	Subsidiaries of the Registrant (Exhibit 21, Form 10-K for the fiscal year ended September 30, 2015)
23	Consents of Experts:
•	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation (Exhibit 23.1, Form 10-K for the fiscal year ended September 30, 2015)
•	Consent of Independent Registered Public Accounting Firm (Exhibit 23.2, Form 10-K for the fiscal year ended September 30, 2015)
23.3	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
•	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Exhibit 32••, Form 10-K for the fiscal year ended September 30, 2015)
99	Additional Exhibits:
•	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation (Exhibit 99.1, Form 10-K for the fiscal year ended September 30, 2015)
•	Company Maps (Exhibit 99.2, Form 10-K for the fiscal year ended September 30, 2015)
101	Interactive Data File:
•	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2015, 2014 and 2013, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2015, 2014 and 2013 (iii) the Consolidated Balance Sheets at September 30, 2015 and September 30, 2014, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2015, 2014 and 2013 and (v) the Notes to Consolidated Financial Statements. (Exhibit 101, Form 10-K for the fiscal year ended September 30, 2015)

- Incorporated herein by reference as indicated.

  All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in the Annual Report on Form 10-K for fiscal year ended September 30, 2015.

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

National Fuel Gas Company
(Registrant)

By /s/ R. J. Tanski

R. J. Tanski
President and Chief Executive Officer

Date: March 3, 2016

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-202877 and 333-198156) and Form S-8 (Nos. 333-206899, 333-202878, 333-165569, 333-51595, 333-55124, 333-102211, 333-102220, 333-117131, 333-130281 and 333-143701) of National Fuel Gas Company of our report dated November 20, 2015 relating to the financial statement schedule, which appears in this Form 10-K/A.

/s/ PricewaterhouseCoopers LLP

Buffalo, New York
March 3, 2016

EXHIBIT 31.1

CERTIFICATION

I, R. J. Tanski, certify that:

1. I have reviewed this Amendment No. 1 on Form 10-K/A of National Fuel Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

Date: March 3, 2016

/s/ R. J. Tanski
R. J. Tanski
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, D. P. Bauer, certify that:

1. I have reviewed this Amendment No. 1 on Form 10-K/A of National Fuel Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

Date: March 3, 2016

/s/ D. P. Bauer
D. P. Bauer
Treasurer and Principal Financial Officer

NATIONAL FUEL GAS COMPANY

SUMMARY ANNUAL REPORT 2015

STRUCTURED FOR SUCCESS

From the very beginning of the natural gas business to today's shale-driven energy renaissance, National Fuel continues to be one of the enduring mainstays in an industry and a region that has seen its share of successes and challenges. National Fuel's proven ability to create and capitalize on opportunities across the natural gas value chain has been supported by the strength and flexibility of its integrated model. From the bottom of the wellbore to the customer's burner tip, National Fuel has structured its collective group of businesses in a unique manner that leverages its geography, quality asset base and talented workforce. The result is a highly efficient, innovative organization driven by a common vision for long-term sustainable growth. In fiscal 2015, National Fuel's integrated model provided financial stability in the face of market volatility. Built upon a strong foundation, the Company is positioned for a period of strategic growth, to prosper and play a meaningful role through the next chapter of the natural gas industry.

Cover: The Tuscarora Lateral pipeline project—one of three major expansions of National Fuel's interstate pipeline system in 2015—installed 17 miles of new pipe to connect the Empire Pipeline system to Supply Corporation.

INTEGRATED OPERATIONS

National Fuel is an integrated energy company with a complementary mix of natural gas assets located in the heart of the prolific Appalachian basin supplemented by quality oil-producing assets in California. National Fuel's integrated operations are strategically **balanced** to promote strength and **stability** through times of change and volatility, while also providing the flexibility to adapt and capitalize on opportunities for **growth** in almost any business cycle. In the current environment, National Fuel is leveraging its vast upstream resources, valuable midstream footprint and reliable downstream operations to responsibly position the Company as a key player in America's energy renaissance.

UPSTREAM

790,000
NET ACRES
Marcellus Acreage

3,000
MBBL/YEAR
California Oil Production

MIDSTREAM

3.8+
BCF/DAY
Contracted Interstate Pipeline Capacity

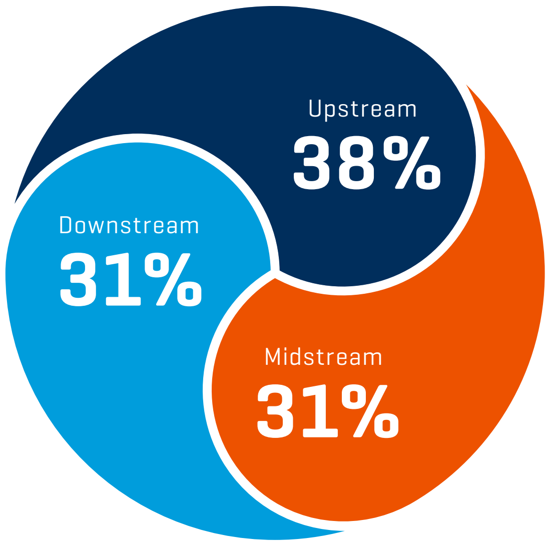
1.2+
BCF/DAY
Gathering System Capacity

DOWNSTREAM

740,000
Customer Accounts

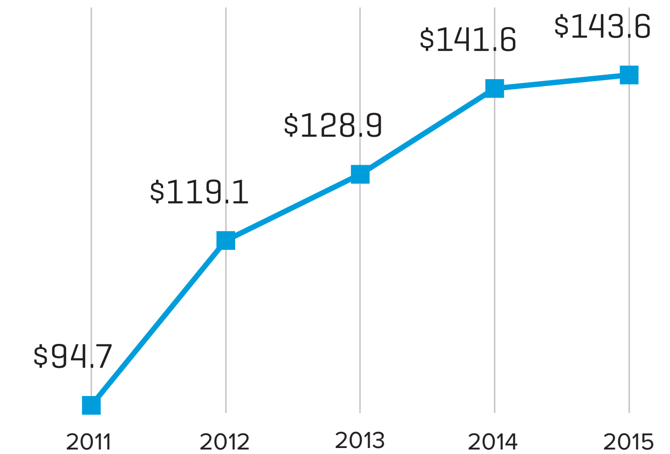
BALANCE

Percent of Consolidated Total Assets by Segment



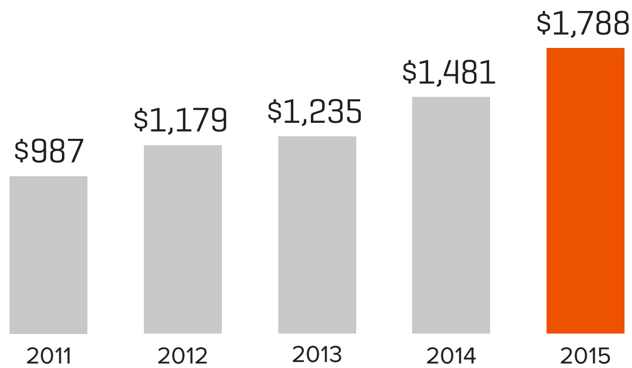
STABILITY

Utility and Pipeline & Storage Net Income (Millions)

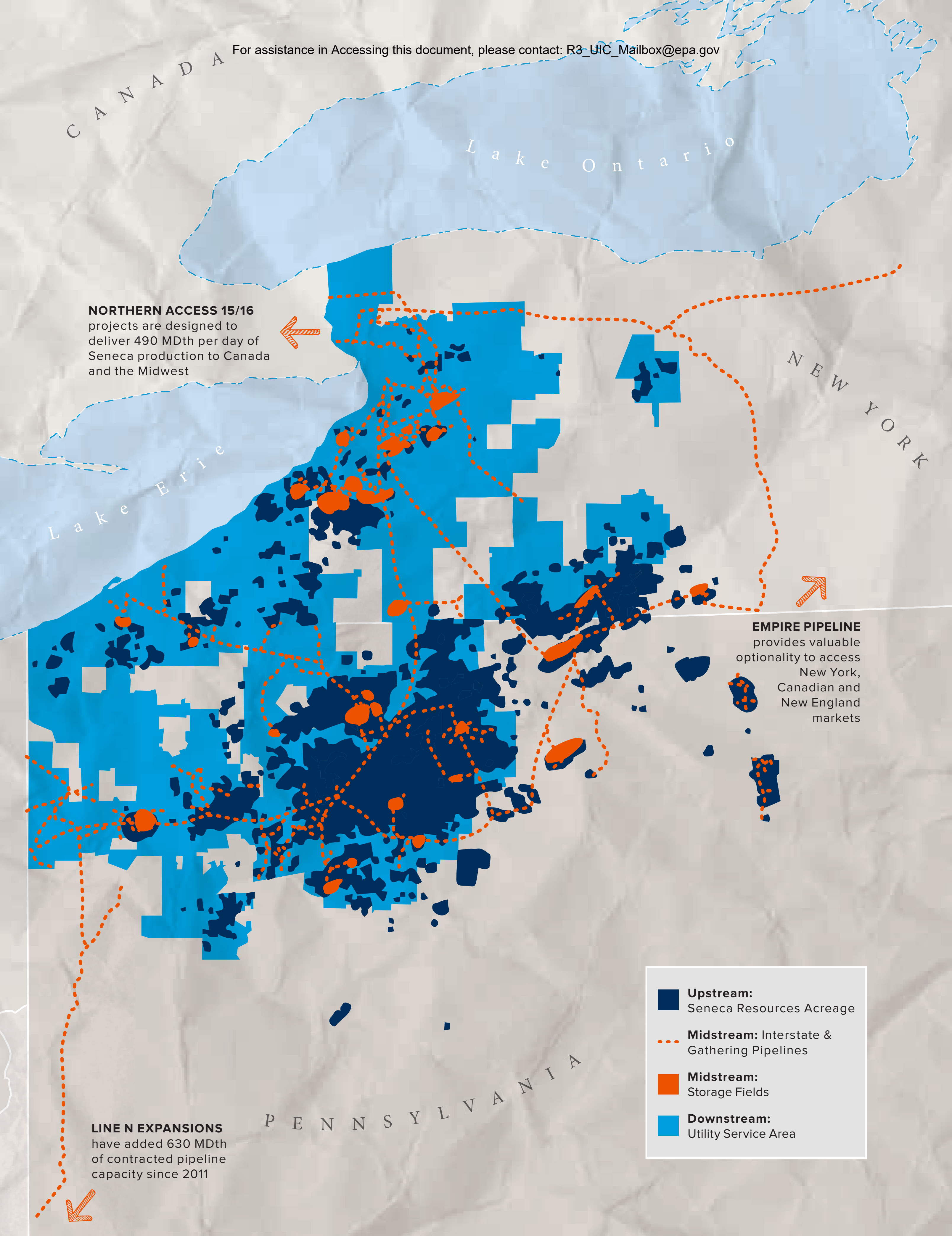


GROWTH

Midstream Businesses Net Plant (Millions)



For assistance in Accessing this document, please contact: R3_UIC_Mailbox@epa.gov



UPSTREAM

National Fuel's upstream business is conducted through its exploration and production subsidiary Seneca Resources Corporation, with operations in Appalachia and California. In 2015, Seneca accelerated development of its large acreage position in northwest Pennsylvania—a 720,000-acre tract called the Western Development Area (WDA)—resulting in another successful year of growing its reserves and decreasing its per-well drilling costs. The rig pictured here is drilling on a WDA multi-well pad in Clermont, Pa., a continued area of focus for Seneca's development.

MIDSTREAM

National Fuel's midstream operations are carried out by the Pipeline & Storage segment subsidiaries, National Fuel Gas Supply Corporation and Empire Pipeline, Inc., and by the gathering subsidiary National Fuel Gas Midstream Corporation. Through these companies, National Fuel is expanding its pipeline systems in Appalachia to provide producers, including Seneca, with a critical link to higher-priced markets. Pictured here, a component of the Clermont Gathering System helps ensure that Seneca's production from a remote area of Pennsylvania has a reliable path to the interstate pipeline system.

DOWNSTREAM

National Fuel's utility and energy marketing subsidiaries, operated by National Fuel Gas Distribution Corporation and National Fuel Resources, Inc., provide safe and reliable natural gas services to residential, commercial and industrial customers in New York and Pennsylvania. Due to the abundant supply of natural gas produced from prolific shale, customers benefited from low prices, contributing to an increase in commercial, industrial and normalized residential usage. Safety remains the Utility's highest priority. Year-round, employees upgrade and replace pipelines as part of ongoing system modernization, as pictured here in Buffalo, N.Y.

Ron Tanski, President & CEO, is pictured along Supply Corporation's NM-44 line in Elma, N.Y., where four miles of transmission pipeline were replaced in 2015 as part of the Company's ongoing modernization and safety program.

FELLOW SHAREHOLDERS

In my letter to you last year, I was excited to report that National Fuel Gas Company had achieved a number of significant milestones. Despite a period of weakening commodity prices, those milestones highlighted our ability to successfully operate and profit from our business model—an integrated collection of diverse assets across the natural gas value chain. I outlined a strategy that would leverage the stability of our integrated model and our world-class Appalachian footprint to navigate what was looking to be a difficult road ahead and turn near-term headwinds into opportunities for the long term.

Fiscal 2015 was indeed a challenging year for National Fuel and the energy industry as a whole. The continued decline in natural gas and crude oil prices, which led our Exploration & Production segment to curtail production and record a series of significant non-cash writedowns of our oil and gas properties, distracted from what was otherwise a very successful year of operations for the Company.

The stability and balance provided by our rate-regulated Utility and Pipeline & Storage segments, along with solid revenues from our California oil fields and a strong hedge position for the majority of our production, provided a layer of protection to the Company's recurring earnings and cash flows that few companies in our industry enjoy. While we expect commodity prices to remain a headwind for producers over the near term, I am pleased to report that your Company remains strong, focused and well positioned to execute our strategy for long-term growth.

The energy industry, including National Fuel, has seen operational success in developing vast quantities of domestic crude oil and long-lived reserves of clean-burning natural gas that has caused a steady and drastic decline in market prices for those commodities. Looking ahead, fiscal 2016 will likely be another challenging year for the industry. National Fuel and peer companies developing natural gas reserves in the Marcellus Shale continue to drill more productive wells at a faster rate and lower cost, consistently exceeding lofty industry growth forecasts while outstripping both consumer demand and takeaway capacity available on pipelines.

The industry is also discovering that another, potentially more prolific, resource lies beneath the Marcellus Shale. Recent well test results from the Utica Shale — including an outstanding well we drilled and tested in Tioga County, Pa., last March — suggest there can be decades or more of natural gas production, in addition to the copious reserves that we expect to extract from the Marcellus.

Incredibly, in just about 10 years, the industry and our economy has been fortunate to transition from a paradigm of declining domestic natural gas supplies to one of energy abundance and opportunity. National Fuel has been a major participant in this transition, developing and growing our natural gas reserves in Pennsylvania, building a Gathering segment from the ground up, and expanding and renewing our interstate pipeline systems to accommodate the new flow of production. Our utility customers and local communities continue to benefit from lower natural gas bills, increased economic output, and ready access to a clean and reliable energy source.

Any period of rapid change, however, is certain to result in a number of growing pains. Over the past decade, the energy industry — from producers to pipeline operators — enjoyed the benefits of both a myriad of growth opportunities and easy access to cheap capital. Markets and investors rewarded producers for achieving growth in production with little concern for earnings and cash flows. Some pipeline operators, with a backlog of expansion projects, looked to financial engineering as a means to accelerate their growth. Meanwhile, the rapidly growing industry, fueled by an influx of capital, could not hide from the basic fundamentals of supply and demand — a force that has helped drive natural gas and oil prices to recent lows and sparked a stock market sell-off of energy companies.

National Fuel remains strong, focused and well positioned to execute our strategy for long-term growth.

While National Fuel has not been immune to the recent downturn in the energy sector, we have been careful through this period to not overextend ourselves. We have prudently managed and structured our business over the years to prepare for and withstand these types of economic shocks. Our integrated model provides the strength through our rate-regulated businesses to weather volatile markets. It also provides the flexibility through our strategic upstream and midstream footprint in Appalachia to quickly react and adapt our plans to the changing environment. Our balanced business model has served us well in the current downturn, and is one that we will rely on as we continue to grow the company.

We are mindful of the impact of low commodity prices on our near-term financial results, but we remain confident that the best long-term opportunity for National Fuel resides in our strategy to coordinate the development of our upstream and midstream assets in Appalachia. In fiscal 2015, we made significant progress executing this strategy. For the first time, National Fuel's annual capital investments surpassed $1 billion, with a substantial share allocated to the midstream side of our business to develop attractive, lower-risk pipeline expansion opportunities and accelerate our investment in system safety and modernization. In fiscal 2016, midstream capital expenditures are expected to eclipse our spending on upstream drilling for the first time since we started our Marcellus development.

Fiscal 2015 marked a successful year of upstream and midstream development of our mineral acreage position in northwest Pennsylvania, a massive 720,000-acre tract we call the Western Development Area (WDA). The large, contiguous nature of our holdings allows us to enjoy significant economies of scale. Since 2012, Seneca Resources has decreased the average well cost per lateral foot by more than 50 percent, demonstrating the competitive advantage of our acreage position, especially in a lower gas price environment.

Seneca's success through the drill bit has contributed to a period of unprecedented growth for our midstream businesses. In fiscal 2015, the Gathering segment invested nearly $120 million to ensure that Seneca's production has a reliable path to the interstate pipeline system. We plan to invest another $125 million in fiscal 2016 to accommodate an anticipated 400 percent increase in production output from the WDA by the end of 2017.

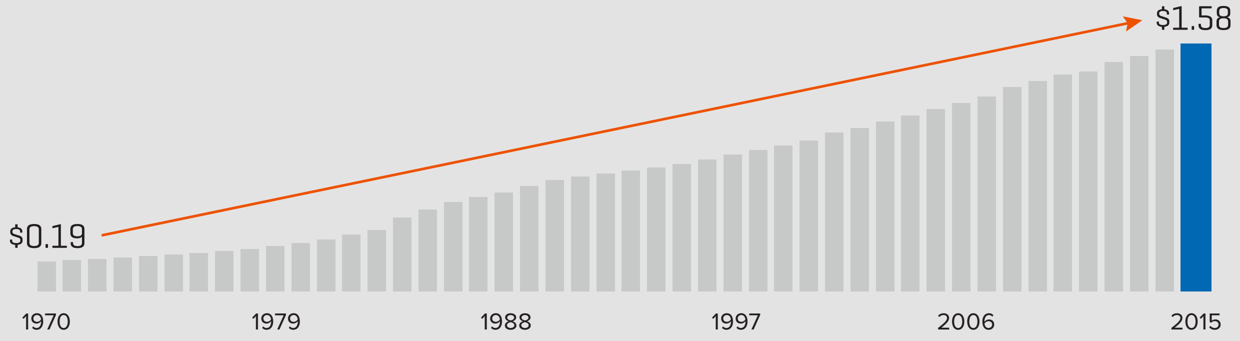
The Pipeline & Storage segment continues to capitalize on its geographic footprint in Appalachia. This past year, we constructed three major expansion projects at strategic points across the system, including the Northern Access 2015 project that is moving Seneca's gas to Canada. In fiscal 2016, we expect to begin construction on our Northern Access 2016 expansion project, the single largest pipeline project in the Company's history and a core component of our Appalachian growth strategy. The two Northern Access projects are critical links in a strategy to transport Seneca's natural gas production to premium-priced, demand-driven markets and to use our own pipeline infrastructure as the preferred path to get there.

Helping to further cement this strategy, Seneca entered into a joint development agreement last month with a partner to help fund the development of up to 80 wells in the WDA. A strategic move in response to the low natural gas price environment, the agreement will meaningfully reduce our near-term upstream capital requirements while maintaining a trajectory of production growth from the area that will fully utilize the gathering infrastructure and pipeline capacity we are building for Seneca.

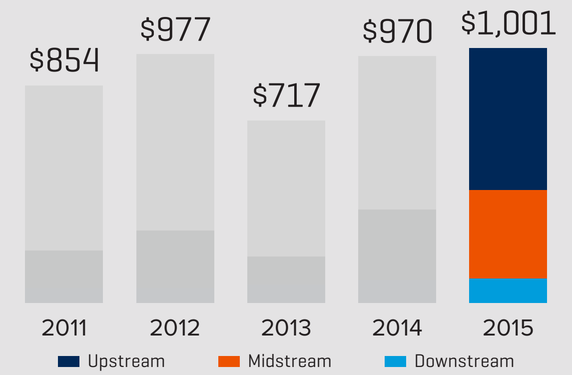
While the financial markets sort through the new supply-and-demand dynamics, the public and our elected officials are wrestling with how the energy renaissance, fueled by shale production, impacts current national priorities of climate change, economic growth, and security. The positives are clear and indisputable: Technological advances and investment have yielded an abundance of clean-burning natural gas right under our feet, leading to energy security, job growth, and economic prosperity across the country. Natural gas provides affordable energy, incenting industry to expand and make our local economy more competitive,

FORTY-FIVE YEARS OF DIVIDEND INCREASES

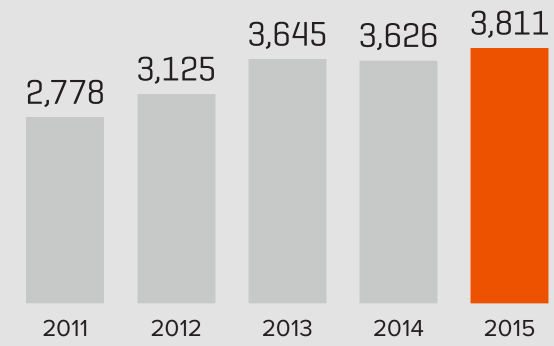
Annual Rate at Fiscal Year-end



INVESTING IN OUR FUTURE
Consolidated Capital Expenditures (Millions)



INTERSTATE PIPELINE TRANSPORTATION CAPACITY UNDER CONTRACT
(MDth per day)



and provides the opportunity to significantly reduce carbon emissions in an environmentally sensitive and sustainable fashion.

Nevertheless, this period of transformation has generated a number of questions from local communities regarding the perceived health and environmental impacts of natural gas drilling practices and pipeline construction. Through a consistent and comprehensive outreach program, the Company has sought to allay these concerns by providing factual information about the development process.

National Fuel has played a significant role in the safe development and delivery of energy in Western New York and northwestern Pennsylvania for more than 100 years. Thousands of National Fuel employees, retirees, and shareholders, and their families, call the region home. We have also produced millions of barrels of oil from our fields in California over the last 28 years and have been recognized as California Operator of the Year by the U.S. Department of the Interior. We are committed to safe, environmentally sound and responsible energy development so that its benefits can be enjoyed for generations. While there are some who decry the continued development of energy from hydrocarbons, our 740,000 customers demand that we keep the gas flowing, particularly during the coldest days of the winter. The safety of our customers, our employees and the communities where we operate continues to be our highest priority. We are proud of our record on safety and environmental stewardship, and we will continue to foster a culture that embraces continuous improvement.

Throughout National Fuel's 113-year history, and just during my 36-year career, the energy industry has gone through multiple cycles. The current imbalance between supply and demand that has forced natural gas prices lower will eventually correct, driven by investments in infrastructure and an inevitable increase in demand for a cleaner, affordable and reliable energy source. While this may take some time, National Fuel remains committed to proceeding responsibly so that we do not sacrifice long-term value for short-term gain. We also remain committed to our dividend, which we have paid without interruption since 1902 and have increased in each of the last 45 years.

Our diversified assets provide us with a solid foundation for continued growth. While the middle part of this decade may be remembered for chronically low commodity prices and volatile stock markets, I believe this period will ultimately be defined by timely investment, responsible development and quality execution of a strategy that will benefit National Fuel shareholders and stakeholders for years to come.

Ronald J. Tanski

Ronald J. Tanski
President and Chief Executive Officer

January 5, 2016

National Fuel is an energy company with a proud 113-year history of operating profitably and responsibly in the Appalachian region. From the early energy boom following Colonel Drake's 1859 discovery of oil in Titusville, Pa., through the glory days of the steel industry, Appalachian oil, coal and natural gas fueled the unprecedented growth of the U.S. economy. The standard of living we enjoy today is made possible by the vast supply of North American energy resources. Natural gas is the cleanest form of hydrocarbon energy available today, and is increasingly being used to generate electricity across North America. National Fuel's business is focused on the continued responsible development and transportation of this abundant and affordable energy source. Federal regulations being proposed by the current administration, however, are seeking to reduce this country's reliance on energy produced with hydrocarbons.

We believe it is possible to achieve long-term prosperity for our shareholders and stakeholders alike in an environmentally sustainable fashion. Our approach to **sustainability** is built on three primary tenets — **strategy**, **safety** and **stewardship** — all firmly anchored in National Fuel's uniquely integrated structure and carefully balanced to foster innovation, accountability and the resilience to thrive in any business environment. The current industry cycle may be testing the strength and endurance of our model, but fiscal 2015 proved to be a textbook illustration of how well National Fuel has assimilated these principles into everyday practice.

> The standard of living we enjoy today is made possible by the vast supply of North American energy resources.

National Fuel's **strategy** for sustainable growth and success in the rapidly evolving American energy sector is simple: We will continue to responsibly capitalize on the many opportunities afforded by our vast natural gas resource and interstate pipeline footprint in the prolific Appalachian basin. Our diverse assets allow us to flex the level, timing and focus of our upstream and midstream investments in a manner that maximizes value creation across the organization. The execution of this strategy will proceed at a pace that is financially prudent and appropriately balances environmental concerns and the long-term interests of all Company stakeholders — shareholders, employees, customers and community members.

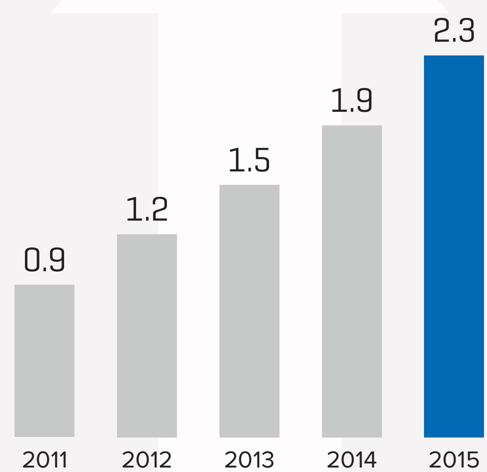
National Fuel employees, Laura Homann and Jim Boccio, discuss plans along a portion of the Line N Westside Expansion and Modernization project in Beaver County, Pa.

Midstream Expansions Driving Significant Growth

Fiscal 2015 proved to be the Company's busiest year yet for expansion projects in our Pipeline & Storage segment. In western Pennsylvania, Supply Corporation expanded its Line N system for the fifth consecutive year, increasing capacity to move Marcellus production to major interconnects. Empire Pipeline built the Tuscarora Lateral project— a new 17-mile pipeline along the New York–Pennsylvania border that connects Empire Pipeline to Supply Corporation, affording Empire customers with additional service options. Finally, Supply Corporation completed the Northern Access 2015 project, providing Seneca access to premium Canadian markets. All three projects were completed on budget, despite challenging weather conditions during the construction season, and placed in service shortly after the close of fiscal 2015.

156% Increase

in Total Proved Reserves Since 2011



Total Proved Reserves at year-end (Tcfe)

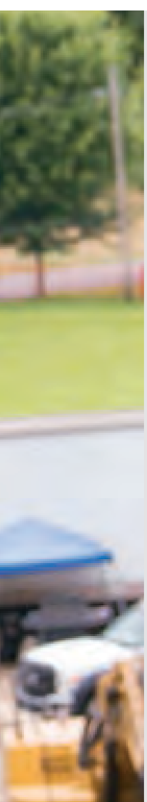
The cornerstone of National Fuel's strategy lies beneath a 720,000-acre area in northwest Pennsylvania we call the Western Development Area (WDA). While the size of the acreage position alone makes this asset unique, National Fuel also owns, rather than leases, the mineral rights underlying a majority of the acreage, relieving the Company from royalties and drilling commitments. Perhaps more importantly, the WDA's close proximity to National Fuel's extensive interstate pipeline network provides the Company's midstream businesses an opportunity to invest in new infrastructure to deliver our production to higher-priced demand markets.

After five years of successful development in the Eastern Development Area (EDA) — where National Fuel's upstream subsidiary Seneca Resources drilled 150 wells in the Marcellus Shale and grew production to more than 400 MMcf per day — Seneca shifted its focus to a key 200,000-acre block in the WDA that

$142 MILLION Invested in pipeline safety and modernization during fiscal 2015

Employees and contractors take part in a daily safety meeting during construction of the Mercer Compressor Station in Mercer County, Pa.

National Fuel engineers, Christian Kanaley and Taylor Kieffer, review pipeline construction reports on the Tuscarora Lateral project in Steuben County, N.Y.



Modernization Initiatives Enhancing Delivery Network

With the support of its state and federal regulatory commissions, National Fuel has long been an industry leader in pipeline integrity initiatives. In fiscal 2015, the Utility replaced a total of 122 miles of bare steel and cast iron main lines and 4,199 bare steel service lines across both service territories. The Pipeline & Storage segment has leveraged the construction of its expansion projects as an opportunity to also modernize portions of its pipeline network while limiting environmental impact. In fiscal 2015, Supply Corporation invested $45 million in modernization efforts, including the replacement of a 23-mile stretch of pipe in connection with the ongoing expansion of the Line N system in western Pennsylvania.

we refer to as the greater Clermont/Rich Valley area. In addition to attractive geological attributes, the highly contiguous nature of the WDA acreage provides Seneca with a significant competitive advantage to optimize well designs and drive operating efficiencies. The acreage has yielded an economic drilling inventory in excess of 1,200 Marcellus wells — approximately 20 years of development at our current activity levels — with further development potential in the Utica Shale down the road.

The results from Seneca's development activities in the WDA have been impressive. In 2015, Seneca grew its proved natural gas reserves by 27 percent while decreasing its Marcellus finding and development cost — the capital cost to drill and produce 1 Mcf of gas — from $1.00/Mcf in 2014 to $0.79/Mcf. Since 2012, Seneca has decreased its Marcellus average well cost by 34 percent, from $8.7 million to $5.7 million, despite drilling wells that have significantly longer laterals. Going forward, Seneca plans to maintain a pace of development that further optimizes its cost structure while carefully coordinating the timing of production growth to match the availability of contracted pipeline capacity.

As Seneca continues its WDA development, the Company's Gathering segment has been busy designing and building the gathering and compression facilities necessary to deliver Seneca's production to the interstate pipeline system. In 2015, the Gathering segment invested $118 million into its systems for Seneca — almost all of which was directed towards the ongoing build-out of the Clermont Gathering System. With plans for more than 100 miles of pipeline and 60,000 horsepower of compression facilities, the multi-year Clermont expansion is being closely coordinated with Seneca's drilling plans to maximize capital efficiency and accommodate more than 1 Bcf per day of production.

As natural gas prices in the Appalachian basin continue to trade at deep discounts to NYMEX-quoted prices, the Company's Pipeline & Storage segment has been actively expanding its interstate pipeline system to move Seneca and third-party production out of the basin to reach higher-priced markets. Over the course of 2015, the Pipeline & Storage segment invested $142 million to expand various portions of its system for Marcellus producers and utility customers. All placed in service shortly after the close of the fiscal year, these projects added more than 360 MMcf per day of incremental transportation capacity, including 140 MMcf per day for Seneca on Supply Corporation's Northern Access 2015 project, and will generate incremental annual revenues in excess of $30 million.

Looking ahead to fiscal 2016, National Fuel expects to commence construction on the Northern Access 2016 expansion project. At an expected capital cost of $455 million, Northern Access 2016 will be the largest single system expansion — measured by both investment and added capacity — in National Fuel's history. The project, built exclusively for Seneca's WDA production, is designed to transport and deliver 490 MMcf per day of production to premium-priced markets, including Canada, the Midwest and the Northeast U.S. The Northern Access expansions will complete a critical link in a strategy that will allow Seneca's Appalachian production and the throughput of the Gathering segment to nearly double, while meaningfully growing the Pipeline & Storage segment, over a period of just a few short years.

National Fuel expects to continually grow its midstream businesses. We remain positioned to play a key role in the ongoing build-out of necessary energy infrastructure in Appalachia as our extensive pipeline system and storage facilities are geographically situated to provide valuable optionality and connectivity to a number of major interstate pipelines in the Northeast.

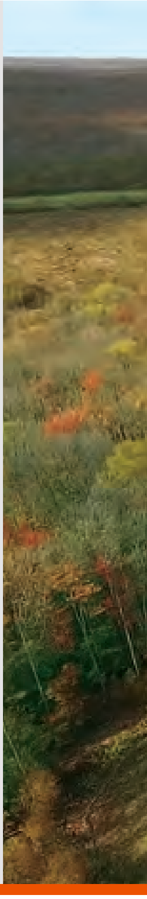
While the unprecedented growth and expansion in Appalachia continues to capture the headlines, National Fuel's highest priority has been, and always will be, the **safety** of our customers, employees and the public in the communities where we operate. Building on a strong track record of pipeline integrity management and infrastructure renewal, in fiscal 2015 National Fuel's Utility and Pipeline & Storage segments invested $54 million and $88 million, respectively, in the safety and maintenance of the Company's pipelines, modernizing utility mains and services, and portions of its interstate pipeline system.

As the natural gas utility serving a region known for its severe winters, National Fuel understands that our customers depend on us for safe, reliable service no matter the circumstance. In fiscal 2015, the Utility's operations and systems were tested once again with record-breaking snow storms and unusually cold temperatures. And once again, National Fuel and its employees met the challenge, limiting the number and duration of any service disruptions and responding swiftly to emergency situations. National Fuel continues to be a leader in emergency response times in New York state, and meets and often exceeds established performance targets for customer service, such as customer satisfaction, percent of appointments kept and telephone response time.

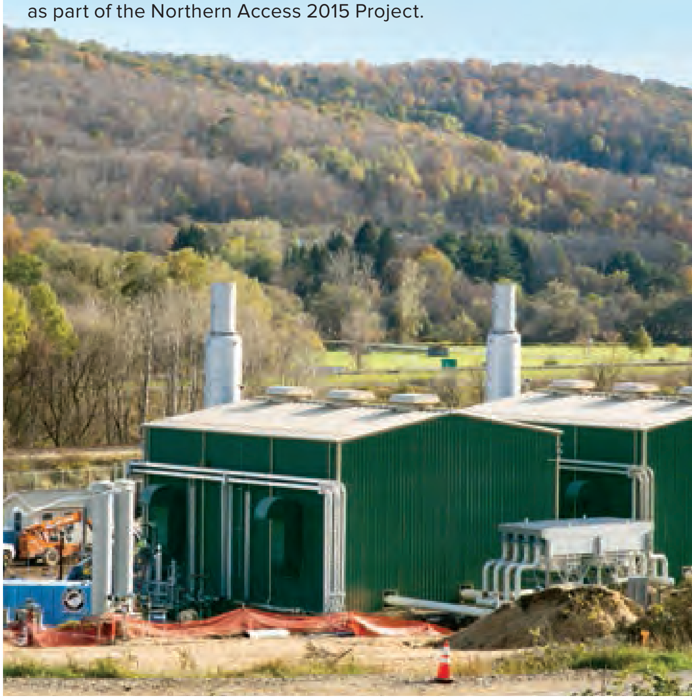
National Fuel is committed to fostering a culture that embraces continuous attention to, and improvement in, all aspects of safety. In fiscal 2015, National Fuel achieved its lowest rate of reportable workplace injuries since the Company has kept such records — a noteworthy result given the year's extreme weather

Seneca Innovation Reducing Costs and Environmental Footprint

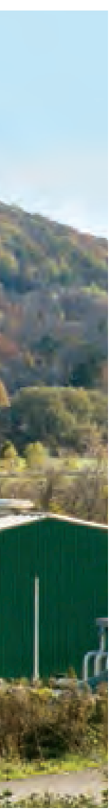
In an effort to reduce costs and the environmental footprint of its WDA drilling program, Seneca started its own water logistics company, Highland Field Services, to manage the handling of a substantial portion of fluids used in its operations. Having invested $20 million in infrastructure — including a centralized storage facility, a treatment plant and a pipeline delivery network — Seneca has significantly reduced the amount of fresh water it uses in drilling operations by reusing produced fluids in future well completions. Seneca also uses Highland's pipeline delivery network to transport water from its centralized storage facilities directly to Seneca's well pads, reducing truck traffic on local roadways. Moving forward, Seneca has a target that fresh water will account for no more than 50 percent of fluids used in well completions, and expects that the recycling of produced fluids can save an average of $0.5 million per well.



The Hinsdale Compressor Station, shown here under construction, will provide $1.7 million in annual property taxes for schools and municipalities near Hinsdale, N.Y., as part of the Northern Access 2015 Project.

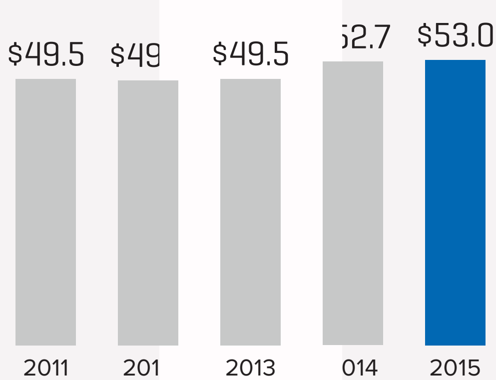


Seneca s centralized water facility, located in Clermont, Pa., handles water sourcing, recycling and transportation logistics for Seneca s drilling operations in the WDA.



$250+ Million

in Property Taxes Paid to NY and PA Schools and Municipalities Since 2011



events and number of capital projects. Enhanced training, mandatory daily construction site safety briefings, and the authority for any employee to halt work on a job site are just a few of the many initiatives the Company has implemented through the years to make National Fuel a safe place to work.

We are keenly aware that our development activities must be done in an environmentally sensitive fashion, minimizing the impact to natural resources and local communities. Many of the Company's employees, retirees, and shareholders, and generations of their families have made their homes in the areas where we operate. We believe that **stewardship** of our valuable natural resources is our duty, which means taking proactive measures to protect the environment.

National Fuel's ongoing commitment to environmental stewardship has been abundantly evident in its natural gas drilling operations in the Marcellus Shale. The large, contiguous nature of Seneca's acreage position in the WDA has allowed Seneca to achieve significant cost savings and operating synergies, and is also helping Seneca to reduce its environmental footprint. Seneca's planned placement of well pads, roads and

28% Increase in industrial customer usage per account since 2011


Morton Salt, a large industrial utility customer in Silver Springs, N.Y., converted its coal-fired boiler to natural gas in 2015.

National Fuel is a Vested Community Partner

National Fuel, a vital community partner and one of the region's largest and most stable locally headquartered companies, employs 2,125 people across its subsidiaries and is woven into the fabric of the communities in which we operate. Over the past five years, the Company has invested more than $4 billion in energy infrastructure and paid more than $250 million in property taxes. The Company and its employees in New York, Pennsylvania, Texas and California, through the National Fuel Gas Company Foundation, have donated more than $12 million to local and national charitable organizations since 2005. As America's energy rebirth coincides with the economic renaissance of the region, National Fuel is excited to continue its long-standing partnership with the proud people and businesses who call these regions home.

A restored right-of-way along the Line N Westside Expansion and Modernization project in Washington County, Pa.

Utility employees, Andrew Klingensmith and Chris Kushner, work in downtown Buffalo, N.Y., an area experiencing substantial economic development and growth.

other infrastructure, and its ability to drill more and longer wells from a single pad location, minimizes land disturbance. Seneca continues to develop innovative solutions, such as those designed to address fresh water consumption and the reuse of produced fluids. These have resulted in significant benefits to both the environment and the Company's bottom line.

The volume of natural gas infrastructure projects in the Appalachian region is also generating increased attention from local communities and regulatory agencies concerning perceived health and environmental impacts.

We believe that stewardship of our valuable natural resources is our duty.

National Fuel minimizes these impacts throughout the entire construction process associated with the expansion of its pipeline network. National Fuel is employing a wide range of modern technologies and engineering practices to design and operate compressor facilities and interstate pipelines in a manner that complies with the stringent regulatory requirements for safety, air emissions, noise levels and other environmental considerations.

The positive economic and environmental impacts of natural gas are leading to a growing demand for commercial and industrial conversions in the Company's utility service territories in New York and Pennsylvania. Since 2011, normalized industrial usage has increased 28 percent—a result of the Company's access to the largest producing basin in North America. National Fuel's downstream Utility and Energy Marketing segments stand positioned to supply the regional economy with clean-burning, low-cost natural gas.

As we navigate a challenging and uncharted stretch for the industry, National Fuel's long-term vision is clear. With every well drilled, mile of pipeline installed and customer served, National Fuel strives to advance **sustainability** through the thoughtful, responsible development of natural gas resources in a way that elevates the quality of life in our local communities. The foundation of our vision is rooted in the Company's unique integrated model. While others have pursued different paths over the years, National Fuel has deliberately maintained its integrated model as a stable platform that promotes the financial strength and flexibility to adapt in any business environment and pursue opportunities for long-term growth and value.

PRINCIPAL OFFICERS

NATIONAL FUEL GAS COMPANY

Ronald J. Tanski
President and Chief Executive Officer

Matthew D. Cabell
Senior Vice President

James D. Ramsdell
Senior Vice President

Paula M. Ciprich
Senior Vice President, General Counsel and Secretary

David P. Bauer
Treasurer and Principal Financial Officer

Karen M. Camiolo
Controller and Principal Accounting Officer

Donna L. DeCarolis
Vice President
Business Development

UPSTREAM

SENECA RESOURCES CORPORATION

Matthew D. Cabell
President

John P. McGinnis
Chief Operating Officer

David P. Bauer
Treasurer

Cindy D. Wilkinson
Controller and Secretary

Steven J. Conley
Senior Vice President

Bradley D. Elliott
Vice President

Jeffrey J. Formica
Vice President

Douglas Kepler
Vice President

Justin I. Loweth
Vice President

Dale A. Rowekamp
Vice President

Kevin M. Ryan
Vice President

Steven Wagner
Vice President

MIDSTREAM

NATIONAL FUEL GAS SUPPLY CORPORATION

John R. Pustulka
President

David P. Bauer
Treasurer

James R. Peterson
Secretary and General Counsel

Karen M. Camiolo
Controller

Ronald C. Kraemer
Vice President

Sarah J. Mugel
Vice President and Assistant Secretary

Steven Wagner
Vice President

EMPIRE PIPELINE, INC.

Ronald C. Kraemer
President

James R. Peterson
Secretary

David P. Bauer
Treasurer

Karen M. Camiolo
Controller

Steven Wagner
Vice President

NATIONAL FUEL GAS MIDSTREAM CORPORATION

Duane A. Wassum
President

James R. Peterson
Secretary

David P. Bauer
Treasurer

Karen M. Camiolo
Controller

Michael D. Colpoys
Vice President

Steven Wagner
Vice President

DOWNSTREAM

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Anna Marie Cellino
President

Carl M. Carlotti
Senior Vice President

Paula M. Ciprich
Secretary

Jay W. Lesch
Senior Vice President

David P. Bauer
Treasurer

Karen M. Camiolo
Vice President and Controller

Joseph N. Del Vecchio
Vice President and Chief Regulatory Counsel

Jeffrey F. Hart
Vice President

Michael W. Reville
Vice President and General Counsel

Steven Wagner
Vice President

Ann M. Wegrzyn
Vice President

NATIONAL FUEL RESOURCES, INC.

Bruce D. Heine
Senior Vice President

Steven Wagner
Vice President

R. Don Cash — Retires after 13 Years as a Director
Having served as Company Director since 2003, Don contributed significantly to National Fuel's strategic direction. His decades of industry experience and expertise proved invaluable to the Company over the past 13 years.

We thank Don for his commitment to National Fuel and offer our sincere gratitude for his valuable guidance. Although Don's tenure has come to a close, he will continue to be a respected member of the National Fuel family.

DIRECTORS

Philip C. Ackerman[3,5*]
Former Chairman of the Board of Directors, Chief Executive Officer, President and Principal Financial Officer of the Company. Director of Associated Electric and Gas Insurance Services Limited. Past Director of the Business Council of New York State, prior Chairman of the Erie County Industrial Development Agency and current member of the Board of Managers of the Buffalo Society of Natural Sciences. *Company Director since 1994.*

David C. Carroll[3,4]
President and Chief Executive Officer of Gas Technology Institute. President of the International Gas Union as the United States prepares to host the 2018 World Gas Conference in Washington, D.C. Former Director of Versa Power Systems, Inc. Member of the Society of Gas Lighting. Chairman of the steering committee for the 17th International Conference and Exhibition on Liquefied Natural Gas in Houston (2013). *Company Director since 2012.*

Stephen E. Ewing[1,2*,5]
Lead Independent Director. Former Vice Chairman of DTE Energy Company. Former President and Chief Operating Officer of MCN Energy Group Inc. and former President and Chief Executive Officer of DTE Gas Company (formerly known as Michigan Consolidated Gas Company). Director of CMS Energy. Past Trustee and Chairman of the Board of The Skillman Foundation. Immediate past Chairman of the Auto Club of Michigan (AAA) and Chairman of the Board of the Auto Club Group (AAA). Former Chairman of the American Gas Association, the Midwest Gas Association and the Natural Gas Vehicle Coalition, and former member of the National Petroleum Council. *Company Director since 2007.*

Joseph N. Jaggers[1]
President, Chief Executive Officer and Chairman of Jagged Peak Energy LLC. Former President and Chief Executive Officer of Ute Energy, LLC. Former Director, President and Chief Operating Officer of Bill Barrett Corporation. Former Vice President, Exploration & Production, for Williams Companies. Former President and Chief Operating Officer of Barrett Resources prior to its sale to Williams Companies. Former Independent Director of Mission Resources Corporation. Past President of the Colorado Oil and Gas Association and past Executive Director of the Independent Producers Association of the Mountain State and inductee into the Rocky Mountain Oil and Gas Hall of Fame. *Company Director since June 2015.*

Ronald W. Jibson[2,4*]
Chairman, President and Chief Executive Officer of Questar Corporation. Chief Executive Officer of Questar Gas Company, President and Chief Executive Officer of Wexpro Company and Chairman and Chief Executive Officer of Questar Pipeline Company. Board member of IDACORP, Inc. Board member of Gas Technology Institute. Past Chairman of the Board of Directors of the American Gas Association and past Chairman of the Western Energy Institute. Chairman of Utah State University's Board of Trustees and past Chair of the Salt Lake Chamber Board of Directors. Past Chair of the Economic Development Corporation of Utah. *Company Director since 2014.*

Craig G. Matthews[1*,2,3,5]
Former President, Chief Executive Officer and Director of NUI Corporation. Former Vice Chairman, Chief Operating Officer and Director of KeySpan Corporation. Former Director of Hess Corporation (formerly Amerada Hess Corporation), Republic Financial Corporation and Staten Island Bancorp, Inc. Member and former Chairman of the Board of Trustees of Polytechnic Institute of New York University, member and founding Chairman of the New Jersey Salvation Army Advisory Board, and former member, for 18 years, of the National Salvation Army Advisory Board. Trustee of Odyssey Networks. *Company Director since 2005.*

Jeffrey W. Shaw[1,4]
Director and former Chief Executive Officer and President of Southwest Gas Corporation. Member of the American Institute of Certified Public Accountants, the Nevada Society of CPAs and the Leadership Las Vegas Alumni Association. Serves on the boards of the UNLV Foundation, the Council for a Better Nevada and the Las Vegas Economic Club. Former Board member of the American Gas Association. Past president of the Western Energy Institute and past president of the Las Vegas Area Council of the Boy Scouts of America. *Company Director since 2014.*

David F. Smith[3*,5]
Chairman of the Board of the Company. Former Executive Chairman of the Board of the Company, and former Chairman, Chief Executive Officer and President of the Company. Board member of Gas Technology Institute (Executive Committee and Audit Committee), the Business Council of New York State (Vice Chair and immediate past Chairman of the Board of Directors, and member of the Executive Committee) and the State University of New York at Buffalo Law School Dean's Advisory Council. Former Director of the American Gas Association. *Company Director since 2007.*

Ronald J. Tanski[3,5]
President and Chief Executive Officer of the Company. Former Chief Operating Officer, Treasurer and Principal Financial Officer. Member and immediate past Chairman of the Board of Directors of the Interstate Natural Gas Association of America (INGAA). Director of the American Gas Association. Member of the Council on Accountancy at Canisius College. Member on the Board of Managers of the Buffalo Museum of Science and a Director of the Buffalo Niagara Enterprise. *Company Director since 2014.*

1 Member of Audit Committee
2 Member of Compensation Committee
3 Member of Executive Committee
4 Member of Nominating/ Corporate Governance Committee
5 Member of Financing Committee
* Denotes Committee Chairman

FINANCIAL AND OPERATING HIGHLIGHTS

National Fuel Gas Company Year Ended September 30	**2015**	2014	2013	2012	2011
Operating Revenues (Thousands)	**$ 1,760,913**	$ 2,113,081	$ 1,829,551	$ 1,626,853	$ 1,778,842
Net Income (Loss) Available for Common Stock (Thousands)	**(379,427)** (1)	299,413 (2)	260,001 (3)	220,077 (4)	258,402 (5)
Return on Average Common Equity (6)	**(17.1%)**	13.0%	12.5%	11.4%	14.2%
Per Common Share					
Basic Earnings (Loss)	**$ (4.50)**	$ 3.57	$ 3.11	$ 2.65	$ 3.13
Diluted Earnings (Loss)	**$ (4.50)**	$ 3.52	$ 3.08	$ 2.63	$ 3.09
Dividends Paid	**$ 1.55**	$ 1.51	$ 1.47	$ 1.43	$ 1.39
Dividend Rate at Year-End	**$ 1.58**	$ 1.54	$ 1.50	$ 1.46	$ 1.42
Book Value at Year-End	**$ 23.94**	$ 28.64	$ 26.23	$ 23.52	$ 22.85
Common Shares Outstanding at Year-End	**84,594,383**	84,157,220	83,661,969	83,330,140	82,812,677
Weighted Average Common Shares Outstanding					
Basic	**84,387,755**	83,929,989	83,518,857	83,127,844	82,514,015
Diluted	**84,387,755**	84,952,347	84,341,220	83,739,771	83,670,802
Average Common Shares Traded Daily	**482,631**	451,731	385,586	558,000	534,526
Common Stock Price					
High	**$ 72.21**	$ 78.79	$ 69.27	$ 64.19	$ 75.98
Low	**$ 48.61**	$ 65.23	$ 48.51	$ 41.57	$ 48.67
Close	**$ 49.98**	$ 69.99	$ 68.76	$ 54.04	$ 48.68
Net Cash Provided by Operating Activities (Thousands)	**$ 853,580**	$ 909,390	$ 738,572	$ 659,010	$ 653,952
Total Assets (Thousands)	**$ 6,702,139**	$ 6,728,040	$ 6,204,977	$ 5,925,694	$ 5,215,358
Capital Expenditures per Statements of Cash Flows (Thousands)	**$ 1,018,179**	$ 914,417	$ 703,461	$ 1,035,007	$ 814,278
Volume Information					
Production					
Gas – MMcf	**139,563**	142,307	103,693	66,131	50,467
Oil – Mbbl	**3,034**	3,036	2,831	2,870	2,860
Total – MMcfe	**157,767**	160,523	120,679	83,351	67,627
Proved Reserves					
Gas – MMcf	**2,142,128**	1,682,884	1,299,515	988,434	674,922
Oil – Mbbl	**33,722**	38,477	41,598	42,862	43,345
Total – MMcfe	**2,344,460**	1,913,746	1,549,103	1,245,606	934,992
Pipeline & Storage Throughput – MMcf					
Gas Transportation	**750,080**	735,995	579,802	371,139	319,954
Gathering Volume – MMcf					
Gathered Volume	**139,629**	138,726	93,449	48,562	29,988
Utility Throughput – MMcf					
Gas Sales	**72,434**	73,892	67,903	64,099	73,857
Gas Transportation	**78,749**	80,949	69,149	61,027	66,273
Energy Marketing Volume – MMcf					
Gas	**46,752**	52,694	46,875	45,756	52,893
Average Number of Utility Retail Customers	**591,098**	584,415	587,760	599,106	609,126
Average Number of Utility Transportation Customers	**148,877**	153,407	147,431	133,467	122,474
Number of Employees at September 30	**2,125**	2,010	1,912	1,874	1,827

(1) Includes impairment of oil and gas producing properties of ($650.2) million and includes reversal of stock-based compensation expense of $5.2 million.

(2) Includes a $3.6 million gain on life insurance policies.

(3) Includes a $4.9 million refund provision related to the Utility segment's New York rate proceeding.

(4) Includes elimination of other post-retirement regulatory liability of $12.8 million.

(5) Includes gain on sale of unconsolidated subsidiaries of $31.4 million.

(6) Calculated using average Total Comprehensive Shareholder Equity.

INVESTOR INFORMATION

COMMON STOCK TRANSFER AGENT AND REGISTRAR
Wells Fargo Shareowner Services
P.O. Box 64856
St. Paul, MN 55164-0856
Tel. **800-648-8166**
Website: **http://www.shareowneronline.com**
Email: **stocktransfer@wellsfargo.com**

Change of address notices and inquiries about dividends should be sent to the Transfer Agent at the address listed above.

NATIONAL FUEL DIRECT STOCK PURCHASE AND DIVIDEND REINVESTMENT PLAN
National Fuel offers a simple, cost-effective method for purchasing shares of National Fuel stock. A prospectus, which includes details of the Plan, can be obtained by calling, writing or emailing the administrator of the Plan, Wells Fargo Shareowner Services, at the address listed above.

INVESTOR RELATIONS
Investors or financial analysts desiring information should contact:

David P. Bauer
Treasurer
Tel. **716-857-7318**

Brian M. Welsch
Director of Investor Relations
Tel. **716-857-7875**
Email: **WelschB@natfuel.com**
National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

ADDITIONAL SHAREHOLDER REPORTS
Additional copies of this report, the 2015 Form 10-K, and the 2015 Financial and Statistical Report can be obtained without charge by writing to or calling:

Paula M. Ciprich
Corporate Secretary
Tel. **716-857-7548**

Brian M. Welsch
Director of Investor Relations
Tel. **716-857-7875**
National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

STOCK EXCHANGE LISTING
New York Stock Exchange
(Stock Symbol: NFG)

TRUSTEE FOR DEBENTURES
The Bank of New York Mellon
Attention: Corporate Trust
101 Barclay Street, 7W
New York, NY 10286

ANNUAL MEETING
The Annual Meeting of Stockholders will be held at 9:30 a.m. (local time) on Thursday, March 10, 2016, at The Ritz-Carlton Golf Resort, 2600 Tiburón Drive, Naples, FL 34109. Stockholders of record as of the close of business on January 11, 2016, will receive a formal notice of the meeting, proxy statement and proxy.

INDEPENDENT ACCOUNTANTS
PricewaterhouseCoopers LLP
726 Exchange Street
Suite 1010
Buffalo, NY 14210

UNITS OF MEASURE

Bcf	Billion cubic feet (of natural gas)
Dth	Dekatherm (Approx. 1 Mcf of natural gas)
Mbbl	Thousands of barrels (of crude oil)
Mcf	Thousand cubic feet (of natural gas)
MMcf	Million cubic feet (of natural gas)
MDth	Thousands of dekatherms (of natural gas)
MMcfe	MMcf equivalent (of natural gas and crude oil)
Tcfe	Trillion cubic feet equivalent (of natural gas and crude oil)

This Summary Annual Report contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in the Company's Form 10-K at Item 7, MD&A, under the heading "Safe Harbor for Forward-Looking Statements," and with the "Risk Factors" included in the Company's Form 10-K at Item 1A. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction and other projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may" and similar expressions.

Forward-looking statements include estimates of oil and gas quantities. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of oil and gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized.

This Summary Annual Report and the statements contained herein are submitted for the general information of stockholders and employees of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith. For up-to-date investor information, please visit the Investor Relations section of National Fuel Gas Company's Corporate website at http://www.nationalfuelgas.com. If you would like to receive news releases automatically by email, simply visit the News section and subscribe.

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National Fuel

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NYSE: NFG